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CHAPTER 3 - VERMONT'S ENERGY USE: PAST, PRESENT, AND FUTURE

To understand the unique challenges and opportunities facing Vermont as we plan our energy future, this chapter focuses on Vermont's past, present, and future energy use. Section one of this chapter presents a history of Vermont's energy sources and background information about recent energy legislation and statewide energy planning. The second section analyzes Vermont's current energy use among sectors, end uses, and fuels, presents graphs of the state's energy use during the past 20 years, and outlines how future trends and issues will influence energy use. Section three presents a base case forecast of Vermont's expected energy use during the next 20 years, given expected changes in the state's economy and population. Chapter 3 thus provides a resource for future energy decisions based on information about our past, present, and possible future energy use patterns.

I. HISTORY AND BACKGROUND

Looking back at our history can create a new understanding of where we have come from and the problems and opportunities that have been encountered. Reflecting on the past also sets current conditions and challenges in perspective and helps in the process of generating new ideas and solutions. In this section, we review some of the major trends and milestones in Vermont's use of energy sources since the time of the state's early settlements. This review of past events is an important preliminary step in assessing our current situation and directing future energy decision making, topics addressed in sections II and III of this chapter.

A. Energy Sources and Uses During Earlier Times

Prior to 1900, Vermont's energy sources were primarily wood, flowing water, and coal. After 1900, electricity and automobile transportation began to play an important role, and the pace of technological change began to increase. As the demand for electricity expanded, new resources for producing it were developed, and growing transportation networks allowed new energy sources to be imported. This overview of energy in earlier times is divided into two parts; major energy sources and uses before 1900 and those after 1900.

1. Pre-1900 Energy Sources

Native Americans lived in the northeastern area of the present U.S. for hundreds of years before Europeans arrived. These early inhabitants used wood fires for cooking, heating, and making pottery. They built canoes to travel the lakes and waterways of northern New England. A system of pathways was developed by these early inhabitants to use for trading, negotiating, fighting, and visiting. Europeans began coming into eastern Canada and the New England area after 1650, and the period from the 1670s to the 1760s was a time of conflicts and wars as the French, English, American colonists, and Native Americans tried to hold claim to areas of New England. Many Native Americans migrated to safer locations in far northern New England and Canada. After the wars with the French and British ended, settlers from the areas that would become New York, Massachusetts, and Connecticut came in growing numbers to the territory that became Vermont in order to work the land and build houses and communities, developing energy sources to meet their needs.

Vermont became a state in 1791, ending disruptions that resulted from conflicting claims between New Hampshire and New York and establishing the rule of law under the state constitution, first drafted in 1777. The constitution guaranteed clear title to land and the legislature granted charters for corporate activity. With this security, settlers came in increasing numbers. Some came with oxen or work horses and used animal power as they cleared and began working the land, but the only source of power most of the original settlers relied on was their own strength and resourcefulness. Communities formed and then grew rapidly. Finding energy sources was essential to survival and a key to success.

Wood and waterways have long been Vermont's abundant, basic energy sources. Burning wood provided heat and light from open hearths and fireplaces. Over time, numerous improvements were made to hearths, stoves, and boilers used to produce heat or mechanical power. From the early settlement period, wood has fired ovens for cooking and manufacturing. For cash-poor settlers, potash from wood burning produced an income. Later, wood powered the first steamboats and locomotives transporting passengers and merchandise in and out of the state.

In the early times, manufacture of wood products depended on another of Vermont's abundant resources: its waterways. Water-powered mills cut logs into lumber and supplemented the manual labor required to build boxes, chairs and furniture, wagons, and other wood products. Rivers were also used to transport timber to major markets. In 1786, Ira Allen constructed the first sawmill at the lower falls in Winooski, and in 1794 Steven Mallet began sending log rafts of Vermont white pines to Québec and growing markets in the north (Meeks, *Vt.'s Land and Resources*, 1986, 248-9). Smaller sawmills were built in villages and cities to meet local demand for lumber. As land was cleared of trees, it was used for construction sites for new buildings, for growing grain and food for human consumption, and for livestock, all of which created greater demand for energy.

Early settlement patterns illustrate the importance of streams and rivers. Flowing water was harnessed for mechanical power; first using the undershot wheels that moved in direct relation to the speed of the water pushing the paddles. Later, more efficient overshot wheels were predominant, designed to deliver a steady flow of water to the wheel, making the weight of the water the propelling force. Dams, flumes, and other improvements were built to increase and stabilize the water supply and to make more efficient use of water. Increasingly, waterways provided the energy to develop Vermont's prime resources -- wood, wool, and grain -- into products for local consumption and distant markets.

A pattern typical of many early Vermont communities is described in the Town of Jericho's Comprehensive Plan, 1991.

> As the wilderness that greeted the early settlers gave way to farms and supporting services, the waterpower provided by Jericho's three streams attracted settlement and industrial development along their banks. It was not long before saw mills, grist mills, woolen mills and various factories and shops appeared (Town of Jericho, 1991, 5).

At about this same time, other towns report having a pottery shop, creameries and cheese factories, carding and clothing mills, distilleries, an ashery, a starch factory, box making factories, wagon shops, etc. The mills and their water power had become the economic heart of communities.

Occasionally conflict arose over how waterways were used. In its 1787 session, the Vermont General Assembly produced a law to protect then-plentiful fisheries. According to the law, dams were not permitted that would impede fish passage, excepting "necessary mills." Nevertheless, dam building continued in earnest (Williams, 1966, 253).

In many towns, centers of commerce were built near waterfalls, and the natural flow of rivers and streams was modified to make use of potential water power. In Glover a small dam was built on the Barton River to form Mud Pond, which held water to power the mills serving the community. In an effort to increase the water level in Mud Pond, a group of townsmen went upstream to enlarge the outlet from Long Pond, the source of the Barton River. On June 6, 1810, they expanded the outlet and unintentionally released Long Pond, called Runaway Pond after this event, allowing it to rush down river and wash out most everything in its path, including much of Glover.

Use of energy from water power continued to grow despite setbacks such as Glover's washout and other floods that are recorded locally and regionally in the state during the 1800s. By the 1840s large woolen mills were operating, the American Woolen Mill on the Winooski being one of the first. With the opening of the Champlain Canal connecting the Lake with the Hudson River and southern markets, sawmilling, particularly in the western part of the state, increased rapidly, and the cost of a shipment of goods, including lumber, fell from about $30 to $10 per ton. Exports of lumber and agricultural products grew, accelerated by improved water transportation. By the 1840s, forest resources in the western part of the state were showing signs of overuse. Finished lumber became Vermont's primary product, and peak production was reached in 1873 when 170 million board feet of finished lumber was produced, ranking Burlington third in sawlog production nationally, following Chicago and Albany (Meeks, *Vt.'s Land and Resources*, 1986, 177-8, 250, 252).

<u>New Modes of Transportation and Expanding Uses for Coal</u>

Early Vermonters were eager to develop export markets for the state's resources, which required improving the primitive transportation network of trails and waterways and reducing the many natural hazards. By the 1850s, new energy sources and transportation innovation brought dramatic change to Vermont towns. As early as 1791 work had begun on the Connecticut River at Bellows Falls to make it navigable to points down river. By 1830 canals had been built at several points along the river to handle boat traffic around falls and rapids. On the west side of the state water transportation also improved with the completion of the Champlain Canal in 1823. Steamboat traffic began on the expanding network of waterways in 1809, with wood as the primary fuel. The Town of Saint Albans Plan reports that two steamboats, the Franklin and the MacDonough, were built in 1827 and 1828 by the St. Albans Steamboat Company, chartered in the fall of 1826 by the legislature. Growth of steamboat traffic in St. Albans is reported by Zadock Thompson in his 1840 *History of Vermont*:

> There is, during the summer, a daily line of steamboats, each way between this place and Burlington, by way of Plattsburgh and Port Kent. There is also a daily line of stages each way through St. Albans village, besides some which are less frequent (St. Albans Planning Commission, 1993, 11).

Vermont had no coal or oil. Both of these fuels were imported from Pennsylvania and sources further away, and efficient transportation systems were needed before it was economical to import them on a large scale. Coal shipments to Burlington began after 1850, and by the late 1850s steamboats, the first means for transporting coal, were burning primarily coal. In 1880, about 70,000 tons of coal came to the Burlington area by water. Coal shipments grew and by 1893 nearly all coal to Burlington came by rail.

Vermont's railroads grew rapidly, starting in the early 1850s. Well into the 1880s, the primary locomotive fuel was wood. Fuel depots were located along the railways, and inland wood that had formerly been valueless was bought by the railroad companies for as much as $5 per cord (Meeks, *Vt.'s Land and Resources*, 1986, 251).

Reports from the Vermont Railroad Commissioner to the General Assembly, starting in 1856, document the growth of railroads in the state and their use of wood and coal as locomotive fuel. According to the commissioner's 1856 report:

> In 1846 we commenced building our first railroad, and the last of 1849, and early part of 1850, our two great roads, the Vermont Central and the Rutland & Burlington, whose united length is 236 miles, were opened for business; and before the close of 1855, we had 500 miles of railroad in operation (Vt. Board of Railroad Commissioners, 1856, 3).

Other railroads were rapidly building, connecting Vermont with Canada, southern New England, New York, and the growing national railroad network. From their outset, the railroad companies dealt with financial situations that led to receiverships and corporate reorganizations.

Fuel use by the Vermont Central Railroad, parent company of the Central Vermont Railroad, shows a pattern of increasing fuel consumption and the conversion from wood to coal. In 1858, this railroad reported that 15,490 cords of wood were used as locomotive fuel, costing $74,279.12, or approximately $4.80 per cord (Vt. Board of Railroad Commissioners, 1858, 17). Information reported for this railroad in 1864 shows that the company used 38,614 cords to fuel its locomotives at a cost of $111,472 or $2.90/cord. In this year coal is also listed as a fuel, but none was used as a locomotive fuel. However, 40 tons of coal is reported under the category "fuel use at the stations," along with 1,721 cords of wood, indicating that the railroads first used coal to heat the passenger waiting stations. Another section of the Central Vermont Railroad's report for 1864, shown in Table 3.I.1, indicates that coal was being purchased by railroads and was starting to compete with wood by the mid-1860s.

Table 3.I.1 Excerpt from Central Vermont Railroad's Fuel Inventory, 1864

Value of Materials on Hand

22,470 cords of wood	$54,415.58	(about $2.42/cord)
56 tons of coal	$ 542.50	(about $9.70/ton)

Source: Vt. Board of Railroad Commissioners, 1864, 31-33.

During the third quarter of the 1800s, coal replaced wood as the preferred fuel for steam driven transportation, and it was also fueling manufacturing facilities and furnaces in railroad stations, businesses, and homes. By the early 1890s regular coal shipments were coming into Vermont by rail, and coal had totally replaced wood as the fuel used by locomotives. For the period 1898-1900, the Central Vermont Railroad reported 81,886 tons of bituminous coal (average cost at distribution point: $2.75/ton) as its locomotive fuel, and zero cords of wood (Vt. Board of Railroad Commissioners, 1900, 144).

As coal began to replace wood as a transportation fuel, fuel vendors also began to see their heating market transform from chunk wood to coal. The Henry M. Tuttle Company of Bennington was founded in 1857 and began selling coal to homes and businesses around the time of the Civil War. Ease of handling and higher fuel content per pound accelerated the switch. Coal was sold in several sizes -- chestnut, pea, rice, and barley -- to suit different stoves. Elaborate coal delivery systems involved bulk shipments delivered by rail and placed in silos via conveyors. Coal dust and frozen rail shipments were the fuel dealer's nightmare. By the early 1900s coal was widely used for heating purposes.

Introduction of Manufactured Gas

The use of "manufactured" gas in the 1800s is sparsely documented, but by the mid-century manufactured gas for interior and exterior lighting was available in many Vermont towns, and there were numerous municipal gas companies. The gas, produced by separating the gaseous fuel in coal from the solids, was distributed through a network of buried pipes. Since many of Vermont's early private corporations were formed through charters approved by acts of the legislature, the founding of Vermont's manufactured gas companies can be traced through the Acts and Resolves Passed by the General Assembly.

In 1852 the Vermont legislature granted the Rutland Gas Light Company:

> . . . power and authority to construct the necessary building and apparatus to manufacture gas, to be made of bituminous coal or other materials, and sell the same for the purpose of lighting the streets, buildings, manufactories, and other places situated in the village of Rutland.
>
> The corporation shall be empowered to lay down gas pipe and to erect gas posts, burners, and reflectors in the streets, alleys, lanes, avenues and public grounds . . . and to do all necessary things to light said city . . . provided public travel shall not be unnecessarily impeded . . . (and) no private property shall be taken without consent of the owner (Vt. Legislature, 1852, 143-4).

Burlington Gas Light Company was also chartered in 1852. Street lighting, promoted as "the silent policeman" and providing a compelling reason for about a dozen towns to incorporate gas companies, was not actually installed anywhere in Vermont.

Burlington Gas Light Company was in operation by 1854, and by 1855 there were gas light companies in Montpelier, Northfield, Windsor, St. Albans, and St. Johnsbury. An 1855 law provided $2,500 to bring gas lighting to the statehouse legislative chambers. The volume of gas produced and the numbers of customers served by these and numerous other similar companies are undocumented. Industrial and domestic gas lighting increased fire hazards and was by no means a clean-burning source of light, but villagers looked on the bright side; manufactured gas lighting was a modern improvement. The 1860 census reports that Burlington Gas Light Company produced 240,000 cubic feet of gas, worth $9,000, with a plant valued at $77,000 (Bassett, 1992, 83).

The growing importance of the gas light companies is also reflected in a bill that the Vermont legislature passed in November 1888, permitting gas light companies to own and operate electrical lighting systems (Tucker, 1986, 72). This bill enabled the gas light systems to get in on the newly developing market that they recognized as their serious competition. Burlington Gas Light Company expanded its business during the 1890s, and several electric companies were consolidated with this company shortly after the turn of the century. The gas operations continued, but electricity was replacing manufactured gas as the main energy source for lighting. However, as the early gas and electric companies were offering their services in the larger towns and cities, it was only a small percentage of Vermont households that had either gas or electric lighting in 1900. For the rural areas and many small towns, candles and kerosene lanterns continued as the primary source of lighting into the 1940s.

Early Electric Companies

Private Companies. One of the first reports of electric generation and use in Vermont appeared in the *Burlington Free Press* on June 6, 1881 when the Van Ness House, a Burlington hotel, began lighting its office, dining room, parlor, and veranda with four lamps using power from a 15 horsepower boiler installed on the premises. A great crowd was present when the machine was first set in motion; throughout the evening the hotel was thronged with sightseers. The newspaper reported that:

> Each light had a diffusive power equal to seventy gas jets . . . (and) in illuminating power is greatly superior to every other kind of light in use (Tucker, 1986, 52).

Another precedent-setting event occurred in 1882 in Middlebury, when a group of local businessmen received a charter from the legislature to establish the Middlebury Electric Light and Power Co.:

> . . . for the purpose of lighting the streets, public and private houses in said Middlebury and also furnishing motive power (Tucker, 1986, 53).

This Middlebury Company never became operational, but soon others' efforts to establish central generating stations and hydroelectric plants were successful.

Rutland was one of the first Vermont communities to have an operating electric distribution system. Rutland Electric Light Company was organized in 1885. It strung lines, wired buildings, and built a steam-powered generating station downtown. The October 9, 1885 edition of the *Vergennes Vermonter* reported:

> Rutland was lighted by electricity Saturday evening for the first time, by the new Electric Light Company. There are 253 Edison incandescent lamps used of thirteen candle power in about forty of the leading business houses. The light gives satisfaction (Tucker, 1986, 53).

Burlington's electric distribution system began operating in 1886, according to the *Burlington Free Press* and a corporate history prepared by Green Mountain Power. The initial system was said to consist of a two mile circuit with power supplied from a small hydroelectric station located on the Burlington side of the Winooski River. This plant was the first utility-operated hydroelectric installation in Vermont and perhaps the state's first example of hydroelectric generation (Tucker, 1986, 54).

The advent of electric energy in Montpelier follows the experience of Burlington and Rutland. In March, 1886 the Thompson-Houston Electric Company sent to Montpelier a small engine, boiler, and generator, which were mounted on a railroad flat car. Six street lights were set up and wired for the demonstration. According to a local newspaper:

> The moon hung up on a string . . . was what a little girl called the first electric light she ever saw in Montpelier (Green Mountain Power, 1984, 1).

Within a month, local businessmen started the Standard Light and Power Manufacturing Co. and in September the first lights were hung, powered by "water motors" which had been installed in the city's water mains that carried water down from Berlin Pond (Tucker, 1986, 55). This new company purchased an old mill on the Winooski in 1888, installed five waterwheels and two steam engines, and before the end of the year extended lines from this new plant to Barre. Service during these early days was available when and if the generating station was operating, which was supposed to be from nightfall to ten o'clock every evening except Saturday, when it was operated until midnight because the stores remained open longer (Tucker, 1986, 55).

Municipally-Owned Electric Companies. In additional to numerous private companies, municipally-owned electric companies started up during the early 1890s. The City of Vergennes obtained authorization from the legislature in 1886 to provide electric lights; two years later Richford and Rutland Town were authorized to purchase an electric light plant and contract for power and service to run it. Swanton, having obtained legislative authorization in 1890, was the first municipality to actually provide service. However, a private rival, Sunset Electric Co., also received authorization from the legislature to supply electricity. Following a series of public meetings to discuss the issue of lights, the town decided to proceed with developing municipal facilities for generating electricity. A municipal site was selected and the town purchased an old grist mill at Highgate Falls. In 1893 a new powerhouse was constructed along with a five mile transmission line to serve the street lights, stores and houses in Swanton village. Formal operation started in January 1894, and on February 9, 1894, the *Swanton Courier* reported that:

> The Village has the best and cheapest plant and lowest rates in the United States (Tucker, 1986, 65).

In 10 communities, the municipality took the lead in starting electric energy service so that by 1900 municipal systems were operating in the villages of Swanton, Morrisville, Hyde Park, Northfield, Enosburg Falls, Johnson, Hardwick, Lyndonville, Barton, and Wells River. Except for Wells River, these municipal electric systems continue to operate today.

Other Companies That Generated and Sold Electricity. Electric energy also became available as commercial businesses began generating electricity first for their own needs and then as a service that could be sold to the surrounding community. Woolen and grist mills generated electricity to sell and some steam traction or electric trolley companies hooked up customers along the trolley lines. (See below for more about electric trolleys.) Vermont Marble, which began generating electricity around 1890 for lights in its stone cutting sheds, soon expanded and provided service to Proctor (Tucker, 1986, 72).

2. 1900 and Following: Major Energy Sources and Uses

By 1900, Vermont's primary energy sources were electricity (generated from hydro and coal burning facilities) coal, manufactured gas, and wood, with electricity and coal steadily increasing and oil gaining usage after it became available in the 1920s. Energy markets grew rapidly, as sketched out below. Little is known about the companies that sold coal and oil, or their customers, rates, and terms of service. Similarly, little is known about the volumes and uses for wood fuel, and prices paid when wood was purchased. In contrast, more is known about the electric and gas companies because they came under state regulation after 1906, and information about the regulated companies providing service in the state began to be published in the Biennial Reports of the Public Service Commission, as required by state statute.

Coal, Oil, Kerosene, and Propane

During the first decades of this century, coal was the primary energy source for locomotive fuel, as well as for many commercial and industrial processes, and it accounted for a significant portion of home heating. Boilers built to withstand coal's high combustion temperatures hastened the introduction and installation of central heating systems, offering greater convenience and comfort in homes and businesses. In the 1910s coal was priced at $10-$15 a ton, a price that doubled over the next 30 years.

In the 1910s oil products began to break coal's grip on the heating fuel market. Long burned for rural lighting, kerosene gained market share for use in crude oil-burning stoves and furnaces. During the 1920s furnaces fired by fuel oil, which burned cleaner than kerosene, were introduced. By the 1930s, central heating systems using fuel oil were greatly improved, providing the advantage of automatic firing.

Frequently coal boilers were refitted to burn oil; many remain operating in Vermont's older homes and businesses.

The coal industry responded by bringing automatic stokers to market, but continued to lose market share to oil. For a brief period around World War II, coal regained some ground when the government warned of oil shortages that never materialized. The anthracite coal industry even subsidized the sale of coal-burning equipment in the 1950s to promote sales but never managed to gain a major portion of the market.

Kerosene, originally used for lighting, was sold at general stores for about five cents a gallon. Later, when used as a heating fuel, a delivery man would carry two 15 gallon containers at a time (210 lbs.) into customers' homes to fill the 55 gallon drums serving their furnaces and boilers. Fuel oil sold for about 10 cents a gallon in the 1930s. Bulk shipments of fuel oil into Vermont were first delivered by rail. Eventually, road tankers took over most of the rail shipment of petroleum products (Walter Noyes, retired employee of Henry M. Tuttle and Company, Rutland, personal communication, June 1995).

Liquefied petroleum gas, or propane, appeared in the Vermont fuel market just before World War II. Although it is a petroleum product like kerosene, there were several significant distinctions that weighed in its favor. Propane was odorless and much easier to handle than coal and wood, the other commonly used cooking fuels. Sold in 100 pound cylinders, propane quickly gained popularity in rural communities. Later, propane dealers in a few locations were able to acquire distribution systems built by manufactured gas companies, and propane service expanded briefly until these old distribution systems were closed down by the state for safety reasons.

Manufactured Gas and Natural Gas

After 1900, companies producing manufactured gas continued to operate in at least eight Vermont cities. Although manufactured gas was displaced as a fuel for lighting after 1920, the gas systems continued to be used for cooking, heating, and commercial purposes.

The advantages of using manufactured gas are promoted by the Rutland Chamber of Commerce in a 1926 publication, *Industrial Survey of the City of Rutland, Vermont*:

> It will also be interesting to note that the progress in the use of gas in Rutland is shown by a recent installation whereby the Hotel Bardwell is completely heated by the use of gas, and in addition all water for domestic and laundry purposes, and all steam tables and other cooking utensils are completely supplied with gas for fuel. The total boiler horse power required for heating is 96, in addition to which additional boilers are installed for the purpose of heating water and for laundry use (Rutland City, 1926, 54).

In 1931 the Public Service Commission issued General Order 18, setting standards and practices to be followed in the manufacture and sale of gas, addressing heating value, purity, pressure, pressure variations, meter testing and records, and other pertinent issues related to gas service. No funding had been authorized for the development of these initial standards, but upon request, the legislature subsequently increased the Commission's appropriation so that an investigation of property, revenue, expenses, and rates of all gas companies in the state could be done. Each of these manufactured gas companies reports rates for categories of service such as General Service, House Heating, and Industrial Service. The typical general service rate was $1.00 for the first 200 cubic feet or less per month. Companies providing gas service and the number of customers as of December 31, 1931 are shown in Table 3.I.2.

Table 3.I.2 Vermont Companies Providing Gas Service, 1931

Gas Company	Location	Customers
Capital City Gas	Montpelier	*
Central Vermont Public Service Corp.	Rutland	3,385
Green Mountain Power Corporation	Burlington	7,323
Twin State Gas & Electric Company	Bennington	1,559
Twin State Gas & Electric Company	Brattleboro	1,581
Vermont Lighting Corporation	Barre	2,142
Vermont Lighting Corporation	St. Albans	1,048
Vermont Lighting Corporation	Springfield	930

*No figures reported.
Source: Vt. PSC, 1932, 37-40 and 1934, 19-21.

The 1934 Commission notes that there has been a steady decline in the gas business and that there is a "need of some means of bringing output sold up nearer capacity of the works owned" (Vt. PSC, 1934, 21).

Later, some of the manufactured gas systems in Vermont's cities were used to distribute propane. The gas systems continued to operate (using propane instead of manufactured gas) supplying energy for cooking, water and space heating, and manufacturing processes as late as the 1960s.

In 1965 Vermont Gas Systems, Inc. obtained a certificate of public good to serve as a public utility and bring natural gas to Vermont consumers. After service began the company acquired the existing manufactured gas system in Burlington, a propane system in St. Albans, and completed construction of a natural gas transmission pipeline from the Canadian border to connect Burlington with the TransCanada pipeline system transmission.

Vermont Gas started with 6,400 customers in Franklin and Chittenden counties; gas service is available now to more than 27,000 residential and business customers for a variety of purposes including heating, water heating, cooking and clothes drying, industrial processing, electric generation, and fueling vehicles (Sheri Larsen, External Affairs Manager, Vermont Gas Systems, personal communication, June 1995).

Automobiles, Highway Transportation, and Gasoline

The automobile and the internal combustion engine that burns gasoline were introduced in Vermont in 1897, when there were 13,000 miles of public highway (Wilgus, 1945, 85). However, a law passed in 1894 entitled "An Act Related to Steam Traction Engines on Highways" indicates that steam powered precursors to the automobile were the first type of motorized vehicle to travel Vermont highways, and their impact on other modes of highway traffic was rather disruptive.

> The owner or person in charge of a carriage, vehicle or engine propelled by steam, except road rollers, shall not cause or permit the same to pass over, through, or upon any public street or highway, except upon railroad tracks, unless he sends, at least one-eighth of a mile in advance of the same, a person of mature age to notify and warn all persons travelling upon or using the street or highway with horses or other domestic animals; and at night such person shall, except in an incorporated village or city, carry a red light. A

> person violating the provision of this act shall be fined not more than ten dollars for each offence (Vt. Legislature, 1894, 71).

We have no further information to report about the steam traction vehicles that are the subject of this early example of traffic regulation, but steam powered vehicles did make a brief appearance in Vermont as evidenced by the steam wagon built by W.A. Lane in Barre in 1900 (*Vermont Life Magazine*, Autumn 1959, 12). (See Figure 3.I.1.)

At the turn of the century, gasoline-powered motor vehicles were perceived as recreational vehicles for the well-off. Automobiles were oddities on Vermont's road, which were used by pedestrians and persons riding or driving one or more horses or other draft animals. From 1900, automobiles traveling the state's public highways steadily increased. Automobiles did not initially displace either the trolleys or trains; it was horse drawn vehicles that were replaced. The growing importance and popularity of the automobile is reflected in a number of state statutes. In 1904, the legislature introduced automobile registration; driver's licenses and speed limits soon followed.

> The registration fee . . . shall be three dollars for each motor vehicle of 20 horsepower or less and five dollars for each motor vehicle of more than twenty horsepower. . . . The secretary of state shall furnish to each person registering a motor vehicle . . . two enameled iron plates . . . with the number given to such motor vehicle . . . placed before the letters "Vt." . . . The fee for a license for operating a motor vehicles shall be two dollars annually (Vt. Legislature, 1906, 110).

In his Biennial Report of 1902, the Commissioner of Highways reports on the status of roads and travel conditions.

> With improved roads we have the motor bicycle and the automobile, the latter, especially, a menace to people who travel by team. The rapidly moving automobile is a terror to most horses on the highways. One instance was brought to our notice of a heavy automobile containing four men, running 11 miles between two Vermont villages in 24 minutes. Of the runaways along the route only two proved serious. Statute law regulating the speed of horseless carriages along the highway would seem prudent (Farrington, unpublished report).

A 1906 state statute established that:

> No motor vehicle shall be run . . . in a careless or negligent manner. . . . A rate of speed exceeding 25 miles an hour outside a city or incorporated village, or at a rate of speed exceeding 10 miles an hour within a city, incorporated village or the thickly settled part of a town . . . [is] evidence that the motor vehicle was run carelessly or negligently (Vt. Legislature, 1906, 109).

By 1910, several statutes indicate that there were efforts to make traffic on the "public highways" suitable for automobiles and at the same time make automobile owners compatible with other highway users, or face fines up to one hundred dollars. For example:

> An automobile or motor vehicle while being operated shall be provided with an adequate brake, a muffler, at least two lighted lamps on the front, and one on the rear . . . which shall display a red light . . . and with a suitable bell or horn or other means of signalling;

the person in control or charge of such automobile or motor vehicle shall, in going around a curve in a highway, or on approaching an intersection of the same, signal with such bell or horn (Vt. Legislature, 1910, 138).

Figure 3.I.1 Steam Wagon, Designed and Built in Barre, Vt., 1900

Source: Reprinted with the permission of *Vermont Life Magazine*, Autumn 1959, 12.
Roads and highways were prerequisites for automobile use. Legislation established Vermont's Commissioner of Highways in 1898, and in 1906 the State Highway Department was created, followed in 1927 by the Motor Vehicle Department. Road improvements became an area of ongoing concern, particularly at railroad crossings. First the Railroad Commission and then the Public Service Commission regularly reported progress in eliminating "grade crossings" and the number of fatal and non-fatal accidents occurring annually. With increasing numbers of automobiles, railroad companies built more overpasses to eliminate "grade crossings" and reduce the number of accidents involving automobiles and trains.

The first stretch of concrete road was built in 1922 in front of Fort Ethan Allen, as a result of agitation by Army Officers for an improved highway between Winooski and Essex. With the War Department paying half the cost, and Essex Junction contributing $10,000, the Highway Board had the necessary funding for the improved road from the Fort to Essex Junction. Improvements at the Winooski end came later. Following the 1927 flood, the Highway Board and the legislature authorized an $8 million bond issue for repairing flood damaged roads and bridges. Approximately 700 projects were approved and all were completed by November 1930 at a total cost of $11.8 million in bond, federal, and local funds (Farrington, unpublished report).

The automobile had a tremendous impact on the decline of railroad passenger service (Vt. PSC, 1906, 15). Railroad service was at its peak around 1900, with more than 1,100 miles of operating rail line. As automobile ownership and use grew in the early 1900s, railroad service declined, and electric trolleys that flourished prior to 1920 could not stay in business after the mid-1920s.

By 1945, railroad milage had decreased by 14% from the time of its peak, to 969 miles, and the decline continued rapidly. The Public Service Commission's 1960 report cites numerous applications by railroads to be relieved of operating passenger trains, petitions to close agency stations, and severe operating losses for the state's last major railroad, the Rutland Railroad.

After World War II, the automobile became a symbol of necessity rather than luxury. Urban and suburban growth made it necessary to have an automobile to get to work or to shop in one of the new shopping centers. The weekend excursion on the electric trolley of 1910 or the hazardous rigors of a motorcar tour of the 1920s and 1930s became an afternoon drive for a growing number of Vermonters and tourists by the 1950s when automobiles became the dominant means of passenger travel (Meeks, *Time and Change*, 1986, 203).

The number of registered automobiles in Vermont gives an indication of the growth and importance of this energy use. Automobile registrations grew rapidly and then declined during World War II. This trend was paralleled by the vehicle miles traveled (VMT) in the state. Between 1920 and 1940, VMT grew from about .1 billion miles to .7 billion miles. (See Table 3.I.3 and Figure 3.I.2.) Miles of public highway also increased, reaching approximately 14,000 in 1943. By 1943, 9% of the highway miles were paved and 51% were graveled, leaving 40% partially improved or primitive (Wilgus, 1945, 85).

After 1950, the automobile was the predominant means of passenger travel, and energy consumption for transportation took off. The 1950s and 1960s were characterized by stable supplies of cheap oil which fueled growth in the transportation sector. Between 1950 and 1973, statewide vehicle miles traveled (VMT) grew from 1.2 billion miles to 3.3 billion miles, and motor fuel use grew from just under 100 million gallons to almost 250 million gallons. (See Figure 3.I.2.) The fuel efficiency of American cars during this time actually decreased, from 14 miles per gallon in 1958 to less than 12 in 1973, due mainly to increased car weights. By 1970, cars and trucks accounted for 75% of all U.S. transportation energy consumed, with cars in urban areas accounting for the largest quantity consumed and the largest proportional increase of any category (Huffman, 1974, 157-8).

Table 3.I.3 Vermont Automobile Registrations, Vehicle Miles Traveled, and Population, 1906-1990

Year	Automobile Registrations	Vehicle Miles Traveled (Billions)	Vermont Population (Thousands)
1906	373		351
1920	30,000	.1	352
1929	90,000	.3	358
1942	88,000	.5	353
1956	123,396	1.4	385
1960	132,679	1.6	390
1970	163,481	2.6	445
1980	254,849	3.7	511
1990	326,997	5.8	558

Source: Wilgus, 1944, 85 for registration information up to 1942; Vt. Motor Vehicle Registries, R.L. Polk Directories for registrations in 1956-70; Vt. AOT for registrations in 1980-1990; Vt. AOT for VMT (1929, 1942, and 1956 are estimates); Bureau of the Census for population information (1906, 1929, 1942, and 1956 are estimates).

In October 1973, the first of two energy shocks within the decade hit, and oil prices skyrocketed. The 1973 energy crisis was precipitated by Arab OPEC countries placing an embargo on exports to the U.S. in response to U.S. support for Israel during the Yom Kippur War. This embargo was lifted in March 1974, but oil prices remained high. In response to shortages and increased gasoline prices, energy efficiency in the nation's transportation sector became more important. A nationwide 55 mph speed limit was imposed in 1974, and automobile efficiency standards went into effect in 1978. Through the combined effects of oil price shocks, regulation, and technical progress, the fuel efficiency of new American lighter weight vehicles almost doubled between 1973 and 1985, from 13 to 24 miles per gallon (U.S. Congress, OTA, 1991, 153). This improvement in fuel efficiency led to both lower energy use and emissions per mile traveled.

Although new cars made gains in fuel efficiency in the 1970s and early 1980s, the total VMT in Vermont and nationwide continued to increase. Vermont's VMT grew from 3.3 billion miles in 1973 to 4.2 billion miles in 1983 (Vt. AOT, *Vt. on the Move*, 1991, 44). At the same time, motor fuel use in the state fluctuated in response to federal fuel efficiency standards and another oil price shock in 1979 from OPEC price increases. In 1981, motor fuel use in Vermont was at almost the same level as in 1971, due largely to high gasoline prices (Vt. DMV Fuel Report). (See Figure 3.I.2)

Since the early 1980s, however, motor fuel use, VMT, and corresponding air pollution problems in Vermont have steadily increased due to relatively low oil prices, an increase in the interstate speed limit from 55 to 65 mph, lack of further gains in fuel efficiency for new cars and trucks, and a trend toward light truck and sports utility vehicle purchases. Motor fuel use between 1981 and 1994 grew from about 233 million gallons to 304 million gallons, a 30% increase (Vt. DMV Fuel Report). Over the same time period, statewide VMT grew from 3.8 billion miles to around 6 billion miles, a 58% increase (Vt. AOT, *Vt. on the Move*, 1991, 44).

Although the pre-1973 conception of oil as "cheap and plentiful" is gone, gasoline prices remain low and Vermont's demand for petroleum remains high. (See Figure 3.I.3 for an overview of changes in Vermont's gasoline prices.) Transportation energy use in Vermont continues to grow at rates similar to the rates in the 1960s and early 1970s, with no sign of slowing. (See the Transportation and Motor Gasoline sections later in this chapter.)

Figure 3.I.2 Vt. Gasoline Use and Vehicle Miles Traveled, 1920-1994

Growth of the Electric Utilities and Electricity Demand

Many electric companies began operation during the 1890s, many merged, competed with gas light companies and either bought them out or were bought up by the gas light companies. Expansion and changes in ownership were common occurrences. In 1900, 52 Vermont communities had electric service, provided by 46 electric distribution systems. (See Table 3.I.4)

Demand for electricity was growing and three important trends emerged: efforts to build stability and provide public oversight of electric and gas companies; recognition of the importance of having electric service and making it available throughout the state; and using new resources and technology to meet the demand.

Expanding Demand for Electricity. After the turn of the century, electric service started being considered a highly desirable commodity, if not a necessity, particularly as new uses for electricity proliferated. The Rutland Railway Light and Power Co., formed in 1906 with the consolidation of electric, gas, and transportation companies, gives a picture of the service, facilities, and rates that were typical of this transitional period. Two coal fired generating plants provided electricity, and the company's circuits covered about 25 miles of streets and a three mile lighting circuit for farm customers near Rutland.

Figure 3.I.3 Vermont Gasoline Prices, 1973-1995

Average dollars per gallon (1994 dollars)

Electricity was used for lighting, and lighting rates for this company were 15 cents per kiloWatthour for the first two kWh, with a drop as low as 7.5 cents per kWh as use increased. Minimum rates were $1 per month per incandescent light (CVPS, 1979, Section 14-Rutland). In St. Albans, customers were billed on the basis of lights installed in a home or shop, and the rate was the same whether the lights were operated for five minutes or five hours. Some bills were calculated on the number of rooms in a house, with owners of larger homes paying more for electric service (CVPS, 1979, Section 18-St. Albans).

At this time Rutland Railway Light and Power also reports that 700 meters were on the company's distribution circuit. They could be read by two men in three days, but they were not used for billing purposes. It is unclear how customer bills were actually prepared, but in the early 1900s as electric utilities were building their distribution systems and adding customers, they were also establishing precursors to standard rates and measured service.

Another early use for electricity was the street railways, also known as the trolley or traction line, which replaced horse-drawn trolley systems that had operated in Rutland, Burlington, and other growing cities, or offered new services in Brattleboro and Montpelier. This application of electric energy to transportation peaked in 1912, when 10 trolley systems were operating. In 1913 the Rutland Street Railway Co., the largest street railway in the state, reported carrying over 3 million passengers on its routes through Rutland and extending to Lake Bomoseen, Fair Haven, Castleton, and Poultney (CVPS, 1979, Section 14-Rutland).

The electric trolley companies rapidly declined during the 1920s, when the automobile started taking over as the preferred means of local transportation, but other emerging uses for electricity continued to increase the demand.

Table 3.I.4 Vermont Communities with Electric Service, 1900

Town	First Electricity	Utility Operating in 1900	Source of Power
Barnet	1894	Pioneer Electric Light Company	hydro and steam
Barre	1887	Consolidated Lighting Company	hydro and steam
Barton	1894	Village of Barton	hydro
Bellows Falls	1888	Bellows Falls Electric Light Co.	hydro and steam
Bennington	1887	Bennington Water Power & Light Co.	hydro and steam
Bethel	1895	Bethel Electric Light & Power Co.	hydro
Bradford	1897	Bradford Electric Lighting Co.	hydro and steam
Brandon	1889	Neshobe Electric Company	hydro and steam
Brattleboro	1888	Brattleboro Gas Light Company	steam
Bristol	1892	Bristol Electric Company	hydro and steam
Burlington	1885	Consolidated Electric Company	hydro and steam
Charleston	1895	Village of Barton	hydro
Chelsea	1899	Chelsea Electric Light & Power Co.	hydro
East Berkshire	1897	John Robb	hydro
Enosburg Falls	1896	Village of Enosburg Falls	hydro
Samsonville	1897	John Robb	hydro
Essex Junction	1893	Peoples Electric Light & Power Co.	hydro
Fair Haven	1894	James Langdon	hydro
Hardwick	1893	Village of Hardwick	hydro and steam
Hartford/WRJ	1893	Mascoma Electric Light and Gas Co.	hydro and steam
Hyde Park	1895	Village of Hyde Park	hydro
Island Pond	1895	Island Pond Electric Light & Power Co.	steam
Johnson	1894	Village of Johnson	hydro
Lyndon/ Lyndonville	1896	Lyndonville Municipal	hydro
Manchester	1896	Reuben Colvin and DeVere Houghton	hydro
Middlebury	1890	Middlebury Electric Company	hydro and steam
Middlesex	1896	J.S. Viles	hydro
Montpelier	1886	Consolidated Lighting Company	hydro and steam
Morrisville	1894	Village of Morrisville	hydro
Newport	1891	Newport Electric Light Co.	hydro and steam
Northfield	1895	Village of Northfield	hydro
North Troy	1896	C.O. Fowler	hydro
Poultney	1896	James Langdon	hydro
Proctor	1893	Vermont Marble Company	hydro and steam
Randolph	1898	White River Electric Company	hydro
Richford	1888	Sweat-Comings Company	hydro and steam
Rochester	1897	Rochester Electric Light & Power Co.	hydro and steam
Rutland	1886	Rutland City Electric Company	steam
St. Albans	1888	St. Albans Electric Light & Power Co.	steam
St. Johnsbury	1888	St. Johnsbury Electric Company	hydro and steam
S. Londonderry	1894	Charles Alexander	hydro
Springfield	1891	Springfield Electric Company	hydro and steam
Stockbridge/ Gaysville	1897	J. E. Safford	hydro
Swanton	1894	Village of Swanton	hydro
Vergennes	1893	Vergennes Electric Company	hydro
Waterbury	1899	Consolidated Lighting Company	hydro
Wells River	1891	Village of Wells River	hydro
Wilmington	1894	Wilmington Electric Light Co.	steam
Windsor	1890	Windsor Electric Light Co.	hydro and steam
Winooski	1887	Consolidated Electric Company	hydro and steam
Woodstock	1893	Woodstock Electric Company	hydro and steam

Source: Tucker, 1986, 68.

The electric motor, several different models of which Thomas Davenport of Brandon had developed and obtained patents for in the 1830s, had evolved and been adapted for many new, labor saving uses. Many Vermont businesses were getting started or growing, and new equipment was purchased and used. In the first decades of the century a new era of home appliances began, changing the performance of tasks of sewing, laundering clothes, and cooking. Electric refrigerators soon made iceboxes obsolete. As more household and business equipment relied on electricity, electric utilities advertised in newspapers and promoted sales, acquainting customers with the care and use of appliances through cooking schools, demonstrations, and service calls by the Home Services Department (CVPS, 1979, Section 3-Historical Notes from Annual Reports).

Building Stability and Regulating Electric and Gas Companies. During the first decades of this century, new companies were established and many of Vermont's small electric companies were consolidated. Mirroring the electric industry nationally, systems were rapidly expanding in the 1920s, credit was easily obtainable, and small investors were pouring their savings into utility stocks, whose prices were climbing. Capital was flowing into utility holding companies. There was speculation in Vermont utility properties along with mergers, acquisitions, and consolidations carried out by utility holding companies that in some cases involved improper inter-company financing. Mergers and buyouts that resulted in the formation of the state's major electric companies, Green Mountain Power, Corp. in 1928 and Central Vermont Public Service Corp. in 1929, are well documented in their respective corporate histories (GMP, 1993 and CVPS, 1979). When Congress passed the Public Utility Holding Company Act of 1935, the era characterized by rapid expansion, risky financing, unsound accounting practices, and utility mismanagement ended. Utility ownership was reorganized and gained stability.

Financial stability, service, and safety related to Vermont's electric and gas companies were matters of public concern from the time these companies were established; however it was 1908 before the legislature revised the state's regulatory body, changing its name from the Board of Railroad Commissioners to the Public Service Commission and extending its authority to "supervision of all persons doing a public service business in this state" (Vt. PSC, 1910, 10). Beginning in 1909, the Commission's Biennial Report included information about telephone and telegraph companies, electric and gas companies, as well as the long established sections on steam and electric railroads. At this time, 71 telephone companies and 65 gas and electric companies submitted the requested information that was then published in the Biennial Report. Several companies are noted for failing to do so. The Commission had very limited resources and funding for any investigations had to be obtained through special authorizations from the legislature.

In 1937 the General Assembly proposed a tax to support full time, independent staff, enabling the Public Service Commission (later called the Public Service Board) to be more independent and active in its regulatory efforts. This regulatory framework continued until its restructuring in 1981, when the legislature separated the Public Service Board into two distinct offices: the Department of Public Service and the Public Service Board. The Board retained the judicial and rule-making role in utility proceedings. The Department was charged to carry out the tasks of representing the public in proceedings before the Board, planning for the state's future energy and telecommunications needs, handling consumer affairs, making and administering contracts on behalf of the state, and other regulatory functions.

Extending Electricity Service. After the turn of the century, the web of power lines grew quickly in Vermont's populated communities, but was slow to advance into rural areas. Utilities were reluctant to extend their lines further into rural areas. The farming community was seriously concerned about the "power haves and have-nots" and predicted they would forever live by lamplight and manual labor.

In 1930, Vermont had about 82,000 domestic customers. While 63% of all Vermont homes had electric power, only 13% of the farms did (Meeks, *Vt.'s Land and Resources*, 1986, 202). By the mid-1930s, political pressure was growing at local, state, and federal levels to bring power to farmers and rural areas of the state. Major efforts were made at the federal and state levels to make electric service widely available and consistent with standards set by regulatory entities. The federal government responded to popular rural sentiment with the National Rural Electrification Act (REA) of 1935 that had a significant impact on Vermont, creating low interest, long term loans to farmer's cooperatives, and state and local governments so they could provide farms with electricity for lighting and improved farm equipment. From the time he first entered politics in 1931 as the representative from Putney (population 835), George Aiken worked to counterbalance the power of utility companies with public involvement in energy issues so that his constituents as well as people in other rural areas could have electric service at a low cost, as residents of more urban areas did. As governor starting in 1936, Aiken strongly promoted public power and rural electrification, and he continued this advocacy when he went to Washington as a U.S. Senator in 1941.

The Biennial Report for 1937-1939 describes a major effort to extend electric service throughout the state. With support from Vermont Farm Bureau and other organizations, the Public Service Commission sent questionnaires to owners of all electric systems within the state requesting information about their miles of rural line and number of farm customers for the years 1937 to 1939.

Information gathered from these questionnaires is shown in Table 3.I.5. The state's REA cooperatives -- Washington Electric Cooperative, Inc., Vermont Electric Cooperative, Inc, and Halifax Electric Cooperative -- were under construction and just starting to serve customers in 1939.

As the Biennial points out, the actual percentage of customers and lines attributed to the cooperatives in 1939 is relatively small, but rural line construction and farm customers both grew more than 10% between 1938-1939, over twice the rate for the prior year. From their first year of reported service, the cooperatives had a major impact, getting service to 436 farm customers with 166 miles of rural line. Washington Electric also had 212 miles of line under construction with 556 customers signed up for service as soon as it was available; similarly Vermont Electric Cooperative would soon have about 200 additional miles of line serving about 400 more farm customers, and Halifax was building 68 miles of line to serve 170 users (Vt. PSC, 1939, 10-11).

Table 3.I.5 Vermont's Progress with Rural Electrification 1937-1939

Miles of Rural Line

	1937	1938	1939
Municipal Utilities	467	486	515
REA Cooperatives	0	0	166
Private Utilities	2,876	3,011	3,179
Total	3,343	3,497	3,860

Farm Customers

	1937	1938	1939
Municipal Utilities	1,386	1,465	1,536
REA Cooperatives	0	0	436
Private Utilities	7,566	7,926	8,422
Total	8,592	9,391	10,394

Source: Vt. PSC, 1939, 10.

In its Biennial for 1945-1946, the Public Service Commission reports that it conducted a statewide field survey of rural electrification ". . . by having all highways in the state perambulated by a member of the PSC staff in his automobile; some 14,300 miles in all". This survey identified 21,872 farms in Vermont, and 14,940 or 69% were electrified. Information was recorded and maps were marked so that the 6,932 farms without electricity could be connected. The Commission also met with the state's utilities and a "postwar rural electrification building program" was set up with each utility, including progress reporting. By November 1946, electricity was available to 90% of all farms in Vermont, ". . . not just the best farms in the state, but 90% of all establishments which by any stretch of an enthusiast's imagination might be called farms." The goal was to connect 97% of the state's farms by the end of 1948 (Vt. PSC, 1946, 1-17). Hundreds of miles of distribution line were added each year during the late 1940s. Victory and Granby, with their 101 residents, were the last Vermont towns to be linked to the grid. The year was 1963.

Meeting Vermont's Need for Electricity: New Sources. Reflecting the national trend, electricity use in the state of Vermont grew dramatically from the beginning of the century until the oil crisis of 1972 , as customer counts were building and uses for electricity were being developed and marketed. Over the decades, the real cost of electricity declined, and consumers responded by using more for an expanding number of energy consuming products. In Vermont the average price of electricity fell steadily from about 40 cents per kWh in 1940 to less than 10 cents in 1972 (both in 1991 dollars,) as average usage per residential customer rose by about 800%, or about 25% per year. (See Figure 3.I.4.)

In the 1940s, as the state's electric utility industry passed its 50th anniversary, there was growing concern about potential future energy sources for generating electricity and how the state could assure that Vermont customers got low cost, reliable power to meet their needs.

The Biennial Report for 1937-1939 indicated that:

> . . . practically all the electricity generated and used within the state is produced by water power. Small amounts are produced by steam or diesel power, but they are relatively unimportant.

In addition, out-of-state companies, New England Power Association and New England Public Service Co., controlled major power stations on the Connecticut and Deerfield Rivers, and moved a major portion of this generation out of the state.

> The combined Vermont generation of these two companies was 87% of the state's total, exclusive of municipals, of which 58% was exported (Vt. PSC, 1939, 29).

The Public Service Commission and the legislature were beginning to look for new sources for supplying the state's growing need for electricity while protecting Vermont's remaining potential hydro sites from the out-of-state power companies that were interested in buying them. Several large scale facilities on the Connecticut and Deerfield Rivers as well as rivers within the state were controlled by out-of-state power companies and a significant portion of this power was exported. There were growing concerns about allowing further control of the state's potential resources by outside interests.

The legislature had given a clear message about developing potential future sources in 1931 when a bill related to flood control and cooperation between the state and private utilities was considered. If passed, this new law would have given power companies broad authority to build dams and reservoirs on potential power sites throughout the state. Despite strong backing by legislative leaders and interest groups, the bill was voted down in the House Conservation Committee. The representative from Putney, George Aiken, led the opposition to the bill on the grounds that this bill would enable private utilities to buy up every dam site on

Figure 3.I.4 Vermont Residential Electricity Prices, 1940-1992
Cents per kWh per year (1991 dollars)

nearly every brook in Vermont where 500 kiloWatts of power could be generated and utilities would thereby gain "control of the destiny and development of the state." In spite of support by the Speaker of the House, the power companies, and railroads, the Conservation Committee voted against the bill, and it died (Oakes, 1995, 148).

To keep pace with the growing demand for electricity after World War II, the Public Service Commission, Vermont's Congressional representatives, and those concerned with energy policy in Montpelier were working to get large scale, long term blocks of "firm power" (guaranteed power) from sources outside the state. Vermont utilities were addressing the need for new power sources by starting to develop contracts for purchasing power and considering new generating plants.

Contracts with New York Power Authority (NYPA). In 1955 the legislature made the Public Service Commission the state's designated agent for the state's power purchases, and in 1957 the legislature gave the Public Service Commission authority to proceed with power purchases from the St. Lawrence Project. The Vermont Electric Power Company (VELCO), formed by a group of Vermont utilities and led by CVPS, was authorized to construct transmission lines and facilities so that Vermont could receive deliveries of power from the New York Power Authority (then called the Power Authority of the State of New York (PASNY)). In 1958 the legislature authorized a contract with the New York Power Authority for the purchase of 100 MW of power from generating facilities at Massena, NY, for distribution to Vermont consumers.

Before the first NYPA contract was finalized, the search was on for additional sources. Vermont was able to contract for an allocation of Niagara power, under the terms of a federal preference project, whereby the New York Power Authority was required to export a reasonable amount of the power generated by these facilities to municipally-owned electric companies, cooperatives, and public bodies. With authorization from the legislature, the Public Service Commission negotiated a contract for 50 MW of Niagara power and allocated it to "preferential bodies" in the state.

From 1958 through 1985, NYPA hydropower was an important source of Vermont's electric energy, providing approximately 65% of the state's requirement in 1962, a proportion that steadily decreased thereafter as the state's requirements grew. By 1985, NYPA was providing 19% of Vermont's energy requirements. NYPA contracts were renegotiated to continue until 2002, but Vermont's allocation of power was greatly reduced so that less than 2% of the state's requirement is currently being provided by NYPA contracts.

Nuclear Power Plants. In the search for additional sources, plans were announced in 1954 for construction of New England's first nuclear power station, sponsored by 11 investor owned utilities including several Vermont utilities. Yankee Rowe Nuclear Power Station, located in Rowe, MA just south of Vermont's border, was completed on schedule in 1960. It was New England's first nuclear plant.

In the mid-1960s Vermont Yankee Nuclear Power Corporation proposed to build a 540 MW nuclear power plant at a cost of $88 million, to be completed by 1970.[i] At this time Governor Philip Hoff was negotiating to bring in a substantial amount of power from the Churchill Falls (Labrador) Hydroelectric Project. Early in 1966 the enabling legislation passed the Senate, ". . . but in the House all hell broke loose. In my entire experience I have never seen lobbying like that in the state of Vermont. And much of it was of very doubtful probity" (Hoff, 1995, 138). The House eventually sent its version of this bill to a study committee, terminating this option for acquiring new, long term sources of power. In August, 1966 the Public Service Board issued a Certificate of Public Good to the Vermont Yankee Nuclear Power Corporation in anticipation of the construction of an "atomic plant" in the state (Vt. PSB, 1966, 33). Vermont Yankee Nuclear Power Station, located in Vernon, Vt., went on line in December, 1972, two years late and at a cost of $220 million, more than twice the original construction estimate.

In 1973, its first full year of operation, Vermont Yankee supplied about 26% of the state's electric energy (3,447,212 kWh) (Vt. PSB, 1974, 50). Its contribution has been as high as 38% in 1975, moving back to the 26% range by the late 1980s. Vermont utilities owned 55% of the unit or 277 MW during the early period of operation, increasing to 281 MW as of May 1995 when a new turbine generator was installed, increasing the plant's output. (See Table 3.I.6)

Table 3.I.6 Vermont Utilities' Ownership of Vermont Yankee, 1995

Central Vt. Public Service	31.25%
Green Mountain Power	17.86%
Vermont Electric Cooperative	1.07%
Washington Electric Cooperative	.62%
Lyndonville Electric Dept.	.61%
Total ownership by Vt. Utilities	55.00%

Source: Vt. DPS

Power Contracts. In addition to building generation plants, Vermont utilities also pursued power contracts. During the early 1960s, VELCO began making arrangements for purchase and transmission of wholesale blocks of power for resale at cost to Vermont utilities. The Public Service Commission found that this form of pooling for power purchases and transmission was advantageous for Vermont utilities and customers (Vt. PSB, 1968, 30). The New England Power Pool (NEPOOL) was established in 1970, in response to a major regional blackout in 1965, and consisted of private, municipal, and cooperative utilities from all six New England states. Under the direction of NEPOOL, there is central dispatch for most of the generation and transmission in New England. Power contracts have provided a significant portion of Vermont's electric energy supply since they were first established.

Contracts with Hydro-Québec and Ontario Hydro. Vermont's ties with Canada for electricity date back many years, when small companies on the Canadian side built hydroelectric sites and began serving customers, some of whom were located in Vermont. These hydropower contracts were continued after Québec's electrical facilities were consolidated and Hydro-Québec was created in 1944. The state negotiated with Ontario Hydro for 52 MW of electricity for the period 1980-1985, which was later renegotiated and extended. In 1984, the Department of Public Service executed a contract with Hydro-Québec for 150 MW of firm power and up to 1.3 billion kWh of energy annually for a 10 year period. Following the completion of NEPOOL's high voltage converter in Highgate, Vt. and 7 miles of transmission line linking Vermont to the Québec transmission system, Vermont received power from Hydro-Québec under this contract for the 10 year period that ended in September 1995. Fifteen Vermont utilities are now purchasing firm power from Hydro-Québec under a follow-up contract. This purchased power is expected to increase from 250 MW at the beginning of 1996 to 310 MW by 2000. After 2011, portions of the contract expire and the contract amount declines to 5 MW for the period 2017 to 2020.

Renewable Energy Sources. The percentage of Vermont's electricity use generated from renewable energy sources has historically been relatively high and is likely to remain so.

Vermont's abundant hydro sites have been used since the 1890s, and in-state hydro plants continue to be an important energy source. A significant amount of in-state electric generation comes from the 46 utility owned hydro sites, the 19 independently owned hydro sites known as qualifying facilities, and the many smaller hydro sites around the state (Vt. DPS, 1994, *Vt. Twenty Year Electric Plan*, 4-30).

Similarly, wood has long been an important energy source for home heating, and more recently has expanded its role to contribute to Vermont's in-state electricity generation. In 1984, the 53 MW wood-fired McNeil Station opened in Burlington; it was the largest wood-fired generator in the world at the time. Vermont's second wood-fired plant came on-line in 1992 in Ryegate, with a capacity of 20 MW. The McNeil Station will continue its role as a leader in the next several years by constructing one of the first wood chip gasification systems as a demonstration project. (See the Electricity from Wood section for more information.)

Vermont also was the site of a wind turbine test project in the early 1940s, and is expected to be the site of another wind test project in the next few years. In 1941, for the first time anywhere in the world, power from a wind turbine constructed on a hill 12 miles west of Rutland was fed into Central Vermont Public Service's transmission line and carried to Rutland and nearby communities. Subsequently, the wind turbine (known as Grandpa's Knob Windmill) went off-line for about three years of test operation, during which it operated in winds up to 70 mph, withstood gales as high as 115 mph, and generated up to 1,500 kW. The turbine went on-line for electricity generation again in 1945 for 23 days. The project ended when one of the 8 ton blades, measuring 70 feet long and 11 feet wide, broke loose (CVPS, 1979, Section 6-Grandpa's Knob Windmill). (For more information, see the Wind Energy section.)

Energy Efficiency Programs and Demand Side Management. Beginning in the 1970s, energy efficiency programs that reduced the need for electricity began to be recognized as valuable resources that could postpone and potentially eliminate the need to add new supply resources to meet peak loads. First came new rate designs and load control programs that (together with consumers' new awareness of energy efficiency efforts) began flattening Vermont's seasonal electricity use pattern and slowed the growth rate in statewide electric sales.

By the 1980s, conservation experience in Vermont and elsewhere made it clear that there was great untapped potential for improving the efficiency of electric power use. The cost for acquiring electric energy resources through investment in energy efficiency and other "demand side" resources could be less than the cost of new generation or other supply resources. In the 1983 *Vermont Twenty Year Electric Plan*, the state's electric utilities were advised and encouraged to treat commitment to or investment in energy efficiency options as seriously as options to purchase additional power or build additional power plants.

In the late 1980s, policy makers, the legislature, and regulators directed Vermont utilities to undertake least cost integrated planning (LCIP) and to prepare integrated resource plans (IRPs) in which each utility forecasts its customers' long range demand for energy and develops a set of least cost options for meeting this need. The procedure for selecting this set of resources must give comparable treatment to generation, transmission, distribution, and demand side management resources, which are typically energy efficiency programs. Environmental costs are also to be taken into account in the selection of resources, along with robustness across a variety of potential futures, potential risks, and the value of diversity.

The recently published 1994 *Vermont Twenty Year Electric Plan* reassesses the state's current and long term needs for electric energy, and reconfirms the principals of integrated resource planning for the state's utilities, as does the Public Service Board's 1990 Order in Docket 5270 and a related statute (30 V.S.A. §218c) which requires integrated resource planning by all the state's utilities. (See the Utility Efficiency Programs section later in this chapter.)

Recent Energy Trends

Since the turn of the century, energy use in Vermont has undergone major changes. Use of fuel sources such as coal, kerosene, and manufactured gas has declined dramatically, while usage of oil, electricity, nuclear power, hydroelectric power, natural gas, and propane increased substantially. A multitude of new energy end uses were in place by the 1970s and 1980s, especially electricity-using appliances and machinery and oil-using vehicles.

Between 1970 and 1995, there were major shifts in the price, supply, and consumption of energy nationally and here in Vermont. During the late 1970s, consumers responded to higher oil prices or uncertain oil supplies by reducing their use of oil, shifting to other types of fuel, and purchasing and using more efficient appliances, machinery, and vehicles. Initial reductions of oil consumption were achieved by a stoic "do-without" approach, but later this approach was replaced by using oil and other fuels more efficiently in heating systems, buildings, vehicles, and manufacturing.

At the national level, the oil market shifted from a federally regulated market (with respect to price and distribution) to a deregulated market in 1981. For much of the 1980s, these competitive markets, along with worldwide oil surpluses, helped to stabilize fuel prices. The late 1980s showed renewed and fairly rapid growth in some energy use areas, particularly in transportation, electricity, biomass, and natural gas use.

As illustrated by Figure 3.I.5, Vermont's energy use, electricity use, and gross state product (GSP) have increased at different rates since the mid-1970s. Because GSP has increased more quickly than total energy

Figure 3.I.5 Vt. Energy Use, Electricity Use, and GSP, 1976-1994

TBTU and GSP (in 1995 dollars) per year

use, the state's energy intensity has decreased. Part II of this chapter gives a more complete analysis of energy trends since the mid-1970s, including other graphs of energy intensity and graphs for energy use among sectors, end uses, and fuels.

As Vermont and the nation plan for future energy use and development, several current trends will likely shape decisions and patterns of use. These trends include relatively low fossil fuel prices; continued concern about global warming around the world; far-reaching air regulations that will continue to limit emissions of nitrogen oxides, sulfur dioxide, particulates, and dozens of toxic compounds; efforts to restructure the electric industry, which likely will lead to increased customer choice and new methods to ensure ongoing protection of the public good and societal interests; and changing directions for national energy policy proposed by the 104th Congress. (See the following sections of this chapter for more information about these trends). In conjunction with these trends, energy demand is projected to continue to increase, especially in the transportation sector. The context for future energy development in the Northeast is currently characterized by an excess capacity in the electric utility sector and relatively flat economic conditions. The ways in which these and other trends will influence future energy decisions is one of the main topics of the remainder of this Plan.

B. Recent Energy Planning Efforts and Legislation

Since the prior version of the *Vermont Comprehensive Energy Plan* in January 1991, important legislation has been enacted at the federal and state levels that will affect energy policy for years to come. In addition, international conferences and ongoing local discussions resulting from them have expanded the understanding of links between energy, the environment, and sustainable economic development. The following is an overview of a few milestones at the international, national, and state levels that indicate progress and new directions in energy planning, energy efficiency, reliance on renewable and alternative fuels, and the protection of environmental resources damaged by energy use.

1. International Energy Efforts

U.N. Conferences on Environment and Development: Earth Summit

The United Nations Conference on Environment and Development, held in June 1992 in Rio de Janeiro, Brazil, brought together leaders from developed and developing countries to form agreements on the need for balance between economic development and environmental protection. During the Rio Summit, 154 nations including the U.S. signed the U.N. Framework Convention on Climate Change (FCCC) that committed the Annex I countries, which are the developed countries and countries undergoing the process of transition to a market economy, to stabilizing their atmospheric concentrations of greenhouse gases at 1990 levels by the year 2000. The signers agreed to a global action approach, focused on the development of national policies and measures to mitigate and adapt to climate change. Measures and policies, it was agreed, must be rooted in specific national circumstances and fashioned from a comprehensive set of options addressing all sectors, sources, and sinks of greenhouse gases (U.S. EPA, *States Guidance Document*, 1995, 2-8). To begin meeting this commitment, the U.S. has undertaken actions to address climate change, including scientific and economic research, policy analysis, and program development. (See Climate Change Action Plan and other National Energy Legislation below.)

Conferences of the Parties to the Framework Convention on Climate Change

In Berlin, March 1995, leaders from more than 120 of the countries that signed the Framework Convention on Climate Change at the Earth Summit in Rio gathered for a follow-up conference: the first Conference of the Parties to the Framework Convention on Climate Change. The purpose of this conference was to assess progress made toward the Framework Convention goals and to negotiate and agree to the next steps of its implementation.

National assessments presented at the conference showed that the world is not meeting the goal set at the Earth Summit of holding industrial country greenhouse gas emissions at 1990 levels by the year 2000. Carbon dioxide emissions (the major greenhouse gas) were already 4%-5% higher than 1990 levels in some industrial nations (including the U.S., Australia, and Canada), and are 10%, 20%, and 40% higher in some developing countries (including China, India, South Korea, and Brazil). A few nations have experienced declines in carbon emissions, including Poland, Russia, Ukraine (due to economic restructuring and a decline in energy-intensive industries), and Germany (due to industrial restructuring and decreasing use of certain types of coal). In the United Kingdom and Japan, carbon emissions are holding roughly steady (Brown, 1996, 30-1).

Some new advocates for strong climate change commitment were important forces at the Berlin conference, including top leaders of the insurance industry, local officials representing 150 cities working to reduce their own emissions, German environmental groups and the public, hundreds of environmental activists from around the world, and leaders of countries belonging to the Alliance of Small Island States (AOSIS) which are threatened by potential global warming and rising seas. This latter group was especially effective in focusing the conference on strong climate change commitments. During the first week in Berlin, the AOSIS submitted a proposal that would commit industrial countries to reduce their emissions by 20%. Midway through the conference, the Group of 77 (a group of mostly developing nations), led by nations such as Brazil, China, India, and Egypt, broke away from the other countries and endorsed the AOSIS stance. This move created a deep split among governments at the conference. The Group of 77 and AOSIS countries arguing for a strong climate change commitment were supported by many European officials, but were opposed by countries such as the U.S., Australia, Kuwait, and Saudi Arabia, which argued for a weaker mandate.

This split among governments came close to allowing conference negotiations to collapse. However, in the last hours of the conference, a final agreement known as the Berlin Mandate was agreed to by all parties. The Mandate charged leaders to negotiate a treaty protocol "to elaborate policies and measures, as well as to set quantified limitation and reduction objectives within specified time-frames such as 2005, 2010, and 2020." This treaty was to be signed at a subsequent conference of the parties in 1997 in Japan. In addition, governments agreed to launch a series of pilot projects through 1999 to transfer less carbon-intensive technologies between countries (Brown, 1996, 33-5). While the Berlin conference agreement did not represent a strong mandate ensuring that greenhouse gases will be stabilized, the continuing commitment to climate change mitigation by all parties gives modest encouragement. (For more on climate change, see below, Chapter 2, and the *Vermont Greenhouse Gas Action Plan: Part I*.)

Kyoto Conference. The third session of the Conference of the Parties of the FCCC took place in Kyoto, Japan in December 1997. The purpose of this meeting was to specify the Parties' commitments that were set in general terms at the 1992 Earth Summit and to render those commitments legally binding. The official outcome of this conference is the Kyoto Protocol to the U.N. FCCC, which was agreed to by more than 150 countries. The Kyoto Protocol will be in force when not less than 55 countries have ratified it (accounting for at least 55% of the total carbon dioxide emissions of Annex I countries, a category that includes developed countries and countries in transition to a market economy). Key features of the Kyoto Protocol are:

- Emissions targets. Greenhouse gases under consideration are carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride. Overall global emissions shall be reduced by at least 5% below 1990 levels in the commitment period of 2008-2012. Responsibility for emissions reductions is differentiated: U.S. must reduce overall emissions by at least 7% below 1990 levels; the European Union and many Eastern European countries must reduce their emissions by 8%; Russia must stabilize its emissions; and Iceland may increase its emissions by 10%.

- Flexibility within Annex I countries is addressed by provisions allowing Annex I countries that ratify the Kyoto Protocol to choose to jointly attain their aggregate emissions reduction commitments.

- Global flexibility is addressed by a special mechanism, the Clean Development Mechanism, that allows countries included in Annex I to achieve compliance with their emission reduction commitments by acquiring emission reduction units from developing countries that are not included in Annex I . The Clean Development Mechanism also assists developing countries achieve sustainable development.

- Compliance and enforcement are addressed by requirements that each Annex I country do the following: establish a national system for the estimation of anthropogenic greenhouse gas emissions (by source) and removals (by sink); incorporate emissions and removals in its annual emissions inventory; and promote cooperation in technology transfers, research, and educational programs.

Finally, after a June 1998 interim meeting in Bonn, Germany, the fourth Conference of the Parties, will be held in Buenos Aires, Argentina in November 1998.

Intergovernmental Panel on Climate Change

The Intergovernmental Panel on Climate Change (IPCC), a working group of several hundred of the world's leading climate scientists from 25 countries, was formed in 1988 under the auspices of the United Nations Environment Program and the World Meteorological Organization. The IPCC has been the primary international forum for addressing climate change since its formation. IPCC working groups focus on assessing scientific evidence on and impacts resulting from climate change, and on considering possible response strategies for limiting or adapting to climate change (U.S. Congress, OTA, 1991, 36, 45). In 1990, the IPCC issued the first report of its findings, followed by an update in 1992. In late summer of 1995, the IPCC issued another report (in draft form), updating their earlier findings (IPCC, *The IPCC Assessment of Knowledge Relevant to the Interpretation of Article 2 of the U.N. Framework Convention on Climate Change: Second Synthesis Report* (draft), 1995).

The 1995 document is important compared to the earlier reports because it asserts for the first time that human activities have already caused some warming of the earth. More specifically, the IPCC report states that the observed increase in global mean temperature of 0.3-0.6 degrees Celsius over the last century (with 0.2-0.3 degrees occurring in the last 40 years) is "unlikely to be entirely due to natural causes," and that a "pattern of climatic response to human activities is identifiable in the climatological record."

The 1995 report also includes projections of the rate of future warming. The IPCC projects an additional rise in global mean temperature of 0.8-3.5 degrees Celsius (1.4-6.3 degrees Fahrenheit) by 2100 if current trends continue and if no climate change policies are implemented. The rate of future global warming has been an area of special concern for scientists, since the faster the earth warms, the harder it will be for humans and natural systems to adapt. For example, the IPCC concludes that even a rate of change of 0.1 degree Celsius per decade (the lower end of the range of projections) would result in significant lost of forest tree species because the species would not be able "migrate" or establish themselves and regrow in new locations quickly enough to keep pace with changing temperatures.

IPCC scientists have also focused on the possible disruption of atmospheric and oceanic systems that regulate weather. Studies indicate that a warming world will have more climate extremes, and the IPCC draft report reinforces this by stating that "the incidence of floods, droughts, fires, and heat outbreaks is expected to increase in some regions" as temperatures rise. Other serious consequences mentioned by the IPCC include the possibility of "significant adverse consequences for food security in some regions of the world," and the likelihood of "a wide range of human health impacts, most of them adverse, and many of which would reduce life expectancy" if projected changes in climate occur (IPCC, 1995, cited in Brown, 1996, 21-8).

2. National Energy Legislation

In 1991, a new National Energy Strategy was published, led by the U.S. Department of Energy. The Strategy led to the passage of several pieces of national legislation that attempted to lay out a new energy course for the country focusing on energy efficiency, renewable energy efforts, and the development of alternative fuels. The Energy Policy Act (EPAct), passed in October 1992, was the most significant piece of new legislation. As a result of EPAct and other energy legislation passed since 1990, changes are starting to be realized. However, new directions for energy policy set by the 104th Congress elected in 1994 could change and in some cases reverse trends set by the 1991 Strategy. (See below.)

Clean Air Act Amendments

The Clean Air Act Amendments (CAAA) link environmental protection goals to strategies that include energy efficiency, renewable energy resources, and alternative fuels. Passed in 1990 to reduce the emissions of sulfur dioxide, carbon monoxide, particulates, nitrogen oxide, ozone, and air toxics, the impacts of these amendments to the Clean Air Act are now being felt and will continue to be felt throughout the decade as rules are made and take effect.

Under the Clean Air Act Amendments, states are required to attain certain air emission standards. Each state must submit a state implementation plan to the EPA for approval; these plans specify how standards on individual emissions are to be met and how controls are to be implemented.

The CAAA provide that emissions of volatile organic compounds and nitrogen oxides (which together lead to ozone, the primary constituent of smog) are to be controlled within "ozone transport regions" (OTRs). The Northeastern U.S. forms a single OTR that extends from Washington DC into northern New England. Although Vermont does not have urban smog problems, it lies within this zone and must coordinate with other states in the OTR to bring the entire region into attainment with ozone standards. Vermont currently has not satisfied all CAAA requirements for ozone standards, including the implementation of a vehicle inspection and maintenance program in Chittenden County.

The CAAA also affects fossil fueled electric generating plants through a new system designed to reduce sulfur dioxide (SO_2) and nitrogen oxides (NO_X), pollutants that contribute to acid rain (and in the case of NO_X, contribute to ozone). Utilities are given SO_2 emission allowances which effectively cap their SO_2 emissions and establish a national trading program of emission allowances. Utilities can sell allowances to other utilities that need them, offering utilities an incentive to cut their emissions in order to sell their allowances, and reducing the relative cost of SO_2 reduction. Annual SO_2 emissions from fossil fueled electric generating plants will be reduced by about 10 million tons and capped at 8.9 million tons by 2000, while annual NO_X emissions will be reduced by about 2 million tons (Lock, 1991, 19). The amendments also include incentives to encourage energy conservation at electric generation plants as a part of an overall strategy to meet the emissions requirements.

In addition, federal energy efficiency standards for air conditioners, refrigerators, and freezers have been increased under the CAAA, and chlorofluorocarbons (CFCs) are being phased out as a result of both the CAAA and the Montreal Protocol.

Rules for alternative vehicle fuels are another area addressed in the Clean Air Act Amendments. The Reformulated Gasoline Program outlined in the amendments require the smoggiest cities to use reformulated gas. Reformulated gas combines gasoline with oxygenates such as ethanol or a natural gas derivative in order to reduce emissions. This rule took effect in the smoggiest cities on January 1, 1995. (For more information on reformulated gasoline, see the Alternative Transportation Fuels section later in this chapter.)

State Energy Efficiency Programs Improvement Act

The federal government provides funding to states for energy efficiency programs through the State Energy Conservation Program and the Institutional Conservation Program. The State Energy Efficiency Programs Improvement Act, passed in 1990, not only reauthorized the programs and their funding levels but also updated, streamlined, and improved them. In general, the bill provides greater flexibility to the states in using these programs to meet their own energy efficiency goals.

Intermodal Surface Transportation Efficiency Act (ISTEA)

Passed in 1991, ISTEA focuses transportation planning on rising concerns of traffic congestion, energy consumption, and air pollution. As a result of ISTEA, each state is required to develop a State Transportation Implementation Plan. The Vermont Agency of Transportation released the state's *Long Range Transportation Plan* in early 1995. This plan lays out the options Vermont will pursue to:

- reduce vehicle miles traveled;
- provide for bicycle transportation and pedestrian walkways in conjunction with road projects;
- address traffic congestion;
- work with clean fuels and clean fuel vehicles; and
- plan for intermodal transportation systems.

Energy Policy Act

The Energy Policy Act (EPAct), passed in 1992, is the most wide-ranging energy legislation passed in over a decade. It touches virtually every sector of the U.S. energy industry, combining regulatory changes, tax incentives, and federal mandates designed to reduce U.S. dependence on foreign oil. A key component of EPAct is a set of measures aimed at improving the energy efficiency of homes, office buildings, utilities, and factories. Mandatory efficiency standards are included for certain appliances, motors, and equipment, along with proposals to foster development and production of energy from renewable sources such as solar, wind, and biomass.

EPAct also includes requirements intended to promote cost-effective energy efficiency in the utility industry. State public utility commissions are required to conduct hearings and consider adopting the following standards, which Vermont has already adopted (Vt. PSB Order 5270; 30 V.S.A. §218c and the *Vermont Twenty Year Electric Plan,* 1994).

- Adoption of an Integrated Resource Planning (IRP) process with regular updating for these plans and the opportunity for public participation;

- Adoption of rate changes to make investment in demand side management (DSM) at least as profitable as investment in new generation, transmission, and distribution equipment;

- Adoption of rates that encourage investment in cost-effective improvements in the efficiency of generation, transmission, and distribution.

EPAct also promotes the development of a more competitive power market by encouraging new power generation entrants. EPAct amends an earlier law, the Public Utilities Holding Company Act of 1935, to exempt certain generators that were prohibited under this Act. Opening the way for this new group of independent generators, known as exempt wholesale generators (EWGs), will expand the number of independent power producers that can access transmission lines and market the power they generate to utilities. (Vermont complied with provisions of EPAct in the PSB Order in Docket 5664, issued 10/93.) An increasing number of competitive supply options may soon become available to utilities for meeting different customers' needs. These developments are part of the restructuring of the electricity industry.

Under EPAct, authority for retail wheeling (the transmission of electricity directly to an ultimate customer) is reserved for governmental entities at the state level. In order to promote competition and open access non-discriminatory transmission services, EPAct makes provisions for disclosure of transmission rates, charges, terms of service, and other related information and defines annual reporting of this information to FERC.

EPAct also includes proposals for promoting greater production and use of alternative motor fuels such as LPG or propane, compressed natural gas, and others.

Climate Change Action Plan

The Climate Change Action Plan, released by the Clinton Administration in October 1993, presents the U.S. strategy for achieving the goals set at the 1992 Earth Summit, which focus on reducing greenhouse gas emissions to 1990 levels by the year 2000.[ii] (See Chapter 2 for more on climate change.) This Climate Change Action Plan includes approximately 50 initiatives that span all sectors of the economy and focus on reducing emissions of greenhouse gases in a cost-effective manner. These initiatives, which are primarily voluntary in nature, call for cooperation between government, industry, and the public. The Climate Change Action Plan and U.S. actions to reduce greenhouse gases are the results of more than $2.7 billion invested in global change research since 1990.

The Climate Change Action Plan also addresses ways to stabilize and further reduce emissions after 2000. A major thrust of the plan is to accelerate the penetration of existing energy efficient technologies into the marketplace. These initiatives also rely on voluntary programs and collaborative efforts between the public and private sectors.

The Climate Challenge Program is one such voluntary program developed in 1994 in response to the Action Plan. A joint effort between the U.S. Department of Energy and the electric utility industry, the Climate Challenge Program encourages utilities to make a commitment to reduce greenhouse gases to a certain level by a certain time (or undertake projects to reduce them), and report annually on achievements. Nine small municipally owned utilities in Vermont, operating in concert under the Vermont Public Power Supply Authority (VPPSA), are participating in the Climate Challenge Program and have agreed to reduce greenhouse gas emissions. In addition to reducing emissions, this program will raise awareness of global warming issues and publicize utilities' mitigation efforts.

Vermont, like many other states, has already independently initiated efforts to address climate change and reduce greenhouse gas emissions through initiatives in energy efficiency, local and regional planning, transportation planning, forest management, and agricultural management.

Competition in the Electric Transmission Network

In a series of recent decisions, the Federal Energy Regulatory Commission (FERC) has moved toward opening the electric transmission network to competition. In the March 1995 Notice of Proposed Rule Making (Docket RM 95-8-000, known as the NOPR), FERC investigates ways to promote wholesale competition through open access, non-discriminatory transmission services and ways to allow recovery of stranded costs by

public utilities and transmitting utilities.
The NOPR proposes to require all public utilities owning or controlling transmission facilities to file open access transmission tariffs and to provide service, prices, and information to others that is comparable to what is used in their own wholesale sales and purchases. In this way, the NOPR lays the foundation for open and competitive wholesale power markets, separating or unbundling the transmission of electric power from the established set of services designated for utilities to provide as part of the services they provide to customers in their respective service territories.

The NOPR also proposes to permit recovery of "legitimate and verifiable" past costs, stranded by the development of competitive wholesale service. However, recovery of any retail stranded costs through transmission tariffs will be allowed in limited circumstances only. Any retail stranded costs must be recovered through local distribution rates or other retail rate mechanisms. (See Section II Current Energy Use, H. Current and Future Issues in Energy Use, 2. Increasing Competition and Restructuring in the Electric Utility Industry for further details.) FERC expects to issue a final rule soon.

National Energy Policy

The Clinton administration in 1993 started to set new directions for the U.S. Department of Energy (DOE), the agency charged with energy policy and programs. The Secretary of Energy, Hazel O'Leary, began to restructure the department, to give more emphasis to efficiency and renewables, and to promote partnerships between DOE laboratories, the states, and industry.

The 104th Congress, elected in 1994, has changed and in some cases reversed these trends. Proposals are currently on the table that would cut or eliminate efforts to promote renewable fuels (including tax exemptions, direct subsidies, and research budgets for renewables), while preserving many of the considerable federal subsidies for fossil fuels and nuclear power. (See the Full Cost of Energy Use section later in this chapter.) In addition, there have been proposals to restructure, downsize, or eliminate the U.S. Department of Energy, and in 1995 the Department significantly reduced its work force. There have also been proposals to dramatically reduce the budget of the Energy Information Administration, the agency which tracks energy statistics and makes projections that inform public policy decisions and planning about our economy and energy supply.

3. Vermont's Energy Legislation

Since 1990, Vermont has set a new state energy policy, passed legislation requiring integrated resource planning of electric and natural gas utilities, set and attempted to refine external environmental costs for utility planning, worked to define how competition will restructure the electric utility industry, and has passed many smaller, more specific pieces of legislation surrounding energy use. The following section summarizes some of the most important of these accomplishments.

Environmental Costs of Electricity Services

In 1990 the Public Service Board established that the environmental costs of power generation were to be taken into consideration by Vermont utilities as they planned and selected future supply resources (Docket 5270). Two assumptions were set by the PSB to be used in utility resource planning: a 10% discount was to be taken from demand side management (utility efficiency program) costs to account for the reduced risk of their acquisition and use, and a 5% value was to be added to the cost of supply resources to account for the external environmental costs of electric generation. These values were approximate and were intended to be refined later to more accurately account for the attributes of specific resources. The legislature codified the requirement that utilities consider environmental costs in energy planning in 1991 by requiring that utilities minimize "economic and environmental costs" among supply, transmission, and demand side options (30 V.S.A. §218c).

In an effort to quantify the environmental costs of power generation more precisely, the Board opened an investigation in 1992 to establish a more refined and complete set of values to replace the 5% adder value (Docket 5611). The Public Service Board and numerous parties, including utilities, independent power producers, environmental advocates, low income consumer advocates, and industrial and commercial consumers participated in the investigation, but after nine months of negotiations, they failed to come to a consensus on a method for setting new values for environmental costs. Proceedings are currently on hold.

In its review of methods used by other states for valuing environmental costs, the Department of Public Service (DPS) has found that the state's 5% adder value grossly understates the environmental costs of electric generation. DPS currently is proposing alternate values for environmental costs for air emissions. (See the Full Cost of Energy Use section later in this chapter for more information about Vermont's experience with external environmental costs.) The movement toward increased competition and restructuring in Vermont's utility industry will likely change the way in which the state values environmental costs as well. (See the Competition and Restructuring section later in this chapter.)

Establishment of State Energy Policy

In 1992, the legislature established that the energy policy for the state is:

> To assure, to the greatest extent practicable, that Vermont can meet its energy service needs in a manner that is adequate, reliable, secure, and sustainable; that assures affordability and encourages the state's economic vitality, the efficient use of energy resources and cost-effective demand side management; and that is environmentally sound (30 V.S.A. §202a).

This statement about the state's energy policy summarizes the goals that the Department, the Board, and the state's regulated utilities pursue, and establishes through state statute a policy for non-regulated energy services.

Least Cost Integrated Planning

In 1992, the Vermont legislature reflected the Public Service Board's Order (Docket 5270) in a state statute (30 V.S.A. §218c) and made least cost integrated resource planning a statutory requirement for the state's electric and gas utilities. A number of utilities have obtained Public Service Board approval for their first integrated resource plan (IRP) filing, and several are now developing or have under review a second round IRP.

Policies Affecting Competition in the Utility Sector

The Public Service Board's Rule 4.100, along with the federal Public Utility Regulatory Policies Act of 1978 (PURPA) have expanded the role of non-utility generation in Vermont's electric supply resources. (The federal 1992 Energy Policy Act also will contribute to this in the future.) With the opening of the transmission network, Vermont can obtain wholesale electric supply resources from utility and non-utility sources over a broader geographic area. (See earlier discussion of Competition in the Electric Transmission Network.)

Since October, 1994, the Board and the Department have been meeting with the state's utilities, businesses, and interested parties to develop guidelines for restructuring the electric industry. This Working Group of the Vermont Roundtable on Electric Industry Restructuring agreed that efficiency and fairness should guide any development of a restructured electric industry in Vermont and the region. A restructured electric industry should also provide opportunities to capture improved efficiencies in the production, delivery, and use of electric energy, and it should maximize customer value at the least cost to society. In addition, members of this Working Group concurred that all producers and consumers should be treated equitably, according to the costs they impose and the benefits they derive, both during and after the transition to a restructured industry. (See the Competition and Restructuring section later in this chapter.) Because the Working Group was split on some key issues, two similar but distinct documents represent the final work product. All members of the group agreed with a set of general principles that should be reached in the restructuring of Vermont's electric industry. Most of the Working Group members, however, endorsed a more detailed set of principles that also included particular ways to ensure environmental protection, low income energy assurance, energy efficiency, renewable energy, and recovery of strandable utility costs.

Following a petition from the Department, the Board issued an Order in Docket 5854 opening an investigation into the restructuring of the electric utility industry in Vermont. The goal for this investigation is to develop a framework for electric utility activities that will provide benefits from a more competitive environment while maintaining and enhancing desirable features of the current regulatory system.

Lawsuit Concerning Radioactive Nuclear Fuel Disposal

Vermont has joined 27 other states and a number of utilities in a legal case against the U.S. Department of Energy (DOE) concerning disposal of high-level radioactive waste. DOE has been required by federal law to build storage facilities for spent fuel from nuclear power plants and to begin accepting this spent fuel January 1, 1998. However, DOE is not developing these facilities and has announced that it cannot *and will not* accept spent fuel from the states. The case is in progress.

4. The State's Role in Energy Planning

Vermont's government participates in energy planning in a variety of ways. State agencies, regional planning commissions, and many cities, towns, and villages create plans that address energy issues. In addition, the Department of Public Service, the Public Service Board, the Agency of Transportation, and the Agency of Natural Resources all have roles in energy planning and development, as outlined below.

State, Regional, and Municipal Planning (Act 200)

State agencies and regional planning commissions are required by Act 200 (and towns are encouraged) to create land use development plans that meet a number of goals related to historic preservation, environmental quality, economic vitality, energy efficiency, and other goals. Act 200 has increased awareness and planning of energy issues at all levels of Vermont's government.

State agencies are required to prepare and adopt State Agency Plans. These plans address the agencies' progress in advancing the planning goals of Act 200, some of which are related to energy and energy efficiency.

Vermont has 12 Regional Planning Commissions which, among other duties, create and implement Regional Plans and assist towns in preparing plans and in implementing recommendations (see 24 V.S.A. §4345 for information about their other duties). Each of these Regional Plans sets out goals, policies, and recommendations to direct future energy use in the region. In addition, there are currently 48 cities, towns, and villages that have municipal plans which have been adopted by the community and have obtained approval from the respective Regional Planning Commission. Local concerns about energy, air quality, utility facilities, and transportation issues are addressed in the municipal plans. (For more information about state agency, regional, and municipal planning, see Appendix 4.)

The Vermont Department of Public Service

The Department of Public Service (DPS) serves all citizens of Vermont through public advocacy, planning, programs, and other actions that meet the public's need for a safe, adequate, reliable, secure, sustainable, affordable, environmentally sound, efficient energy supply and regulated utility systems. The Department undertakes the following ongoing programs which are directly related to energy planning.

Comprehensive Energy Planning. The Department, in conjunction with other state agencies designated by the governor, prepares this long term energy plan for the state that seeks to implement the state's energy policy, as required by state statute (30 V.S.A. §202b). This plan, which is updated periodically, includes analysis and projections on the use, cost, supply, and environmental effects of all forms of energy resources used within Vermont. In the process of updating the plan's recommendations, the Department seeks public participation and input by issuing a public review draft and encouraging the public to review the draft and provide comments by participating at a public hearing or by sending in written comments. The final product, the *Vermont Comprehensive Energy Plan*, sets out the state's recommended energy policies and models their impacts over the next 20 years. (See the text box on the *History of the Comprehensive Energy Plan* and 30 V.S.A. §§202a and b in Appendix 2.)

Electric Energy Planning. The Department prepares and distributes the *Vermont Twenty Year Electric Plan*, which reviews the state's current and long term need for electric energy and analyzes the resources available for meeting future demand. In this plan, guidelines are presented for the state's electric utilities in their preparation of integrated resource plans (IRPs). Utility IRPs assess alternative resource options and propose the utility's optimal mix of supply resources, demand side management programs, and transmission and distribution improvements that will enable the utility to meet its future demand in a least cost manner, recognizing environmental costs. The current edition of this plan was released in 1994. (See 30 V.S.A. §202 in Appendix 2.)

Review of Utility Integrated Resource Plans. Vermont's electric and gas utilities update their respective long range integrated resource plans on a three year cycle, in accordance with a schedule set by the Board. Utilities file the updated version of their IRP with the Board and the Department. The Department reviews each IRP and works with utility staff to clarify any questions about the data, analysis, methodologies, and assumptions used in identifying the preferred set of supply, DSM, and transmission and distribution efficiency improvements that will guide utility decisions in meeting customers' long range demand for electricity. The Department makes a recommendation to the Board about whether the Board should fully approve an IRP, give approval with agreement that stipulated conditions are met, or reject the IRP filing.

Review of Utility Demand Side Management Annual Reports. Utilities report annually to the DPS and PSB on the Energy Efficiency Programs that they are conducting for their customers. The Energy Efficiency

In 1989, Governor Madeleine Kunin issued an Executive Order calling for a comprehensive review of all forms of energy used in the state, and a plan to modify that energy usage in order to achieve goals related to environmental quality, affordability, and renewability. The Department of Public Service, in conjunction with the Agency of Natural Resources and the Agency of Transportation, created the first *Comprehensive Energy Plan* issued in January 1991. The plan included an analysis of and recommendations for regulated, non-regulated, and transportation fuels. Goals of the plan included reducing global warming gases and acid rain precursors by 15% by the year 2000; reducing per capita non-renewable primarily fossil fuel energy use by 20% by 2000; and maintaining the affordability of energy.

In 1991, the Vermont Legislature directed the Department of Public Service to prepare a 20-year comprehensive state energy plan, to be updated on a regular basis. This plan is the result of that mandate. Future energy plans will continue to analyze and recommend policies for Vermont's energy future.

Division reviews each utility's report, which is meant to include information on all of the current residential, commercial, and industrial programs and their respective participation rates, costs, and other relevant factors, as well as the resources each program has been able to acquire. The Department's assessment is sent back to the utility, to be used by utility staff as they assess their own programs and plan and prepare for the future.

Participation in Land Use Planning. The Department participates in the Environmental Board's review process for land use and development known as Act 250 Reviews, which are conducted in accordance with 10 V.S.A. §6086. This is Vermont's only statewide building efficiency review process. The Department participates as a statutory party under 10 V.S.A. §6086(a) Criteria 9(F) Energy Conservation and 9(J) Public Utility Services.

Criterion 9(F) provides that:

> the planning and design of the subdivision or development [must] reflect the principles of energy conservation and incorporate the best available technology for efficient use or recovery of energy.

Criterion 9(J) provides that:

> necessary supportive and governmental and public utility facilities and services are available. . . . An excessive or uneconomic demand will not be placed on such facilities

> and services. . . . Provision of such facilities and services has been planned on the basis of a projection of reasonable population increase and economic growth.

Development of Statewide Building Standards. Currently, Vermont has no statewide prescriptive building standard for residential or commercial and industrial new construction. DPS participation in Act 250 has functioned as a form of energy efficiency review that has some of the same effects as a building standard.

In July 1991, the City of Burlington adopted a set of energy efficiency standards for new residential, commercial, and industrial construction and for substantial renovations. These standards are based on nationally recognized energy efficiency standards that apply to a building's lighting, heating, ventilating, air conditioning, and envelope (ASHRAE/IES 90.1-1989 and CABO/MEC), with modifications from those standards to increase efficiency levels in certain areas such as lighting and motors.

The Department of State Buildings in conjunction with the DPS developed a building standard in 1991 entitled "State of Vermont, Department of State Buildings Energy Conservation Standard for New and Existing State Buildings." This standard is based on an updated and modified version of ASHRAE/IES standard 90.1-1989. In 1992, the Vermont legislature required that this standard be applied to "new state funded buildings, or new additions to state funded buildings, on which construction is begun after June 30, 1993" (21 V.S.A. §252(f)). This law means that the standard will apply to projects receiving state funding, such as schools and water and sewer facilities. The Department of Labor and Industry is in the process of implementing this legislative requirement.

The National Energy Policy Act of 1992 requires that within two years of the passage of the Act (by October 1994), all states must review both their residential and C&I building codes to determine whether they should be revised to "meet or exceed" CABO Model Energy Code, 1992, (for residential structures) and ASHRAE/IES 90.1-1989 (for commercial structures). Since Vermont has neither of these codes in place on a statewide basis, it is not clear how this requirement will be met. DPS is currently working to ensure that the State of Vermont addresses the building energy standard requirements of EPAct, involving interested constituencies such as home builders, designers, engineers, developers, and trade associations.

Energy Emergency Planning. The Department has prepared a plan that defines the steps that must be taken in the event of a serious energy shortage, including energy monitoring activities, responsibility assignment, and procedures to be carried out under various energy emergency conditions.

Telecommunications Planning and Advocacy. The Department has responsibility to develop and implement the *Vermont Telecommunications Plan* and promote the public interest in regulatory issues related to telecommunications. Insofar as telecommunications services reduce the need to use energy for transportation purposes, such services are also a component of energy planning. (See 30 V.S.A. §202d in Appendix 2.)

Planning Documents and Reports. The Department also prepares a number of other planning documents and reports. Appendix 3 lists the documents and reports prepared by DPS since 1993.

The Vermont Public Service Board

The Public Service Board consists of three members who are appointed by the governor through the judicial selection process for staggered terms of six years. The Board operates as a quasi-judicial body, hearing cases on activities of regulated companies in Vermont, including electric and gas utilities, telecommunications companies, and small, private water companies. The Board initiates investigations, adopts rules implementing state and federal laws, and makes decisions based on presented records of facts. The Board has issued Orders, such as Order 5270, requiring the state's regulated utilities to do long range planning in accordance with principals of integrated resource planning. Board approval is needed for the Integrated Resource Plans that utilities prepare. The Board also plays a significant role in energy planning for the state in its proceedings related to utility financings, major supply contracts, and facilities.

<u>The Vermont Agency of Transportation</u>

Transportation planning is conducted by the Vermont Agency of Transportation's (AOT) Planning Department. Their authorization derives from 19 V.S.A. §10, which establishes that:

> The Agency [of Transportation] shall be the responsible agency of the state for the development of transportation policy. It shall develop a mission statement to reflect state transportation policy encompassing all modes of transportation, the need for transportation projects that will improve the state's economic infrastructure, as well as the use of resources in efficient, coordinated, cost-effective, and environmentally sound ways.

AOT's mission is to work cooperatively to anticipate and meet the need for the movement of people and goods in a safe, cost-effective, environmentally sensitive, and timely manner. The Agency manages transportation projects aimed at providing safe and efficient transportation and economic opportunities for Vermonters, taking into consideration the state's natural resources, Act 200 planning goals, and local, regional, and state agency plans.

A primary component of the transportation planning process is AOT's preparation and adoption of a long range, multi-modal systems plan integrating all modes of transportation. This statewide plan reflects AOT's mission and policy, policies approved by the legislature, demographic and travel forecasts, design standards, performance criteria, and funding availability. Developed with participation from public, local, and regional governmental entities, this plan draws on corridor studies and projects developed from these studies. (See Vt. AOT, *Vermont's Long Range Transportation Plan*, 1995).

<u>The Vermont Agency of Natural Resources</u>

The Agency of Natural Resources (ANR) is composed of the Department of Environmental Conservation, the Department of Fish and Wildlife, and the Department of Forests, Parks, and Recreation, as well as a central office that includes planning, policy, and administrative staff. ANR was created in 1970 by the legislature and charged to "protect and improve the quality and balance of the environment and natural resources and to improve the opportunities to maintain health within the environment."

The central planning division at ANR facilitates planning within each department. Planning in the Department of Environmental Conservation often has relevance for or includes planning related to energy issues. For instance, the Strategic Plan of the Environmental Assistance Division (a branch of the Dept. of Environmental Conservation) outlines several goals involving recycling, pollution prevention, energy efficiency products, and consumer education about sustainable use of resources (Vt. ANR, *Strategic Plan*, 1995).

ANR has recently identified 25 "outcomes" or goals that Agency planning and programs will seek to meet. Each outcome will eventually be accompanied by a set of measurable indicators through which the Agency will track how well the outcome has been achieved. Many of the outcomes and indicators are related to energy use. The following list is a sample of selected outcomes and proposed indicators related to energy use.

1. Sustainable natural resource use:

   - Amount of wood harvested and processed from Vermont's forests
   - Number of vehicles using alternative fuels
   - Percent of solid waste stream diverted to recycling, and other recycling measures

2. Minimal potential for human and biotic exposure to toxic substances:

   - Level of toxic substances detected in biota, soil, water, groundwater, and air

3. Clean air that meets current ambient air quality standards:

   - Percent of time air quality meets ambient air quality standards at monitoring stations
   - Concentration of ozone, sulfur dioxide, carbon monoxide, lead, hydrocarbons, VOCs, and nitrogen oxides in the air
   - Number of vehicles participating in an emission inspection and maintenance program
   - Percent of gas stations with Stage II vapor recovery systems
   - Number of people who commute through ride-share programs, biking, or walking
   - Number of annual passenger miles traveled in mass transit systems
   - Tons per year of air pollutants released from industrial sources
   - Amount of unplanned releases of toxic chemicals or radioactive substances to air
   - Number of citizen complaints about bad air, and other indicators

4. Clean earth materials:

   - Number of underground fuel tanks replaced

5. Healthy aquatic ecosystems:

   - Percent of impaired surface waters
   - Changes in abundance and distribution of fish populations

6. Good land stewardship:

   - Acres harvested with sustainable practices (including wood)

7. An aesthetically pleasing landscape:

   - Number of days with poor versus good visibility

(Source: Vt. ANR, *Agency of Natural Resources Outcomes: Draft*, 1995.)

II. CURRENT ENERGY USE

Vermont's energy comes from many fuel sources and is used to power a diverse set of appliances, equipment, and vehicles. In this section we focus on the state's current sources and uses of energy. After a quick review of recent U.S. and statewide energy use, we examine Vermont's energy use among sectors and among end uses over the past 20 years. Then we turn to energy use among fuels, analyzing each fuel source in-depth and exploring trends and issues that will influence the near-term future use of each fuel source. Non-electric fuel sources are discussed first, followed by a discussion of electricity use and the primary fuels used to generate electricity. In this discussion, we also review Vermont's utility efficiency measures (or demand-side management measures). We then turn to an examination of energy sources and technologies that are not widely used today, but that have the potential for greater use in the future. These include renewable energy sources, alternative transportation fuels, and technologies that are currently available or may be available in the future. We end this section by examining two issues that will be extremely important for our future energy use: the full cost of energy use, and increasing competition in the electric utility industry.

A. Escalating Energy Use

Worldwide energy use has grown phenomenally in the past 40 years, quadrupling between 1950 and the early 1990s. At the same time, oil use rose more than five-fold (Flavin, *Power Surge*, 1994, 34-5). Industrialized countries, including those in North America, were responsible for much of this growth. In 1991, North America accounted for 28% of the world's energy use with only 6.8% of the world's population. North Americans used 263 million BTU per person, four times the world average, in 1991. (See Figures 3.II.1 and 3.II.2.)

Since 1950, energy use in the U.S. has increased, plateaued, and increased again, as illustrated in Figure 3.II.3. Between the late 1950s and early 1970s, U.S. energy use increased significantly. However, in the mid-1970s, total use decreased for two consecutive years due to higher oil prices and conservation measures stemming from the first oil crisis, but then resumed its upward track. In the early 1980s, energy use fell again (this time for four years), due to an economic recession, oil price increases, and gains from fuel efficiency measures in vehicles, appliances, and buildings. Because of these years of decreasing use, total energy use in the mid-1980s was at about the same level as use in the early and mid-1970s. Thus, high oil prices, improving technologies, government regulations, and economic recessions combined to give us about 10 years in which energy use did not follow the increasing path of the 1950s, 1960s, and early 1970s. Energy use grew by 101% between 1950 and 1970, but only 27% between 1970 and 1990.

However, since the mid-1980s total U.S. energy use resumed its strong yearly increase, except for a slight decline during the 1990 recession. The increase has been fueled by low oil prices, economic growth, and rising transportation energy use due to increasing miles traveled and the absence of gains in the average fuel efficiency of the vehicle fleet.

As shown in Figure 3.II.4, Vermont's energy use from 1976 to the present roughly paralleled U.S. trends. Although there are some differences between U.S. and Vermont trends, Vermont's consumption decreased in the late 1970s and early 1980s as U.S. consumption did. Since then, energy use has increased in the state, due partly to the economic recovery following the recessions of the early 1980s and to declining emphasis on energy efficiency after initial savings were achieved. Between 1989-1990, there was a decrease in total consumption in the state; however, energy consumption has resumed its strong growth since the 1990 recession. Vermont's per capita delivered energy use, at 245 million BTU in 1993, is lower than the U.S. average of 322 million BTU during the same year (U.S. DOE/EIA, *State Energy Data Report*, 1995, 18).

Both "delivered" and "primary" energy use are presented in Figure 3.II.4 and in some subsequent Figures. Both measures of energy use are important. Delivered energy use is the measure of the energy consumed as it enters (or is delivered to) the consumer's home, building, or vehicle. Delivered consumption is the measure most often used in reports of energy use, so it provides a baseline for comparison with other sources. Primary use is the measure of the delivered energy consumption plus the energy lost in the generation, transmission, and distribution of electric energy and natural gas.[iii] Electric generation plants that use fossil fuels and nuclear power require roughly three times the amount of energy input as is produced in output, and this is reflected in measures of primary energy use. Primary consumption includes some of the "energy used to produce energy," and as such, gives a more complete indication of our total energy use.

Vermont's decrease and subsequent increase in energy use since 1976 was accompanied by roughly opposite trends in total energy expenditures. As depicted in Figure 3.II.5, the state's expenditures for energy rose between 1978 and 1981, but falling oil prices in the 1980s led to declining expenditures in some of the subsequent years. Since 1986, Vermont's total energy expenditures have risen only 6.96%, or an average of 0.84% per year, even though primary energy consumption increased an average of about 3% per year during the same period of time.

The following sections break down this data by sector, end use, and fuel source, and a text box gives data and descriptions about air emissions from Vermont's energy use.

B. Energy Use Among Sectors

While total Vermont energy use after 1976 first decreased and then increased, these trends did not occur at similar rates in the transportation, residential, commercial, and industrial sectors. As illustrated in Figure 3.II.6, energy use in all four sectors declined from 1976 to the early 1980s, but since then has increased at a different rate for each sector.

The residential sector experienced the smallest increase of energy use since the early 1980s, with delivered energy use rising only 10% between 1980 and 1994. Primary energy use (presented in the second table of Figure 3.II.6) increased 14% during the same time period, as residential use of electricity expanded at a greater rate than the use of some other types of energy (because primary use includes energy used to generate electricity). The more moderate increase of both delivered and primary residential energy use between 1980-1994 is due mainly to increased efficiencies of equipment, appliances, homes, and buildings.

Although the industrial and commercial sectors are smaller in Vermont than in many other states, energy use in both sectors grew substantially between 1980 and 1994. Delivered energy use in the industrial sector grew 21%, while primary use grew 34% during this time-frame. As in the residential sector, industrial use of electricity grew at a much greater rate than its use of some other energy sources. In the commercial sector, delivered energy use increased by 47% and primary use increased by 53% between 1980-1994. Growth within both the commercial and industrial sectors was largely due to economic growth in the state following the recessions of the early 1980s. Significant opportunities for energy savings exist in these sectors; however, combined commercial and industrial energy use in the state is still smaller than our total transportation energy use.

Energy use in the transportation sector has experienced strong growth since 1980, increasing 50%. While energy use increases in the commercial and industrial sectors stemmed largely from a recovering and expanding economy, increases in the transportation sector were due mostly to a different set of factors. These factors include the following: 1) Vermont's gasoline prices fell from $2.21 in 1980 to $1.14 in May 1995 in Vermont (in 1994 dollars) (Vt. DPS, Fuel Price Survey). (See Figure 3.I.3.) 2) While new cars made impressive gains in fuel efficiency in the 1970s and early 1980s, the total Vehicle Miles Traveled (VMT) in

Vermont and nationwide continued to increase. (See Figure 3.I.2.) Vermont's rural nature and dispersed land use pattern contributed to the increase in VMT. 3) The number of vehicles on the road increased dramatically in the 1970s and 1980s. Between 1970 and 1990, the number of vehicles increased 100% in Vermont, due partly to the state's 27% increase in population during the same time period. Vermont's vehicle growth rate over this time period exceeded the growth rate in the U.S., even taking into account differences in population growth (Vt. Motor Vehicle Registries; U.S. Bureau of the Census, 1994; Gordon, 1991, 21; see also Table 3.I.3). 4) Virtually no gains were made in the average fuel efficiency of cars sold since 1985 (U.S. Congress, OTA, 1991, 153). In the past several years, there have also been growing numbers of light trucks and vans on the road; light-truck and van VMT grew at five times the rate of auto VMT between 1970 and 1985, largely because these vehicles were used to transport passengers rather than freight (Gordon, 1991, 42). This trend lowers the overall efficiency of the vehicle fleet and increases emissions.

Currently, energy use in the transportation sector accounts for 43% of Vermont's total delivered energy consumption, while residential use accounts for 31%. (See Figure 3.II.7.) These sectoral shares are somewhat different for primary energy consumption, as depicted in Figure 3.II.8. While the transportation sector share is smaller in terms of total primary energy use, the other sectors' shares are larger. This reflects the large amounts of electricity used in the residential, commercial, and industrial sectors.

Vermont's primary energy sectoral shares differ considerably from national shares, as illustrated by Figure 3.II.9. The industrial sector accounts for the largest portion of U.S. energy use, with 37% of the total. While the industrial sector's share is greater in the U.S. than in Vermont, transportation and residential sector shares are significantly lower. Vermont's character as a rural northern state with a small industrial base is reflected in these differences.

C. Energy Use Among End Uses

Within each sector, Vermonters use energy for many purposes or "end uses," including space heating, water heating, lighting, industrial motors, aviation, etc. (See Figure 3.II.10.) While transportation is considered as a sector of energy use in the previous section, specific types of transportation are also end uses and are analyzed as such in this section. Looking at Vermont's end uses during recent years shows us where our energy goes and where opportunities for energy savings lie.

Road transportation has been the largest end use of energy in the state since 1977. Energy use for space heating was relatively close to that used for road transportation through the early 1980s, but subsequently stabilized and in some years declined while road transportation use grew substantially (by about 40% between 1985 and 1994). Other end uses require significantly less energy than road transportation and space heating. Water heating, currently the next largest end use, has grown by 17% in energy consumption since 1976, while process heat for industrial purposes (the fourth largest end use) has declined by 14%. All other end uses have increased their energy consumption since 1976, most notably air conditioning (125%), motors for industrial purposes (121%), miscellaneous electricity end-uses (90%), and lighting (60%).

As illustrated in Figure 3.II.11, road transportation currently accounts for 42% of Vermont's total delivered energy use, while space heating accounts for 28%. Energy use for water heating and process heat (industrial)are about equal at 8%-9% of the total, and all other end uses have much smaller shares. Primary energy use, depicted in Figure 3.II.12, presents slightly different shares for the various end uses. Transportation and heating end uses have smaller shares of primary use, while water heating, miscellaneous uses, motors, lighting, and refrigeration all have larger shares, reflecting the high electricity use among these end uses.

Carbon dioxide is emitted during the combustion of all fossil fuels. Carbon dioxide is the largest contributor to global warming; of the global warming to be brought about by the human-caused greenhouse gases released in 1990, carbon dioxide is responsible for 66% (U.S. EPA, *States Workbook*, 1992, v). While burning fuels more completely can reduce the emissions of many of the other pollutants, it cannot reduce carbon dioxide emissions. Carbon dioxide emissions can be reduced by decreasing energy use, using more efficient furnaces, vehicles, etc., or switching to fuels that emit smaller amounts of carbon dioxide.

Carbon monoxide is an air pollutant as well as a contributor to smog. Motor gasoline and diesel use emits more carbon monoxide per unit of energy used than any other fuel in Vermont. (See Table 3.II.1.) Nationwide, two-thirds of carbon monoxide emissions come from transportation sources, with the largest contribution from motor vehicles. Exposure to this gas inhibits the blood's capacity to carry oxygen to organs and tissues, and places additional stress on people with heart and respiratory diseases, infants, and elderly persons. Exposure can also affect healthy people, impairing exercise capacity, visual perception, manual dexterity, learning functions, and the ability to perform complex tasks (U.S. EPA, *I/M Briefing Book*, 1995, 4).

Nitrogen oxides emissions lead to the formation of ground-level ozone, the major constituent of smog (see below), and contribute to acid precipitation, which acidifies lakes and streams and harms forests. Motor gasoline and diesel use emits more nitrogen oxides per unit of energy used than any other fuel in Vermont. Nitrogen oxides can irritate the lungs, cause bronchitis and pneumonia, and lower resistance to respiratory infections.

Volatile organic compounds (VOCs), sometimes referred to as non-methane hydrocarbons, are often toxic, and as a group they contribute to ground-level ozone. Ground-level ozone, the major component of smog, is formed from the combination of VOCs and nitrogen oxides as they react in the presence of heat and sunlight. The primary source of the constituents of ground-level ozone is auto exhaust. Unhealthy levels

Energy consumption among end uses varies from sector to sector, as shown in Figures 3.II.13 - 3.II.16. In the residential sector, road transportation and space heating end uses have consumed close to the same amount of energy (delivered) since 1976 (around 35%-40% of the total), but have started to diverge in the past several years as transportation energy use increased while heating declined. Water heating, the next largest end-use in the residential sector, required 19% more energy in 1994 than in 1976. Most other end-uses experienced larger increases over the same time-frame, especially air conditioning energy (233%), miscellaneous electric uses (63%), and drying (55%).

of smog are a problem across the U.S., with about 90 cities exceeding the National Ambient Air Quality Standard for ozone; nine of these are"severely" polluted. Ozone usually is not formed at the point where emissions are produced. Instead, the chemicals typically are carried some distance by the wind before ozone is created. For this reason, emissions in one area can contribute to a smog problem in another area. In regions of the country where many urbanized areas are located close to one another, as in the Northeast, this problem is worsened. Thus, ozone is a regional problem rather than a local one. Vermont, as part of the Regional Northeast Ozone Transport Commission, is working to help mitigate the problem in the Northeast. Smog is responsible for choking, coughing, and stinging eyes. It can damage lung tissue, aggravate respiratory disease, and make people more susceptible to respiratory infections. Adults with existing diseases and children are especially vulnerable to its harmful effects, but healthy adults also can experience impaired health. In addition, smog can damage crops and reduce crop yields (U.S. EPA, *I/M Briefing Book*, 1995, 2-3).

Sulfur oxides are health hazards and significant contributors to acid rain. Sulfur oxides emissions result from burning any fossil fuel, but the combustion of coal produces the largest amount (per unit of energy used). Nitrogen oxides and sulfur oxides react to form acid precipitation that acidifies waterways and damages plant life. Sulfur oxides can remain in the atmosphere for up to ten days after they are emitted and can be carried more than 600 miles before they are deposited as precipitation. Thus, emissions in one region can cause impacts in distant regions.

Particulate emissions consist of dust, soot, smoke, and other suspended matter resulting from the burning of fossil fuels. PM-10 emissions are of the greatest concern because they can most easily enter humans' lungs. These emissions are respiratory irritants and may be implicated in acid-precipitation formation.

Nitrous oxide is a potent greenhouse gas, trapping 270 times more heat in the atmosphere than an equivalent amount of carbon dioxide emissions traps. Of the global warming effect from human-caused greenhouse gases released in 1990, nitrous oxide is responsible for 5% (U.S. EPA, *States Workbook*, 1992, v).

Methane is also a serious greenhouse gas, trapping 11 times more heat in the atmosphere than an equivalent amount of carbon dioxide emissions traps. Of the global warming to be brought about by the human-caused greenhouse gases released in 1990, methane is responsible for 18% (U.S. EPA, *States Workbook*, 1992, v).

In addition to the human health effects of energy emissions, these pollutants also are responsible for extensive environmental deterioration, damage to agriculture and wildlife, the corrosion and soiling of buildings, the degradation of visibility, and the contamination of water.

In the commercial sector, transportation use dominates even more, as shown in Figure 3.II.14. In 1976, transportation and space heating consumed about the same amount of energy, but since then, heating energy use first declined and then rose slowly, while transportation use increased steadily (by 106%). Currently, transportation energy use accounts for 61% of total delivered use in the commercial sector, while space heating accounts for only 29%. The next largest end use, lighting, represents only 6% of total delivered energy use, but its energy use has grown substantially since 1976. All other end-uses consume much less energy, but most increased rapidly between 1976 and 1994, especially air conditioning (106%), miscellaneous electric uses (104%), and refrigeration (48%).

As portrayed in Figure 3.II.15, the largest end use in the industrial sector is process heat, which currently accounts for about half the energy use in the sector. Energy consumed for process heat has declined since 1976, but consumption by all other end uses has risen substantially. Transportation energy use increased by 88% between 1976 and 1994, and now accounts for one-quarter of total industrial use. Energy use for motors, the next largest end-use, increased 121%, and miscellaneous electric uses and lighting energy use increased 133% and 122% respectively.

Energy use in the transportation sector is shown in Figure 3.II.16. Car and truck transportation energy use increased by 45% between 1976 and 1994. A major portion of this increased energy use is attributable to the categories "light trucks" and "other trucks" (Davis, 1997, 2-14). Energy use among the sum of all other transportation end-users remained about the same. Specifically, aviation energy use grew dramatically. Energy used for trains has been declining in the state due to less freight being shipped by rail. Several recommendations in the New England Transportation Initiative (NETI) report could make a difference in these transportation energy consumption trends. The NETI Report recommends "creating a New England Regional Intermodal Freight Alliance to assist the states in the development of a strategic, intermodal, and regional approach to the movement of goods in New England." This agreement among Connecticut, Maine, Massachusetts, New Hampshire, and Vermont would follow an intermodal approach, ensuring that products move by the optimal combination of modes, including rail, bus, truck, and air (NETI, 1995, ES-2).

D. Energy Use Among Fuel Sources

Vermonters use a variety of fuel sources to meet our energy needs, but by far the predominant fuel used is petroleum, as shown in Figure 3.II.17. From 1976 to 1982, petroleum use declined due to an economic downturn, higher oil prices, and the improving fuel efficiency of vehicles. However, since the early 1980s, petroleum use has increased to about its 1976 level and is continuing to grow. Total electric energy use has risen steadily since the mid-1970s, increasing 65% from 1976 to 1994, in spite of the fact that many efficiency gains have been made in electric end-uses. Wood use has fluctuated over the years, and is currently at a plateau. Natural gas and LPG (propane) use have risen steadily.

The second table of Figure 3.II.17 shows Vermont's demand for primary fuels, breaking out electricity use into specific fuels. In terms of primary fuels, nuclear energy is the second most-used source after oil. Although Vermont uses a large amount of hydroelectric power, hydro energy use appears relatively low in this presentation because there are no thermal losses in the generation of hydropower. By contrast, recreational thermal electric generation plants that use fossil fuels and nuclear power require about three times the amount of energy input as is produced as output. Because Vermont currently uses electric energy from two wood-fired plants and one coal-fired plant, wood and coal energy use are larger in this table than they are in the delivered energy use table. The energy lost in electric and natural gas generation, transmission, and distribution accounted for a total of 27 TBTU in 1994, or 19% of total primary energy consumption.

Figures 3.II.18 and 3.II.19 show the state's delivered and primary energy consumption for 1993. Energy used for electricity was only 15% of the total in the delivered energy use chart, but was much larger in the primary energy use chart, as evidenced by the addition of the nuclear and hydro categories and the increased values for oil, wood, and coal. Vermont's primary consumption is quite different from consumption in the U.S. as a whole. As Figure 3.II.20 illustrates, oil (including LPG) is used to meet 40% of U.S. primary energy needs, while oil and LPG are used to meet 67% of Vermont's primary energy needs. The nation also uses much larger proportions of natural gas and coal than Vermont, and a smaller proportion of nuclear power.

Figure 3.II.2 World Primary Energy Use per Person, 1991

Million BTU per person

Figure 3.II.3 U.S. Primary Energy Use

Quadrillion BTU

Figure 3.II.4 Vermont Primary and Delivered Energy Use
TBTU

Figure 3.II.5 Vermont Energy Expenditures
Millions of 1995 dollars

Figure 3.II.6 Vermont Delivered Energy Use by Sector
TBTU

Figure 3.II.10 Vermont Delivered Energy Use by End Use
TBTU

Figure 3.II.13 Vt. Residential Delivered Energy Use by End Use

TBTU

Figure 3.II.14 Vt. Comm. Delivered Energy Use by End Use

TBTU

Figure 3.II.15 Vt. Industrial Delivered Energy Use by End Use
TBTU

Figure 3.II.16 Vt. Transportation Delivered Energy Use by End Use

TBTU

Figure 3.II.17 Vermont Delivered Energy Use by Fuel

TBTU

Figure 3.II.21 Vermont Emissions from Energy Use

Tons

E. Non-Electric Fuel Sources

Non-electric energy sources used in Vermont include petroleum products (motor gasoline, distillate fuel, LPG, and others), natural gas, wood, and small amounts of coal and solar energy. Each of these fuel sources is described in more detail below, along with an exploration of trends and issues that will influence the future use of each source. Because petroleum products comprise the largest portion of the state's energy use, they are discussed both as a group and individually below.

1. Petroleum Products

In 1993, Vermont used a total of 78 TBTU of petroleum products for non-electric purposes, representing 71% of our total delivered energy use (Vt. DPS).

Petroleum products include motor gasoline, distillate fuel (heating oil and diesel fuel), liquid petroleum gas, kerosene, aviation gasoline, jet fuel, and residual fuel (a "heavy" or thick oil used mostly for electricity generation and industrial heating).[iv]

Vermont's use of petroleum products is far greater than our use of any other fuel source. Oil is the most-used fuel in the transportation and residential sectors, and currently competes with electricity for the top usage in the commercial and industrial sectors (Vt. DPS). Oil accounts for 53% of total residential delivered energy use, 49% of commercial use, and 39% of industrial use (Vt. DPS). Of our total oil consumption, about 59% occurs in the transportation sector, 24% occurs in the residential sector, and the remainder occurs in the commercial and industrial sectors (U.S. DOE/EIA, *State Energy Data Report*, 1995).

The U.S. also uses petroleum more than any other energy source, representing 40% of the 1993 primary energy use, or 33,842 TBTU. (See Figure 3.II.20.) The transportation sector uses the largest amount of petroleum, accounting for 66% of all U.S. petroleum demand in 1993. The industrial sector is the second largest user, representing 25% of total U.S. petroleum demand (U.S. DOE/EIA, *State Energy Data Report*, 1995, 21, 24-5).

On a per capita basis, Vermont uses slightly more petroleum than the U.S. average. Vermonters consumed about 135.4 million BTU of petroleum per person in 1993, while Americans consumed 131.4 million BTU.[v]

Future Trends and Issues

Supply. Proven worldwide oil reserves are about 1.1 trillion barrels.[vi] These proven reserves will last 32 years from 1995 if oil usage grows at 1.6% per year, the average growth rate the U.S. Energy Information Administration predicts through 2010.[vii] The "world ultimate resources" are the technically recoverable oil resources assuming existing technology, including reserves already used, proven reserves, future additions to reserves in existing fields, and estimated undiscovered resources; these resources are estimated at 2.3 trillion barrels (Masters, 1994, 529). If we use all of the world ultimate resources that remain (about 1.6 trillion barrels), the supply will last 43 years from 1995 at the predicted growth rate. In addition, there is oil available in Canadian tar sands and in Venezuelan extra heavy oils that is currently not economical or practical to retrieve; if the retrievable oil from these sources is considered, the world oil supply would last 54 years from 1995 at the predicted growth rate. Other fuels such as coal could be substituted for oil for an even longer time through the creation of synthetic oil.

These figures do not necessarily indicate that the world will run out of petroleum supplies in 50 years. As oil supplies decrease, the price will increase, which in turn will lower demand and cause more oil to become profitable to extract. Furthermore, the estimates for world proven and world ultimate resources are subject to modification as new oil is found and as new technologies and information become available. For instance, estimates of worldwide proven oil reserves have fluctuated through the years due to different rates of annual crude oil discoveries and production. Up through the mid-1960s, yearly oil discoveries were much greater than yearly oil production. Since the mid-1960s, however, annual oil discoveries have fallen, and around 1980, they fell below yearly production for the first time. During the early 1990s, annual oil discoveries have been about one-third of annual oil production (Masters, 1994, 537).

However, even if world ultimate resources are actually double the amount of their current estimate, our oil supply would last only 77 years from 1995, assuming the current growth rate in usage. Moreover, there is very little petroleum to fuel the development of non-industrialized nations and simultaneously maintain current levels of oil use in industrialized countries. In order for petroleum use per capita in all nations to reach the level of current per capita use in the U.S. over the next 100 years (and assuming U.S. energy use did not grow beyond its current level), the proven oil reserves would have to be twelve-and-one-third times greater than they are currently.[viii]

Oil reserves are located around the world, but are concentrated most heavily in the Persian Gulf area and a few other areas. Seventy-six percent of the worldwide proven oil reserves are located in OPEC.[ix] On a country-wide basis, the U.S. ranks 11th in the world for the amount of proven reserves of crude oil. Texas has 27% of the U.S. total, Alaska has 25%, and California has 16% (U.S. DOE/EIA, *U.S. Crude Oil*, 1994, 23-7).

Demand and Price Growth. The Department of Energy predicts that total worldwide oil use will grow by 33% between 1992 and 2010, or an average of 1.6% per year (U.S. DOE/EIA, *International Energy Outlook*, 1995, 81). The forecast used to calculate future energy demand in Vermont presented later in this chapter assumes world oil consumption will increase at 1.9% per year through 2015 (Energy Ventures Analysis, 1995). In Vermont, both primary and delivered oil use is projected to increase at about 1.7% per year between 1990 and 2015 (Vt. DPS).[x] (See Chapter 3, Part III.)

The world price for oil has declined since 1990 and is currently near its 1970 level in constant dollars. Between 1970 and 1994, oil prices fluctuated dramatically, ranging from $10.10 per barrel in 1972, to $58.70 per barrel in 1980, to 1994's price of $14.90 per barrel (all in 1993 dollars). (See Figure 3.II.22.) According to the U.S. Department of Energy, today's relatively low prices are a result of enhanced oil production capacity, more efficient end-use technologies, and shifts from oil to other energy sources for some purposes (U.S. DOE/EIA, *International Energy Outlook*, 1995, 31). Additional factors include increased production from outside OPEC, and the inability of OPEC to control worldwide oil prices as they did in the 1970s. Unless a major political event occurs that affects oil prices, DOE expects oil prices to remain stable over next few years.

During the next few years, many analysts believe that oil prices will rise, pointing out that significant expansion in oil production capacity will be needed to meet the growing world oil demand, but that OPEC capacity will likely peak and stabilize shortly after the turn of the century. In addition, analysts believe that costly investment will be necessary in the next 15 years to upgrade heavier crude oils into lighter products. The strong demand outlook for oil, combined with oil inventories that are at their lowest level in five years and no substantial excess OPEC production capacity, could signal an end to declining or level oil prices.

The Department of Energy estimates a crude oil price of about $24 per barrel by 2010, compared to 1994's price of $14.90 per barrel (in 1993 dollars) (U.S. DOE/EIA, *International Energy Outlook*, 1995, 31-4). The forecast used to calculate future energy demand in Vermont presented later in this chapter assumes oil prices will rise to $25 per barrel by 2015 (in 1994 dollars) (Energy Ventures Analysis, 1995). (See Figure 3.III.6.)

Figure 3.11.22 World Oil Prices
1993 dollars per barrel

Consideration of the future price of petroleum must also take into account the unpriced consequences of oil use, referred to as external costs. In the future, there will be increasing pressure to include the costs of global warming, resource depletion, and land, air, and water pollution into the price of petroleum. Taxes, efficiency standards, and tradable permits are possible mechanisms for internalizing these costs, and each is likely to increase the price of oil use. (See The Full Cost of Energy Use section later in this chapter.)

Imports. In 1994, net oil imports (imports minus exports) to the U.S. were 7.99 million barrels per day, or 45.2% of the nation's oil consumption. This share approaches the all-time high of 46.5%, or 8.56 million barrels per day, in 1977. After 1977, oil imports declined through the mid-1980s, and then rose again starting in 1986. Since 1972 (before the oil crises of the 1970s and 1980s), net oil imports have increased by a total of 3.47 million barrels per day, or 77%. (See Figure 3.II.23.)

Of the net oil imports to the U.S., the majority (53%) comes from OPEC, and just under half of that comes from Arab OPEC.[xi] Because of the relative closeness of the northeastern U.S. to foreign oil markets and the lack of internal petroleum sources, our region imports a larger percentage of its oil than the rest of the nation.

U.S. oil imports have been growing since the mid-1980s while U.S. oil production has fallen. Total U.S. crude oil production in 1994, at 6.63 million barrels per day, was at its lowest level since 1955.[xii] The average productivity of U.S. oil wells has fallen consistently since 1972, except for a slight rise in 1979. The average productivity has fallen from 18.4 barrels per day per well in 1972 to 11.4 in 1994, a 38% decline. Average productivity per well is currently at its lowest point since 1954. The total number of U.S. producing wells has also declined from its all-time high of 647,000 in 1985 to 582,000 in 1994 (U.S. DOE/EIA, *Annual Energy Review*, 1995, 139, 141, 151).

Figure 3.II. 23 U.S. Oil Imports and Exports

Million barrels per day

As U.S. sources of petroleum are depleted in the years ahead, total oil imports are projected to grow. By 2010, net imports will comprise 59% of total U.S. oil consumption (U.S. DOE/EIA, *Annual Energy Outlook*, 1995, 37). Crude oil imports are expected to come increasingly from Persian Gulf countries, as production from other nations declines (as it has in the U.S.) In fact, U.S. imports from all countries except Mexico and OPEC are predicted to decrease in the future. Within OPEC, U.S. imports from North Africa, West Africa, and Indonesia are expected to decrease; imports from Latin America are expected to increase slightly; and imports from the Persian Gulf are expected to increase an astounding 5.9% per year, or 167% between 1993 and 2010. By 2010, 49% of our crude oil imports are projected to come from the Persian Gulf (U.S. DOE/EIA, *Supp. to Annual Energy Outlook*, 1995, 267).

National and Energy Security. Our nation's reliance on foreign oil imports threatens our national, economic, and energy security. The political instability of many of the countries from which the U.S. imports oil leads to a greater risk of an oil supply or oil price disruption. This, in turn, leads to a greater risk of an inadequate oil supply during times of disruption and an unstable U.S. economy, since a healthy U.S. economy currently depends on adequate supplies of oil. All of the U.S. recessions since 1973 have been complicated by high oil prices. In addition, reliance on foreign oil increases both the costs of the U.S. military, which patrols the Persian Gulf area, and the pressure to use the military in case of oil supply disruptions. Finally, reliance on foreign oil increases the U.S. trade deficit. If foreign oil imports were eliminated, the $101 billion U.S. trade deficit (as of 1990) would decrease by one-half (U.S. DOE/EIA, 1991, 45). These factors all place our national, economic, and energy security at greater risk.

There are a number of ways to address these problems. We can reduce dependence on foreign oil by using less oil or by using other energy sources to replace some of our oil consumption. These strategies are discussed in greater detail in Chapter 4. We can also make our oil supply more secure by storing fuel for use during possible disruptions in the foreign oil supply.

The U.S. Government created an oil storage reserve in 1975 by passing the Energy Policy and Conservation Act that established the Strategic Petroleum Reserve (SPR). The SPR was created in response to the oil supply disruptions of the early 1970s, and was intended to stabilize the economy and ensure the continued supply of oil during times of future disruptions. In the event of an interruption of imported oil or other emergency, the President would authorize the use of the SPR, which was meant to work within the market by selling oil to the highest bidder (except for 10% of the sales which can be designated by the Secretary of Energy). The SPR was intended to store up to one billion barrels of oil; currently, it is authorized to store up to 750 million barrels.

In 1977, the SPR began storing crude oil and by the end of 1989, it held 580 million barrels. The first sales of SPR crude oil occurred following the Iraqi invasion of Kuwait in August 1990. Purchases for the SPR were suspended in August 1990 due to concern about world crude oil supplies, but purchases resumed again in 1992. The SPR currently holds 592 million barrels.

One measure of the SPR's adequacy is the number of days of net imports of oil it could supply (replace) in the event of an oil supply interruption. Although it is unlikely that there would be a protracted interruption of all U.S. imports, the oil currently stored in the SPR is equal to 74 days worth of total net petroleum imports. This number has been falling steadily since 1985 (when it was at its all-time high of 115 days) due to smaller additions to the SPR and increasing oil use and imports. The oil in the SPR is equal to 140 days worth of petroleum imports from OPEC (U.S. DOE/EIA, *Annual Energy Review*, 1995, 151, 169).[xiii] While the number of days of imports contained in the SPR is a useful measure of its adequacy, the measure is hypothetical only. The SPR is capable of distributing about 3.5 million barrels per day during a 90-day period, which is less than half of U.S. daily net imports.

The oil stocks currently in the SPR probably would not be sufficient in the case of an extended interruption of imported oil. Without a greater oil supply in the SPR, there will be an increased likelihood of quick military action and increased pressure to use oil resources in ecologically sensitive areas such as the Arctic National Wildlife Refuge during times of disruption. A greater oil supply in the SPR or less reliance on oil to meet our energy needs, however, could reduce these pressures and improve our national and energy security. Adding to the SPR now, while oil prices are low, could be advantageous for the future.

Emissions and Environmental Impacts. Emissions from oil use vary depending on the type of petroleum product used, the type of equipment or vehicle used, the level of maintenance, and other factors. All petroleum products emit pollutants, including those that cause negative human health effects, global climate change, acid precipitation, and smog. Emissions from propane and natural gas are smaller than emissions from other fossil fuels. Summaries of the emissions from the use of each petroleum product are given in the following sections. (Also, see Tables 3.II.1 and 3.II.3.) Most emissions come directly from fuel combustion, but emissions also result from oil extraction, processing, refining, distribution, and vehicle refueling.

In addition to emissions, oil extraction, processing, and use poses other environmental risks. Oil tanker spills and oil pipeline and storage tank leaks, for example, occur frequently and have adverse effects on the environment. Areas where oil drilling is prohibited because of the unique environmental value of the location (such as the Arctic National Wildlife Refuge) will continue to be threatened by the possibility of oilextraction, as pressure to reduce the foreign oil supply and to ensure against foreign oil supply disruption persist.

2. Motor Gasoline

In 1993, Vermonters used about 37.3 TBTU of energy from motor gasoline, accounting for 34% of the state's total delivered energy use (U.S. DOE/EIA, *State Energy Data Report*, 1995, 299; Vt. DPS). State records show that we consumed 305.2 million gallons of gasoline in 1993 (Vt. AOT, personal communication, 1995; see Figure 3.I.2 for consumption during the past).

Motor gasoline is the most-used petroleum product in both Vermont and the U.S., representing 48% and 42% of total 1993 petroleum use respectively (U.S. DOE/EIA, *State Energy Data Report*, 1995, 21). However, Vermont uses more motor gasoline per person than the U.S. average; in fact, the state consumes 12.32 barrels per person per year, compared to 10.59 barrels in the U.S. (in 1993).[xiv] The high use of motor gasoline in Vermont is mirrored in the fact that the state's per capita annual vehicle miles traveled (VMT) is the seventh highest in the nation. Vermont also has more passenger cars per capita than the national average and than any other New England state (U.S. DOT, *Our Nation's Highways*, 1992, 36-7).

Future Trends and Issues

Demand and Price Growth. Motor gasoline use in Vermont is projected to increase by 1.6% per year or 38% between 1995 and 2015 (Vt. DPS). According to a national forecast, motor gasoline use is projected to increase an average of 0.7% per year in the U.S. between 1990-2010 (U.S. DOE/EIA, *Supp. to the Annual Energy Outlook*, 1995, 103, 121).[xv] This trend is expected to be mirrored by rising vehicle miles traveled (see below).

Real motor gasoline prices in Vermont are expected to increase an average of 1.3% per year between 1994-2015 (excluding taxes) (Energy Ventures Analysis, 1995). The future price of motor gasoline and other motor fuels will also be affected by efforts to limit and control pollution and to internalize external costs. In addition, it is likely that motor fuels will include in their price a greater portion of the cost of building and maintaining our road network in the future. The road network is becoming increasingly more expensive to build and maintain at a time when there is enormous pressure to reduce contributions from traditional sources of revenue. For example, the projected cost to maintain just one Vermont corridor (Route 7) at roughly the same level of service and keep up with increasing vehicle miles traveled is more than $500 million over the next 20 years (Wilbur Smith Associates, *U.S. Route 7: An Economic Lifeline*, 1994; Wilbur Smith Associates, *U.S. Route 7 Corridor Management Study*, 1992). Increasing road network costs are further complicated by a unique aspect of Vermont's highway funding: property taxes contribute an unusually large amount to build and maintain roads in Vermont ($65 million or 24% in 1993, compared to a national average of 5%). Pressure to reduce property taxes in the state, combined with the increasing cost of the road network and reduced contributions of state and federal sources, will likely result in higher federal and statewide gas taxes in the future (U.S. DOT, *1993 Highway Statistics*, 1995, IV-9). (See The Full Cost of Energy Use section later in this chapter.)

Increasing Driving, Decreasing Efficiency. Vermont's increasing gasoline use in the transportation sector has been brought about by a combination of factors, including growth in vehicle miles traveled and little or no gains in the average fuel efficiency of the vehicle fleet. These trends are likely to continue in the near future.

The total vehicle miles traveled (VMT) in the U.S. and Vermont has increased phenomenally in the past few decades, leading to much greater energy use. In Vermont, VMT rose from 2.69 billion in 1970 to 5.98 billion in 1994, a 122% increase (Vt. AOT, personal communication, 1995). (See Figure 3.I.2.) By 2020, VMT is expected to increase a further 50%-80% in the state. The Vermont Agency of Transportation calculates that, using the most likely growth rate, Vermont's VMT will exceed 10 billion by 2020, almost doubling in only 25 years. This growth rate assumes slow economic growth and a stable population. More rapid economic expansion, an increase in jobs, or population growth would increase VMT even more (Vt. AOT, *Vt.'s Long*

Range Transportation Plan, 1995, 23).

Low gasoline prices have largely caused our nation's high levels of VMT. U.S. gas prices are among the lowest in the world, encouraging more frequent driving. Gas prices in 1992 were $1.13 per gallon in the U.S., compared to $1.72 in Canada, $3.34 in the U.K., $3.70 in Japan, and $4.68 in Italy (U.S. DOE/EIA, *International Energy Outlook*, 1994, 17). Between 1992 and 1995, Vermont gasoline prices have been at their lowest level (measured in constant dollars) since DPS record-keeping began in 1973. (See Figure 3.I.3.) If gasoline taxes or oil prices rise in the future, our use of gasoline and our VMT will decrease. (See Chapter 4 for policies about taxation.)

In addition to gasoline prices, other factors also lead to increasing VMT and growing energy use. Sprawling land use patterns (encouraged by low gas prices) continue to encourage more driving. Between 1980 and 1986, about 64% of population growth in the U.S. occurred in suburbs, ensuring that jobs and services were farther from homes. While Vermont has taken measures to encourage growth in town centers and plan for appropriate development, dispersed land use development is an increasing pattern here as well.

Another contributor to increasing VMT is the larger portion of "just-in-time" freight deliveries that provide inventory to businesses, stores, factories, etc. to use immediately instead of to store in warehouses. These types of deliveries occur more frequently and in smaller lots, and thus cause both increasing VMT and a greater use of aircraft and trucks instead of rail and water vessels, reducing total fuel efficiency.

In recent years, the country's increasing VMT has been combined with stagnant or falling gains in the average fuel efficiency of the vehicle fleet. While the average fuel efficiency of the nation's vehicle fleet improved in the 1970s and 1980s, there have been virtually no gains made in the average fuel efficiency of cars sold since 1985. In addition, Americans' purchases of less fuel efficient light trucks, vans, and jeeps have been increasing. From 1970 to 1985, vehicle miles traveled in light trucks, vans, and jeeps grew at five times the rate of VMT in autos, largely because trucks and jeeps were used as passenger vehicles and not freight haulers. Light trucks are, on average, 25% less fuel efficient than cars (Gordon, 1991, 42-4). These trends are likely to continue into the future unless rising gasoline prices or other factors cause an increased interest in efficiency.

Emissions and Environmental Issues. Motor vehicles that burn motor gasoline and diesel fuel are responsible for nearly 70% of the air pollution emitted in Vermont (Vt. ANR, *Air Pollution Emissions Inventory*, 1993, Appendix A). Most gasoline emissions come from fuel combustion, but they also result from fuel extraction, processing, refining, distribution, and vehicle refueling. (See Chapter 4 for a policy about vapor loss recovery during refueling.)

The major emissions of concern from motor gasoline combustion are carbon dioxide, carbon monoxide, nitrogen oxide, volatile organic compounds (VOCs), and particulates. (See Table 3.II.1.) Smaller amounts of sulfur dioxide, nitrous oxide, and methane are also emitted by motor gasoline combustion. Chlorofluorocarbons are not emitted by gasoline combustion, but are emitted from vehicle air conditioners and during the manufacture of vehicles. (For more on the impacts of each pollutant, see the text box on Air Emissions from Energy Use.)

Carbon dioxide is one of the most serious pollutants from gasoline use due to its contribution to global warming. Carbon dioxide emissions from gasoline can be reduced by decreasing total vehicle miles traveled, driving more efficient vehicles, driving in a more fuel-efficient manner, switching to vehicles that use lower-emitting fuels such as natural gas or biomass-based products, or switching to other, more efficient modes of transportation.

Combined motor gasoline and diesel use emits more carbon monoxide per unit of energy used than any other

Table 3.II.1 represents Vermont's energy emissions factors for appliances, equipment, and vehicles used in the residential sector. These factors are helpful in comparing emissions of a certain pollutant from different fuels. However, the emissions factors do not directly correspond to health risks; different pollutants present health and environmental risks at different levels of emissions. Emissions factors for the electric sector are given in Table 3.II.3.

fuel in Vermont. (See Table 3.II.1.) Carbon monoxide is a product of the incomplete burning of motor fuel and is emitted from vehicle tailpipes. Its emissions are worst in places where cars idle, as in congested areas. Nationwide, two-thirds of carbon monoxide emissions come from transportation sources, with the largest contribution from motor vehicles. Motor vehicles typically contribute more than 90% of the carbon monoxide pollution emitted in urban areas.

Motor gasoline and diesel fuel use also emit more nitrogen oxides per unit of energy used than any other fuel in the state. Nitrogen oxides contribute to acid precipitation and react with VOCs (volatile organic compounds) to form ground-level ozone, the major component of smog. The primary source of the constituents of ground-level ozone is vehicle exhaust. Because smog often is not formed at the point where emissions are produced, emissions in one area can contribute to a smog problem in another area. In the Northeast, this problem is made worse by the fact that many urban areas are located close to each other. Vermont is required to help mitigate smog problems in the Northeast as part of the Regional Northeast Ozone Transport Commission.

VOCs are emitted from auto and truck exhaust, from the evaporation of gasoline and solvents, and during petroleum refining. In addition to their role in ground-level ozone formation, many VOCs are also toxic. Three of the most recognizable toxic chemicals in gasoline are benzene, a known human carcinogen that is toxic to the human blood system and may cause kidney damage; toluene, which adversely affects the nervous system; and xylene, which adversely affects human development and may adversely affect the reproductive system (Vt. ANR, *Air Pollution Control in Vt.*, 1995, 1).

The Federal Highway Administration (FHA) monitors air emissions for the transportation sector, and reports improvements for highway vehicles as a result of major investments in research and technological improvements in fuels, vehicles, and industrial processes. FHA also reports that off-highway engines such as lawn and garden equipment, boats, etc. show dramatic increases in emissions; a 40% increase for CO_2 and VOCs and nearly 80% for nitrogen oxides. FHA estimates that operating a lawnmower for one hour emits the same amount of VOCs as driving a 1992 car from Dallas to New York. Clearly the off-highway engines merit greater attention.

The greatest source of particulates from automobiles is the re-entrainment of silt from roadways into the air stirred up by passing vehicles. The size of this effect is difficult to quantify because it varies depending on humidity and road surface. Thus, there are no estimates of this effect in Vermont.

Motor gasoline combustion emits small amounts of sulfur oxides, which are health hazards and significant contributors to acid rain. Nitrous oxide, a potent greenhouse gas, is also emitted in smaller amounts from vehicle exhaust. Methane, a serious greenhouse gas, is emitted in gasoline combustion and in the production and processing of petroleum fuels. In addition, carbon monoxide elevates methane concentrations by reacting with a substance that normally removes methane from the atmosphere, and transportation accounts for most carbon monoxide emissions (Gordon, 1991, 60).

Chlorofluorocarbons (CFCs) are emitted from vehicle air conditioners and often during vehicle manufacturing. CFCs lead to stratospheric ozone depletion and also contribute to global warming. Of the global warming to be brought about by the human-caused greenhouse gases released in 1990, the CFC share is 11% (U.S. EPA, *States Workbook*, 1992, v). Through the Montreal Protocol and the Copenhagen Amendments (the agreements which control the production and consumption of CFCs) the U.S. has agreed to phase out the production and use of all CFCs and other ozone-depleting substances by January 1996. However, all of the

CFCs already present in vehicles will still be released over the lifetime of the vehicles. In addition, the Montreal Protocol did not cover a family of CFC replacements which are also powerful greenhouse gases (U.S. EPA, *States Workbook*, 1995, iii).

Proper maintenance of existing technology installed on cars is essential to mitigate gasoline emissions. Vehicles with malfunctioning air pollution equipment can emit 8-10 times the pollution of vehicles with properly functioning equipment, and can be 10%-40% less fuel-efficient (Vt. ANR, personal communication, 1995). As part of the Regional Northeast Ozone Transport Commission, Vermont is required to set up in Burlington a vehicle inspection and maintenance program to help mitigate smog, and is currently in violation of that EPA requirement. (See the Chapter 4 policy regarding vehicle emissions.)

The Regional Northeast Ozone Transport Commission is also considering recommending that the region adopt the California Low Emissions Vehicle Program (LEV), which phases in increasingly more stringent vehicle emissions standards over time. This program is intended to ensure that new motor vehicles entering the fleet are the "cleanest cars in mass production." Eventually, the LEV program would reduce auto air pollution up to 90% beyond what is required by the federal emission standard (Vt. ANR, personal communication with Harold Garabedian citing California Air Resources Board, 1995). The vehicles now being produced to meet the first emissions level in California are obtaining up to a 10% increase in fuel efficiency (Vt. ANR, personal communication, 1995). Automakers, however, have been resisting the adoption of the LEV standards by other states, and are currently negotiating to put in place less stringent standards that would apply to the other 49 U.S. states and which might exclude the adoption of more stringent standards.

In addition to emissions, motor gasoline use produces other environmental impacts and risks. One important environmental impact is damage to groundwater and surface water caused by leaking underground gasoline storage tanks. Vermont established a petroleum cleanup fund in 1987 to clean up and restore contaminated soil and groundwater caused by petroleum releases from underground storage tanks (10 V.S.A. § 1941, 1942). The fund was established after private insurance companies were no longer willing to cover cleanup costs associated with leaking tanks. Money for the fund is collected through tank assessment fees paid by tank owners and a $.01 per gallon tax on motor fuel, to be collected through March 2001. The fund acts primarily as an insurance policy for tank owners, providing money when cleanup actions become necessary. In addition, the fund can be used to take corrective action on abandoned tank sites, and can act as an interest-free lender to small gasoline outlets and small municipalities to upgrade their tanks. Older, single-wall, unprotected tanks are required to be replaced with double-wall, overfill protected tanks by 1997. So far, about $1.7 million has been loaned out to 100 Vermont facilities to upgrade their tanks. The Vermont

Table 3.II.1 Vermont Residential Energy Emissions Factors by Fuel
(Lbs/million BTU)[a]

	CO_2	SO_x	NO_x	PM-10	CO	VOCs	CH_4	N_2O[b]
Motor Gasoline/Diesel	153	0.0264	0.752	0.0212	5.528	0.5467	0.0105	0.0107
Distillate Oil								
Space and Water Heating	173	0.2180	0.068	0.0190	0.030	0.0190	0.0123	0.0136
LPG (Propane)								
Space Heating	139	0.0098	0.114	0.0017	0.015	0.0056	0.0021	0.0033
Water Heating	139	0.0098	0.122	0.0025	0.006	0.0040	0.0012	0.0033
Cooking	139	0.0098	0.089	0.0019	0.067	0.0066	0.0027	0.0033
Drying	139	0.0098	0.068	0.0025	0.067	0.0066	0.0027	0.0027
Natural Gas								

Space Heating	116	0.0006	0.110	0.0015	0.028	0.0043	0.0441	0.0033
Water Heating	116	0.0006	0.122	0.0025	0.012	0.0027	0.0432	0.0033
Cooking	116	0.0006	0.089	0.0019	0.126	0.0053	0.0447	0.0033
Drying	116	0.0006	0.068	0.0025	0.125	0.0053	0.0447	0.0033
Wood								
Space Heating[c]	224[d]	0.0083	0.042	0.6682	2.915	2.8758	0.0025	0.0095
Water Heating	224[d]	0.0083	0.114	0.7724	3.234	3.3025	0.0023	0.0095
Coal								
Space and Water Heating	219	1.5600	0.120	0.4000	3.600	0.4000	0.3200	0.1310

[a]As a benchmark for comparison, the average Vermont household uses about 152 million BTU per year, and the average car uses about 73 million BTU per year.
[b]N_2O emissions factors represent only rough estimates. Emissions factors for N_2O that have been widely used in the past have recently been shown to be inaccurate. The estimates presented here were extrapolated from the reliable data that does exist. It is important to estimate emissions factors for N_2O because it contributes significantly to global warming.
[c]Current wood space heating appliances in Vermont, which these emissions factors are based on, are assumed to be: 65% conventional stoves, 15% advanced stoves, 10% forced air furnaces, and 10% hot water boilers. In the future, however, conventional stoves will be replaced by advanced stoves due to EPA standards, with a corresponding drop in many wood emissions from space heating.
[d]Carbon dioxide emissions for wood are zero if wood resources are managed sustainably. See the wood section later in this chapter for more information.

Agency of Natural Resources estimates that the program will need $64.7 million through 2001; however, a shortfall of about $9 million is expected in 2001, in part due to the fact that $3 million was transferred from the cleanup fund to the state's General Fund. Because of the expected shortfall, an increase in the fee collected for the cleanup fund is likely to be needed.

Alternative Gasoline Fuels. There are a number of alternative gasoline fuels, including reformulated gasoline, oxygenated gasoline, and gasohol, that will likely be used more in the future as air emissions from vehicles continue to become more serious. For a description of each of these fuels, see the Alternative Transportation Fuels section in this chapter.

3. Distillate Fuel (Heating Oil and Diesel Fuel)

Vermonters used 31.2 TBTU of distillate fuel in 1993, accounting for 28% of our total delivered energy use (U.S. DOE/EIA, *State Energy Data Report*, 1995, 299; Vt. DPS).[xvi]

In Vermont, about 44% (13.8 TBTU) of the distillate fuel demand comes from the residential sector, primarily for space heating and water heating purposes. Another 32% (10 TBTU) of the demand comes from the transportation sector from diesel-burning vehicles, with the remaining demand from the commercial sector (14%) and industrial sector (10%) (U.S. DOE/EIA, *State Energy Data Report*, 1992, 311-6).

Heating oil is the fuel most-used for residential heating in Vermont. In the 1993-94 heating season, an estimated 46% of Vermont households used heating oil as their primary source of heat. Water heaters fueled with heating oil were used by about 24% of Vermont households, representing the second most-used fuel for water heaters after electricity (Vt. DPS, *Vt. Residential Fuelwood*, 1995, 4).

The Northeast uses more heating oil than much of the rest of the country. Altogether, 11 million homes in the U.S. use heating oil, with 7.7 million of those homes in the Northeast (American Petroleum Institute, 1990, 2). In the U.S., distillate fuel represents 19% of total petroleum demand. U.S. demand for distillate fuel comes mainly from the on-highway diesel transportation sector (48%), with a much smaller amount coming from the residential sector (14%). The commercial, industrial, farm, railroad, vessel bunkering, and off-highway diesel uses each account for between 4%-7% of U.S. distillate fuel use (U.S. DOE/EIA, *Fuel Oil and Kerosene Sales*, 1995, 10).

Future Trends and Issues

Demand and Price Growth. In the U.S., total distillate fuel use in the residential and commercial sectors is expected to decline in the future, while use in the industrial and transportation sectors is expected to increase. Overall, U.S. distillate use is projected to increase an average of 1.4% per year (U.S. DOE/EIA, *Supp. to the Annual Energy Outlook*, 1995, 102-3, 121).

In Vermont, real diesel fuel prices are expected to rise an average of 1.3% per year between 1994 and 2015 (excluding taxes). Real distillate fuel prices in the residential, commercial, and industrial sectors are expected to increase between 1.2% and 1.5% per year in Vermont over the same time-frame (Energy Ventures Analysis, 1995). Pressures to internalize the external costs of oil use could also raise the price of distillate fuel in the future. (See The Full Cost of Energy Use section later in this chapter.)

Emissions. The emissions of greatest concern from heating oil are carbon dioxide, sulfur oxides, particulates, and volatile organic compounds. In Vermont, distillate heating oil emits more sulfur oxides (major contributors to acid precipitation) per unit of energy used than any other home heating fuel except coal. (See Table 3.II.1.) Emissions of carbon dioxide per unit of energy used are higher for heating oil than for LPG, natural gas, or motor gasoline. Particulate emissions and VOCs are both higher with heating oil than with LPG or natural gas (per unit of energy used). Emissions from heating oil combustion depend on the grade and composition of the fuel, the type and size of the boiler or furnace, the firing and loading practices used, and the level of equipment maintenance (U.S. EPA, *Compilation of Air Pollutant Emission Factors*, 1995, 1.3-1, 1.3-11-15).

In general, diesel fuel emits more carbon dioxide, particulates, and sulfur oxides per unit of energy used than other transportation fuels, but usually emits smaller amounts of nitrogen oxides, carbon monoxide, and VOCs.
New Technologies. In 1992, an efficiency standard went into effect that required all furnaces and boilers sold

in the U.S. to have an annual fuel utilization efficiency (AFUE) measure of at least 78%. (AFUE is a measure of seasonal efficiency.) The most efficient oil furnaces and boilers available today have AFUE measures in the mid- to upper-80% range. These systems achieve their high efficiency levels by using condensing technologies which reclaim most of the heat in the exhaust gases that normally escape up the chimney. Condensing heating systems on the market today are much more efficient than older furnaces and boilers, and upgrading an older oil furnace or boiler in a cold climate area results in significantly fewer air emissions (Wilson, 1993, 51-4).

The efficiency standard for furnaces and boilers is scheduled to be revised again in 2002 and 2012 through the National Appliance Conservation Act. The standard that will be set in 2002 is not yet defined, and estimates of the standard depend on how large a role condensing heating systems are assumed to play in the future. Condensing furnaces currently enjoy a 22% market share in the U.S. Because of this, one recent appraisal of the 2002 standard assumes that condensing furnaces and boilers will be technically feasible and economically justified in the future, and as such, estimates that the 2002 standard will be set at 92% AFUE for furnaces and 87% for boilers (Nadel, 1994, 12).

As efficiency standards continue to rise, as older oil furnaces and boilers continue to be replaced with newer ones, and as more people switch to cleaner fuels, air emissions from oil heating systems will fall and less energy will be consumed compared to what would have happened otherwise.

4. Liquid Petroleum Gas (LPG)

In 1993, Vermont used 6.6 TBTU of liquid petroleum gas, representing 6% of the total delivered energy consumption (Vt. DPS).

Both propane and butane are considered LPG products. In Vermont, the most commonly used type of LPG is HD5, which consists of propane, less than 5% propylene, and small amounts of trace gases. The residential sector accounted for 75% of the state's 1993 LPG demand, with the remaining demand almost equally divided between the commercial and industrial sectors.

In the 1993-94 heating season, an estimated 14% of Vermont households used LPG as their primary heating source, with 6% using it as a supplemental source. Twenty-four percent of Vermont households used LPG as a primary or supplemental water heating source. LPG is currently the third largest fuel source for both home heating and water heating in Vermont (Vt. DPS, *Vt. Residential Fuelwood*, 1995, 4, 11). In 1993, Vermont used more total LPG than any other New England state (New England Governors' Conference, *Regional Energy Assessment Project*, 1995, II-11).

In the U.S., LPG represents 7% of total primary petroleum use. Of this amount, 79% is used in the industrial sector (U.S. DOE/EIA, *State Energy Data Report*, 1995).

Future Trends and Issues

Demand and Price Growth. LPG use is projected to increase by an average of 1.6% yearly or 30% between 1993-2010 in the U.S. Within New England, LPG use is expected to drop significantly in the residential sector as it rises in the other sectors (U.S. DOE/EIA, *Supp. to the Annual Energy Outlook*, 1995, 103, 121). In Vermont, delivered energy use of LPG is expected to increase an average of 2.4% per year between 1990 and 2015, one of the highest growth rates of any fuel.[xvii] (See Part III of this chapter.)

Real LPG prices are projected to increase only modestly into the future in Vermont, by 0.4% per year in both the residential and commercial sectors (Energy Ventures Analysis, 1995). Like other fuels, the future price of LPG is also likely to be influenced by pressures to include the unpriced consequences of its use into its price. (See The Full Cost of Energy Use section later in this chapter.)

Supply and Delivery. Since 1989, retail dealers and wholesale transporters have added storage facilities and more truck transporters, the terminals supplying New England have expanded to meet increased demand. A bottleneck can develop in the Selkirk, N.Y. terminal of the Texas Eastern Pipeline Company, when winter demand peaks. This means forcing LPG transporters to rely on more distant LPG terminals, notably Providence, R.I., Newington, N.H. and others in Québec and Ontario. Some dealers in Vermont are set up to take rail service directly. Lyndonville has a rail terminal. Truck transporters have an option of hauling from rail terminals in Auburn ME, Springfield MA, Albany NY, or Lyndonville, VT. To mitigate supply constraints, Vermont LPG industry representatives have proposed legislative relief from truck weight limits and driver-hour restrictions. When severe shortages of propane occur, the *State of Vermont Energy Emergency Plan* (Vt. DPS, 1993, 29-31) makes provisions for modifying the required permits so haulers can expedite bulk deliveries and suspending driver hours of service restrictions through a process that coordinates the governors and premiers of states and provinces in the region and the US Department of Transportation.

LPG and Consumer Issues. In recent years, the Department of Public Service has received consumer inquires about "fill charges" or service charges newly levied by LPG dealers on customers who consume small amounts of the fuel, e.g., for cooking only. These consumers are referred to the Attorney General's Consumer Assistance Program, the area of state government that regulates liquified petroleum "propane" gas in accordance with Rule CF 111. Because LPG dealers own the fuel tanks which supply customers, it can be difficult for the consumer to switch fuel dealers. In addition, price schedules that charge low-volume users a high price per gallon while high-volume users pay less, leave many consumers confused. The inverse pricing practices of LPG dealers can also frustrate customers who lower consumption through efficiency improvements, only to find their per-unit price increases.

Emissions. When compared with heating oil, LPG has lower emissions per unit of energy used for every pollutant except nitrogen oxides. The major emissions of concern from LPG are nitrogen oxides and carbon dioxide. (See Table 3.II.1.) Nitrogen oxide emissions (important contributors to acid precipitation and smog) from LPG are roughly similar to such emissions from natural gas (per unit of energy used). Carbon dioxide emissions per unit of energy used for LPG are higher than those for natural gas, but lower than those for distillate fuel or gasoline. Other emissions, including particulates, carbon monoxide, VOCs, methane, and nitrous oxide, are similar for both LPG and natural gas. Although emissions from LPG deserve mitigation efforts, they are less serious than most emissions from other fuels.

New Technologies. For a description of current and future efficiency standards for LPG furnaces and boilers, see the discussion above on New Technologies in the Distillate Fuel category. The most efficient LPG furnaces currently have annual fuel utilization efficiency (AFUE) measures in the mid-90% range, while LPG boilers have AFUE measures in the mid- to upper-80% range (Wilson, 1993, 54). As older furnaces and boilers are replaced with these more efficient ones and as efficiency standards continue to increase, LPG heating systems will release fewer emissions and use less energy compared to what would have happened otherwise.

In addition, LPG can be used to power vehicles. In Vermont, 281 LPG vehicles were registered in mid-1995, far more than any other alternative fuel vehicle. For more information about LPG-fueled vehicles, see the Potential Energy Sources and Technologies for the Future section later in this chapter.
Over the past five years, the propane industry has made major investments in clean fuel and clean engine technology; increasing the availability of heating equipment with fuel efficiency ratings of at least 80%,

developing clean fuel vehicles (heavy, medium, and light duty vehicles), and further development of clean fuel technologies for propane will be supported by the Propane Education and Research Council, started in 1997.

Safety. LPG must be handled by trained personnel conforming to high levels of safety standards in order to ensure proper practices. The Vermont Propane Gas Association has taken a leadership role nationally to this end. Vermont was the first state to implement a training program, the Certified Employees' Training Program, and Vermont continues to be one of only two states in the US to have such a program. LPG safety regulation is presently handled jointly by the Departments of Labor and Industry and Public Service, who have concentrated on equipment installation and carbon monoxide emissions issues to minimize hazards to the public. Safety concerns will continue to be important as LPG use increases in the future.

5. Kerosene

Vermont used 1.6 TBTU of kerosene in 1993, representing 1.5% of the state's delivered energy use (Vt. DPS).

Virtually all of Vermont's kerosene use (about 81%) was in the residential sector in 1993 (U.S. DOE/EIA, *State Energy Data Report*, 1995, 299-300). Kerosene was a primary heating source in an estimated 5% of Vermont households, and a supplemental source in 2% of the state's homes during the 1993-94 heating season. About 1% of Vermont households used kerosene for water heating (Vt. DPS, *Vt. Residential Fuelwood*, 1995, 4, 11).

Vermont and Maine used the most total kerosene in 1993 among the New England states (New England Governors' Conference, 1995, II-11). On a national basis, kerosene represents only 0.3% of total primary petroleum use, with 74% of use occurring in the residential sector (U.S. DOE/EIA, *State Energy Data Report*, 1995).

Future Trends and Issues

Demand and Price Growth. Kerosene use is projected to decrease by an average of 0.9% per year in the U.S. and 2.2% per year in New England between 1993-2010 (U.S. DOE/EIA, *Supp. to the Annual Energy Outlook*, 1995, 103, 121). Real kerosene prices in Vermont are expected to increase an average of 1% per year between 1994 and 2015 (Energy Ventures Analysis, 1995).

6. Other Petroleum Products

Vermonters used 3.8 TBTU of residual fuel, jet fuel, and aviation gasoline for non-electric purposes in 1993, accounting for 3.5% of total delivered energy use (Vt. DPS).[xviii]

Residual fuel is used primarily for electric generation and industrial purposes. Vermont's residual fuel use, at about 3 TBTU, occurred in the commercial and industrial sectors. The state's jet fuel and aviation gasoline consumption were 0.8 TBTU in 1993. Nationally, residual fuel accounts for 7% of total petroleum use, while jet fuel accounts for 9% (U.S. DOE/EIA, *State Energy Data Report*, 1995).

Future Trends and Issues

Demand and Price Growth. Jet fuel use in the U.S. is projected to grow an average of 2.3% per year between 1993 and 2010, the largest growth rate of any other fuel (U.S. DOE/EIA, *Supp. to the Annual Energy Outlook*, 1995, 103, 121). This projection is parallel to predictions by the Federal Aviation Administration that passenger air travel, freight air travel, and airport congestion will experience very large growth rates in the next 25 years (Gordon, 1991, 43-44). However, Vermont's use of energy for airplanes is projected to decrease in the future, possibly reflecting the state's relatively small airports.[xix] Real prices for jet fuel in Vermont are projected to increase by 1.5% per year between 1994 and 2015.

Demand for residual fuel is expected to grow by 1.8% per year in the U.S. between 1993 and 2010. Residual fuel prices in the commercial and industrial sectors in Vermont are projected to increase by 1.4% per year between 1994 and 2015 (Energy Ventures Analysis, 1995).

7. Natural Gas

In 1993, Vermont used 7.1 TBTU of natural gas for non-electric purposes, accounting for 6% of the state's total delivered energy use (Vt. DPS).

The residential sector used about 39% of the state's total natural gas, while the industrial sector used 35%, and the commercial sector the remainder. The residential sector uses natural gas for space heating and water heating, with an estimated 8% of Vermont households using natural gas as their primary heating source and water heating source during the 1993-94 heating season (Vt. DPS, *Vt. Residential Fuelwood*, 1995, 4, 11).

Natural gas, which consists mostly of methane, is available only in the northwest corner of Vermont in portions of Franklin and Chittenden counties. The state has a single natural gas distribution company, Vermont Gas Systems, which currently serves about 27,000 customers.

During the past two years, Vermont Gas Systems (VGS) has obtained its supply of natural gas primarily from Canadian supplies in Alberta, gathered by Western Gas Marketing and transported via the Trans-Canada pipeline. VGS has also contracted with its parent company, Gaz Metropolitan, L.P. for a liquid petroleum gas (LPG) supply during seasonal peaking periods. The LPG is mixed with natural gas during the peak times when demand is greater than the natural gas pipeline can supply. This allows VGS to supply more customers without expanding its pipeline.

Natural gas use per capita in Vermont, New Hampshire, and Maine is lower than much of the rest of the country, due largely to the limited availability of natural gas in the area. In 1991, for example, New England used only 2.5% of the total natural gas consumed nationwide (U.S. DOE/EIA, *Natural Gas*, 1993, 14). Natural gas accounts for 25% of the total energy consumed nationwide, but accounts for only 18% of energy consumed in New England (New England Gas Association, *Pocket Guide*, 1995, 10). Natural gas use was 20,867 TBTUs in the U.S. in 1993, with 45% of that total in the industrial sector, 24% in the residential sector, and the remainder divided almost equally between the commercial and electric utility sectors (U.S. DOE/EIA, *State Energy Data Report*, 1995, 11; U.S. DOE/EIA, *Annual Energy Review*, 1995, 197).

Future Trends and Issues

Supply. Proven worldwide natural gas reserves are about 4,980 trillion cubic feet. However, the Energy Information Administration believes this number most likely is conservative because proven natural gas reserves have increased dramatically in the past few decades. Proven reserves will last 40 years from 1995 at a 2% growth rate per year, the average growth rate predicted by the Energy Information Administration through 2010.[xx] World ultimate reserves of natural gas are estimated at 12,000 trillion cubic feet, of which approximately 10,096 trillion cubic feet remain. These reserves will last 63 years from 1995 at a 2% growth rate.

Forty percent of worldwide natural gas reserves is located in the former Soviet Union and Eastern Europe; 33% is located in the Middle East. The remaining 27% is fairly evenly distributed around the rest of world except for the Pacific region which has very little natural gas (U.S. DOE/EIA, *International Energy Outlook*, 1995, 37, 44). The U.S. has about 3% of world natural gas reserves (U.S. DOE/EIA, *International Energy Annual*, 1995, 99-100). Texas, Louisiana, and Oklahoma, the largest U.S. producers of natural gas, accounted for 61% of U.S. production in 1994.

Net imports of natural gas to the U.S. grew substantially between 1986 and 1994, from 4.2% to 11.6% of total consumption. This increase was due almost entirely to higher levels of imports from Canada (U.S. DOE/EIA, *Annual Energy Review*, 1995, 183-4, 190). Natural gas imports are projected to grow quickly in the future as well, at a rate of 3.2% per year between 1993 and 2010 (U.S. DOE/EIA, *Annual Energy Outlook*, 1995, 73).

Demand and Price Growth. Throughout the 1950s and 1960s, the U.S. market for natural gas expanded as low prices encouraged demand. Consumption reached an all-time high in 1972, but thereafter, uncertainties about supply and rising energy prices caused demand to fall. In 1986, natural gas consumption reached its lowest annual total since 1965. This reduced demand spanned all sectors, but was most severe in the industrial and electric utility sectors. Since 1986, natural gas consumption has increased again; total consumption grew by 27% between 1986 and 1994 (U.S. DOE/EIA, *Annual Energy Review*, 1995, 183, 190).

The Department of Energy projects total U.S. natural gas use will grow at an average of 1.2% per year (or 26%) between 1993 and 2010, the largest percentage increase of any fuel source except renewable fuels. In Vermont, delivered natural gas energy use is projected to increase at 3% per year between 1990 and 2015, while primary energy use is projected to increase by 8.7% per year, reflecting the large amounts of natural gas expected to be used for electric generation in the future.[xxi] (See Part III of this chapter.) Natural gas will show the largest increase nationwide of any electric fuel source in the future, overtaking nuclear energy as the second-largest source of electricity in the U.S. by 2010. (See the Electricity from Oil and Natural Gas section.) Much of this growth in the share of natural gas will be due to its security and environmental advantages, since there are large U.S. and Canadian reserves, and natural gas has lower emissions of most pollutants compared to other fossil fuels (U.S. DOE/EIA, *Annual Energy Outlook*, 1995, 29).

In Vermont, real natural gas prices are expected to decrease by 0.6% per year in the residential sector and 0.3% per year in the commercial sector between 1994 and 2015 (Energy Ventures Analysis, 1995). Increased opportunities to use natural gas storage capacity in Canada could also contribute to lower total costs of natural gas electric generation in Vermont. Natural gas prices will also be influenced by pressures to internalize the external costs of gas use, but these costs are lower than costs for other fossil fuels. (See Chapter 3.II, Section H. The Full Cost of Energy Use section.)

In-state Natural Gas Availability. Natural gas is currently available only in northwestern Vermont and only from Western Canadian supplies. Interstate pipeline companies and energy corporations have expressed interest in the past in constructing an interstate natural gas pipeline that would make natural gas available to other parts of Vermont. However, these efforts have not led to new pipelines. Extending natural gas to other areas of Vermont would improve opportunities for cost-effective electric generation and cogeneration and likely would reduce air emissions as natural gas replaced other, more polluting fossil fuels. However, low customer densities make the feasibility of such extensions uncertain.

Air Emissions and Environmental Issues. Natural gas use emits the lowest amount of almost all pollutants per unit of energy used compared to other fossil fuel sources. (See Table 3.II.1.) Carbon dioxide and nitrogen oxides are the pollutants of greatest concern from natural gas combustion. Carbon dioxide emissions per unit of energy used are the lowest of any fossil fuel source, but these emissions are still problematic due to their contribution to global warming. Natural gas emissions of nitrogen oxides per unit of energy used are at a similar level as LPG nitrogen oxides emissions, and at a higher level than emissions from distillate fuel or wood use. Nitrogen oxides contribute to smog, acid precipitation, and human health problems. The other pollutants from natural gas use are emitted at levels smaller than or similar to levels emitted from other fossil fuels. (See Table 3.II.3.)

In addition to the small amounts of methane released from natural gas combustion, a small portion of methane leakage from natural gas distribution systems contributes to gas companies' "unaccounted-for gas." Methane emissions from all sources are serious because of their powerful contribution to the greenhouse effect. The leakage rate of methane from natural gas is estimated to be very small in most U.S. cities, but in some other parts of the world it is estimated to be much higher.

There is also a growing concern about an uncontrolled "gas rush" disrupting pristine sections of the Canadian Rockies and other regions with exploratory drilling efforts. If natural gas use continues to grow as it is predicted to do, this problem could increase.

New Technologies. The main role of natural gas until recently was as a source for heat in buildings and industry. Efficient new technologies such as natural gas powered cooling systems and heat pumps are beginning to compete with electricity in other end uses. In addition, the use of natural gas for electric power generation is growing rapidly in many countries, spurred by its environmental advantages over coal. Natural gas is also attracting attention as a vehicle fuel, as cities look for cleaner transportation options. In the U.S. many governments have started to promote these vehicles in public and private fleets. An industry study estimates that as many as four million natural gas powered vehicles could be on U.S. roads by 2005 (Brown, 1994, 56). In Vermont, increasing the use of natural gas-powered vehicles represents a way that natural gas energy use could grow without extending the pipeline beyond its current area. (See the section on Potential Future Sources and Technologies for the Future for more about natural gas-powered vehicles.)

8. Wood

During 1993, Vermonters used about 7.6 TBTU of wood for non-electric purposes, representing 7% of the state's total delivered energy consumption (Vt. DPS).

The majority of this wood use (84%) occurred in the residential sector, while most of the rest (11%) occurred in the industrial sector. (Additional wood was used to generate electricity; see the "Electricity from Wood" section below.) Popular wood varieties for fuel in Vermont include ash, beech, yellow birch, hard maple, and oak.

In the 1993-94 heating season, wood was the second most popular fuel source for home heating in the state (oil was first). Wood was used as a primary source of heat in about 21% of Vermont households, as a supplemental source of heat in 17% of all households, and for "pleasure burning" in fireplaces in 5% of

Vermont households. About 3% of Vermont households used wood for hot water heating (Vt. DPS, *Vt. Residential Fuelwood*, 1995, 3-4, 11).

Vermont has a long history of wood use for home heating. In the recent past, however, the percentage of Vermont homes that use wood as their primary heat source has decreased. In the 1981-82 heating season, about 42% of Vermont households heated with wood for primary heat, compared to 21% in the 1993-94 heating season. (The recessions of the early 1980s may have caused people to use more wood heat because of its lower cost.) Use of wood as a supplemental heat source has increased during the same time period, however. In the 1981-82 heating season, only 11% of households used wood as a supplemental heating source, compared to 17% in 1993-94 (Vt. DPS, *Vt. Residential Fuelwood*, various years).

Outside the residential sector, wood is used in 75 state buildings, primarily through district heating, and in approximately 175 industries and businesses CONEG, *Northeast Regional Biomass Program*, 1995, 56-7). In addition, there are 18 Vermont schools that use wood-chip heating systems. (See the text box on Wood-Chip Heating in Vermont.)

Regionally, wood use for fuel is higher compared to the rest of the nation. Maine and Vermont are among the top three states nationally in the proportion of total energy obtained from wood and other biomass sources. A recent study estimated that the wood energy industry produced 34,387 jobs and $1.8 billion in net income for the Northeast in 1992. Approximately 1,870 of those jobs and $85 million of the income occurs in Vermont (High, 1994, 1, 6-7).

Nationally, wood accounted for about 2.7% of the total primary energy consumed in the U.S. in 1992, with the industrial sector consuming the majority in the paper, lumber, and wood products industries. The majority of the industrial wood energy usage occurred in the South, with only a small amount occurring in the Northeast. In the residential sector, however, the Northeast accounted for 22% of U.S. usage. Total wood energy use in the U.S. has declined since the early 1980s in the residential sector, but has stayed relatively flat in the industrial sector (U.S. DOE/EIA, *Est. of U.S. Biomass Energy Consumption*, 1994, 9-13). Worldwide, wood use for fuel has increased about 150% since 1950 (During, 1993, 30).

Future Trends and Issues

Supply. In many areas around the nation and world, forest resources are depleted or declining where they were once abundant. In Vermont and other northern New England states, however, one of the last remaining large contiguous forests exists, the Northern Forest. Vermont is fortunate to have plentiful forest resources. About 80% of the state's land area is forested, with an estimated 475 million green tons of living trees, 80 million green tons of cull and salvable dead wood, and 12 million green tons of annual forest growth per year in the state's forests.

In 1994, a typical recent year, the total harvest from Vermont's forests was about 3.85 million green tons of wood (of which about 1 million tons were harvested for fuel uses) (Vt. ANR, Bob De Gees, personal communication, 1995). A reasonable estimate of the sustainable amount of wood that could be available for human use is 50% of the net annual growth, or 6 million tons per year, if harvested in a sustainable manner. (See below for more on sustainable harvesting.) This is considerably more than Vermont's current levels of use (although 50% or more of net annual growth of certain species or certain species in specific locations may be currently harvested). Thus, there appears to be potential for the state to harvest additional wood and still ensure that wood use remains sustainable (though there may be need to manage individual species more carefully). Care and attention to sustainability can enable Vermont to use the forest as an energy resource to the extent that the forest is not irreversibly harmed. Over the long-term, declining forest areas around the

Vermonters have a long tradition of using wood to heat their homes. But a recent, more unusual trend in Vermont has been the installation of wood-chip heating systems in larger buildings.

nation and world could lead to increasing pressures to over-utilize the wood resources that remain, including those in the Northern Forest.

Demand and Price Growth. The Department of Energy predicts that non-electric wood and wood waste fuel consumption in the U.S. will increase an average of 1.3% per year between 1993 and 2010 (U.S. DOE/EIA, *Annual Energy Outlook*, 1995, 23). In Vermont, delivered wood energy use is projected to increase 1.2% per year between 1990 and 2015, and primary use is projected to increase 2.8% per year; this difference reflects the increased amounts of wood expected to be used in the electric sector.[xxii] (See Part III of this chapter.)

Real wood prices are projected to decrease slightly in the future in Vermont. Residential prices are expected to decrease by an average of 0.27% per year between 1994 and 2015, while industrial and commercial prices decrease 1.36% and 0.5% per year respectively (Energy Ventures Analysis, 1995). This trend will make wood energy more attractive compared to other fuels, especially as prices of other fuels increase. As with other renewable fuels, wood could offer economical advantages over fossil fuel sources if external environmental costs were included in the price of all energy sources. (See The Full Cost of Energy Use section later in this chapter.)

Harvesting Impacts. Wood can be harvested sustainably and in a manner that has few environmental impacts. In many areas throughout the world today, however, trees are being cut and burned for fuel and other purposes without sustainable forestry management practices. As a result, worldwide deforestation, and the environmental impacts that accompany it, is a serious problem.

In Vermont, about 80% of the land area is forested and our land use needs are not substantial compared to more populated states and countries. In addition, natural tree regrowth in Vermont is fairly rapid. As a result, good forest management practices are generally practical and attainable here.

To ensure that our fuelwood use is sustainable in Vermont, wood harvesting practices are needed that use forest resources at or below the natural regeneration rate and in a manner that protects the environment over time. This involves avoiding the practice of clear-cutting in most areas. Some methods of wood harvesting can improve the health of the forest, if smaller, less valuable trees are removed to allow more valuable trees needed room to grow. In these ways the health of the forest, including trees, soils, and habitats is maintained, while a consistent supply of fuel is available for future energy production.

Vermont has made a commitment to sustainable forest practices through education, research, and tax policy. This commitment includes not only sustainability considerations, but also includes efforts to protect the health of forests for their scenic, wildlife, recreational, and environmental values. State and county foresters, a growing network of private foresters, and the Use Value Appraisal tax program have all improved the management of Vermont's forests (32 V.S.A. §§ 3751-3775).[xxiii] In addition, electric generating facilities burning wood chips in Vermont are required (due to conditions imposed by the PSB in the permit for each facility) to buy only from harvesters who follow exacting forest management standards.

Emissions and Solid Waste. The emissions of greatest concern from wood burning are carbon dioxide, particulates, carbon monoxide, and volatile organic compounds (VOCs). (See Table 3.III.4.) Vermont's current mix of residential wood space and water heaters emit more of these pollutants per unit of energy used than virtually any other fuel source used for heating. (See Table 3.II.1.)

In terms of other air emissions, newer wood-chip systems are believed to be very clean. Wood-Chip fired boilers of a size greater than 90 hp are regulated by ANR. These systems have to meet air quality regulations in order to obtain a permit for operation. It is in the context of a valid permit that any system can be said to be **clean**. The type of system is of much less interest than whether it can meet the air quality standards required to pass the permitting requirements. **Efficiency** of a wood-chip fired boiler system is determined by both the combustion efficiency and how well the system satisfies the financial needs of the owner. Modern wood-chip fired boilers can achieve combustion efficiencies of 70% or better. These systems are also notable for reducing the cost of energy to the owner. Schools that have converted from electric heat to wood-chip heat have seen the cost of heat decrease by a factor of 10; that is, a $30,000 electric heat bill became $3,000 for wood-chip heat. Complete and comprehensive data on air emissions for all fuel types and technologies is only now starting to be collected and analyzed. The Coalition of Northeastern Governors (CONEG) recently commissioned an air emissions test on two wood-chip systems used in Vermont. This study discovered no significant difference in the health risk of the two Vermont systems that burn northern hardwood chips (chipped and screened sawmill residue) compared to systems that burn #2 distillate fuel oil (VT Dept. of Health, memo from Razelle Hoffman, Dec. 1, 1995; Environmental Risk Limited, *Emissions Test Report*, 1995).

Disadvantages to wood-chip systems include space demands for storage and fairly high installation costs, including costs for the wood-chip system itself, for the wood-chip storage area, for a backup heating system, and for retrofitting the building's heating network. However, high initial costs can be offset by lower fuel costs over the life of the system. Further disadvantages include the fact that, unlike several other renewable resources, wood sources emit some pollutants. Wood fuel harvesting practices must also be monitored closely to ensure that they are managed sustainably in order to remain environmentally sound.

However, compared with using fossil fuels, the disadvantages to using wood as a fuel source are minor from environmental, sustainability, and security viewpoints. Heating large buildings with wood-chips is still a relatively new idea in the U.S. and the practice is not widespread. Like other renewable fuel sources, the cost of wood-chips would be lower than other fuel sources if external costs were better reflected in the prices of all energy sources. Vermont's current use of wood-chip heating systems has given the state valuable experience with new combustion technologies and with a renewable energy source that will become even more important in the future.

dollars circulating in the local and regional economy, thus providing added security. From an environmental standpoint, wood chips have an advantage over fossil fuels because they can be used sustainably; carbon dioxide emitted during the burning of wood will be reabsorbed through new tree growth in a sustainably managed forest.

Although wood use emits more carbon dioxide than any other combustion fuel source, no net carbon dioxide emissions are attributed to wood burning if forest resources are managed sustainably. The carbon found in trees is part of a process that includes carbon exchange between living organisms, the atmosphere, the soils, and the oceans. When wood is burned, the carbon that was originally captured from the atmosphere during the tree's lifetime is released back into the atmosphere. Sustainable forest practices that allow new tree growth to replace the harvested and burned trees ensure that an equivalent amount of carbon dioxide will again be captured from the atmosphere.

In Vermont, a system of sustainable forest practices is a reachable goal, as discussed above. An important indicator of overall sustainability (the net annual growth compared to annual harvest) suggests that Vermont's harvest is sustainable, though there may be certain species of trees that are being harvested at non-sustainable rates. On a worldwide basis, however, carbon dioxide emissions from deforestation are a serious problem because the carbon dioxide is not being recaptured in new tree growth. Worldwide, tropical forest clearance contributes about 16% to the median annual estimate of global carbon released into the atmosphere (Dean Wang, oral presentation, February 1995).

Wood energy offers Vermont a unique opportunity to reduce carbon dioxide emissions in two ways: 1) the use of sustainably harvested wood has no net emissions, and 2) if wood use replaces or offsets fossil fuel use, it also offsets fossil fuel carbon dioxide emissions. Offsetting fossil fuel carbon dioxide emissions is particularly important because burning fossil fuels such as oil and coal releases carbon (in the form of carbon dioxide) that has been sequestered from the atmosphere for millions of years. Trees and other organisms have been unable to sequester the increased levels of carbon dioxide from fossil fuel emissions, which has led to increased atmospheric concentrations of carbon dioxide and has contributed to climate change.

The other major air pollutants from wood-burning -- particulates, carbon monoxide, and VOCs -- have negative impacts on human health. Although Vermont's current mix of residential wood heaters produce more of these pollutants per unit of energy used than other fuel sources for heating, the pollutants from wood systems will decrease in the future as older heaters are replaced with new EPA certified systems. (See New Technologies below.) These new wood stoves have much lower emissions of particulates, VOCs, and carbon monoxide compared to the mix of systems currently in use in Vermont. However, emissions of these three pollutants per unit of energy used from the new stoves are still higher than emissions from the current mix of heating systems that use oil, LPG, and natural gas (Vt. DPS).

Nonetheless, wood energy use has advantages over use of other sources. Net carbon dioxide emissions of wood use can be reduced to zero if managed sustainably, unlike any fossil fuel source. Because carbon dioxide is the largest contributor to global warming, this is a significant advantage of wood use. Furthermore, wood energy use can displace oil and other fossil fuel use, reducing carbon dioxide emissions even more and reducing problems of foreign oil reliance. Wood and other biomass sources are the only combustible energy sources currently available that can be used sustainably and renewably, and wood is the only renewable source readily available to Vermonters. In addition, wood energy use in Vermont contributes to local jobs and improves the local economy. Although the emissions from wood burning will continue to be an important concern, the advantages to wood use are significant.

Wood burning also produces ash, which is very low in heavy metals and sulphate content, and is suitable for use as an agricultural and forestry fertilizer. The ash can also be used around the home as fertilizer for gardens, lawns, and trees. The low quantities of leachates present in wood ash makes landfill disposal straightforward and relatively cheap (MIT, 1992, 3). Wood ash has recently been discovered to contain very low levels of cesium-137, a radioactive isotope formed as a byproduct of nuclear fission. This cesium was absorbed by trees after the atmospheric nuclear weapons tests of the 1950s and 1960s. Higher levels of radioactivity have been found in New England wood ash samples compared to other regions of the country, probably because the soils in the region have properties that prevent trees from releasing cesium through their roots. However, even these higher levels in New England are believed to be below those that would create a public health risk (Science News, *Wood Ash*, 1991, 95; Bradbury, 1991).

New Technologies. In the late 1970s, the sale and use of wood stoves grew rapidly, leading to a corresponding increase in particulate emissions. In the Northeast, Pacific Northwest, and in Colorado, air inversions compounded the problem of wood stove emissions. As a result, some states and localities passed ordinances restricting the use of wood stoves. The growing concern that conventional wood stoves were emitting unhealthy concentrations of particulates led air pollution agencies, environmentalists, and researchers to look for ways to lower particulate emissions and improve wood-burning in stoves.

In 1988, the EPA passed regulatory standards that restrict air emissions of wood stoves and fireplace inserts. All new wood stoves and inserts must now be federally tested and certified to ensure that they meet improved emissions requirements.[xxiv] Typical wood stoves in use before these standards emitted between 60-70 grams per hour of particulates, while the standards currently in place require new stoves to emit no more than 4.1 or 7.5 grams per hour, depending on the type of stove. This reduction in particulate emissions produces a corresponding drop in other societal costs currently incurred from health care, mortality, and household damage. Certified wood stoves also operate more efficiently and burn less wood than older, non-certified stoves. The EPA estimates that the stoves burn 25%-33% less wood for the same heat output. Although the EPA standards focus on reducing particulates, the stoves also have lower emissions of polycyclic organic materials (carcinogens) and carbon monoxide, because they burn fuel more completely; furthermore, they produce 90% less creosote than conventional, non-certified stoves, reducing the risk of chimney fires and the cost of chimney cleaning. Thus, federal standards on wood stoves have started to reduce air pollution, improve human health problems, save energy and forests, and make new stoves and inserts safer and less costly to maintain. These benefits will be even greater in the future as more old stoves are replaced with new ones (Vt. DPS, *Buying a Wood-Burning Appliance*, 1991; Georgia Governor's Office of Energy Resources, Forestry Commission, 1987, 41).

Another important technology for larger wood-burning systems is the wood-chip gasification system, which "gasifies" wood before it is burned. Vermont has become a leader in the installation of this fairly new technology. Currently, there are 18 Vermont schools that use wood-chip heating systems; most of these are gasification systems. (See the text box on Wood-Chip Heating in Vermont.)

9. Coal

About 0.41 TBTU of coal was used for non-electric purposes in 1993 in the state, representing only 0.4% of Vermont's total delivered energy use (Vt. DPS).

Slightly less than half of this coal use occurred in the industrial sector, while the remainder of the use was divided fairly evenly between the residential and commercial sectors. Coal was used as a primary or supplemental heat source in an estimated 1.5% of Vermont households in the 1993-94 heating season (Vt. DPS, *Vt. Residential Fuelwood*, 1995, 4).

Throughout the U.S., coal is used mainly for electricity generation. For information about future trends and issues in coal use, see Chapter 3, Section II. F. Electric Fuel Sources, 7. Electricity from Coal.

10. Solar

During 1993, Vermont used an estimated 0.07 TBTU of solar energy, representing a very small portion of the state's total energy consumption (Vt. DPS).

Vermont's usage of solar energy occurred almost entirely in the residential sector. A survey of residential heating sources in the 1993-94 heating season found that approximately 1,400 Vermont households used solar energy as a supplemental heating source (Vt. DPS, *Vt. Residential Fuelwood*, 1995, 4). There are an estimated 3,500 solar water heaters in use in Vermont (Solar Works, personal communications, July 1995). In addition, solar energy is used to provide lighting in these and other homes and buildings.

Solar energy can also be used to power photovoltaic (PV) panels that produce electricity. There are an estimated 300 Vermont homes that are disconnected from the utility power grid, using photovoltaic power for their electricity (Solar Works, personal communication, July 1995). Because Vermont's climate is much cloudier in the winter than in the summer, most large systems that use PVs also include an oil or propane generator that can be used as backup when solar energy is not available.

Although New England and Vermont receive less solar energy than many other locations in the country, there is still great untapped potential for solar energy use here. The section below, Potential Energy Sources for the Future, discusses solar energy in much greater detail and explores how use of solar energy could be increased in Vermont.

F. Electric Fuel Sources

As a result of PURPA, Vermont saw a flurry of independent power development during the 1980s. This activity resulted in the development of nearly all of the state's remaining hydroelectric sites. Currently 20 Qualifying Facilities sell power through the state purchasing agent. (This function is currently performed by Vermont Electric Power Producers, Inc. (VEPPI)) Nineteen of the state's QFs are hydroelectric plants and one is a wood-burning generator. The hydroelectric sites range in size from capacities of 0.11 MW (Nantana Mill) to 26.38 MW (Sheldon Springs). Altogether, the hydro facilities have a maximum capacity of 53.39 MW. (In addition, there are many very small hydro facilities that provide power directly to utilities.) The wood-burning generator located in Ryegate has a capacity of 20.3 MW. Together, these wood and hydro sources supplied about 325 GWh in 1994 or about 5.6% of Vermont's electricity needs (on an ownload basis).

In Vermont, the Public Service Board has jurisdiction over sales from Qualifying Facilities to utilities (but not over licenses to build hydroelectric facilities, which rests with the Federal Energy Regulatory Commission), and has developed a rule governing the sale of power between all IPPs and utilities (30 V.S.A. §209(a)(8); Rule 4.100). This rule implements PURPA, setting up the conditions under which QFs operate and creating a purchasing agent to contract with and manage QFs. A revised rule has been proposed that would make the acquisition of power from IPPs more competitive, emphasizing negotiation between utilities and IPPs to set contract terms and rate structures. The revised rule also proposes that

Vermont currently has 22 electric distribution utilities, ranging in size from the Village of Readsboro Electric Department with 311 customers to Central Vermont Public Service with 135,265 customers in 1993. The five largest utilities are Central Vermont Public Service, Green Mountain Power, Citizens Utilities Company,

the City of Burlington Electric Department, and Vermont Electric Cooperative; these five utilities provide electricity for about 87% of all customers in the state. In addition, Vermont has one natural gas utility, Vermont Gas Systems, located in Chittenden and Franklin counties, serving about 27,000 customers.

Electric utilities are granted monopolies over service territories, which guarantees them the right to provide electric service to customers within a certain geographic area and gives them privileges such as the right to build power lines on private property. In exchange for these guarantees, utilities are subject to government regulations which require them to act as trustees for public resources. A utility must provide (and carry out the planning necessary to continue to provide) adequate electricity or gas service at reasonable prices, meeting industry standards for reliability and quality of service. Electric utilities in Vermont are required to base their supply decisions on the most societally cost-effective measures identified through a planning process called least cost integrated planning. These measures generally must include efficiency or demand-side management programs as well as traditional supply sources. (See the Utility Efficiency Programs section below for a discussion of this planning process.)

accepted IPP proposals fit into the goals, plans, and other details outlined in a utility's Least Cost Integrated Plan. (See the Utility Efficiency Programs section later in this chapter for a description of Least Cost Integrated Planning.) Revision of the rule has been pending.

At the national level, approximately 7% of total generating capacity came from Independent Power Producers in 1992. In the same year, IPPs built more of the new generating capacity in the U.S. than did utilities. Many experts expect this trend to accelerate, because recent federal legislation (EPACT) further opens the power industry to competition by establishing greater access to utility transmission lines and encouraging utilities to form IPP subsidiaries. Partly as a result of IPPs' growing share of the power market, there is a shift across the country to smaller generators. The average size of U.S. utility-built plants declined from more than 600 MW in the mid-1980s to about 100 MW in 1992 (Flavin, *Powering the Future*, 1994, 17).

There have been some concerns that utilities' contracts with QFs and IPPs are inflexible and too costly. On the other hand, independent power projects can be credited with displacing a great deal of fossil generation, boosting the use of renewable energy sources, boosting the efficiency of new generation systems, preserving air quality, providing less costly ways of meeting new clean air standards, and benefitting local and state economies by providing jobs and keeping energy dollars in-state.

Furthermore, IPPs have given us valuable experience for the future. During the next decade, the U.S. will need to replace 215,000 MW of electric generating capacity, due in part to the expected retirement of the country's nuclear power plants and stricter air quality controls for polluting fuel sources. In addition, Asia, South America, Eastern Europe, and Africa, with their expanding population and economies, will face an enormous need for electricity in the next several decades. This demand for new electric energy sources can be sustainably met only by relying more on renewable and efficient fuel sources and technologies. Experience gained from IPPs will allow such sources and technologies to compete successfully in emerging markets against fossil fuels, meeting both our energy needs and the environmental standards of the future (Sterzinger, 1995).

1. The New England Power Pool

All of Vermont's electric distribution utilities, along with most other utilities and a few independent power producers in New England, are members of NEPOOL, the New England Power Pool. (Vermont utilities are represented in NEPOOL by VELCO, the Vermont Electric Power Company.) The members of NEPOOL pool the operation of their electricity generation and transmission resources, allowing them to attain greater reliability at a lower cost than if they operated independently. Each utility in NEPOOL has a portfolio of supply sources available for the use by the pool; NEPOOL dispatchers "turn on" and "turn off" these supply sources as needed to meet reliably the electricity requirements of the region at the lowest cost, given the available sources. NEPOOL turns on (dispatches) the lowest-cost supply resources first, and as power demand increases, dispatches the next most economical supply resource not already being used. However, there are some supply sources that must be run at specific times, depending on a number of factors such as plant engineering requirements, contract specifications, reliability considerations, and proximity of supply sources to demand locations. In addition, the plants authorized as Qualifying Facilities under the federal Public Utilities Regulatory Policy Act (PURPA) of 1978 generally run whenever they are able under the terms of their power sale contracts. (See the text box on Independent Power Producers and Qualifying Facilities for more information.)

Being members of NEPOOL gives utilities several important advantages compared to operating independently. First, and most importantly, NEPOOL offers great reliability of service. If one of Vermont's large generating plants unexpectedly shuts down, for example, NEPOOL will provide backup power. NEPOOL also has procedures in place to supply utilities with power or manage contingency plans during times of region-wide electricity deficiency or emergency situations. Second, NEPOOL assists utilities in planning for future power needs. Third, NEPOOL dispatches the power as it is needed, removing a task that each utility would otherwise do individually. Finally, pooling supply resources saves utilities and customers money. This occurs because utilities need different amounts of electricity at different times; when one utility has a heavy load, or electricity requirement, another utility may have a light load. If the utilities operated ndependently, the first utility would most likely use costly generating resources to meet its high load, while the second utility would have cheaper supply sources that remain idle. Through NEPOOL, dispatchers use the cheaper resources from the second utility to fill part of the electricity needs of the first utility. Pooling resources produces considerable savings. During 1994, Vermont utilities received about $733,426 in NEPOOL savings as a result of economic dispatch (VELCO, personal communication, August 1995).[xxv]

2. Vermont's Base Load, Intermediate, and Peaking Power Plants

Utility planners must carefully study their customers' demands for electricity as they make decisions about how much and what kind of power to generate. Total electricity demand fluctuates throughout the day and the year, and these differing levels of demand are most economically served by different types of power plants. Vermont's load, or electricity requirement, is at least 400 MW in every hour of the year. This is the base load, or the minimum amount of electricity that is always needed, and base load power plants meet this first segment of the load. They usually run continually, although some base load sources may be operated at less than full power during some hours with low loads. Most base load plants have high fixed costs, but utilize inexpensive fuels. With a large portion of their expenses tied up in fixed costs, these plants are only economical if they run continually.

Power plants that meet intermediate loads operate during daily hours that require more electricity, and can be cycled off overnight, on weekends, and during times of the year when electricity use is light. Plants filling intermediate loads are likely to run when the total load is between about 400-850 MW. Such plants usually have moderate fixed costs but higher fuel costs, so they are more economic to run at variable levels and to shut down when base load plants are available. Some older plants which originally provided base load power are also operated at intermediate capacity.

Peak electricity loads occur for relatively short periods of time, primarily during the business week and during certain seasons. Thus, peaking plants which meet this demand are idle far more hours than they run. Peaking plants are likely to run when the total load is greater than about 850 MW. Such plants tend to be designed to have low fixed costs (with the exception of some hydro plants), but they usually have high operating and/or fuel costs. (Hydro peaking plants are somewhat different in that they store water behind a dam for release through the turbines at times when the energy is needed.) Peaking plants are designed to have rapid response times when electricity is needed and can frequently be started up from cold conditions and brought to full output in ten minutes or less. For this reason peaking plants are also used as backup plants to meet unanticipated load spikes or to respond quickly to the unscheduled loss of a base load or intermediate source.

Currently, Vermont's base load electricity needs are met largely with nuclear power from Vermont Yankee and hydroelectric power from Hydro-Québec, as well as with smaller amounts from the Merrimack 2 coal-burning plant in New Hampshire, the New York Power Authority hydroelectric projects, some in-state hydroelectric power, and the in-state Ryegate wood-fired plant (a Qualifying Facility). These power plants usually are available to run between 70% and 90% of the time. Intermediate load requirements are met by a

Table 3.II.2 Fixed, Dispatch, and Average Total Power Costs of Selected Generation Plants used by Vermont

(Fixed costs: nominal $/KW-yr; Dispatch and power costs; nominal cents/kWh)

collection of in-state and out-of-state plants which may run between 30% and 60% of the time, often running during weekdays but not at all on weekends in certain periods of the year. For peak load requirements, Vermont is amply supplied with in-state gas turbines, diesel systems, and hydroelectric facilities.

The fixed costs of base load plants are generally higher than the fixed costs of intermediate and peaking plants. At the same time, the dispatch costs of base load plants (the fuel costs plus the other variable costs of running a plant) are much lower than the dispatch costs of other types of plants. Table 3.II.2 illustrates the fixed, dispatch, and combined fixed and dispatch costs of selected power plants used by Vermont.

3. Vermont's Daily and Yearly Electricity Demand

Throughout each day, the amount of electricity required by Vermont customers changes. Utilities must constantly monitor and anticipate the varying electricity demand to ensure that power production can meet demand. As demand increases throughout the day, different power plants are dispatched. Utilities also must

Figure 3.II.24 Vt. Electricity Avg. Weekly Dec. Load Shape, 1991
MegaWatts

plan for power demand as it varies throughout the year. Vermont utilities are required to have approximately 12%-15% more electric generating capacity available than the projected peak demand for each year in order to maintain reliable and adequate service, and account for units that are out of service for maintenance or other reasons. Thus, utilities' electricity capacity (or amount of electricity they can generate) is greater than their customers' usage (or amount of customer demand).

Vermont's daily "load shape" shows how electricity demand fluctuates dramatically throughout a typical day. "Load shape" is a graphical representation of electricity use (including transmission losses) for each hour of the day. Figure 3.II.24 shows the Vermont average weekly load shape in December 1991, illustrating several interesting characteristics of Vermont's electricity use. (The following numbers correspond to the numbers in Figure 3.II.24.) 1) In the middle of the night, Vermont uses only about half of its electric capacity, or about 500 MW. In other words, more than half of Vermont's electric generating capacity is sitting idle at night. 2) The lowest electric energy use generally occurs between 2-3 a.m. 3) There are generally 2-3 periods of peak electricity use during the day, around 8 a.m., 12 noon, and 6 p.m. 4) Electric energy demand climbs sharply between 6-8 a.m. and falls sharply between 10-12 p.m. 5) Demand is lower on the weekends than during the week, and has only two peaks, occurring around 12 noon and 6 p.m.

Load shapes vary not only with the time of day, but also with the seasons. Figure 3.II.25 shows the average load shape for Tuesdays in each month during the year. (Again, the following numbers correspond with the

Figure 3.II.25 Vt. Electricity Load Shape, Avg. Of Tuesdays Each Month, 1991

MegaWatts

numbers in the Figure.) 1) Not surprisingly, Vermont's peak electricity demand is in the winter. The greatest energy use or peak usually occurs in December during the holidays when, in addition to the "normal" demands of Vermont homes, businesses, and industries, second homes in the state have a higher occupancy rate, heating demands are high, and ski areas are in full operation and making snow. Occasionally, the peak demand occurs in January. 2) Vermont must always generate at least 400 MW to meet customer demand. Even in the middle of the night, street lights, night shifts at manufacturing plants, heating and cooling fans and pumps, electric hot water heaters, refrigerators, etc. consume 400 MW of electricity. 3) Electric demand varies with the seasons. There are about 250 MW of demand that vary with the seasons, shown by comparing the winter and summer peaks. The troughs of winter and summer show a baseload difference of about 300 MW. The largest segment of this additional wintertime electricity demand is used by electric heating systems, with smaller amounts being used by snow-making operations at ski areas, electric pumps and fans for heating systems, engine block heaters, water heaters (only a slight amount), and students and tourists who are not in the state during the summer. 4) Summer months do not exhibit the sharp peaks that winter months exhibit. Less predictable habits (because of summertime outdoor activities, vacations, and no school) and more hours of sunlight contribute to fewer and smaller peaks. 5) Lighting demand in the summer is significantly smaller due to more hours of sunlight. This can be seen by the evening peaks that become smaller and later in the day in the summer, corresponding to the time of the sunset. Reduced summertime lighting demand can also be seen by the disappearance of morning peaks for those months when the sun rises before most Vermonters.
The yearly peak demand in Vermont has not grown since 1989 due to a sluggish economy, less extreme weather patterns, and effective efficiency programs. The state's all-time record peak demand was 968 MW in the winter of 1989. That peak level was driven by extremely cold weather and a relatively strong economy. By comparison, the recent cold of the 1994 winter produced a peak demand that was only 942 MW, well below the record level of 1989.

Vermont's daily and yearly load shapes and peak demands help to illustrate some important ways that utility planners can save electricity and lower their electric rates. If some of the electricity usage that occurs during daily or yearly peak times can be saved (or at least "shifted to" or used during other times), money can be saved in two ways. First, the electricity usage during the peaks is most expensive and provides significant savings if avoided or shifted to other times of the day, when utilities can use less expensive base load or intermediate plants to meet those needs. Second, as the peak demand decreases, the costs of owning capacity to meet that demand decrease. (Capacity is the total amount of electricity the utility must be able to generate, about 112%-115% of the yearly projected peak.) Both of these savings can reduce electricity rates.

4. Recent History of Electricity Use

Compared to the rest of the world, electricity use in the U.S. is extremely high. With only 4.6% of the world population, our country uses 27% of the total electricity consumed worldwide. On a per capita basis, U.S. electricity use is almost twice that of Japan and more than twice that of Western Europe. Electricity use per capita in developing countries is much smaller. Average worldwide electricity consumption per capita is only one-sixth that of U.S. consumption per capita. (See Figures 3.II.26 and 3.II.27.)

Electricity use in countries with growing economies and large populations, such as China (with 22% of the world population), is predicted to skyrocket in the future, as more of the world's people demand the services and benefits electricity provides. As such countries increase their electricity use, there will be serious consequences for environmental quality, global warming, and depletion of the world's fossil energy resources. These trends suggest a continued need to reduce future negative impacts by ensuring that electricity use is as efficient, clean, and sustainable as possible.

Although Vermont has captured efficiency gains in electricity use during the past several years, the state can still do much more to move toward a more sustainable electricity supply. Vermont's total electricity consumption has grown substantially since 1976. (See Figure 3.II.28.) Delivered electricity use rose 59% between 1976 and 1989, with the greatest rate of growth occurring during the strong economic years of 1986-1988. Growth in electricity use decreased between 1988 and 1990 due to a slower economy and efficiency gains from utility programs. Electricity usage growth has recently resumed in Vermont.

Similarly, electricity expenditures have grown substantially since 1976, as illustrated in Figure 3.II.29. Growth in expenditures slowed during the late 1980s, due partly to moderate oil prices and an over-supply of electricity in the New England market during that time. However in the late 1980s and early 1990s, Vermont's relatively inexpensive electricity contract with New York Power Authority phased down, and more expensive contracts with Hydro-Québec and Independent Power Producers began. This change contributed to the resumption of growth in electricity expenditures.

Electricity consumption in the residential, commercial, and industrial sectors has grown steadily in the past 20 years, except for a leveling off of residential use after 1989. As Figure 3.II.30 shows, the largest growth in electricity use occurred in the industrial sector, which grew by 121% since 1976. Electricity use in the commercial sector also grew substantially (by 78%), while the residential sector experienced slower growth (at 33%). The commercial and industrial sectors' use has risen largely as a result of new business and industrial growth in the state. Electricity use in the residential sector is tied more closely to population growth (which grew by 20%) than to economic growth, accounting for the more gradual increase in use. About 41% of electricity consumption occurs in the residential sector in Vermont, a higher proportion than the nationwide residential use of 35%. (See Figures 3.II.31 and 3.II.32). This is due mostly to Vermont's smaller-than-average industrial sector.

Electricity use in Vermont is distributed among a number of end-uses. (See Figures 3.II.33 - 3.II.35). In the residential sector, more than half of all electricity use powers water heaters and refrigerators. Water heating itself accounts about one-third of all electricity consumed in the residential sector. Electricity use for water heating has declined slightly in recent years due to high electricity prices, more efficient electric water heaters, and more competitive propane water heaters. Refrigeration electricity use has also shown a stabilization in recent years, partly due to federal refrigerator standards that came into effect after 1990. Miscellaneous uses in the residential sector are also substantial and have shown significant growth during the past 20 years, largely as a result of consumers using more appliances such as computers, microwaves, second and third TVs and stereos, and others. Electric heating, cooking, drying, and lighting uses have all decreased or stabilized in recent years, while air conditioning electricity use continues to grow.

Lighting is the largest end use in the commercial sector, accounting for just over 40% of total commercial electricity use. In recent years, growth in lighting electricity use has stabilized partly as a result of utility efficiency programs. As in the residential sector, miscellaneous uses have also grown in the commercial sector, due to new businesses, more automation, and more use of office equipment such as computers, fax machines, and others. The earlier growth in electric heating, water heating, cooking, and refrigeration end uses has stabilized or declined slightly in recent years.

In the industrial sector, electricity to run motors accounts for about two-thirds of total usage. This end use has grown significantly since 1976, due mostly to more industrial businesses locating in Vermont. Heating used for industrial processes accounts for about 11% of industrial electricity usage, with lighting accounting for only 4%. Miscellaneous industrial uses include cooling, refrigeration, space heating, and automation.

Figure 3.II.36 illustrates the percentage of Vermont's total electricity use dedicated to each end use. Surprisingly, the miscellaneous category garners the largest segment of electricity use, due to large miscellaneous uses in each sector. There is considerable potential for energy savings in these miscellaneous end-uses as a group, but savings are difficult to achieve except with federal standards for each individual appliance or item. Industrial motors represents the next largest electric end-use, and considerable savings can also be achieved here with more sophisticated systems currently on the market. The large lighting category is mostly a result of high lighting use in the commercial sector; utility efficiency programs have achieved some savings with lighting efficiency measures, but there is still a great deal of savings to be gained. The water heating category is large due to usage in the residential sector; again, while some progress has been made in recent years, there is still significant opportunity for savings in this end-use. While air conditioning is the smallest category, significant future growth is likely as more buildings and residences acquire air conditioners; thus, air conditioning is another end use that deserves attention. Growth in most of the remaining end uses has stabilized or decreased in recent years, and likely will continue to do so.

Fuel Sources Used for Generating Vermont's Electricity

Figure 3.II.37 shows changes in the shares of fuel sources that generate Vermont's electricity. Hydro and nuclear power have generated most of the state's power since 1976. Use of nuclear power has fluctuated somewhat throughout that time, but in the mid-1980s Vermont began purchasing power from the Millstone 3 Nuclear Power Plant, accounting for a subsequent rise in the use of nuclear power. Since the early 1990s, Vermont utilities have sold some of their Vermont Yankee power in order to diversify their supply mix, leading to a subsequent decrease in nuclear power use. The use of hydropower grew substantially between 1984 and 1987, due to larger contracts with Hydro-Québec. Hydropower use fell again in the late 1980s and early 1990s because of expired contracts with Hydro-Québec and the New York Power Authority. Coal consumption has fluctuated since 1976, but has fallen since 1989 as a result of an expiring contract with Ontario Hydro (which burns coal), and decreasing use of generation from the Merrimack 2 coal plant in New Hampshire. In 1998 the contract for Merrimack 2 power ended. Currently Vermont has no long term contracts or ownership interest in coal fired power plants. Electricity generation from oil and natural gas has traditionally been low, but has increased since 1990 due to utility purchases intended to diversify their supply mixes and the low cost of oil. Wood use for electricity had been limited in Vermont to the McNeil Station, but recently rose due to the completion of the Ryegate plant which also burns wood. The growth in economy purchases (short-term, inexpensive purchases made from a variety of fuel sources) since the late 1980s is largely a result of the increased inexpensive electricity supply in the New England market. This over-supply has been caused by slack demand, an influx of power from the Seabrook nuclear plant in New Hampshire (which came on-line in 1990), new independent power producers, and savings from utility efficiency programs. (Note: In Figure 3.II.37 values after 1991 are projections. Information on Vermont Ownload Electricity Supply shown in Figures 3.II.38, 3.II.38a, and 3.II.39 give the most recent information on fuel sources for generating Vermont's electricity.)

For purposes of comparison, distribution of Vermont's electricity supply by generator fuel is shown for 1993, 1994, and 1997 in Figures 3.II.38, 3.II.39, and 3.II.38a. Between 1993 and 1997, hydro power's share increased from about 42% to about 47% and nuclear power's share held steady at about 34% of the state's electricity supply. Coal was the next most used fuel with about 10% of the total during the years 1993 and 1997, while oil and natural gas dropped from about 6% to 2%, renewables held steady at about 4%, and there were small portions of system power.

This distribution of Vermont's electric supply resources differs substantially from the nationwide distribution, as illustrated in figure 3.II.40. On a national level in 1993, coal is used to generate about 57% of the country's electricity, with nuclear power generating about 22%, and natural gas and hydro each generating about 9%.

Vermont's electricity supply mix, in 1993 and recently, contains about five times as much hydropower and over one and one-half times as much nuclear power as the nation's 1993 supply mix.

As Vermont works to define policies and make wise decisions about electric energy use in the future, our past and current situations illustrate where our attention should be focused. Considerable potential exists for electric energy savings in all three sectors. In the residential sector, water heating stands out as having especially large potential for savings; other end uses which deserve attention are refrigeration, heating, and miscellaneous plug loads. Lighting end uses represent significant potential for savings in the commercial sector, with heating and miscellaneous plug loads representing less, but still important, potential. In the industrial sector, motors consume a great deal of electricity; work to develop and use more efficient motors deserves significant efforts.

In the future, our attention should also be focused on which fuels we use to generate electricity, taking into consideration stricter air emissions and environmental regulations, sustainability, foreign oil dependence issues, and nuclear waste disposal issues. Vermont's electricity supply is and has been generated largely by hydro and nuclear power, but environmental and sustainability issues associated with each of these fuel sources must be addressed as the state searches for generation sources in the future. Our use of coal has decreased dramatically in recent years as a result of stricter emissions regulations. Oil has traditionally been used as an electric fuel source in the Northeast, and newer technologies are available that burn oil more efficiently; however, oil use has numerous environmental, sustainability, and foreign dependence problems. The state has potential for increased use of wood and wind energy to generate electricity, but whether the economic and regulatory climate will prove advantageous for such renewable energy plants remains to be seen. The issues surrounding the fuel sources that Vermont currently uses (or might use in the future) for electricity generation are outlined in the sections below.

Figure 3.II.27 World Electricity Use per Capita, 1993
Thousand kWh per capita

Figure 3.II.28 Vermont Primary and Delivered Electricity Use
TBTU

Figure 3.II.29 Vermont Electricity Expenditures
Millions of 1995 dollars

Figure 3.II.30 Vermont Delivered Electricity Use by Sector
TBTU

Figure 3.II.33 Vt. Residential Delivered Electricity Use by End Use

TBTU

Figure 3.II.34 Vt. Commercial Delivered Electricity Use by End Use

TBTU

Figure 3.II.35 Vt. Industrial Delivered Electricity Use by End Use
TBTU

Figure 3.II.37 Vermont Delivered Electricity Use by Fuel
Thousands of GWh

5. Nuclear Power

Nuclear power contributed about 1,935 GWh (6.6 TBTU) to Vermont's energy supply mix in 1993, accounting for 34% of the state's total electric power.[xxvi] In 1997, nuclear power was also 34% of Vermont's ownload supply mix. (See Figures 3.II.38 and 3.II.38a.)

About 76% of this nuclear power (1,462 GWh) was generated by Vermont Yankee Nuclear Station, located near Vernon. Vermont Yankee began generation in 1972, and is licensed to operate until 2012. The plant has achieved a high level of output, especially in recent years. About half of the energy Vermont Yankee generates is used by Vermonters, while the other half is used in other New England states.

Vermont also used nuclear energy from several other nuclear generating stations in New England in 1993: Seabrook in New Hampshire (154 GWh), licensed until 2030; Maine Yankee in Wiscasset, Maine (104 GWh), licensed until 2008; Millstone 3 in Waterford, Connecticut (117 GWh), licensed until 2026; Connecticut Yankee in Haddam Neck, Connecticut (75 GWh), licensed until 2007; and Pilgrim in Plymouth, Massachusetts (22 GWh), licensed until 2012.

U.S. utilities used nuclear power for 21% of their total energy input in 1993, considerably less than Vermont's usage (U.S. DOE/EIA, *State Energy Data Report*, 1995). Across the country, there were 109 operable nuclear generating plants in 1992, with five more plants holding construction permits (U.S. DOE/EIA, *Energy Facts*, 1992, 82). The vast majority of
the operable nuclear plants are located in the eastern half of the country. Around the world, about 400 operable nuclear power plants exist, supplying 17% of the world's electricity (Shapiro, 1992, 155-6; Brown, 1994, 52). In absolute terms, the U.S. generates more nuclear energy annually than any other country (U.S. DOE/EIA, *Energy Facts*, 1992, 111).

Future Trends and Issues

Demand and Price Growth. Nuclear electric generating capacity in the U.S. is projected to decrease slowly in the future, averaging a 0.6% per year drop between 1992 and 2010 (U.S. DOE/EIA, *Annual Energy Outlook*, 1995, 84). Total nuclear energy consumption is expected to decrease by an average of 0.1% per year between 1993 and 2010 in the U.S. as a whole, but is expected to decrease by 1.4% per year or 22% in the New England region (U.S. DOE/EIA, *Supp. to the Annual Energy Outlook*, 1995, 103, 121). Vermont's use of nuclear energy is expected to grow in the near future, and decrease sharply after Vermont Yankee's license expires in 2012. (See Chapter 3, Part III.)

Uranium prices for nuclear plants in southern New England are projected to increase 1.8% per year between 1994 and 2015 (Energy Ventures Analysis, 1995). However, the primary costs of operating a nuclear plant are fixed costs, so changes in uranium prices likely will not significantly alter the price of nuclear power. As discussed below, the price of nuclear power in the future has uncertainties related to the ultimate costs for decommissioning and radioactive waste disposal.

Radioactive Waste. The ultimate disposal of the radioactive waste generated by Vermont's nuclear power use remains a significant challenge. Both low-level and high-level radioactive waste require disposal.

Low-level radioactive waste includes contaminated metals, filters, resins, and other materials used at nuclear plants. Most low-level radioactive waste decays to safe levels within one hundred years. In the past, Vermont's low-level waste has been held in disposal facilities in South Carolina, Washington, and Nevada. These facilities had closed by July 1994, but the South Carolina Legislature recently voted to re-open its facility. Currently, Vermont Yankee and the other nuclear plants which supply Vermont with power store their low-level waste on-site. The recently approved a Low-Level Radioactive Waste Compact allows Vermont and Maine to dispose of low-level radioactive waste at a Texas facility. Low-level waste disposal is not resolved for the Connecticut nuclear plants that supply Vermont with power or Yankee Rowe in Massachusetts that supplied Vermont with power in the past, and no solution is currently in sight.

A more important issue is the disposal of high-level radioactive waste, which consists of spent fuel. This high-level waste must be managed for many thousands of years in order to protect present and future generations. (See Chapter 2 for a discussion of human health, environmental, and security hazards associated with nuclear waste.)

In 1982, the federal government embarked on a policy for high-level waste disposal and began collections from nuclear electricity customers at a rate of $0.001 per kWh with the expectation that a disposal facility would be available in 1998. In 1987, Congress designated the Yucca Mountain site in Nevada to be developed as a disposal facility. Although the federal government has accumulated more than $11 billion from nuclear electricity customers for high-level waste disposal, Congress has been reluctant to appropriate amounts necessary to develop facilities on a reasonable schedule, preferring to use collected funds to offset portions of the federal deficit. In addition, the Department of Energy has been inefficient in its use of amounts that have been appropriated. The Department of Energy has recently claimed that it is not required to meet the 1998 deadline, and 27 states (including Vermont) and 13 nuclear utilities have sued DOE to meet this date. (The lawsuit is pending.) Now, the Department of Energy projects completion of the facility by 2015. In fourteen years, the schedule has slipped seventeen years. This lack of reasonable progress leaves doubt whether a disposal facility will ever be completed.

High-level waste currently is stored in water-filled pools at reactor sites. Without a disposal facility, utilities are requesting and gaining regulatory approval to move high-level waste into dry storage in concrete and metal casks on the reactor sites. As this occurs at more sites, the concern arises that these dry casks may become the final storage/disposal solution for a long time into the future. This possibility carries the economic, public safety, and environmental protection uncertainties of waste stored at 74 separate reactor sites across the country long after the generating facilities have been retired. A single national interim storage facility is an alternative to these multiple default storage locations. Legislation for a single interim storage is introduced in Congress, but its fate is uncertain.

Currently, Vermont Yankee stores its spent fuel on-site in storage pools, but if present outage and fuel management practices continue, existing storage capacity will run out in 2001. At present, Vermont Yankee has made no statement regarding spent fuel storage beyond 2001.

Decommissioning. Another unresolved issue with nuclear plants is the cost of decommissioning. Decommissioning is the process of removing all radioactive components to a disposal facility and restoring the site to federally established standards after a nuclear plant is permanently shut down. However, few nuclear plants have been decommissioned, and the cost for doing so is subject to ongoing increases. Funds for decommissioning are collected from customers during the operating life of the plant and set aside (invested).

Despite the best attempts to estimate the costs of decommissioning accurately, each updated cost estimate has shown the cost to be higher than previously estimated. These increases in estimates have come from uncertainties about decommissioning techniques, difficulties in radioactive waste disposal, lack of definition of an acceptable radioactivity standard for site cleanup, and higher-than-inflation increases in labor and equipment costs. Increasing decommissioning estimates are detrimental to electricity customers in three ways. First, customers' electric rates increase to ensure satisfactory funds are collected. Second, present and future customers pay more than their fair share for decommissioning since customers in earlier years paid less. Third, increasing decommissioning cost estimates mislead decision-makers who wish to assess the effects of a shutdown before license expiration.

Vermont Yankee's decommissioning estimates have followed the trend and have risen during the past several years. Their decommissioning estimate was $190 million in 1988, which equates to $229 million in 1993 dollars. The most recent 1994 forecast is $313 million in 1993 dollars.

There are positive developments, however, in the settlement agreement for Vermont Yankee's most recent decommissioning cost estimate. A cost escalation factor above the estimated inflation rate is included in the cost estimate which recognizes and partly takes into account the increasing trend of estimates. And, the settlement agreement allows up to 30% of the decommissioning fund to be invested in common equities instead of municipal bonds and U.S. Treasuries, which have a low return rate. The higher returns from this new investment strategy have resulted in no increase in collections through rates, despite the higher decommissioning cost estimate.

Early Shutdown. The possibility of early shutdown for economic reasons is one of the greatest planning uncertainties related to nuclear power. Currently, no commercial nuclear plant has operated longer than 31 years before shutting down. Since 1989, six U.S. nuclear plants have opted to permanently shut down for economic reasons well before the end of their 40-year operating licenses. Early shutdowns have been prompted by major technical or equipment problems, which nuclear plants often encounter as they age, and which are evaluated as too costly to repair. An early shutdown is sometimes the most cost-effective response to a problem.

Across the nation, most nuclear plants will face the possibility of early shutdown in the next 10-20 years as they age; by 2010, almost all nuclear plants will be more than 20 years old (U.S. DOE/EIA, *Annual Energy Outlook*, 1995, 31). With the recent shutdowns of several U.S. nuclear plants, it has become clear that economics is the most likely cause of the end of a nuclear plant's life. In fact, Shearson Lehman Brothers estimates that nearly one-quarter of all U.S. nuclear plants may be closed for financial reasons during the next decade (Flavin, *Powering the Future*, 1994, 52). The Yankee Rowe nuclear plant in Massachusetts shut down permanently in 1992, due to financial considerations as a result of technical problems with its reactor pressure vessel. This early shutdown not only eliminated a source of inexpensive energy, but left a continuing and as yet unfunded liability for decommissioning expenses and disposal of radioactive wastes.

The Department of Public Service prepared a report in 1988 that studied the possible effects of an early shutdown of Vermont Yankee. The report analyzed what the proper economic basis should be for an early shutdown, and concluded that an early shutdown was not economically advantageous at that time. The Department of Public Service will continue to study this topic.

Relicensing. The possibility of relicensing nuclear plants after their original licenses expire depends on a number of uncertain factors, including economics, plant performance, and the relicensing process. The Nuclear Regulatory Commission is currently working on rules for the relicensing of nuclear plants. A September 1995 report from the Nuclear Regulatory Commission, however, states that the agency's reactor licensing activities are being reduced and their regulatory attention is "being drawn instead toward problems related to the aging of existing licensed reactors and decommissioning, as reactors that were once leading candidates for license renewal have been instead prematurely shut down" (Hart, 1995, 2).

Any license renewal procedure should take into consideration the human health risks and environmental costs of the radioactive waste created by nuclear power. In addition, license renewal should not be pursued until high-level and low-level radioactive waste disposal issues have been resolved and public acceptance of nuclear power is higher. Because the radioactive waste issue is uncertain and likely to remain so, relicensing should be viewed with great skepticism.

New Nuclear Plants. No new U.S. nuclear power plants have been started since 1979, and there are currently no plans to build new ones. However, four nuclear plants holding construction permits are indefinitely postponed. The nuclear industry is currently promoting advanced nuclear reactors which are smaller and simpler than the ones already in use. This "new nuclear option" is promoted by the nuclear industry as advantageous for reducing greenhouse gas emissions.

However, nuclear energy's advantages in reducing greenhouse emissions must be compared with the unresolved problems with storage of high-level and low-level radioactive wastes. Nuclear plants also have potential financial problems as they age, and decommissioning and radioactive waste disposal costs are higher than previously thought.

In addition, the possibility of future financial problems increases the risk of investing in nuclear plants. This risk becomes more problematic for utilities as the utility industry undergoes restructuring. (See the Competition and Utility Restructuring section.) One of the outcomes of restructuring could be that utilities will no longer be guaranteed a reliable and consistent customer base, making utilities more reluctant to accept risky power plant investments. This could have an impact on the willingness of utilities to invest in nuclear power in the future.

Finally, public sensitivity in New England has been heightened due to the early shutdown of Yankee Rowe in Massachusetts, problems with licensing of Seabrook nuclear plant in New Hampshire, operating and management problems with Pilgrim nuclear plant in Massachusetts, and early shutdown studies of Vermont Yankee and Maine Yankee commissioned by the legislatures of those states. Although nuclear plants can be operated safely, many are suspicious that safety is too easily compromised. Unless remarkable progress is made in resolving these issues, new nuclear power generation cannot be considered an option of choice in the future for Vermont.

Fusion. Inexpensive, safe, clean energy from nuclear fusion remains a theoretical possibility which has not yet been demonstrated on a practical scale. Billions of dollars have been spent to develop the concept, but to date it remains simply a concept with tremendous potential. Although recent laboratory advances have been encouraging, it is generally agreed that nuclear fusion will not be ready for serious consideration in the near future.

Public Opposition. Nuclear power as a future energy source is dependent to a great extent on public perceptions of nuclear power. Some people advocate nuclear power, citing the relatively clean safety record of U.S. plants, the security advantages of a domestic energy supply, and the absence of combustion air emissions. Others are willing to accept nuclear power if safety is ensured and if an acceptable radioactive waste disposal strategy is found. Others believe that a satisfactory radioactive waste disposal solution will not be found, that nuclear power presents a security problem by making radioactive materials available, that it is unacceptable to leave future generations with the burden of radioactive waste, and that the nuclear accidents at Three Mile Island and Chernobyl show that nuclear power is too risky. Overall, the public's opposition to nuclear power has risen since the inception of nuclear power. Siting radioactive waste disposal facilities has been met with strong public opposition both in the U.S. and abroad. Such public opposition toward nuclear power will likely make it difficult to invest more in this energy source in the future.

Sustainability Considerations. Sustainability concerns for nuclear power fall into two categories: the depletion of uranium resources and the burdens nuclear power use places on future generations.

Uranium is mined primarily for nuclear weapons production and nuclear energy use. Worldwide, there are 2.1 million metric tons of reasonably assured uranium resources that can be produced at less than $130/kg. Market prices are currently under $40/kg. ("Reasonably assured resources" can be seen as the rough equivalent of "proven reserves" for fossil fuels.) There are also an estimated 966,000 metric tons of potential additional reserves (These two reserve figures, plus the uranium already extracted, is roughly equivalent to "world ultimate resources" for fossil fuels.) Complete information was not available about worldwide uranium production in the past, due to secrecy surrounding weapons production during the Cold War. However, total production for energy and weapons has fallen significantly since 1989 (OECD, 1994, 24-5, 36, Table 2). Assuming that weapons production does not increase in the future, the reasonably assured uranium reserves should last at least 41 years and the additional reserves should last another 20 years at current levels of use. Because uranium production has been dropping, the reasonably assured reserves and additional reserves will most likely last longer than the above estimates. In addition, there are uranium resources that would be more expensive than $130/kg to produce.

Uranium, then, is a limited resource like fossil fuels and its supply must be drawn down slowly to remain sustainable. The technology exists for "recycling" nuclear fuel through the use of breeder reactors, which generate more fissionable material than they consume. Such recycling could remove sustainability concerns related to uranium depletion. Breeder reactor programs, however, have been plagued by financial and technical problems; in addition, they significantly increase the risk of nuclear weapons proliferation because they produce high concentrations of plutonium-239, which can be used to create nuclear weapons. (Conventional power plants, unlike breeder reactors, do not require or produce material that can be used as easily in weapons.) Illicit smuggling of plutonium and other weapons grade material has been increasing in Russia, Eastern Europe, and parts of Western Europe, which could lead to serious security implications in the future (Williams, 1996, 40-4).

The most important sustainability considerations of nuclear power revolve around the burdens nuclear power use places on future generations. These burdens include the risk to human health and the environment from radioactive waste, the financial burden of managing radioactive waste, the loss of land areas to store radioactive waste, and the increased risk of nuclear weapons proliferation. These burdens represent costs that current and past generations shift to future generations through nuclear power use. This shift in costs to future generations constitutes an unsustainable use of this energy source.

The burdens left to future generations by nuclear power use are unique because the risks extend over time-frames unprecedented in human history. Our current and past use of nuclear power will require attention and investments from people for a time period that defies our usual notion of time. For example, plutonium-239 will be dangerous for a quarter of a million years, or 12,000 human generations; and as it decays, it becomes another radioactive component that will be dangerous for even longer (Lenssen, 1991, 9). These long time-frames add another dimension to the burdens placed on future persons. While the risk of a radiation release accident occurring during our lifetimes is quite low, the likelihood of an accident that releases radiation into the environment increases with the time-frame considered. It is clear that even if no more radioactive nuclear waste is created, the nuclear age will continue for an unfathomably long time.

The sustainability considerations associated with nuclear power use are very different from the sustainability issues surrounding fossil fuel use. Nuclear power avoids the serious threats to human health and the environment from air pollution and global warming caused by fossil fuel use. If nuclear power was replaced by power from fossil fuels, these threats would greatly increase. However, nuclear power places serious long-term risks and burdens related to proliferation, accidents, and radioactive waste on future generations. Moving toward a sustainable energy supply in which both nuclear power and fossil fuels are eventually replaced with renewable energy sources would avoid adding more to future generations' burdens.

Replacement Power for Vermont Yankee. Vermont should plan now for how to replace the energy Vermont Yankee supplies. Vermont Yankee's license expires in 2012, around the same time that many other nuclear plants' licenses expire, and Vermont will need good energy options in place at that time to fill our electricity needs. The need for replacement energy would come earlier if Vermont Yankee faced a premature, permanent shutdown. Because we know that the power supplied by nuclear plants likely will need to be replaced within the next 20 years, Vermont now has the lead time necessary to ensure that nuclear plants are replaced in an orderly way with efficiency improvements and renewable and sustainable power sources.

6. Hydroelectric Power

Vermont's 1993 electric supply mix included 2,377 GWh (8.1 TBTU) of hydroelectric power, accounting for 41% of the state's electric energy use.[xxvii] In 1997, hydropower contributed about 47% of Vermont's supply mix. (See Figures 3.II.38 and 3.II. 38a.) In 1993, Hydro-Québec supplied 67% of the hydropower Vermont used. In 1997, Hydro-Québec provided 74% of Vermont's hydropower. Vermont purchases power from Hydro-Québec under a number of firm contracts which are scheduled to increase capacity, reaching a maximum of 310 MW in 2001. The bulk of these contracts expire in 2015 with very small purchases continuing to 2020.

Other out-of-state hydropower suppliers include the Niagara and St. Lawrence hydro projects owned by the New York Power Authority (NYPA). In 1993, Vermont purchased 192 GWh from these projects, and in 1997, our NYPA purchases were less than half this amount. Power from these hydro projects has been very inexpensive in the past and continues to be attractive. The contract for NYPA power at the 1997 level is being renegotiated to extend to 2012.

In 1993 and 1997, almost all of the remainder of Vermont's hydroelectric mix, about 25% of it, came from in-state sources. In-state hydro sources include independently-owned hydro sites operating as Qualifying Facilities, and hydro sites owned by utilities. (See the text box on Independent Power Producers and Qualifying Facilities.) Vermont has 19 independently-owned hydro sites, with a capacity of about 53 MW, that sell power to utilities through an independent purchaser. (In addition, there are several very small independent sites that sell power directly to utilities.) Most of these hydro sites operate as "run-of-river" facilities, generating power as the water flows through the facility. The sites that can operate as "ponding" facilities and store water behind dams for use during peak load periods are more valuable economically. There can be negative environmental impacts associated with ponding facilities (see below). Slightly less than half of the power that comes from utility-owned hydro sites is generated from run-of-river facilities, with the remainder from ponding operations.

Vermont uses a greater proportion of hydroelectric power than many other U.S. states, although states in the Pacific Northwest and parts of the West also use a great deal. Most of the best hydro sites in the U.S. are already fully developed, but there are small hydro dams throughout New England no longer in use. In 1994, only 8% of the electricity net generation in the U.S. was from hydroelectric power (U.S. DOE/EIA, *State Energy Data Report*, 1995).

Future Trends and Issues

Demand and Price Growth. Growth in hydroelectric generation is projected to be moderate. According to reported plans of electric utilities, hydroelectric generation in the U.S. will grow at about 0.6% per year through 2010 (U.S. DOE/EIA, *Annual Energy Outlook*, 1995, 32). Hydroelectric power production is also projected to increase in Canada, Greece, China, several Asian countries, and a few African countries. Hydroelectric use in Vermont is expected to remain fairly constant through 2015 due to the state's power contracts with Hydro-Québec. However immediately after 2015, delivery schedules with Hydro-Québec expire. Hydro-Québec is in the process of constructing a number of plants, although plans for the James Bay II project (the second phase of Hydro-Québec's two-phase project) were suspended in 1994 due to environmental concerns and a decline in the projected electricity demand in North America (U.S. DOE/EIA, *International Energy Outlook*, 1995, 58-63).

Because fossil fuel prices have historically been volatile, reliance on hydroelectric power lends important price stability to the region's source mix. In addition, trends toward including the full cost of energy in energy prices will likely give hydroelectric power an economic advantage. While hydropower has serious environmental impacts (see below) that should be accounted for in determining its full cost, other energy sources such as coal, oil, and nuclear power have environmental and sustainability problems which are also very serious. Prices of power from Vermont's hydro projects that operate as Qualifying Facilities are for the most part, fixed in their contracts. Utilities are required to purchase their power under the federal law, PURPA. (See the text box on Independent Power Producers and Qualifying Facilities.)

Environmental Impacts. There are numerous environmental impacts associated with hydropower development and use. The physical, chemical, and biological character of the river upstream, downstream, and at the dam site are altered by the construction of the dam and the operation of the hydropower facility.

Hydropower damming changes the anatomy of a river from a free-flowing environment to one which may be characterized by fluctuating water levels, impoundment (accumulation of water in a reservoir), and bypass reaches (sections of a river from which most or all water has been diverted). Across Vermont, hydropower projects impound more than 100 miles of streams. These alterations to the river anatomy obstruct water and nutrient flow, and the movement of fish and other aquatic organisms. Many fish and other aquatic organisms have evolved to live in a limited range of environmental conditions within lakes and river systems. Hydropower facilities can be operated in ways that alter these natural conditions. Sensitivity to the timing and extent of manipulation of the naturally occurring stream flow can minimize impacts on inhabitants of the river system.

The extent of river alteration from a hydropower facility depends to some extent on the mode of operation of the facility. Hydroelectric dams operate as run-of-river or as ponding facilities. At true run-of-river facilities, water outflow equals inflow on an instantaneous basis and power is generated as the water is naturally available. At ponding facilities, water is stored in a pond and released when electricity is needed. The stream flow regime is less significantly altered at run-of-river facilities than at ponding hydropower projects.

When water is stored and released in ponding facilities, the pond level fluctuates on a daily, weekly, and/or annual basis in response to the volume of water released. The pond level fluctuation can range from one or two feet to more than thirty feet, and it can result in shoreline erosion and poor wetland development. Shoreline erosion can cause the zone used for spawning by some fish species to become inadequate due to lack of a gently sloping shoreline. Wetlands development can be hindered by pond level fluctuations, leading to a reduction in the habitat area that would occur on a natural lake.

Both ponding and run-of-river facilities can cause changes in the aquatic environment by altering the stream flow regime. This happens in several ways. If the powerhouse section of the facility is located downstream from the dam, water flows may be diverted out of the river and carried to the powerhouse by a penstock or canal. In these cases, the riverbed is left with little or no water, creating a bypass. If the project is operated as a ponding facility, downstream flows fluctuate in response to electrical demand. The rate at which this fluctuation occurs can also impact stream life.

When the natural stream flow regime is significantly altered in some of the above ways, the life cycle requirements of many organisms are compromised. For example, many fish spawn in sections of a river which are characterized by specific depths, water velocities, and streambed materials. Periodic flooding and dewatering of habitat areas limit their suitability for cover, food production, and spawning. If there are no restrictions on the rate at which river flows can fluctuate, rapidly changing flows can stress or kill aquatic organisms. Immobile aquatic organisms can be adversely affected by both increasing and decreasing water flows. Increasing flows may wash immobile organisms downstream while decreasing flows may strand them, leaving them vulnerable to desiccation (drying out). When sections of a river are bypassed, the result is usually a complete loss of aquatic habitat. Unless provisions are made for providing adequate minimum water flows in bypassed areas, the river section may actually become a semi-terrestrial environment that cannot support organisms depending on aquatic habitat. Dams can also cause lower levels of dissolved oxygen levels in the water, as a result of increased water temperatures from impoundment and increased levels of organic material.

While hydropower projects that operate as run-of-river facilities do not alter the natural flow to the same extent as a ponding facility or result in a fluctuating impoundment, they still depend on the presence of a dam and therefore create a barrier to the movement of fish and other aquatic organisms. For example, fish such as the Atlantic salmon and the steelhead rainbow trout may be blocked from reaching their spawning areas regardless of the operating mode of the hydropower facility unless efforts are made to assist the spawning fish around the obstruction. Conversely, creation of an impoundment and associated reservoir can create a new habitat for different species of organisms. Informed and responsible management of impoundments can minimize many impacts.

There are measures that can reduce the impacts of hydropower dams on river systems. Using run-of-river facilities instead of ponding facilities is advantageous because they have a smaller impact on stream flow. In addition, dissolved oxygen monitoring can be used to maintain water quality, and restrictions on minimum flows and ponding release rates can be put in place to reduce the impact of fluctuating flows and impoundment levels (Vt. ANR, *Hydropower in Vermont*, 1988, 2-1-2-7; Kathy Fallon, Vt. ANR, personal communication, August 1995). Further, hydro projects can be operated in a manner that reflects the seasonal activities in the river basin. For example, ponding facilities can restrict drawdowns during spawning season to prevent dewatering of eggs. Other operational measures can minimize effects on other aspects of riverine biology as well.

In addition to the environmental impacts of hydroelectric dams, recreation opportunities and aesthetics can be impacted both positively and negatively. Hydropower projects, especially large ones, can displace human populations as well. Vermonters and environmentalists in other states have protested purchases from Hydro-Québec because the facilities have submerged large areas of land, causing displacement of Native Americans and negative environmental impacts for wildlife and aquatic species and habitats. In recent years, some Vermonters also have protested expansion of or continuing use of in-state hydroelectric plants due to negative environmental impacts.

Although hydroelectric power has environmental impacts, it is a renewable energy resource which avoids air emissions and many other negative impacts caused by the use of fossil fuels. While the operation of many hydroelectric plants has not focused on maintaining a healthy aquatic environment, hydropower has the potential to be used wisely, economically, sustainably, and with reduced environmental impacts. As existing plants apply to renew their operating licenses, informed judgment can be exercised regarding the cost to these facilities of altering their operating mode relative to the benefits to be gained for the aquatic environment. Every kiloWatt-hour of electricity generated by hydro power displaces one generated by fossil fuels. Significant air emissions are avoided as a result.

Future Hydro-Québec Purchases. Within a few years, Hydro-Québec power will become the largest electric source in Vermont's supply mix. (See Figure 3.II.38a Vermont Ownload Electricity Supply, 1997.) Purchasing additional long term power from Hydro-Québec in the near future would not be wise because of the risks associated with concentrating heavily on one supplier. Vermont utilities are likely to continue making short term incremental purchases from Hydro-Québec as they compete in the New England marketplace.

New In-state Hydro. Virtually all of the economically feasible hydro sites of any significant size have already been developed in Vermont, either by utilities or independent owners. In addition, environmental regulations for hydroelectric plants are strict, and Vermonters have expressed concern about the environmental effects of in-state hydro plants. For these reasons, it is unlikely that new hydropower dams will be built in Vermont.

Relicensing In-state Hydro. License renewals involve extensive evaluations of the environmental impacts of the hydro facility by both the state and the Federal Energy Regulatory Commission. Tables 3.II.2a - 3.II.2c list In-State Hydro Projects that are FERC licensed, FERC unlicensed, and FERC exempt. In nearly all cases, changes in operation are required to mitigate adverse environmental effects not anticipated in the original licenses and to enhance river habitats. Restrictions imposed during relicensing most likely will reduce or alter output, resulting in increased costs to customers. Early estimates suggest that environmental conditions attached to the new operating licenses will result in a 10%-20% reduction in their expected output. In some cases, restrictions may shift operations from ponding applications to run-of-river applications. As discussed above, hydro sites that have ponding operations are more economically attractive because they can produce more power during expensive peak periods. Operation during peak periods also displaces inefficient and polluting fossil generation.

Repowering In-state Hydro. Many of the hydro facilities owned by utilities in Vermont use old equipment and could benefit significantly from "repowering," or installing new, more efficient equipment. However, the current availability of inexpensive power in New England makes it economically unattractive for utilities

Table 3.II.2a In-State Hydropower Projects
FERC Licensed Projects

Project Name	Owner	U=Utility N= Non-Utility	Installed Capacity (MW)	License Expires	401 Issued	Stream
Barton Village (Pensioner Pond)	Barton Electric	U	1.40	10/01/04	06/04/84	Clyde River
Arnold Falls	CVPS	U	0.35	11/30/34	06/16/94	Passumpsic River
Cavendish	CVPS	U	1.50	10/31/24	10/07/93	Black River
Gage	CVPS	U	0.70	11/30/34	06/16/94	Passumpsic River
Lamoille	CVPS	U	20.45	12/31/87		Lamoille River
Middlebury Lower	CVPS	U	2.25	06/30/00	12/31/74	Otter Creek
Passumpsic	CVPS	U	0.70	11/30/34	06/16/94	Passumpsic River
Pierce Mills	CVPS	U	0.25	11/30/34	06/16/94	Passumpsic River
Taftsville	CVPS	U	0.50	08/31/24	09/29/93	Ottauquechee River
Weybridge	CVPS	U	3.00	05/31/00	03/20/75	Otter Creek
Clyde River	Citizens Utilities	U	4.80	12/31/93		Clyde River
Bolton Falls	GMP	U	8.80	01/31/22	03/31/81	Winooski River
Essex No. 19	GMP	U	7.20	02/28/25	11/09/93	Winooski River
Vergennes	GMP	U	2.40	5/31/99		Otter Creek
Waterbury (Little River No. 22)	GMP	U	5.52	09/01/01		Little River
Great Falls	Lyndonville Electric	U	1.90	05/31/19	02/26/84	Passumpsic River
Vail	Lyndonville Electric	U	0.35	01/31/01	03/10/80	Passumpsic River
Morrisville	Morrisville Water and Light	U	3.34	08/15/15	03/24/81	Lamoille River
Morrisville	Morrisville Water and Light	U	1.89	08/15/15	03/24/81	Green River
Bellows Falls	New England Power	U	40.80	04/30/18		Connecticut River
Deerfield	New England Power	U	37.60	03/31/37	01/30/95	Deerfield River
Fifteen Mile Falls	New England Power	U	291.40	07/31/01		Connecticut River
Vernon	New England Power	U	24.40	04/30/18		Connecticut River
Wilder	New England Power	U	37.40	04/30/18		Connecticut River

Table 3.II.2a In-State Hydropower Projects
FERC Licensed Projects

Project Name	Owner	U=Utility N= Non-Utility	Installed Capacity (MW)	License Expires	401 Issued	Stream
Center Rutland	OMYA	U	0.30	12/31/23	04/13/95	Otter Creek
Proctor-Beldens-Huntington Falls	OMYA	U	10.04	03/31/12	07/21/81	Otter Creek
Canaan	Public Service of New Hampshire	U	1.10	07/31/09	05/10/84	Connecticut River
North Hartland	Vermont Electric Coop.	U	4.00	10/31/21	03/06/81	Ottauquechee River
Enosburg Falls	Village of Enosburg Falls	U	0.75	04/30/23	06/10/82	Missisquoi River
Highgate Falls	Village of Swanton	U	4.60	04/30/24	12/09/83	Missisquoi River
North Branch No. 3 (Wrightsville)	Washington Electric Coop.	U	0.93	10/31/22	03/30/83	North Branch
Barnet	Barnet Hydro Co.	N	0.53	07/31/32	03/01/82	Stevens River
Martinsville Upper	Jay Boeri, Jr.	N	0.28	11/30/34	11/28/83	Lulls Brook
Comtu Falls	Comtu Falls Corp.	N	0.46	06/30/26	08/23/82	Black River
Deweys Mills	Consolidated Hydro	N	1.90	12/31/32	07/12/82	Ottauquechee River
Sheldon Springs	Missisquoi Assoc.	N	21.67	09/30/24	03/19/84	Missisquoi River
Moretown 8	Moretown Hydro Energy Co.	N	1.14	11/30/22	08/27/82	Mad River
Newbury	Newbury Hydro Co.	N	0.36	08/31/23	12/12/82	Wells River
Gilman	Simpson Paper Co.	N	4.65	03/31/24	07/28/89	Connecticut River
Brockways Mills	S.R. Hydropower	N	1.12	12/31/32	12/01/82	Williams River
Fellows	Westinghouse Electric Corp.	N	0.15	06/30/26	03/23/86	Black River
Lovejoy	Westinghouse Electric Corp.	N	0.15	06/30/26	03/23/86	Black River
Chace Mill (Winooski One)	Winooski One Partnership	N	6.50	10/31/28	05/05/87	Winooski River
Winooski No. 8	Winooski Hydro Co.	N	0.81	07/31/23	12/29/82	Winooski River

Source: Vt. ANR, Water Quality Division, 1998

Table 3.II.2b In-State Hydropower Projects FERC Unlicensed Projects

Project Name	Owner	U=Utility N=Non-Utility	Installed Capacity	Stream
East Pittsford/Chittenden	CVPS	U	3.60	East Creek
Glen	CVPS	U	2.00	East Creek
Patch	CVPS	U	0.40	East Creek
Salisbury	CVPS	U	1.30	Leicester River
Silver Lake	CVPS	U	2.20	Sucker Brook tributary
Carver Falls	CVPS	U	1.90	Poultney River
Troy Hydroelectric	Citizens Utilities	U	0.60	Missisquoi River
Gorge No. 18	Green Mountain Power	U	3.00	Winooski River
Middlesex No. 2	Green Mountain Power	U	3.20	Winooski River
Mollys Falls (Marshfield)	Green Mountain Power	U	5.00	Mollys Brook
West Danville #15	Green Mountain Power	U	1.00	Joes Brook
Wolcott (Portersville)	Village of Hardwick	U	1.00	Lamoille River

Source: Vt. ANR, Water Quality Division, 1998.

Table 3.II.2c In-State Hydropower Projects FERC Exempt Projects					
Project Name	**Owner**	**U=Utility N=Non-Utility**	**Installed Capacity (MW)**	**401 Issued**	**Stream**
Bradford	CVPS	U	1.50	10/3/80	Waits River
East Barnet	CVPS	U	2.20	3/19/82	Passumpsic River
Bethel Mills	Bethel Mills, Inc.	N	0.33	7/21/86	Third Branch White River
Dodge Falls (East Ryegate)	Dodge Falls Associates L.P.	N	4.65	3/21/86	Connecticut River
Emerson Falls	Emerson Falls Hydro, Inc.	N	0.25	9/17/84	Sleepers River
Wells River (Boltonville)	Essex Hydro Associates	N	0.97	2/29/84	Wells River
Fairbanks Mill	Fairbanks Mill Hydro	N	0.02	8/20/82	Sleepers River
Flower Brook	Flowerbrook Hydro, Inc.	N	0.02	7/22/82	Flower Brook
Killington	Killington Hydro Inc.	N	0.10	8/15/84	Kent Brook (Thundering Falls)
Kingsbury	Kingsbury Hydroelectric Co.	N	0.20	6/3/83	Kingsbury Branch
Dog River	Nantana Mill Dam Partnership	N	0.20	1/5/83	Dog River
Harrisville Mill	Raymond C. Miller	N	0.02	6/22/84	Green River
Cold Brook	Dr. and Mrs. Robert Ruhl	N	0.01	6/5/81	Cold Brook
Downers Mill	Simon Pearce Glass	N	0.40	5/11/82	Ottauquechee River
Slack Dam	Springfield Hydroelectric Co.	N	0.40	1/31/85	Black River
White Oak Water Power	Sardar Thanhauser	N	0.01	5/4/82	Halls Brook
Woodside (Hyde Park)	M/M Robert Woodside	N	0.12	3/28/83	Gihon River
Ottauquechee Woolen Mill	White Current Corp.	N	1.89	6/30/77	Ottauquechee River
Ladds Mill	Worcester Hydro Co., Inc.	N	0.15	1/25/85	North Branch

Source: Vt. ANR, Water Quality Division, 1998.

to repower their hydro sites at this time. Upgrading the independently-owned hydro sites known as Qualifying Facilities is more economically feasible (for developers), because these power sites receive a fixed price for their output that is not effected by market conditions. (See the text box on Qualifying Facilities.) On a nationwide basis, increases in hydropower capacity that come from repowering are expected to be offset by retirements in the future (U.S. DOE/EIA *Annual Energy Outlook*, 1995, 29).

Other Benefits of Hydro Electric Generation. Hydro generation facilities provide other benefits to their owners and the regional power system. They are a low cost and reliable source of spinning reserve. Spinning reserve is back-up generation that can be brought online immediately in the case of a failure within the pool. Hydro generation plants provide a distributed source of power which reduces losses throughout the grid and provides local stability. Hydro has no fuel cost. Consequently owners and users of hydro plants are at least partially immune to the vagaries of fossil fuel price fluctuations.

7. Electricity from Coal

Coal supplied Vermont with 555 GWh (1.9 TBTU) of power in 1993, contributing 10% of the state's electric supply.[xxviii] In 1997, coal also contributed about 10% of Vermont' ownload supply mix. (See Figures 3.II.38 and 3.II.38a.) Currently, Vermont utilities have no long term contracts or ownership interests in coal fired power plants.

Vermont's coal power came from the Merrimack 2 power station in Bow, New Hampshire, under a contract that ended in 1998. Merrimack 2 is affected by the 1990 federal Clean Air Act Amendments, which place restrictions on sulfur dioxide and nitrogen oxide emissions from coal power plants. Merrimack 2 will be able to comply with the conditions mandated in Phase I of the federal requirements by burning low-sulfur coal. However, compliance with Phase II of the Clean Air Act is likely to be costlier. The Phase II operating restrictions begin in 2000, but the cost of achieving compliance conceivably could alter the current economics of Merrimack 2 and lead to an early plant retirement.

Since the 1970s, U.S. coal consumption has grown constantly. In response to oil embargoes and price shocks, consumers began to substitute coal for petroleum products. Coal is currently the predominant electric fuel source in the U.S. Vermont uses much less coal for electric generation than many other U.S. states. In 1993, coal plants accounted for 55% of the total energy input at electric utilities in the U.S., as shown in Figure 3.II.40. (U.S. DOE/EIA, *State Energy Data Report*, 1995).

Future Trends and Issues

Supply, Demand, and Price Growth. Coal is currently one of the most abundant fossil fuel resources in the world. Worldwide proven coal reserves are about 1,145 billion short tons (U.S. DOE/EIA, *International Energy Outlook*, 1995, 44). These proven reserves of coal will last 96 years from 1995 if world coal use grows at 1.5% per year, the average usage growth rate projected through 2010 by the U.S. Energy Information Administration.[xxix] No estimate of "world ultimate resources" for coal exists. The U.S. Geological Survey is currently in the process of reassessing coal reserves; when complete, their analysis will be the most comprehensive examination of worldwide coal resources in about 20 years (U.S. Geological Survey, personal communication, September 1995).

Much of the worldwide coal reserves is located in the U.S. and the former Soviet Union, which each have around 23% of the world total. China and Western Europe each have about 11% of world reserves, and the remaining 32% is scattered throughout other countries.

As outlined above, worldwide coal use is expected to increase by 31% between 1992 and 2010, or an average of 1.5% per year. An increase in coal use in China is expected to account for more than 75% of this growth (U.S. DOE/EIA, *International Energy Outlook*, 1995, 43-4, 83). In the U.S., coal is projected to remain the dominant source of electricity through 2010, reflecting the importance of coal to the U.S. economy and some state economies. The Department of Energy predicts that no new coal plants will be built in the U.S. before 2000, but slow electric demand growth and the huge investment in existing coal plants will keep coal in its dominant position (U.S. DOE/EIA, *Annual Energy Outlook*, 1995, 29). Total coal use in the U.S. and the

New England region is projected to increase by an average of 0.8% per year or 14% between 1993 and 2015 (U.S. DOE/EIA, *Supp. to the Annual Energy Outlook*, 1995, 103, 121). Since early 1998, coal is a very small portion of Vermont's ownload supply mix, but coal is still part of the New England supply market.

Future prices of coal will be influenced by current and future environmental regulations. Restrictions imposed by the Clean Air Act Amendments will change the future economics of coal-fired plants, and could increase the cost of sulfur dioxide emissions allowances. If further environmental restrictions such as a carbon tax, nitrogen oxides or particulates emissions standards, or stricter ash landfill regulations were applied to coal combustion, prices would also rise. Coal prices for electric utility plants in southern New England are projected to decrease slightly or remain about the same in constant dollars, depending on which type of coal is used (Energy Ventures Analysis, 1995).

Air Emissions. Burning coal produces significant amounts of several dangerous pollutants, including carbon dioxide, sulfur oxides, nitrogen oxides, and particulates (PM-10).

Coal use in the electric utility sector emits much more carbon dioxide per unit of energy used than oil, LPG, or natural gas. (See Table 3.II.3.) Coal contains 80% more carbon per unit of energy than natural gas, and 30% more than oil. Burning coal released 2.3 billion tons of carbon into the atmosphere in 1993, or about 40% of all energy-related carbon emissions (Brown, 1994, 58).

Coal electric use also releases more sulfur oxides per unit of energy used than any other fuel source, and high amounts of nitrogen oxides and PM-10. Sulfur oxides and nitrogen oxides cause acid precipitation; nitrogen oxides contribute to smog; and particulate matter emissions cause human health problems. Coal burning also emits smaller amounts of carbon monoxide, nitrous oxide, organic compounds including VOCs (volatile organic compounds) and formaldehyde, trace metals, and fugitive emissions (due to leakage, storage, etc.). The exact levels of emissions from coal combustion depend on the rank and composition of the coal, the type and size of the boiler, the firing conditions, the size of the electric load, the type of emission control technologies, and the level of equipment maintenance (U.S. EPA, *Compilation of Air Pollutant Emission Factors*, 1995, 1.1-2).

As mentioned above, coal burning is affected by the Clean Air Act Amendments (CAAA), which place restrictions on emissions of sulfur dioxide and nitrogen oxides. Phase I of these restrictions began on January 1, 1995, and Phase II will begin on January 1, 2000. Currently, electric utilities emit about 20 million tons of sulfur dioxide annually. The CAAA will reduce annual sulfur dioxide emissions by about 10 million tons and cap them at 8.9 million tons by the year 2000. In addition, annual nitrogen oxide emissions will be reduced by about 2 million tons (Lock, 1991, 19).

Solid Waste. Solid waste streams from coal power plants have not received as much regulatory attention as gaseous emissions, but these wastes can be 6%-40% by mass of the fuel intake of a generator. They therefore present a significant waste stream that must be disposed of in an environmentally acceptable manner. Currently, the waste generated per unit of electricity is increasing due to new, cleaner technologies, and is likely to continue to increase.

Ash produced from coal can be sold to the construction industry for concrete mixing, backfilling, and soil cementing. The ash that is not sold, however, must be disposed of in a landfill. There have been fears that improper landfilling of these solid ash wastes could result in harmful chemicals leaching into the groundwater; if these fears are justified, landfill costs would rise dramatically, with a parallel increase in generation costs from coal plants. However, most ash types currently are considered non-hazardous. If

Table 3.II.3 Vt. Electric Generation Emissions Factors by Fuel (lbs/million BTU)

	CO_2	SO_2	NO_x	PM-10	CO	VOCs	CH_4	N_2O[a]
Oil	169	1.1868	0.4790	0.0809	0.0501	0.0016	0.0003	0.0325
LPG (propane)	139	0.0002	0.1364	0.0057	0.0270	0.0109	0.0003	0.0040
Natural gas	117	0.0006	0.4788	0.0066	0.0637	0.0059	0.0003	0.0244
Wood	228[b]	0.0222	0.1550	0.1405	0.3654	0.0111	0.0010	0.0040
Coal	209	1.5500	0.2970	0.6330	0.0239	0.0014	0.0010	0.0325

[a] N_2O emissions factors represent only rough estimates. Previously used emissions factors for N_2O have recently been shown to be inaccurate. The estimates presented here were extrapolated from the reliable data that does exist.
[b] Carbon dioxide emissions for wood are zero if wood resources are managed sustainably. See the wood sections in this chapter for more information.

certain ash types were upgraded to the status of a hazardous waste, which has been suggested, disposal costs would increase substantially.

In addition to ash, another solid waste stream is created by removing sulfur from airborne emissions. Some sulfur waste is difficult to dispose of, while some can be sold. The developing technology of coal gasification (see below) produces a saleable byproduct of pure sulfur. In the foreseeable future, there should be a profitable market for pure sulfur, but if gasification use increases in the future, there could be a pure sulfur disposal problem. (MIT, 1992, 1-5).

New Technologies. One new technology that could make burning coal more efficient is the coal gasification combined-cycle plant. This technology turns coal into a combustible gaseous fuel that can be used in combined-cycle systems, which are more efficient than conventional systems. (See the Energy Technologies for the Present and Future section for a description of combined-cycle plants.) A few small coal gasification plants have been tested successfully, and larger units are currently under construction. These new technologies are promoted by the U.S. Department of Energy's "clean coal" program.

Compared to a conventional steam-cycle coal plant with scrubbers (devices that remove some pollutants from the stack exhaust), a coal gasification combined-cycle system can achieve 91% less nitrogen oxide emissions and 65% less sulfur dioxide emissions, but only 14% less carbon dioxide emissions. By comparison, a natural gas combined-cycle plant would emit 54% less carbon dioxide than a coal gasification combined-cycle plant, with about the same amount of nitrogen oxide emissions and no sulfur dioxide emissions (Flavin, *Powering the Future*, 1994, 23). Thus, while coal combined-cycle plants offer an improvement in emissions compared to conventional coal plants, they still are much more polluting than other competing fuel sources such as natural gas. As efficiencies for all fuel sources improve in the future, coal will remain one of the most polluting sources.

Some scientists have discussed the possibility of burning coal so that very little carbon dioxide is produced. However, only 24% of the energy value of coal would be available using such a process, making the idea relatively impractical (MacCracken, 1990, 128).

Because a vast reduction in carbon dioxide emissions is necessary to mitigate the potential impacts of global warming, and because coal emits more carbon dioxide per unit of energy than any other fuel source, carbon dioxide emissions from coal must be reduced. However, there is no feasible way to significantly reduce carbon dioxide emissions from coal without reducing coal use. "Clean coal" technologies are unable to "clean" one of the most important pollutants from coal. The Oregon Department of Energy's report on reducing greenhouse gas emissions recommends that the U.S. Department of Energy abandon research on "clean coal" because there is no foreseeable technology that will significantly reduce carbon dioxide emissions from coal power plants (Oregon Department of Energy, 1995, 15).

8. Electricity from Oil and Natural Gas

Oil and natural gas supplied about 332 GWh (1.1 TBTU) of Vermont's 1993 electric supply mix, accounting for 6% of our total electric use.[xxx] About 57% of this power (190 GWh) came from the Commonwealth Electric's Canal 2 plant alongside the Cape Cod canal under a medium-term contract held by Vermont utilities. In addition, 57 GWh came from United Illuminating's New Haven Harbor Station in Connecticut, 19 GWh came from the Yarmouth 4 unit in Maine, and 46 GWh came from the Stonybrook combined-cycle facility in Ludlow, Massachusetts. Stonybrook is the only facility of the group which generates power with both oil (winter) and natural gas (summer). Utilities also purchase smaller amounts of power from oil and gas-fired units in New England under year-long and short-term contracts. Vermont utilities operate several oil-fired facilities that generate electricity during peak load periods. These facilities accounted for about 10 GWh of use in 1993.

In 1997, oil and natural gas are less than 2% of Vermont's ownload supply mix. (See Figures 3.II.38 and 3.II.38a.) Vermont now uses less oil and natural gas than many other U.S. states. On a national level, oil accounted for 3% of the energy input at electric utilities in 1993, while natural gas accounted for 9% (U.S. DOE/EIA, *State Energy Data Report*, 1995, 26).

<u>Future Trends and Issues</u>

Oil Supply, Demand, and Price Growth. Proven worldwide oil reserves, about 1.1 trillion barrels, will last 32 years from 1995 if oil usage grows at 1.6% per year, the average growth rate predicted by the U.S. Energy Information Administration through 2010.[xxxi] The world ultimate resources of oil are estimated at 2.3 trillion barrels (Masters, 1994, 529). If we use all of the world ultimate resources that remain (about 1.6 trillion barrels), the supply will last 43 years from 1995 at the predicted growth rate. In addition, there is oil available in tar sands and in extra heavy oils that currently is not economical or practical to retrieve; if all the oil from these sources was retrieved, the world oil supply would last 54 years from 1995 at the predicted growth rate. (See the Petroleum Products section earlier in this chapter for more information.) Oil reserves are located around the world, but are concentrated most heavily in the Persian Gulf area and a few other areas. Seventy-six percent of the worldwide proven oil reserves are located in OPEC[xxxii] (U.S. DOE/EIA, *U.S. Crude Oil*, 1994, 23-7).

The Department of Energy predicts that total worldwide oil consumption will grow by 33% between 1992 and 2010, or an average of 1.6% per year (U.S. DOE/EIA, *International Energy Outlook*, 1995, 81). The forecast used to calculate future energy demand in Vermont presented later in this chapter assumes world oil consumption will increase at 1.9% per year through 2015 (Energy Ventures Analysis, 1995).[xxxiii] Electricity from oil-fired power plants nationwide is likely to remain fairly small into the future (U.S. DOE/EIA, *Annual Energy Outlook*, 1995, 29). In Vermont, both primary and delivered oil use is projected to increase at about 1.7% per year between 1990 and 2015. (See Part III of this chapter.)

The world price for oil has declined since 1990 and currently is near its 1970 level in constant dollars, but is projected to increase in the future. The forecast used to calculate future energy demand in Vermont presented later in this chapter assumes oil prices will rise to $25 per barrel by 2015 (in 1994 dollars). (See Figure 3.III.6.) Residual oil prices for electric utility plants in southern New England are projected to increase by 1.4%-1.5% per year between 1994 and 2015 (Energy Ventures Analysis, 1995).

Consideration of the future price of petroleum must also take into account the unpriced consequences of oil use, referred to as external costs. In the future, there will be increasing pressure to include the costs of global warming, resource depletion, and land, air, and water pollution into the price of petroleum. Taxes, efficiency standards, and tradable permits are possible mechanisms for internalizing these costs, and each is likely to increase the price of oil. (See The Full Cost of Energy Use section later in this chapter.)

Air Emissions from Oil. Oil combustion in electric utility plants produces significant air emissions; major emissions are carbon dioxide, sulfur oxides, nitrogen oxides, and particulates (PM-10). Oil electric use produces very high emissions of sulfur oxides and nitrogen oxides per unit of energy used compared to other fuel sources. (See Table 3.II.3.)

As outlined in above sections, carbon dioxide is a significant greenhouse gas; particulate matter emissions cause human health problems; sulfur oxides and nitrogen oxides cause acid precipitation; and nitrogen oxides contribute to smog. Combustion of residual oils (the most commonly used oil in power plants) results in significantly higher particulate matter emissions than combustion of distillate oils. Oil combustion also emits nitrous oxide, carbon monoxide, organic compounds including VOCs (volatile organic compounds) and formaldehyde, and trace metals.

Natural Gas Supply, Demand, and Price Growth. Proven worldwide natural gas reserves, at about 4,980 trillion cubic feet, will last 40 years from 1995 at a 2% growth rate per year, the average growth rate predicted by the Energy Information Administration through 2010.[xxxiv] World ultimate reserves of natural gas are estimated at 12,000 trillion cubic feet, of which approximately 10,096 trillion cubic feet remain. These reserves will last 63 years from 1995 at a 2% growth rate.

Forty percent of worldwide natural gas reserves is located in the former Soviet Union and Eastern Europe; 33% in the Middle East; and about 3% in the U.S. (U.S. DOE/EIA, *International Energy Outlook*, 1995, 37, 44; U.S. DOE/EIA, *International Energy Annual*, 1995, 99-100). Net imports of natural gas to the U.S. grew substantially between 1986 and 1994, from 4.2% to 11.6% of total consumption, due almost entirely to higher levels of imports from Canada (U.S. DOE/EIA, *Annual Energy Review*, 1995, 183, 190). Natural gas imports are projected to grow quickly in the future as well, at 3.2% per year between 1993 and 2010.

The Department of Energy projects that natural gas-fired power plants will show the largest increase of any electric fuel source in the future, overtaking nuclear energy as the second-largest source of electricity by 2010 (U.S. DOE/EIA, *Annual Energy Outlook*, 1995, 29, 73). Total U.S. natural gas use will grow at an average of 1.2% per year (or 26%) between 1993 and 2010, the largest increase of any fuel source except renewable fuels (U.S. DOE/EIA, *Supp. to Annual Energy Outlook*, 1995, 121).

In Vermont, delivered natural gas energy use is projected to increase at 3% per year between 1990 and 2015, while primary energy use is projected to increase by 8.7% per year, reflecting the large amounts of natural gas expected to be used for electric generation in the future around the region; this generation is assumed to serve Vermont in this Plan's base case forecast.[xxxv] (See Part III of this chapter.)

Natural gas prices for electric utility plants in southern New England are expected to increase by 1.1%-1.9% per year through 2015 (Energy Ventures Analysis, 1995.) Natural gas prices will also be influenced by pressures to internalize the external costs of its use, but these costs are lower than costs for other fossil fuels.

Air Emissions from Natural Gas. Natural gas is one of the cleanest-burning fossil fuel sources, but it still produces emissions. Carbon dioxide and nitrogen oxides are the major pollutants of concern from natural gas combustion. Natural gas electric utility uses produce one of the highest amounts of nitrogen oxides per unit of energy used compared to other fossil fuel sources. (See Table 3.II.3.) Burning natural gas also produces smaller amounts of carbon monoxide, particulate matter, VOCs, methane, nitrous oxide, and sulfur oxides (U.S. EPA, *Compilation of Air Pollutant Emission Factors*, 1995, 1.4-1).

In addition to the small amounts of methane (the primary component of natural gas) released from natural gas combustion, a small portion of methane leakage from natural gas distribution systems likely contributes to gas companies' "unaccounted-for gas." Methane emissions from all sources are serious because of their powerful contribution to global warming. The leakage rate of methane from natural gas is estimated to be very small in most U.S. cities, but in some other parts of the world it is estimated to be much higher.

There is also a growing concern about the impact of an uncontrolled "gas rush" that is disrupting pristine sections of the Canadian Rockies and other regions with exploratory drilling efforts (Brown, 1994, 56). If natural gas use continues to grow as it is predicted to do, this problem could increase.

In-state Natural Gas Availability. Natural gas is available only in northwestern Vermont. There have been numerous proposals for gas-fired cogeneration units adjacent to industrial sites, but none have yet been built. Similar proposals are likely when Vermont and New England need new electric generation supplies. Extending natural gas to other areas of Vermont would improve opportunities for cost-effective electric generation and cogeneration. This increased availability would also open up additional opportunities for independent entrepreneurs to set up generation facilities. Extending natural gas to other statewide regions is most likely to happen if Vermont becomes a corridor between Canadian gas supplies and southern New England demand centers.

New Technologies. There are a number of technologies that can dramatically improve the efficiency and emissions of both oil- and natural gas-fired electric plants. They include cogeneration, combustion turbines, and combined-cycle plants. Increased competition for new electric generation markets should encourage these new technologies. A description of each of these is contained in the section on Potential Energy Sources and Technologies for the Future below.

9. Electricity from Renewable Resources: Wood and Wind

In 1993, Vermont used about 247 GWh (0.8 TBTU) from wood-generated power, accounting for 4% of the state's electric usage.[xxxvi] At this time, wood represented the only renewable energy source besides hydro with a significant place in Vermont's current electricity supply. By 1997, the Searsburg Wind Project, a demonstration site with 11 wind turbines and capacity of 6 MW, was generating electricity and renewable resources were about 5% of Vermont's supply mix. (See 3.II.G. for more on wind power.)

McNeil Station in Burlington contributed 33% (82 GWh) of the state's wood-fired electric supply in 1993 and about 26% in 1997. (See Figures 3.II.38 and 3.II.38a.) McNeil is the largest municipally-owned wood-fired power plant in the country, with a capacity of 53 MW. When it began operation in 1984, it held great promise for providing an in-state electric generation source, a market for low-grade wood, insulation from fluctuating oil prices, and employment opportunities and other economic benefits. Thus far, McNeil's price has not been competitive, given low oil prices and the increase in Qualifying Facilities which generate power that must be used. However, McNeil has taken measures to improve operation procedures and reduce fuel management problems, and in 1989, added the capacity to fuel its boiler using natural gas as an alternative fuel or in combination with wood. This allows the plant to be used when wood firing is not economical. During 1994, McNeil used wood to produce 87% of its total power, with natural gas providing 11%, and oil the remainder. The percentage of power coming from wood has been increasing in recent years; in 1993, for example, wood produced 80% of the total power. About 65%-70% of the wood McNeil uses comes from in-state sources (McNeil Plant, personal communication, 1995). McNeil station's principal owner, Burlington Electric Department, has worked with the forestry community and its fuel suppliers to develop wood harvesting guidelines that ensure the forests remain a sustainable source of energy for Vermont.

A wood-fired generation plant that began operation in 1992 in Ryegate contributed 165 GWh to the state's supply mix in 1993 and about the same amount in 1997. Ryegate is the second large-scale wood-fired facility in Vermont with a capacity of 20 MW, and it operates as a Qualifying Facility. Unlike the McNeil station, Ryegate is powered only by wood.

The Northeast as a whole currently has about 830 MW of wood-fired electric generation capacity, with another 80 MW in development stages.[xxxvii] The majority of the capacity is located in Maine and New Hampshire, with 490 MW and 129 MW of capacity respectively (CONEG, *Northeast Regional Biomass Program*, 1995). On a nationwide basis, wood provided 11 TBTU of electric energy in 1992. Wood-fueled plants represent less than 1% of the total electric capacity in the U.S. Primary wood fuel sources in New England are whole tree chips (70-80%) (hardwood and softwood) and sawmill residue (20-30%), including wood and bark waste, sawdust, and green wood (MIT, 1992, 2).

Future Trends and Issues for Wood Resources

Supply, demand, and price growth. In many areas around the nation and world, forest resources are depleted or declining. In Vermont and other northern New England states, however, one of the last remaining large contiguous forests exists, the Northern Forest. Vermont is fortunate to have plentiful forest resources. Between 77%-80% of the state's land area is forested. There appears to be potential for the state to harvest additional wood and still ensure that wood use remains sustainable. (See the Wood section earlier in this chapter for more information.) Over the long-term, however, declining forest areas around the nation and world could lead to increasing pressures to over-utilize the wood resources that remain (both for energy and non-energy purposes), including those in the Northern Forest.

On a nationwide basis, electric generation from wood is projected to grow only slightly before 2005, but to increase more quickly afterwards, as technology enhancements improve, prices for conventional fuels rise, and the need for new generation capacity increases (U.S. DOE/EIA, *Annual Energy Outlook*, 1995, 32). In Vermont, delivered wood energy use is projected to increase at 1.2% per year between 1990 and 2015, while primary energy use is projected to increase by 2.8% per year, reflecting the greater amounts of wood expected to be used for electric generation in the future.[xxxviii] (See Part III of this chapter.)

The real price of wood chips for electric generation in Vermont is projected to decrease by 0.82% per year through 2015, while the prices of fossil fuel sources are projected to increase (Energy Ventures Analysis, 1995). This may be advantageous for the future of wood-fired plants in Vermont. In fact, given the current price forecast of all energy sources, the McNeil wood station is projected to operate as a base load plant by the end of the next decade, operating between 75%-85% of the time. In addition, if external environmental costs were included in the price of all energy sources, wood-fired plants could offer economical advantages even sooner because of the environmental advantages of using wood as a fuel source.

McNeil Upgrade. The McNeil station's owners are currently investigating a proposal to use waste heat from the facility to dry the wood chips it uses as fuel. The Burlington Electric Department, the primary owner of McNeil, reports that drying the wood before burning would result in a 30% savings in fuel costs and would also allow the plant's boiler to make more steam than the current steam turbine can use. Adding a second, appropriately sized steam turbine would enable McNeil to use the extra steam to increase its net generation capability by 9.5 MW. The cost-effectiveness of this proposal remains to be seen.

McNeil Gasification Project. Gasification technologies are some of the most efficient and cleanest large-scale technologies currently being developed. They operate by turning fuel sources such as coal, wood, and other biomass sources into a gaseous fuel for use in combustion turbines or combined-cycle technologies. (See the Energy Technologies for the Present and Future section for a discussion of combustion turbines and combined-cycle technologies.) The first wood-fired, combined-cycle prototype was completed in Sweden in 1994 and generates 6 MW of power (Flavin, 1994, *Powering the Future*, 23). Vermont has been involved in testing new wood-fired gasification technologies as well. In 1992, the McNeil Station owners, in collaboration with a developer of wood gasification technology, won a grant from DOE to demonstrate a wood gasification system at McNeil Station in Phase 1 of the project, and an integrated gasification combustion turbine system in Phase 2 of the project. This system would be capable of powering a 20 MW electric generator. Construction of the wood gasifier is now complete and testing is underway. When fully operational, this prototype will be one of the first wood gasification systems of its kind in the world, and will provide valuable information as a demonstration and experimental model.

Emissions and Solid Waste. The emissions of greatest concern from wood burning for electricity are carbon dioxide, particulates, carbon monoxide, and volatile organic compounds (VOCs). Of the pollutants emitted per unit of energy for all electric generation fuels, wood emits the highest or virtually highest amounts of these pollutants. (See Table 3.II.3.)

Although wood use emits more carbon dioxide than any other fuel source, no net carbon dioxide emissions are attributed to wood burning if forest resources are managed sustainably. For an explanation of this point, see the Wood section earlier in this chapter.

The other significant emissions from wood-burning steam plants, carbon monoxide, PM-10, and VOCs, all have serious human health consequences. In addition, wood use emits smaller amounts of sulfur oxides, nitrogen oxides, methane, and nitrous oxide. Wood gasification may have the potential to eliminate much or all of these emissions.

Wood burning also produces ash, which is very low in heavy metals and sulphate content, and is suitable for use as an agricultural and forestry fertilizer. If it is uneconomical to sell the ash, the low quantities of leachates present in the ash makes landfill disposal straightforward and relatively cheap (MIT, 1992, 3). Wood ash has recently been discovered to contain very low levels of a radioactive isotope that was absorbed by trees after the atmospheric nuclear weapons tests of the 1950s and 1960s. However, these levels of radioactivity are believed to be far below those that would create a public health risk (Science News, *Wood Ash*, 1991, 95; Bradbury, 1991).

Internalizing external costs into energy prices would affect wood as well as all fuel sources. When external costs are not reflected in the price of energy, sustainably harvested wood is placed at a disadvantage (like all renewable fuels) because the absence of net carbon dioxide emissions is not valued. Some models which seek to include external costs into the price of energy also place wood at a disadvantage because they account only for the carbon dioxide emitted during combustion, and not for the carbon dioxide recaptured through new tree growth (U.S. DOE/EIA, *Northeast Regional Biomass Program*, 1995, 6). Vermont's least cost integrated planning process allows utilities to assume that wood has no net carbon dioxide emissions as they compare different supply options (See The Full Cost of Energy Use section and the Utility Efficiency Programs section below).

Wood Harvesting Impacts. Wood can be harvested sustainably and in a manner that has few environmental impacts. To ensure that our fuelwood use is sustainable in Vermont, we must develop and follow wood harvesting practices that use forest resources at or below the natural regeneration rate and in a manner that protects the environment over time. For more information, see the Wood section earlier in this chapter.

Vermont has made a commitment to sustainable forest practices through education, research, and tax policy. This commitment includes not only sustainability considerations, but also includes efforts to protect the health of forests for their scenic, wildlife, recreational, and environmental values. State and county foresters, a growing network of private foresters, and the Use Value Appraisal tax program (32 V.S.A. §§ 3751-3775) have all helped improve the management of Vermont's forest land. In addition, electric generating facilities burning wood chips in Vermont are required to buy only from harvesters who follow exacting forest management standards (due to conditions imposed by the PSB in each permit).

Tree plantations. If the number of wood-fired electricity plants becomes widespread, tree plantations for harvesting fuel wood could become a reality in some regions. Tree plantations, often called short-rotation woody crops, contain trees which are grown and harvested for energy in 3-7 years. Tree plantations likely would not be a serious possibility for Vermont in the near future, since the state's natural tree regeneration rate is high.

Burlington Electric Department (BED), the principal owner of the McNeil wood-fired station, recently has applied for a grant from the U.S. DOE for a short-rotation woody crop project. If the project goes forward, BED in conjunction with the Salix Project at Syracuse University will plant trees of various species such as willow and/or hybrid poplar on a trial basis at a site in or near Burlington, and harvest the trees for use in the McNeil station. This project has the potential to provide valuable information about how tree plantations might perform in the future in Vermont.

The environmental impacts are probably greater with plantations than with other sustainable forest harvesting techniques. Monocultures of fast-growing, frequently harvested trees could reduce soil nutrients, the diversity of vegetation, and species diversity. Genetic engineering could confront us with another unknown; when new species of trees are introduced into the natural environment, it is not known how they will interact with the environment. Although these impacts could be cause for concern, they may be warranted because the threat to the environment from uses of other energy sources are also serious (Bernow, 1992, 129).

10. Electricity from Landfill Gas

As solid waste decomposes in a landfill, it produces gases which can be collected and used to power small generators. In this way, landfill gas systems convert what was wasted energy and a significant pollutant (methane) into valuable electricity. The Wingham County Landfill in Brattleboro (with a capacity of 350 kW) and Burlington Intervale Landfill (with a capacity of 550 kW) are capturing methane and generating electricity. In addition, there are several smaller landfills that use landfill gas for space heating purposes.

The technology of converting landfill gas to energy has been known for at least two decades. Vermont's landfill gas projects, along with most similar projects in the Northeast, use specially designed internal combustion engines to generate electricity (SCS Engineers, 1994, 2-8). Landfill gas emissions peak several years after a landfill closes and then decline; emissions can last for 10-15 years or longer. In recognition of this fact, developers have structured the generation facilities as modular units which can be added to increase capacity and removed as emissions decrease.

Gas recovery at landfills started in the 1970s in California as a result of smog problems, energy shortages, and high energy prices. The landfill gas energy industry grew constantly until about 1983, when it slowed due to low prices for electricity and natural gas. Currently, there are some federal incentives for energy production from landfill gas. The Energy Policy Act of 1992 extended a fuel credit for landfill gas energy plants in some cases. In addition, EPA landfill regulations may stimulate energy production by requiring emissions control and monitoring (U.S. DOE/EIA, *Est. of U.S. Biomass Energy Consumption*, 1994, 20-1).

There are currently 39 operating landfill gas energy projects in the Northeast, and an estimated 100-120 projects nation-wide (SCS Engineers, 1994, 2-6). The Northeast as a whole consumed about 18 TBTU of energy generated by landfill gas plants in 1992, with a nation-wide use of about 70 TBTU. Almost half of the U.S. energy output from landfill gas occurred in the western states (U.S. DOE/EIA, *Est. of U.S. Biomass Energy Consumption*, 1994, 19-20).

Future Trends and Issues

Emissions. Gas emitted from landfills is composed primarily of methane (40%-60%) and carbon dioxide (30%-50%), with trace amounts of volatile organic compounds (VOCs) and toxic gases. As landfill gas escapes into the atmosphere, it contributes to global warming and can contribute to negative human health effects. The major portion of landfill gas is methane, and thus landfill gas emissions are serious due to their contribution to global warming. Methane's "global warming potential" is 21 times greater than that of carbon dioxide over a 100-year time-frame (U.S. Congress, OTA, 1991, 55). Landfills are the largest human-caused source of methane in the U.S., comprising 36% of nationwide methane emissions (U.S. EPA, *Landfill Methane Outreach Program*, 1994, 2).

Newer, larger landfills are required to collect and dispose of methane emissions. Disposal is often accomplished by "flaring" the gas, a process which converts the methane into carbon dioxide and water, and converts the VOCs and other gases into less harmful substances; nitrogen oxides and carbon monoxide can also be emitted through flaring. Another disposal option is to use the gas to power an internal combustion engine or turbine to create electricity. This option has about the same effect on emissions as flaring does, although it often reduces toxic emissions even more (Brian Fitzgerald, Vt. ANR, personal communication, September 1995). Thus, flaring emissions or collecting the gas for electricity use results in less dangerous air emissions compared to simply allowing the gas to escape from the landfill; in addition, these options result in less net greenhouse gas emissions, because methane is converted to carbon dioxide, a less harmful greenhouse gas. Collecting the gas for electricity generation also offsets the combustion of other fuels in electric power plants, and in this sense it results in even fewer emissions than flaring. A typical 100,000-ton landfill in Vermont releases about 1,400 cubic feet of methane per hour. When used to generate electricity, this methane not only does not enter the atmosphere and contribute to global warming, it also produces between 1,848-3,696 kWh per day, enough power per year for 84 to 193 typical Vermont residences (Doug Elliott, Vt. ANR, personal communication, October 1995).[xxxix]

Future Outlook. By the early 1990s, low energy prices, fuel-price competition, and the phasing out of tax incentives were making it more difficult for developers to earn an attractive net return on investments in landfill gas recovery projects. However, other factors have combined to give the projects a new boost. Landfill generation potential is expected to peak in the 1990s as many landfills approach capacity and fewer new landfills are sited. Stricter regulations have prompted the closing of hundreds of landfills and mandated pollution controls on thousands more. The two alternatives for landfill operators complying with the stricter environmental regulations are flaring the landfill gas or harnessing it for energy (U.S. DOE/EIA, *Northeast Regional Biomass Program*, 1995, 26). Harnessing the gas for energy may begin to look more attractive to landfill operators with these stricter regulations in place.

The potential for landfill gas projects in the Northeast was studied in a recent report; it estimates that, in addition to the 39 existing projects and 25 planned projects, there are 112 additional landfills that could be used as landfill gas projects. Five of these potential sites are located in Vermont.[xl] If all the planned and potential project sites were developed under favorable economic conditions, the Northeast could add an estimated 370 MW of generation capacity to its electricity mix (SCS Engineers, 1994, 5-2 - 5-4). According to the Vermont Agency of Natural Resources, most Vermont landfills are too small or do not produce enough landfill gas to make electric power production for sale through a utility cost-effective or attractive to investors. However, direct use of landfill gas as a fuel or for electricity by a nearby facility is feasible for more Vermont landfills, because selling to a nearby facility increases the cost-effectiveness of the project. Feasibility depends on the presence of a nearby facility that has a continuous need for fuel or power. Such facilities could include wood furniture plants or sawmills requiring process heat for kilns, or any other facility with significant electrical or heat needs (Vt. ANR, memo from Doug Elliott, Aug. 29, 1995).

Capturing Gas from Other Sources. The Foster Brothers Farm near Middlebury produces electricity from the methane gases produced by cow manure; in 1992, their electricity production was 0.35 GWh. In addition to producing energy and reducing the amount of methane emitted into the atmosphere, this process also reduces water pollution (from runoff) and produces a high quality fertilizer as a byproduct. Other sources besides cow manure could be used for electricity or space heating purposes in similar ways. Manure from other animals and sewage sludge can provide energy from gases much like the energy captured from landfills. These fuel sources are only minimally utilized in the U.S., but their potential is quite large. Using such fuel sources not only prevents methane, a destructive greenhouse gas, from entering the atmosphere, it also captures valuable energy that is otherwise wasted.

11. Electricity from Waste

The ownload supply mix for Vermont utilities included about 30 GWh of waste-powered generation in both 1993 and 1997 as shown in Figures 3.II.38 and 3.II.38a. This energy was used by customers in the small region of New Hampshire that Central Vermont Public Service serves. The New Hampshire - Vermont Solid Waste facility in Claremont, New Hampshire supplied this generation. Despite recent financial troubles, this facility continues to operate.

Waste energy power plants became more popular during the 1980s as a solution to the problem of municipal waste and decreasing landfill space. Incineration reduces the volume of waste and the cost of landfilling, while destroying some of the waste's toxic elements. For power generation, this type of system was attractive because the generator could be paid to take fuel. In recent years, however, there has been a shift away from the exclusive use of incineration as a solution to the waste problem and a shift toward recycling and waste reduction. Waste power plants are now seen as a technique of last resort, largely because the public perceives incineration as wasteful and environmentally harmful.

Vermont has no in-state waste energy plants, but other New England states have substantial capacity.

Massachusetts has 264 MW of licensed waste energy power, Maine 51 MW, and New Hampshire 18 MW (MIT, 1992, 1,3). The Northeast as a whole derived 126 TBTU of energy from municipal solid waste and 4 TBTU from manufacturing waste in 1992, the largest amount of any region in the country. The U.S. consumed a total of 387 TBTU from waste energy plants, converting about 17% of the nation's municipal waste to energy. The electric generating capacity of U.S. plants was about 2,300 MW in 1992 (U.S. DOE/EIA, *Est. of U.S. Biomass Energy Consumption*, 1994, 15-7).

Future Trends and Issues

In-state Waste Power. A waste-fired facility that previously operated in Rutland has been shut down since 1988, and recently failed to obtain the necessary air quality permit for resuming operation. Waste-powered generation facilities may have no place among Vermont's future generation sources without a significant change in the solid waste and air quality policies of Vermont, or significant improvement in waste-burning technology.

Emissions and Solid Waste. The main environmental problems associated with waste energy plants are air emissions and ash disposal. Public concern has focused on potentially toxic emissions from waste energy plants because of the possibility of hazardous chemicals being present in the waste stream. Generally, plants apply emissions control equipment, but some consider this protection inadequate because it does not prevent the emission of some particles from combustion products that may cause cancer. Ash disposal presents similar problems because there are fears that dangerous chemicals will leach out of landfilled ash and enter the groundwater. Environmental and public health groups are campaigning to have waste energy ash declared a hazardous substance, which would require much stricter landfilling standards.

Future Plants. The uncertainty about environmental effects, emissions control costs, and the future regulatory framework has led to a moratorium on new waste energy plants in most of New England. One study concludes that it is unlikely that more waste energy capacity will be built in New England in the next ten years. Over the longer term, prospects are uncertain and will depend on the market for recycled materials, future environmental regulations, landfill costs, and public attitudes toward waste energy plants (MIT, 1992, 2-3).

12. Utility Efficiency Programs

Utility efficiency measures installed in 1993 will save 750,512 MWh of electricity over the lifetime of the measures. These savings are a substantial increase from the measures installed in 1992, which will save 353,518 MWh over their lifetimes. In 1994, savings decreased from 1993 levels to 504,820 MWh (Annual Reports of utilities). (These numbers represent savings from Burlington Electric Department, Central Vermont Public Service, Citizens Utilities, Green Mountain Power, and Washington Electric Cooperative, which together serve 85% of Vermont's electricity customers. Additional savings were also garnered by Vermont's smaller utilities. See Table 3.II.4.)

Utility efficiency programs for buildings, appliances, and machines reduce the need for electricity and cost less than building and operating new power plants. Utilities have gradually increased their involvement in efficiency programs during the past decade. Traditionally, utilities' goals have run contrary to the goals of efficiency; utilities have been accustomed to promoting power use to increase their revenues. However, in the 1980s regulatory agencies across the U.S. began to encourage and then require utilities to adopt

Table 3.II.4 DSM Program Accomplishments by Vermont Utilities[a]

	1992	1993	1994	Total
Energy audits	4,469	14,939	8,458	27,866
DSM installations (# of customers)	15,973	36,256	31,242	83,471
MWh savings (over lifetime of measure)	353,518	750,512	504,820	1,608,850
Utility cost for DSM programs	$10,845,021	$20,165,773	$14,806,205	$45,816,999
Utility cost per kWh of lifetime savings	$.030-.038	$.026-.030	$.029-.030	$.028-.032
Electric cost savings to customers[b]				
Residential customers	$13,441,630	$26,241,508	$15,858,378	$55,541,516
Commercial and industrial customers	$17,841,295	$41,362,378	$29,838,367	$89,042,040
Total	$31,282,925	$67,603,886	$45,696,745	$144,583,560

[a]As reported by Vermont utilities. This table includes accomplishments by Burlington Electric Department, Citizens Utilities, Central Vermont Public Service, Green Mountain Power (Vermont's four largest utilities), and Washington Electric Cooperative as reported in their annual DSM reports. These five utilities serve approximately 85% of Vermont's electricity customers. Additional DSM accomplishments have also been made by Vermont's smaller utilities. Other load management activities as well as transmission and distribution efficiency measures are not reported in the annual reports of utilities.

[b]Over the lifetime of the measure. These cost savings represent the amount customers will save through reduced electricity use only. The cost savings do not reflect the investment by customers in DSM measures. In some cases, this investment was substantial, and in some cases, it was minimal. However, in all cases, the customer's investment was cost-effective over the lifetime of the measure. The cost savings also do not include other benefits of DSM measures such as environmental, health, safety, and productivity benefits.

efficiency measures. This new focus on efficiency programs was called demand side management (DSM), reflecting the practice of managing and seeking to influence customers' levels of demand for electricity as an alternative means of meeting customers' energy needs.

Throughout the country, utilities spent about $900 million on efficiency measures in 1989; that figure grew to an estimated $2.8 billion in 1993 (Flavin, *Powering the Future*, 1994, 35).

Regulatory agencies in many states, including Vermont, require utilities to evaluate efficiency measures at the same time they evaluate new supply sources in their planning processes. If a specific efficiency program proves to be a more cost-effective way to meet customers' energy needs than generating or purchasing more power, then the efficiency program is the better investment and must be included in the utility's planning process and implemented. In this way, efficiency programs can be seen as part of a utility's supply mix, because they add supply capacity to the mix. The planning process in which utilities weigh the societal costs and benefits of efficiency programs and new supply sources is called least cost integrated planning (LCIP),

and the plans produced through this process are called least cost integrated plans or integrated resource plans

(IRPs). Some states use accounting techniques that reflect the environmental costs of supply sources and the reduced risk of DSM programs compared to conventional supply sources in their decision-making about cost-effectiveness.

Utilities often implement their own DSM programs, but in some states other companies or entrepreneurs implement DSM programs for utilities. In these states, a bidding process occurs in which entrepreneurs, energy service companies, and other companies submit proposals for reducing electricity use through various DSM programs. The bidder who can deliver the greatest electricity savings for the lowest cost wins the bid and implements the program. States and utilities incorporate DSM bidding in different ways, but DSM bidding processes can effectively capture the advantages of more competition and innovation in the design, choice, and implementation of efficiency programs.[xli]

There are many advantages to utilities' focus on DSM programs and least cost integrated planning. First, DSM programs displace the need to generate or purchase additional power. When that "displaced power" would have been generated by fossil fuels, the result of implementing DSM programs is lower air emissions, less environmental damage, and lower costs for compliance with environmental regulations. Even when DSM displaces nuclear or hydroelectric sources (which release almost no air emissions), there are environmental advantages; nuclear power presents long-term human and environmental threats, and hydroelectric dams alter river and land environments. In addition to the environmental advantages of using less energy, there are other advantages such as a slower depletion of our energy resources, reduced reliance on fossil fuels and foreign imports, improved public and worker health, reduced need for potentially unsafe mining and transport operations, reduced need for transmission and distribution systems, and others.

Second, utilities' focus on DSM has created a multibillion dollar market in efficient technologies, encouraging manufacturers to invest in improved light bulbs, super-insulating windows, improved motors, efficient refrigerators, better insulation, and many other products and technologies. In addition, DSM has promoted the emergence of energy service companies that package cost-effective investments in efficiency measures and sell them to factories, businesses, and homes.

Third, DSM programs lower the energy bills of the customers who participate, because the DSM measures allow such customers to use less electricity. This is especially important for low-income customers with tight budgets. These customers can benefit strongly from DSM programs involving weatherization, fuel switching, and other measures.

Fourth, DSM programs offer competitive benefits to businesses who participate, because the businesses have lower operating costs as they use less electricity. DSM measures are, by definition, those that are cost-effective compared to new generation sources.

Fifth, adding DSM programs to utilities' energy resource mix creates a more diversified, reliable, and flexible mix. A diverse resource mix is preferable to one which relies on only a few sources of energy because it can more easily adapt to changes in the market while continuing to meet customers' needs. In general, DSM programs have a lower level of risk than power plants, making them a reliable addition to utilities' resource mix. In addition, DSM energy savings can be obtained in smaller amounts and with less lead time than traditional power generation, and can be stopped or altered more quickly; this leads to more flexibility in the total resource mix.

Sixth, DSM programs provide local jobs in energy auditing and DSM installation. These jobs contribute to local employment and keep dollars re-circulating in local and regional economies.

Finally, utility DSM programs encourage citizens to learn more about their own energy use and allow them to participate in and influence decision-making about energy resources.

There are also some potential disadvantages to utilities' focus on DSM and least cost integrated planning. Like any utility investment, DSM programs often raise electricity rates, at least in the short run. This occurs not because DSM programs are not cost-effective, but because utilities have direct short-term costs for the programs and because they have lost revenues from less electricity use over the long term. Because DSM programs result in less energy use, utilities may need to raise their rates to meet their revenue needs. It is important to remember, however, that electricity rates typically increase much more for new power acquisition than for utility efficiency improvements. New England rate increases in the early 1990s, for example, have been driven almost entirely by new supply and other utility operating costs -- not by efficiency programs (Cohen, 1992, 20). In addition, raising rates does not mean that all customers will pay more for electricity. In fact, those customers who participate in DSM programs may have lower total electricity bills because they use less electricity, which typically more than offsets the increase in rates.

However, customers who do not participate in DSM programs may not have lower bills, which points to a potential disadvantage of DSM: namely, that the advantages are not evenly distributed among all customers. For example, if a utility targets most of its DSM programs to large commercial and industrial customers, those customers on average would see a decrease in their total electric bills, while residential customers could see a slight increase in their bills because their rates go up but their energy use doesn't go down. The benefits to all customers from lower power costs may not be realized until later. This points to the importance of designing utility DSM programs that benefit all customers as evenly as possible.

One difficulty of the least cost integrated planning process is that it works best when the societal costs and benefits of DSM and all energy sources are well-reflected in the decision-making process that determines which supply or DSM resources to use. Regulatory agencies outline how these societal costs and benefits will be accounted for in making decisions, usually by requiring that certain external costs must be added to the cost of polluting energy sources for the purpose of comparing them with other sources and investments. However, coming up with a complete system of external cost "adders" that reflect all the costs and benefits of different energy sources is controversial. (See Chapter 3.II.H.1. The Full Cost of Energy Use.)

A final aspect of utilities' focus on LCIP, a consequence that could turn out to be a challenge, relates to the changes that are transforming the electricity industry due to increased competition. (See Chapter 3.II.H.2. Increasing Competition and Restructuring the Electric Utility Industry.) Growth in competition in the electricity industry has already begun and will become a major focus of regulatory agencies and utilities in the years ahead. It is not currently clear how the principles of LCIP translate to an environment of expanded competition and reform. The emergence of new technologies which would make it easier and less expensive for customers to generate their own electricity on-site would further complicate LCIP for utilities. The challenge in this changing environment is to find a way to maintain the advantages of LCIP, including the ability to reduce electricity use cost effectively and protect the environment, a strong emphasis on long-term investment returns and long-term planning, and a commitment to renewable sources, sustainable energy, and energy efficiency. (See Chapter 4.I.G. Increase Competition in the Electric Utility Industry.)

Some utilities in New England have argued that the current over-supply of electricity generating capacity in the region means that energy efficiency programs are not needed now because they are not competitive compared to generating options. However, such an argument focuses on short-term conditions instead of long-term economic efficiencies and planning. Later in the decade when the region's over-supply will not be as large, the efficiency gains made in the past will seem like wise decisions. In addition, electricity growth trends can change quickly, as happened in the mid-1970s and mid-to-late 1980s. Efficiency is the region's best option against growth uncertainties because it can be implemented in smaller increments than power plants and it does not face the often intractable problems associated with siting, financing, and constructing new power plants (Cohen, 1992, 20).

Vermont's Utility DSM Programs

In Vermont, efficiency programs started to receive intensified attention in the 1983 *Twenty Year Electric Plan* produced by the Department of Public Service, and in the legislative actions that led up to the Plan. The Electric Plan recommended that utilities devise and implement an efficiency plan or adopt a minimum approach to efficiency with several specific measures. Several utilities responded by adopting the minimum approach (which included measures for improving the efficiency of electric water heaters and space heaters), but none devised complete programs.

Throughout the 1980s, utilities continued to implement only a few DSM measures and did not make strong investments in energy efficiency options. As a result, the DPS issued a 1987 draft Plan update (finalized in 1988) calling for full LCIP. Also in 1988, the Public Service Board (PSB) opened what would be a two-year investigation about whether regulatory steps should be taken to make the most of the state's potential for efficiency savings. In 1990, the Board issued an Order in Docket 5270 which outlined principles for utility efficiency programs. The Vermont Legislature endorsed many of these principles, and in 1991 passed 30 V.S.A. §218c which requires all electric and gas utilities to implement least cost integrated planning.

With this planning process in place, each utility is now required to forecast its customers' long-range demand for energy and analyze in detail the optimal mix or portfolio of resources to meet this demand at the lowest societal cost. This preferred mix must include the lowest cost options selected from existing and planned generation sources as well as investments in comprehensive energy efficiency programs and available transmission and distribution options. Utilities look at many factors in this process, including costs, operating characteristics, environmental impacts, and other factors such as how electricity requirements vary over time. The plans that utilities produce through this process must be approved by the PSB.

In Vermont, societal costs and benefits in least cost integrated plans currently are calculated in the following way. As a default, utilities must subtract 10% from the cost of DSM programs due to the lower risk of the programs, and add 5% to electricity supply costs due to emissions and environmental costs for the purpose of comparing the cost-effectiveness of DSM resources with supply resources. (In some cases, more realistic, fuel specific pollution adders have been used as a result of negotiations between a utility and the DPS.) The Public Service Board (PSB), however, has a pending investigation of the issue of how best to calculate and quantify societal costs and benefits. (See the section on the Full Cost of Energy for a more complete discussion.) In comparing DSM resources to electricity supply resources for the purpose of determining the least cost option, utilities' avoided costs are used. Avoided cost is the amount it costs a utility to deliver electricity (either by purchasing it or generating it) if the utility does not use an alternative resource. The alternative resource in this application would be a DSM resource. Avoided costs are used to determine whether existing and new electricity requirements can be met at a lower cost by DSM resources or supply resources.[xlii] Because investments are long-lived, avoided costs represent least cost generation opportunities over a long time.

Since the PSB's and legislature's mandates on least cost integrated planning, utilities have implemented DSM measures in a variety of ways. Five utilities collaborated with three non-profit public interest groups to design comprehensive DSM programs Other smaller utilities have moved more slowly. Currently, 12 of Vermont's 22 utilities have produced IRPs that have been approved by the PSB.[xliii] In addition, the DPS has reviewed another 11 IRPs (some of which are an update of an approved IRP), and has worked with the utilities that prepared them to resolve major concerns. These IRPs are currently in the DPS/PSB review process.
Utility DSM programs can involve a wide variety of measures and program designs, including energy audits and assistance in arranging services, rebates for efficient appliances or compact fluorescent lamps, low-interest

loans for home weatherization or industrial retrofits, rebates for the purchase of solar water heaters, or many other measures. Vermont utilities' DSM programs fall into two broad categories: "lost opportunity programs" encourage customers to make energy efficient choices when they buy or renovate a home, commercial building, or industrial facility, and when they purchase new appliances or machinery; "retrofit programs" encourage customers to modify their existing homes, businesses, and appliances to reduce their electricity use. Utilities target different DSM programs to various customer groups in the residential, commercial, and industrial sectors. In addition, some utilities target separate DSM programs to unique customer groups such as low-income consumers or dairy farmers.

Although many utilities have focused their efforts on retrofit programs in the past, lost opportunity programs offer several advantages. Many efficiency savings can only be captured cost-effectively during new construction or when customers make appliance and machinery changes. Over the long term, more efficiency can be secured more cost-effectively with lost opportunity programs. It is also easier to convince customers to participate in lost opportunity programs because they are already making changes in their homes or businesses. Finally, lost opportunity programs save energy and money not only through immediate savings, but also because the need for retrofit measures in the future is reduced.

Retrofit programs also have some strengths that lost opportunity programs do not have. Older homes and buildings often are not replaced with new construction but remain in use. Retrofit programs are the only way to capture comprehensive energy and dollar savings from this sector of homes and buildings, many of which are highly inefficient due to their age and condition. In addition, residential retrofit programs can accomplish dramatic savings for low-income customers, who often live in rental units that are poorly weatherized, poorly insulated, and inefficiently heated.

Lost Opportunity Programs for Residential Customers. Several utilities have implemented similar DSM programs for new construction in the residential sector; these programs included cash incentives for making energy efficient choices, an optional home energy rating as an added incentive for participation, educational material for consumers and builders, and marketing to encourage participation. One utility, the Burlington Electric Department, took a different approach and made enhanced energy efficiency design a part of Burlington's building code. Every new building in the service territory is expected to meet a predictable level of energy efficiency for the building envelope, insulation, lighting, space heating, and water heating.

Some progress has been made by electric utilities in using Act 250 as part of their DSM new construction programs, but there is still potential for additional progress. Act 250 is Vermont's land use planning law which requires new development proposals to go through a permitting process. Developers must present evidence from the electric utility that will serve the development stating that the development will not burden that utility system. Utilities could encourage or require developers to participate in a DSM program such as the one outlined above in order to acquire an Act 250 permit. (See the text box on Act 250.)

Many new lighting and refrigeration products use only a fraction of the electricity that similar products required 10-20 years ago. Because lighting and refrigeration make up one-quarter of the typical residential electric bill, Vermont utilities have developed programs to influence consumer buying habits for these products. Utilities have made high efficiency lighting products available at a great discount through mail order firms; they have provided mail-in rebates or instant discount coupons for purchases of high efficiency lighting products at local stores; they have labeled high-efficiency refrigerators and freezers and sometimes have paid cash incentives to customers who purchase them; and they have offered a free pick-up service of a home's working second refrigerator or freezer for recycling to encourage the removal of the most inefficient refrigerators.

Retrofit Programs for Residential Customers. Most Vermont utilities have offered customers informational programs about how to retrofit their homes for efficiency and have offered energy audits for individual homes.

In addition, some utilities offer "direct install" programs in which efficiency measures such as water heater jackets, hot water flow aerators, pipe insulation, and energy-efficient light bulbs are installed at the time of an energy audit. For example under a direct install program, Burlington Electric Department installs some of the above efficiency measures at no cost, and then reviews household energy usage with the customer and provides information about other energy-saving opportunities. Some utilities are actively implementing such direct install programs, while other utilities have determined that such programs are not currently cost-effective for residential customers.

Some DSM retrofit programs target residential customers who use large amounts of electricity. Usually, these are customers who use electric heat. Some utilities have aggressively provided customers with cash payments or other incentives to switch to another fuel for heating. Other utilities have resisted fuel switching measures. However, if a utility has many high-use residential customers, it can gain a significant amount of electricity capacity on a cost-effective basis by encouraging customers with electric heat to switch to other heating fuels. In addition, such programs dramatically reduce energy use, as well as the energy bills of customers who switch. Fuel switching thus creates a better allocation of energy and economic resources.

Lost Opportunity Programs for Commercial and Industrial Customers. Several utilities offer design assistance for commercial and industrial customers who propose new construction projects or major renovations, and financial incentives to offset some or all of the additional design and construction costs for higher efficiency measures. For new construction or renovation projects in Burlington, energy efficiency guidelines which require the installation of some high efficiency measures must also be met. A combination of design assistance and financial incentives are included in most utilities' new construction programs for commercial and industrial customers. Vermont's land use planning law, Act 250, also plays a part in energy efficiency for new construction; it requires developers of commercial or industrial facilities to "incorporate the best available technology for efficient use or recovery of energy" and to demonstrate that their construction will not place "an excessive or uneconomic demand" on public utility facilities and services. (See the text box on Act 250.)

DSM programs capture efficiency improvements with new equipment when commercial, industrial, municipal, or institutional customers replace a piece of electrical equipment at the end of its useful life. Utilities have various services in place for this, including financial incentives that cover the cost difference between standard equipment models and high efficiency models; informational programs to educate customers and provide referrals with the help of vendors, equipment suppliers, contractors, and the design community; and programs that contact customers directly to encourage their participation in replacing equipment such as motors with more efficient models.

Retrofit Programs for Commercial and Industrial Customers. Most utilities target their largest commercial and industrial customers for customized energy audits. These energy audits typically identify not only current opportunities to improve energy efficiency, but also future opportunities that will come up as equipment is retired and replaced. Based on audit recommendations, the utility works with each customer to design a package of energy efficient measures and incentives. These measures range from lighting upgrades for stores, businesses, and schools to improvements in industrial processes for plants. Participation rates in these DSM programs have been relatively high.

In reviewing and commenting on development proposals, the DPS applies a life-cycle cost test to determine the appropriate level of energy efficiency required of the development. This approach examines whether the developer has incorporated energy efficiency up to the economic break-even point for the particular structure, occupancy, and usage pattern. This approach also allows for flexibility in the design of a structure without sacrificing energy efficiency.

Based on DPS testimony beginning in 1983, the Environmental Board has interpreted the phrase "best available technology" in criterion 9(F) (outlined above) to include any proven building practice or design, and any equipment and materials, that can be obtained through normal construction channels. A project that reflects the principles of energy conservation will include all such energy efficiency siting and design features, building practices, and equipment that can be justified on a life-cycle cost basis. This is modified in practice by allowing for consideration of factors specific to a development, such as aesthetics, special functions, maintenance problems, safety or other unique concerns of the proposed design and use (Twin State Development, #5W1021-EB, Finding of Fact, Conclusions of Law, and Order, page 8 (June 12, 1990)).

Approximately 30%-35% of Vermont's new residential construction and 40%-50% of the state's new commercial construction (on a construction cost basis) is subject to Act 250. The DPS has helped to achieve increased efficiencies in energy use by working with developers to improve the efficiency of their projects. Since 1980, the Act 250 permitting process has eliminated the need for an estimated 35 MW of inefficient and uneconomical electrical demand and has gained significant savings in fossil fuel use. By requiring energy efficiency through Act 250, Vermont businesses and homeowners have made improvements over the past 15 years that will save several hundred million dollars in energy costs. These efficiencies have been built into Vermont's infrastructure and will continue to provide savings in the future. Surveys also suggest that these standards have raised the level of Vermont building practices outside Act 250 coverage as well.

Many utilities also implement programs for smaller commercial and industrial customers. Typically, utilities identify efficiency improvements on a site-specific basis for lighting, heating, cooling, refrigeration, water heating, and cooking. With some programs, a package of efficiency measures is installed at no charge during the initial site visit. Other utilities offer financial incentives, equipment and installation specifications, and sometimes assistance with contractor arrangements and financing for the installation of cost-effective efficiency measures.

Retrofit Programs for Dairy Farm Customers. In 1991, the Vermont Legislature passed a law requiring electric utilities to provide energy efficiency programs for their dairy farm customers (30 V.S.A. §218b). As a result of this directive, most utilities are implementing separate retrofit programs for these customers. Utilities generally provide energy audits for farm customers, and then offer financial incentives for the installation of cost-effective efficiency measures. Measures that are typically installed include improvements in lighting, water heating, milk cooling, ventilation, and stock watering. Most utility programs for farm customers also provide equipment specifications, installation arrangement, and follow-up inspection for installed efficiency measures. Because farm equipment has a very specific retail marketing and service network, vendor cooperation is critical to the success of dairy farm retrofit programs.

To date, nearly 1,200 or 60% of Vermont's dairy farms have received energy audits by utilities, and 720 farms or 35% have installed energy efficiency equipment as a result of utility DSM programs. Farms that have installed such equipment are saving on average 9,800 kWh each year, with annual electric bill savings ranging between $700 and $1,250.
Although the three utilities with the largest number of dairy farm customers have implemented farm DSM programs, the utility with the fourth largest number of dairy farm customers, Vermont Electric Cooperative, has not yet implemented an effective DSM program. Vermont Electric Cooperative, with approximately 190 farm customers (some of which may not be dairy farms), represents the most critical hole in farm DSM

program coverage in the state.

Citizens Utilities Company actively acquires efficiency improvements from new farm customers or those who are undergoing extensive renovations, system upgrades, or changes. In 1994, this utility acquired as much savings and served almost as many customers from such lost opportunity programs as with its retrofit farm program. Other utilities have not implemented formal lost opportunity programs specifically for dairy farm customers, although many may capture these savings in their farm retrofit programs or commercial lost opportunity programs.

Energy Efficiency Measures in State Government. In 1992, the Vermont legislature passed Act 259, which mandated a program of energy efficiency and conservation in state government. Among other things, the Act called for the use of life-cycle costing by state government in all purchases of energy-consuming items; the installation of energy efficiency measures in new and renovated state buildings; the evaluation of potential energy efficiency measures in all state buildings; an effort to reduce Vermont government's overall energy consumption by at least 20%; an effort to reduce transportation fuel consumption of workers and employees; and an evaluation of a pilot program using alternative fueled vehicles (Vt. Agency of Administration, *Vt. State Agency Energy Plan*, 1996, 5).

Progress has been made toward many of the goals of Act 259. For example, considerable efficiency measures have been installed in state buildings since 1992. From fiscal 1993-1995, the State (in cooperation with utilities) invested about $1.2 million to install high efficiency lighting, variable speed air handling motors, and other energy saving measures in some 30 state buildings and complexes. Energy management systems, in which computers monitor and regulate temperatures in individual areas of buildings, have also been installed in several buildings around the state, including the State House and surrounding buildings. A wood chip gasification system, designed to burn wood chips at a higher rate of efficiency than conventional wood-burning systems, has been installed at a facility in Pittsford, and another such system currently is being installed at a courthouse in Middlebury (Vt. Agency of Administration, *Vt. State Agency Energy Plan*, 1996, 10-3). These installations of new wood-burning technologies build on Vermont state government's practice of heating with wood -- a local, renewable energy source. Currently, approximately 48 state buildings and 18 schools in Vermont are heated with wood. (See text box on Wood-Chip Heating in Vermont.)

Since the passage of Act 259, other measures have been authorized that affect energy use in state buildings. Starting in 1993, the Vermont Energy Conservation Standard, a building code adapted from a national standard, has been applied to new construction, additions, and major renovations of state buildings, and to any construction that uses state funding. Also in 1993, the School Energy Management Program (SEMP) was begun to help school boards and administrators implement energy efficiency measures. SEMP works with schools in various ways -- as project manager or consultant, as an ally in pursuit of grants, or as a public educator. The Program has assisted more than 50 Vermont schools with energy related projects and issues, and in 1994 helped develop a coordinated wood-chip purchasing effort for schools that heat with wood-chips (Vt. Agency of Administration, *Vt. State Agency Energy Plan*, 1996, 12, 18).

Progress has also been made on goals of purchasing energy efficient goods and recycling in state government. Life-cycle costing, in which the life-cycle total costs (including maintenance and energy costs) of appliances, equipment, and vehicles are considered in purchases, is being performed to a partial or full extent on lighting equipment, heating systems, vehicles, water heaters, air conditioners, and appliances. In addition, the state made about $5.86 million in documented purchases of recycled products in 1994, up 33% from 1993 and up 53% from 1992. Purchased recycled items included office items as well as machinery, equipment, and various materials for roads. An Executive Order from Governor Howard Dean in 1994 mandated the development of a Clean State Program, to be managed by the Vermont Clean State Council, which monitors and sets programs for state agencies (Vt. Agency of Administration, *Vt. State Agency Energy Plan*, 1996, 20-2).

State government efficiency efforts have also included transportation measures. EVermont, the state's electric vehicle demonstration project, is testing several electric vehicles in Vermont's climate. (See text box on EVermont Tests Electric Vehicles.) In addition, the Vermont Agency of Transportation is working with the state's Regional Planning Commissions to develop regional transportation plans with the input of local governments. The Agency also promotes vanpooling and ridesharing, by funding an interest-free loan program for vanpools and helping to match people for carpools.

Transmission and Distribution System Efficiency Measures. Electric transmission and distribution systems offer significant opportunities for reducing Vermont's energy and capacity needs. Vermont's annual generation and purchases of electric energy is nearly 9% greater than our annual sales of electricity due to losses in the transmission and distribution system.

Through the least cost integrated planning process, Vermont utilities are required to evaluate options for improving transmission and distribution system efficiency, and to implement a program to bring the system to the level of electrical efficiency that is optimal on a present value of life cycle societal cost basis. In addition, each utility is required to implement a program to maintain transmission and distribution efficiency improvements on an ongoing basis.

A number of measures are available to improve the efficiency of transmission and distribution systems, both for retrofits and new designs. Strategic placement of capacitors on the transmission and distribution system can reduce losses and enhance system capacity. Conductors can be replaced with larger, lower-resistance conductors, thereby reducing losses and sometimes providing reliability and safety benefits. Replacing conventional transformers with amorphous metal or high-efficiency silicon steel core transformers can reduce core losses by up to 80%. These low-loss transformers offer a significant opportunity for avoided losses, and a number of major utilities are pursuing their purchases. Other efficiency measures include: increasing the voltage of distribution circuits; using load management programs to optimize the use and sizing of distribution transformers; and reconfiguring distribution systems to balance loads. An energy efficiency program called conservation voltage regulation (CVR) can also be applied to a utility's distribution system to provide electricity at the lowest practical voltage level. Field studies have shown that, in general, a 1% reduction in the voltage delivered to customers through a CVR program results in a 1% reduction in energy use (Vt. DPS, *Vt. Twenty Year Electric Plan*, 1994, 5-23). Finally, there are a number of measures still in experimental stages that could improve transmission and distribution efficiency. See the *Vermont Twenty Year Electric Plan* for a description.

The replacement of distribution equipment efficiency measures often is not cost-effective, especially in cases where the existing equipment is adequate. However, nearly all distribution equipment is replaced over time due to age, inadequacy, or outside factors such as relocations due to road widening. During these times, certain efficiency upgrades may be cost-effective because the incremental cost of higher efficiency measure will be justified by the resulting savings.

G. Potential Energy Sources and Technologies for the Future

There are a number of energy sources and technologies whose use will likely grow in the future. While all of these sources and technologies are used now in certain applications, increasing pressures to move toward a more energy efficient, environmentally sound, and sustainable future will likely broaden their applications. These energy sources include all renewables; some renewable sources were discussed earlier in this chapter, while wind, solar, and hydrogen sources are examined below. Alternative transportation fuels also offer great promise for decreasing our dependence on oil and reducing emissions; such fuels outlined below include reformulated gasoline, gasohol, oxygenated gasoline, ethanol, methanol, natural gas, LPG, and electricity. Finally, several energy technologies also are likely to be more commonplace in future, including cogeneration, combustion turbines, combined cycle power plants, distributed generation, improved energy storage technologies, and fuel cells.

1. Renewable Energy Sources

In 1875, almost 70% of U.S. energy needs were provided by the renewable sources of water, wind, and wood. By the early 1900s, however, renewable energy use had plummeted while coal use had grown dramatically. Use of renewables has continued to decline gradually up to the present, with only a small upturn in the 1970s in response to the first oil crisis. (Flavin, *Power Surge*, 1994, 41).

This historic decline in renewable energy use jeopardizes the possibility of a sustainable global energy future. The near future will see the energy use of developing nations such as China increase dramatically. As the pressures for modernization combine with the large populations of these developing countries, global energy use will increase dramatically; a DOE forecast suggests worldwide energy use will increase by 36% between 1992 and 2010 (U.S. DOE/EIA, *International Energy Outlook*, 1995, 79). This trend, combined with the growing global environmental problems resulting from energy use, means that relying on and investing in renewable energy sources is essential for a sustainable energy future. If managed properly, renewable resources will be available indefinitely and will leave ourselves and future generations with clean air, water, and land. (See the Sustainability section in Chapter 2.)

There are a number of barriers to widespread renewable energy use. Traditionally, large corporations have not invested in renewable technologies because of the higher risk and the absence of many experts in such technologies. However, use of renewables in the U.S. increased in the 1970s, largely due to substantial investment in renewable research and development by the U.S. Department of Energy (DOE) following the oil crisis, illustrating the importance of federal assistance for renewables. Federal funding rose from just under $100 million in 1975 to about $700 million in 1980, the all time peak. However, funding for renewables dropped abruptly in 1982 and continued to decline almost to the 1975 level. Since 1990, funding has been growing again; 1995 funding levels are around $400 million (Cole, 1995, 4). With the current trend toward reduced government spending at the national level, it remains to be seen whether renewable funding will continue its recent trend or will change course and decline again. As this plan is being written, the U.S. Congress is considering a cut in funding for renewables.

However, federal funding of renewable programs continues to garner strong bipartisan public support. A survey in December 1994 found that 75% of Americans agree that while the overall budget for DOE should be reduced, resources should be redirected toward renewable energy and energy efficiency technologies and away from nuclear power and fossil fuel technologies. (Subsidies for fossil fuels are more than 23 times greater than subsidies for emerging renewable technologies (Rothschild, 1995, 17).) Furthermore, 64% of Americans believe renewables should be the highest or second-highest funding priority for energy (Solar Today, 1995, 12).

Although research and development funding is essential to moving toward greater use of renewables, many of the other barriers to using renewables on a large scale today are political and perceptual. Such barriers include a strong fossil fuel industry lobbying for the status quo, low consumer demand for renewable technologies, and a focus by the market on short-term profit instead of long-term planning.

Renewable fuel sources are those that can regenerate, such as wood, or those that are not depleted by use, such as wind and solar. (Although fossil fuel sources regenerate, they do so over time-frames that are so vast that they are non-renewable for all practical purposes.) Using renewable resources sustainably means we must use them in a manner that does not place economic, social, and environmental burdens on future generations or limit their ability to meet their needs. Therefore, we must manage renewables such as wood and other biomass sources so that they regenerate and do not cause extensive harm to the environment. If we follow the advice in the quotation that introduces Chapter 1, "Include tomorrow's child in every decision you make," we will be selecting renewable energy sources and using them in a sustainable manner.

There are many energy sources that qualify as renewables; they are described briefly below. Wind, solar energy, and hydrogen are discussed in greater detail in following sections because of their importance to Vermont's future energy situation. Other major renewable sources already in use in Vermont (hydropower, wood, and landfill gas) are mentioned briefly below and discussed in more detail in earlier sections of this plan.

The potential of renewable resources varies greatly with location. For instance, the desert Southwest has excellent solar sources, the Great Plains has substantial wind resources, and New England has good wood, wind, and hydro resources. Even within a state, renewable sources can be quite localized. This may encourage a more dispersed generation system for the future and give citizens more control over and involvement in their energy supply.

Currently, the most widely used renewable source is hydropower. Most hydropower comes from hydroelectric dams on rivers, but there are also three less commonly used forms of hydropower: tidal power, wave power, and ocean thermal energy conversion. There are experimental projects demonstrating these technologies, but all require more testing. Vermont uses hydroelectric power from Québec and New York, as well as from 18 independent sites around the state and a number of utility hydro plants. For more information about hydroelectric use in the future, see the above section Hydroelectric Power.

Biomass energy is another renewable source already used widely in the state. We use biomass in the form of wood in Vermont, but biomass sources include any plant material. Wheat stalks, grasses, crop residue, peanut shells, corncobs, sugarcane stalks, as well as wood, can all be burned to produce energy. In addition, some plants can be made into ethanol or other alternative transportation fuels. Many Vermonters burn wood to heat their homes, and a number of Vermont schools and large buildings heat their facilities with wood-chips. Vermont also has two wood-burning electric generation facilities, one an Independent Power Producer with a capacity of about 20 MW, the other a utility-owned facility with a capacity of 53 MW. The latter facility is currently involved in building and testing a utility-scale wood gasification system, which will be one of the first of its kind when complete. For more information about Vermont's use of wood, see the Wood and Electricity from Wood sections. Information about alternative transportation fuel use from biomass sources is outlined in the Alternative Transportation Fuels section below.

Human and animal waste, landfills, and garbage also provide renewable fuels. The methane that escapes from the human waste at sewage treatment plants, from animal manure, and from landfills can be harnessed to provide electricity. Vermont currently has two landfills that capture methane for electric energy, and a farm in Middlebury that produces electricity from cow manure. In addition, garbage is often burned to provide energy. For more information, see the Electricity from Landfill Gas and Electricity from Waste sections above.

Another renewable source is geothermal energy, which is created from the decay of unstable radioactive elements in the earth's core. This process heats groundwater which has percolated down through deep faults and fissures. As the heated groundwater rises back toward the surface, it can be captured for energy use. Geothermal resources can be depleted if used incorrectly, but worldwide resources are so large that this resource can be treated as renewable. The U.S. likely has huge geothermal reserves, but extracting that energy will demand creative research, engineering, and funding. Geothermal energy is now used in more than two dozen countries to provide heat and generate power (Flavin, *Power Surge*, 1994, 190-1). Vermont, like most of New England, does not possess any potential geothermal sites; however, northeastern New York has some geothermal potential. Smaller amounts of geothermal energy can also be captured at any location from heat in the earth and groundwater by using heat pumps. While Vermont's average earth and groundwater temperature is only in the mid-40-degrees-Fahrenheit, this heat level could provide significant energy gains during the winter when our land surface and air temperatures are much lower (Kozloff, 1993, 52).

Wind and solar power have great potential across the world. Vermont possesses substantial wind power resources, and, although the state has less solar potential than some other states, substantial energy savings could be garnered from certain solar applications. Both wind and solar power potential in Vermont are discussed in more detail below.

Because renewable energy sources are currently more expensive than most non-renewable sources and because many renewable sources must work in conjunction with energy storage devices, using renewables on a widespread basis will require that energy be used much more efficiently than it is currently to keep costs affordable. Although we have made significant progress in improving energy efficiency in recent years, there are still substantial efficiency savings that can be made; utilities can use cogeneration systems and improve their transmission and distribution networks, developers can build energy efficient homes and buildings, car-makers can make more fuel-efficient cars, industries can use more fuel-efficient processes, and consumers can purchase energy efficient products. If improvements in energy efficiency can displace fossil fuel sources while the share of renewable sources grows, we will be well on the way toward a sustainable energy future.

Wind Power

Wind power is one of the most promising renewable energy sources for the future. The technology is well-developed and continues to improve, and the cost is nearly competitive with conventional generation sources. Worldwide wind resources are vast, readily available, and have the potential to supply a significant portion of our energy needs. In the U.S., the states with the largest wind potential are in the Midwest and West, but most states except for those in the Southeast have areas where wind potential is great enough to make wind power economical. In addition, many states and countries bordered by the ocean could obtain significant power from wind farms located on offshore platforms (Flavin, *Power Surge*, 1994, 126-7).

Harnessing the wind for energy is not a new idea; in rural America, windmills have been used to generate electricity since the early 1900s. In the past several years, however, wind turbine technology and siting procedures have improved dramatically. Today's wind turbines are much larger, more efficient, and have greater availability. Turbines can now generate up to 5 MW, compared to the 100 kW average of the late 1980s models (Jayadev, 1995, 79; Brown, *State of the World*, 1995, 60). In addition, the new machines have lighter and more aerodynamic blades, improved rotor-hub connections and drive trains, new aerodynamic and electronic blade controls, and more advanced power electronics, including some that operate at variable speeds, allowing the turbines to operate more efficiently at a range of wind speeds. The new designs are less expensive and can be used in more moderate wind-speed areas. (Flavin, *Power Surge*, 1994, 121). The latest wind turbines are now available for operation more than 90% of the time compared to only 50-60% in the early 1980s (American Wind Energy Association, 1991, 1).

The cost of wind-generated electricity has been decreasing rapidly in recent years, and is now nearly cost-competitive with conventional electricity generation. In the early 1980s, wind-generated electricity cost about $0.20 per kWh (in 1993 dollars). For wind turbines installed in the early 1990s, the average cost is $0.07 per kWh, and a few wind developers using new technologies have signed recent contracts to sell wind-generated electricity at about $0.05 per kWh (Flavin, *Power Surge*, 1994, 121). With these most recent contracts, wind energy is starting to become cost-competitive with new generation plants fueled by natural gas or coal, which cost $0.04-0.06 per kWh. The National Renewable Energy Laboratory predicts that wind-generated electricity will be produced for $0.04 or less per kWh by 2000 (including up-front capital costs) in modest, 13 mph wind regimes. Wind power soon could be one of the cheapest power sources available; if environmental and social costs were internalized into energy prices, wind power likely would be cost-competitive today. In addition, wind power can act as a hedge against future fossil fuel price fluctuations in utilities' generation portfolios.

Wind-generated electricity is one of the most versatile forms of energy for a number of reasons. First, wind turbines can act as utility grid-connected machines or as stand-alone systems in more remote areas. Second, wind turbine capacities range in size from 5 MW to less than 50 kW, making it possible to size wind power systems for almost any application (Jayadev, 1995, 79). Finally, because they are modular, wind power systems can grow in increments that are appropriate to the growing need for electricity.

One of the greatest advantages to wind power is its avoidance of environmental problems. Wind energy has no emissions, no solid waste disposal, and no fuel delivery and storage. Worldwide, wind turbines avoid the emission of 3.25-6.5 million tons of carbon dioxide annually that would occur if conventional energy sources were used. The wind turbines in California alone avoided 1.45 million tons of nitrogen oxides, volatile organic compounds, particulates, and carbon dioxide in 1994 compared to emissions from an average gas-fired power plant in California (Kenetech Windpower, 1995). This avoidance of air emissions is significant and it makes wind energy one of the most environmentally sound energy sources available.

However like any energy source, wind power sites have some environmental impacts. The best wind sites are often in remote areas, which causes roads and transmission facilities to be built in areas that might otherwise have remained undeveloped. At some wind sites in California, birds such as raptors and eagles have flown into the moving rotors of the turbines. Research is ongoing to determine why this has happened and what can be done to solve the problem. Wind turbines also cause an aesthetic impact because they are large and often must be located on visually prominent ridgelines to maximize production. Some people find wind turbines aesthetically offensive, while others do not. Although these impacts must be taken seriously, they are generally far less damaging than the environmental impacts of almost all other energy sources.

Wind energy systems have one final advantage: they can stimulate local economies by investment in local resources, which furthers Vermont's energy goal of security. Regional studies show that wind energy creates more jobs than conventional energy sources such as coal, natural gas, and nuclear power. A New York State Energy Office study found that wind energy creates 66% more jobs than natural-gas fired plants and 27% more jobs than coal fired plants per unit of energy produced.

Wind generation capacity has been growing extremely quickly in the past several years. Global generating capacity reached more than 5,000 MW in the first quarter of 1996, a *doubling* of capacity since 1992 (American Wind Energy Association, 1996; Brown, *Vital Signs*, 1995, 55). More than 1,300 MW of this capacity was installed in 1995 alone, a 35% increase over 1994. Germany and India accounted for almost two-thirds of the new wind power capacity installed in 1995, while Spain, Holland, the United Kingdom, and China also significantly increased their capacities (American Wind Energy Association, 1996). Although energy produced by wind in the U.S. more than tripled between 1985 and 1990, it has increased much more slowly in recent years (EPRI, 1991). In the last ten years, the U.S. share of world wind energy capacity has dropped from about 90% to 30%. This recent lag in the U.S. is due partly to the pending restructuring of the electric utility industry and a consequent short-term outlook by many planners (American Wind Energy Association, 1996). California and Denmark have traditionally had the majority of the world's wind turbines. Denmark had roughly 3,600 wind turbines in operation by 1994, supplying 3% of the country's electricity; California had 15,000 turbines, supplying 1.2% of the state's electricity (Brown, *State of the World*, 1995, 59). The 1993 output from California's wind turbines would have provided enough energy for 57% of Vermont's total 1994 electricity usage (Flavin, *Power Surge*, 1994, 119; Vt. DPS).

Wind energy currently supplies only a very small percentage of the world's electricity, but it's one of the fastest-growing energy sources (Brown, 1994, 50). Commitments for rapid wind power growth in the future are being made by many countries, utilities, and businesses. A number of U.S. utilities have started to incorporate wind power into their plans; currently, sizable wind power projects are being built or planned in 11 states. Major wind power projects were announced in India, China, Argentina, Germany, Ukraine, New Zealand, Québec, and other countries in 1994. Together, China and India are projected to add between 1,050 and 2,200 MW of wind power capacity by 2000 (Jayadev, 1995, 80). European Union countries plan to install 12,000 MW of wind power capacity by 2005, more than six times their 1993 capacity (Flavin, *Power Surge*, 1994, 121-2). Furthermore, a number of major corporations, including Enron, Westinghouse, and Siemens, announced new investments in both wind and solar energy technologies in 1994 (Brown, *State of the World*, 1995, 59). DOE projects that installed wind energy capacity in the U.S. will grow to about 4,000 MW by 2005 and about 10,000 MW by 2010, more than all other non-hydro renewable sources combined (U.S. DOE/EIA, *Annual Energy Outlook*, 1995, 32). The American Wind Energy Association projects that global installed wind capacity will reach 18,500 MW by 2005, representing a market of more than $18 billion (American Wind Energy Association, 1996).

New England and Vermont Wind Energy Potential. New England possesses significant wind resources, mostly along mountain ridgelines, coastal areas, and offshore areas. The mountains of Vermont, New Hampshire, and Maine have annual average wind speeds of between 12.5-16.8 mph on exposed locations; these wind speeds constitute a "Class 4" rating. (Class 3 or greater wind site ratings are considered developable for wind power, although Class 3 sites are seen by some as marginal areas for development at this time.) Most of the land area of Vermont and New Hampshire, and about one-quarter of the area of Maine is rated as Class 4 or greater wind site areas. At the best-exposed mountaintops and ridgetops in Vermont's Green Mountains, New Hampshire's White Mountains, and Maine's Longfellow Mountains, average wind potential is in the Class 5 or 6 area, increasing to even higher speeds in the winter. The other major areas of wind potential in New England are the exposed coastal and offshore areas, which have speeds of Class 5, 6, or 7 (Pacific Northwest Laboratory, 1980, 16).

Maine possesses particularly plentiful wind resources, with its coastal and mountainous areas. Kenetech Windpower is currently building a large wind power project in Maine near the northern edge of the Maine-New Hampshire border. The project, which is in the final stages of the permitting process, would bring 100 turbines with a capacity of 40-50 MW on-line by the Fall of 1996. More turbines would be added in 1997-98 for a final capacity of 210 MW (Kenetech Windpower, Chris Herter, personal communication, July 1995).

Vermont possesses substantial wind resources compared to many other states. The ridgelines of Vermont's Green Mountains, from Massachusetts to Canada, have an annual average wind power in the Class 5 category. In addition, a portion of extreme northeastern Vermont has Class 5 wind ratings. Most of the eastern half of the state falls in a Class 4 wind rating, as well as a smaller portion of land in southwestern Vermont. The land bordering Lake Champlain, as well as other pockets of land around the state, have Class 3 ratings (Pacific Northwest Laboratory, 1980, 93-104). Some of these class ratings rise in certain areas during the winter, which is the windiest time in Vermont; this conveniently corresponds to the time of greatest energy need in the state. According to Pacific Northwest Laboratory, if only the Class 4 and greater areas in Vermont are considered, the state possesses 411 square kilometers of land potentially available for wind power development (excluding all environmentally sensitive land, urban land, and a portion of forest, agricultural, and range lands). This represents 1.7% of Vermont's total land area, which if completely developed with wind power, would have provided for 107% of Vermont's 1992 electricity needs (Pacific Northwest Laboratory, 1993). While no one expects that Vermont would actually develop all this land into wind generation sites, the calculation illustrates that the state could meet a significant portion of its electricity needs with wind power. It also points to the importance of energy efficiency; efficient use of energy would require less land for wind generation.

Green Mountain Power (GMP) has been involved with wind power projects for several years. They have operated several wind turbines on Mt. Equinox in Manchester, Vermont since 1989, gaining valuable small-scale experience. Since the early 1980s, GMP has taken wind measurements at 25 locations around Vermont, recording 50,000 hours of data on wind conditions and representing ten potential wind site areas.

GMP has recently developed a utility-scale wind generating station (Docket 5823). The project, made possible with a $3.5 million grant, has 11 wind turbines with a capacity of 6 MW near Searsburg, Vermont. Power from the project is projected to cost about $0.07 per kWh after grant funds are taken into account. Although current plans are for developing only the 6 MW station, there is additional wind potential and incremental development at this site should be less costly than the initial development.

There are also a number of wind-related businesses located in Vermont. Atlantic Orient of Norwich does research and development related to wind energy, NRG of Hinesburg does wind testing and site evaluation, and Northern Power Systems builds remote, high-reliability wind systems. Further development of wind energy, both in and outside the state, will benefit these wind-related businesses and the Vermont economy.

Wind power is a renewable, sustainable, and environmentally sound energy source. Wind is expected to be cost-competitive with traditional energy sources before solar power in New England, making it one of the most feasible near-term renewable energy sources for Vermont.

Solar Power

Using solar energy for heating and lighting and converting solar energy into electricity have great potential to help fill our energy needs. Like wind energy, solar energy is readily available and sustainable, has minimal environmental impacts, and displaces fossil fuels and energy imports.

The sheer abundance of solar energy suggests that it will play a large part in a sustainable energy future around the world. Although the amount of sunshine New England receives is lower than in other parts of the U.S., there is still great potential to use the sun's energy here. Every acre in Vermont receives the energy equivalent of nearly 5 million kWh of electricity each year from the sun (Seddon, 1988, 18). It is estimated that electricity equivalent to Vermont's 1992 electricity use could have been supplied by approximately 11,000 acres of photovoltaic modules, an area about twice the size of Lake Memphremagog.

Because the solar energy available to Vermont varies throughout the year and because there are difficulties with storing energy, it generally is not economic to design solar systems in Vermont to deliver 100% of the energy needed year-round. For example, a south-facing window in Vermont receives around 1,000 BTU of energy per square foot in September, compared to only 400 BTU in December (Vt. DPS, *Solar Energy Guide*, 1993, 2). Solar energy can be used in combination with other energy sources year-round. To explore new opportunities for using solar energy, Vermont utilities and businesses are finding ways to participate in the National Presidential Challenge, the Million Solar Roofs Initiative.

Solar Lighting, Space Heating, and Water Heating. All sizes of buildings, from small homes to apartment complexes to large commercial buildings, can be built to capture sunlight for lighting, heating, and water heating. These uses of solar energy are especially efficient, because they use the energy directly with no conversion losses (except for losses associated with pumps and other devices that enhance some solar equipment).

The sun's energy is captured in buildings by either "passive" or "active" solar systems. Passive solar systems utilize architectural design and special building materials to capture and distribute sunlight. Active solar systems use non-solar energy to power mechanical devices such as pumps and fans that enhance the solar system.

Most solar lighting applications are passive since they simply utilize the sun for indoor lighting. Because lighting is the second-largest end use for energy in the commercial sector (after heating) in Vermont, solar lighting or "daylighting" is especially important in commercial buildings. It is achieved by orienting the building and windows appropriately, installing outdoor materials or devices that reflect light into windows, using light-colored indoor wall and floor coverings that reflect light, using special techniques that reduce the glare of direct sunlight, and installing special roof skylights that filter sun and distribute it throughout the building. Solar lighting provides a better quality of light than conventional lighting, and gives a building a feel of brightness, openness, and connection to nature. The pleasant ambiance created by daylighting can improve the productivity of workers and give psychological benefits that are not easily quantified. And, daylighting is a proven technology for reducing energy use and operating costs.

To capture solar energy for heating, architects combine solar designs with energy efficiency measures, carefully considering how to orient the building, where to place the windows, and how to incorporate good insulation, tight-fitting multiple-paned windows, roof overhangs, and wall and floor coverings that store heat and slowly release it later. Indoor ponds or beds of crushed rock can also store up the sun's daytime heat. In other solar designs, a sunspace collects the sun's energy, heats up, and distributes warm air to the rest of the building. In addition to providing heat in the winter, many of the same measures (such as insulation and roof overhangs) promote cooling in the summer. Additional measures that promote cooling include planting deciduous trees outside windows and using light-colored materials for building and ground surfaces. More sophisticated systems that promote cooling can be built in solar buildings in areas which have high temperatures much of the year. Across the U.S., passive solar designs can save between 10%-95% of a building's heating requirement.

Solar buildings often combine measures for heating, cooling, and lighting. In many cases, passive solar buildings can be constructed at little or no extra cost compared to conventional building practices. In instances where construction costs are slightly higher, the benefits from reduced fuel and electricity costs as well as savings from downsizing heating and cooling equipment often offset them. A developer in Nevada builds solar tract homes that lower energy use by 50%-60% by incorporating solar measures that account for only 1%-1.25% of the sales price (Aitken, 1995, 31-2).

Passive solar buildings require a one-time investment that provides free heat and light for as long as the building lasts. As such, passive solar design is one of the simplest, cheapest ways to use renewable energy and reduce fossil fuel use, emissions, and reliance. Although New England does not have as much sunlight as some other parts of the U.S., there is substantial solar potential to be garnered here by simply incorporating cost-effective passive solar heating and lighting measures into our buildings.

Solar water heating is another solar measure that can capture considerable solar energy in Vermont. Modern solar water heating technology has been in use for more than 20 years and is highly reliable. There are currently about 3,500 solar water heaters in use in Vermont (Solar Works, personal communication, July 1995). More than 1.5 million solar water heaters were installed in the U.S. during the late 1970s when federal tax credits were available. Israel had some 900,000 solar water systems in place by 1994, and Japan had 4.5 million installed by 1992 (Flavin, *Power Surge*, 1994, 133, 136-7). Solar water heating is also widely used in many developing countries.

There are many types of solar water heaters in use around the world, but the most common systems in Vermont use "solar collectors" mounted on the roof to absorb heat energy. Because of Vermont's cloudy winter climate, it is not economical to install a solar water heater that will provide all the hot water needed year-round. Solar water heaters in Vermont are typically designed to provide all the hot water needed in the summer, and about 65% of the hot water needed on an average yearly basis, thus requiring back-up systems.

Solar water heating is especially effective when it displaces electric water heating. Water heating is the second largest energy cost in a typical household (not including transportation costs). An average family of four using an electric water heater and paying $0.09 per kWh will spend about $400 a year on hot water heating. Solar water heaters cost more to install than other types of heaters, but their yearly fuel costs are much lower (even when a back-up system is used).

Photovoltaic Power. Photovoltaic cells (PVs) convert solar energy into electricity when sunlight excites electrons in the cell's silicon material. They can be located on the roofs and sides of buildings and homes or on land set aside for the purpose. On a much smaller scale, they can also be located on many kinds of appliances and devices, from street lights to calculators.

Photovoltaics offer a wide range of applications. For example, they can be an attractive option for those living in remote areas where transmission line extensions would be costly to install. Homes powered by PVs can be either completely disconnected from the electric power grid or can use utility power to supplement their solar collection. Niche applications for PVs which are currently cost-effective in some cases include street and parking lot lights, gate controls, environmental monitoring systems, vehicle battery chargers, remote rest area lights and fans, remote stock watering pumps, irrigation controls, and others. On a much larger scale, utilities can site photovoltaic panels in one area to form a solar generation plant.

The use of photovoltaic cells is growing around the world. In 1988, there were more than 15,000 homes in the U.S. that got all or part of their electricity from the sun (Seddon, 1988, 18). In the past few years, PV systems on rooftops have been added to thousands of homes in the Dominican Republic, South Africa, Sri Lanka, and other countries. Norway has 50,000 PV-powered country homes. Germany's "Thousand Roofs" PV-installation program was recently upgraded to 2,500 roofs. Switzerland has focused on integrating PVs into the facades of commercial buildings. Japanese and U.S. manufacturers have developed "solar tiles" that could become a common roofing material. There are now more than 30 companies manufacturing solar cells worldwide, with the market growing at a rate of 12% annually (Brown, *State of the World*, 1995, 42). U.S. growth would accelerate more if costs drop significantly or if large-scale investment in PVs occurs (U.S. DOE/EIA, *Annual Energy Outlook*, 1995, 33).

Although PV use is growing, improvements are still needed to make the technology more economically competitive. By 1993, the average wholesale price of PVs had fallen to $0.25-0.40 per kWh, but projections suggest that price could fall to $0.10 per kWh by 2000 and even $0.04 per kWh by 2020 (Flavin, *Power Surge*, 1994, 156, 173). Like all technologies that use renewable resources, photovoltaics could become cost-competitive even sooner if the environmental costs of using energy were included in energy prices.

Vermonters have already constructed a significant number of photovoltaic-powered residences. An estimated 300 Vermont homes are disconnected from the utility power grid, using only photovoltaic power (Solar Works, personal communication, July 1995). The electricity usually is not used directly but instead charges a battery bank. Because Vermont's climate is much cloudier in the winter than in the summer, most large systems include a gas or propane generator that can be used to run appliances or charge the battery bank when needed. Homes in remote areas or on sites without utility power are good candidates for PV power in Vermont. The cost of extending utility power distribution lines costs between $20,000-$40,000 per mile in Vermont, which can make PVs the least-cost option for many new homes, even if they are fairly close to existing power lines (Vt. DPS, *Solar Energy Guide*, 1993, 22).

Utility-sized PV plants are not likely to be a cost-competitive near-term option for Vermont. However, their falling cost, as outlined above, suggests that they will become feasible for the sunniest U.S. regions by the next century.

Electricity from Solar Thermal Energy. Solar thermal energy systems collect the sun's heat energy and use it to heat a working fluid, which in turn drives a turbine and produces electricity. These utility-sized systems generally use parabolic dishes, parabolic troughs, central-receiver systems with heliostats, or solar ponds as heat collectors and concentrators.

Like utility-sized PV systems, solar thermal systems are not likely to be a cost-competitive energy option in the near-term for the Northeast because of our comparatively low levels of year-round sunshine. However, in other parts of the U.S., especially the South and Southwest, solar thermal systems could be widely used. These parts of the U.S. and several other countries have a few solar thermal plants and projects. According to several studies, solar thermal technologies should provide power at $0.05-0.07 per kWh by 2000 in such areas, which could be competitive with gas-generated electricity (Flavin, *Power Surge*, 1994, 151).

Hydrogen

Hydrogen produced from renewable resources is one of the few long-term energy options that could meet the world's growing energy needs without contributing to global warming, local air pollution, or acid precipitation. For this reason, hydrogen could emerge as the cornerstone in a sustainable energy future.

Hydrogen is a very versatile fuel. It could eventually replace coal, oil, and natural gas in virtually all of their present end-uses. Hydrogen can be burned to produce electricity in steam or turbine power plants, and it can also be converted to electricity using fuel cells. (See below for a description of fuel cells.) Furthermore, it can fill our energy needs for heating, water heating, cooking, industrial heat, and transportation.

Hydrogen fuel can be produced in a number of ways. One way is to strip the hydrogen molecules from hydrogen-rich fuels such as methane (CH_4), natural gas, or other fossil fuels. Hydrogen also can be produced when water molecules are split into hydrogen and oxygen through electrolysis, a century-old commercial technique. Electrolysis, however, is relatively expensive and requires more energy than can be recaptured from the hydrogen (a problem with all "energy storage" fuels or systems). Research is also being conducted on the use of sunlight and biological organisms to produce hydrogen from water and carbon monoxide.

In a sustainable energy future, renewable power sources such as hydroelectricity, biomass, wind, or solar generators could generate electricity that is fed into the electric power grid when power demand is high, and could produce hydrogen when demand is low. Additional hydrogen could be produced in individual homes and commercial buildings using rooftop solar photovoltaic cells (Johansson, 1993, 926). The stored hydrogen could then be used when extra electric energy is needed or used for end-uses such as transportation. The key to hydrogen's role in a sustainable energy future is to produce hydrogen cheaply and without using large amounts of non-renewable energy sources. Developing a surplus of clean, renewable energy, therefore, is necessary before hydrogen will have a significant role in a sustainable energy future.

If hydrogen is produced with renewable fuel sources, the environmental impacts are minimal. Relatively small amounts of water are required to create hydrogen through electrolysis; all current U.S. energy needs could be met with just 1% of today's U.S. water supply (Brown, *State of the World*, 1995, 71). When hydrogen is combined with oxygen to produce heat or electricity, the main byproducts are water and nitrogen oxides. While nitrogen oxides are a concern, it is thought that they can be reduced to negligible levels with improved heaters (Johansson, 1993, 926).

Currently, the U.S. hydrogen market is very small, and of the hydrogen consumed annually, less than half of it is used as an energy source (the rest is used for manufacturing and refining processes) (Gordon, 1991, 106). However, experimental hydrogen vehicles and heating and power generation systems do exist. Researchers have developed home heating systems and appliances that use pure hydrogen. In the near term, hydrogen for transportation is likely to be the most important end-use because of the growing demand for clean transportation fuels. Hydrogen-powered vehicles have already been built and tested by companies in

several countries, including Daimler-Benz in Germany which has accumulated several years of driving experience with a fleet of hydrogen cars. In addition, a liquid hydrogen-fueled jet airplane was recently tested in the former Soviet Union (Johansson, 1993, 936-938).

In 1988, DOE phased out its hydrogen research and development projects. However, countries such as Japan and Germany provide significant government funding for hydrogen research efforts. Ongoing research and development with hydrogen energy could hasten its preparation for the market.

The timetable for hydrogen energy replacing significant fossil sources is uncertain and depends on energy costs, a large supply of renewable energy sources, further research and development, and improvement in the infrastructure necessary to create, transport, store, and use hydrogen. According to DOE, hydrogen could provide 10% of U.S. energy needs by the year 2025 (U.S. DOE/EIA, *Energy, Our Future is Today*, 1994).

2. Alternative Transportation Fuels

There are a number of alternative transportation fuels that could substitute for gasoline and diesel. These include gasoline-based products such as reformulated gasoline, gasohol, and oxygenated gasoline. Other alternatives include ethanol, methanol, compressed natural gas, propane, and electricity. All of these alternatives to traditional petroleum fuels are currently used as transportation fuels, all have some environmental advantages over gas and diesel, and some also could lower our dependence on petroleum. Using is a step toward solving some of our problems regarding the sustainability, environmental soundness, and security of our current fuel use, and while not a complete solution, alternative fuels can make significant contributions until more definitive solutions are found. This is particularly important because transportation is the least sustainable energy end use (dependent almost entirely on non-renewable fossil fuels), the most polluting end use, and the end use with the least diverse energy sources.

Alternative fuels currently cost more than gasoline and diesel fuel (excluding external costs). The development of these fuels into a significant source of transportation energy will happen only when they become cost-competitive with gas and diesel or when public policy encourages their use. Since it is unlikely that these alternative fuels will cost less than gasoline in the near future, to capture their benefits now requires public policy decisions favorable to those fuels. This was the case with the change from leaded to unleaded gasoline, and this is exactly what is happening with many of these new fuels. Reformulated gas, gasohol, and oxygenated fuels are either required in many areas or given a tax subsidy in others. The 1990 Clean Air Act Amendments require some fleet vehicles to run on fuels such as natural gas, and electric vehicles will soon be required to be sold in California. Some fuels are recipients of state and federal research and development efforts, such as Vermont's Electric Vehicle Project and Vermont Gas's compressed natural gas test vehicles.

There are other important challenges to the widespread use of alternative fuels. Many alternative fuels require modification of vehicle engines as well as fuel storage and delivery systems. Car-makers, however, are reluctant to make significant changes to the automobile when there is not a strong production, distribution, and supply of alternative fuels. Similarly, producers of alternative fuels are unwilling to commit large amounts of capital to alternative fuels if car-makers do not design cars to run on alternative fuels. And finally, car-buyers are reluctant to purchase vehicles that are difficult to refuel. These difficulties are not, however, insurmountable. One creative solution is to design automobiles to run on more than one fuel to minimize the problems related to finding an adequate fuel supply. Development of a Clean Corridor and alternative fuel infrastructure linking Boston and Montreal and passing through Vermont, will promote the introduction of alternatively fueled (non-gasoline) vehicles to the general public.

Some alternative fuels incorporate additives to gasoline or are slight modifications of unleaded gasoline, while others have quite different properties than gasoline. The following is a brief description of several important alternative fuels and their current status and use in Vermont.

Reformulated Gasoline

Reformulated gasoline is produced by altering the chemistry of gasoline in the refining process. Reformulated gas burns cleaner than unleaded gasoline. It contains less butane so it is less likely to evaporate and escape into the atmosphere during storage and while fueling vehicles. It also contains less benzene (a carcinogen) and contributes less to smog. Some emissions (carbon dioxide and 1,3-butadiene, a highly flammable hydrocarbon), however, are greater than for unleaded gasoline, and fuel economy is slightly lower (Gordon, 1991, 92-3).

Reformulated gasoline has the advantage of not requiring modification of vehicles or service stations, although it does require modification of refineries and the refining process. The cost difference between reformulated and unleaded gasoline is between $0.02-0.05 per gallon.

The major disadvantages of reformulated gasoline are that more crude oil is required to manufacture it, engines that run on it are somewhat less efficient, and its use further increases our dependence on petroleum (including foreign petroleum) and does not help increase the diversity of the transportation fuels.
In order to reduce pollution and smog, the 1990 Clean Air Act Amendments require that reformulated gasoline be sold in place of unleaded gasoline in the nine smoggiest metropolitan areas as of January 1, 1995; altogether, these areas represent 60 million people (the Los Angeles, San Diego, Houston, Chicago, Milwaukee, Philadelphia, Hartford, New York, and Baltimore areas). In addition, 12 other states or portions of states plus Washington DC voluntarily "opted in" to the program, representing 30 million people. However, a few regions subsequently "opted out" of the program because reformulated gasoline was expected to cost more than conventional gasoline (*The Quad Report*, February 1995, 5). Vermont is not among the areas where reformulated gas is required and currently no reformulated gas is sold in Vermont.

Gasohol

Gasohol is a blend of 90% gasoline and 10% ethanol (grain alcohol). It is made by fermenting corn, but it also can be produced from other biomass sources. (See Ethanol below.)

Gasohol and ethanol contain oxygen which helps to ensure more complete combustion of the fuel. This, combined with other properties of ethanol, helps to reduce the amounts of a number of emissions, including carbon monoxide, hydrocarbons, nitrogen oxides, and evaporative emissions. More acetaldehyde (a highly reactive organic compound created by the oxidation of primary alcohols) is emitted, however. When the fuel used in growing corn and the energy used in manufacturing the fertilizer to grow the corn for ethanol are considered, carbon dioxide emissions are roughly the same as with unleaded gasoline.

The use of gasohol requires no modification to automobiles. Ethanol, however, is corrosive and can damage some metals and elastomers (rubber parts), so it is added at the distributor level instead of at the refinery and is not shipped in pipelines.

Gasohol is partially subsidized by the equivalent of a $0.06/gallon federal tax exemption when the ethanol is made from domestic farm products (5% of the total domestic corn crop is used to make ethanol).
Furthermore, a number of farm states provide incentives for gasohol. Gasohol accounts for about 8% of the

motor fuel sales nationwide (Gordon, 1991, 87, 90). It is most common in the Midwest -- no gasohol is currently sold in Vermont.

Oxygenated Gasoline

Methyl tertiary butyl ether (MTBE) and ethyl tertiary butyl ether (ETBE) are two additives to gasoline that add oxygen to the fuel and help improve combustion, especially in older vehicles. MTBE is also regularly used to boost the octane of fuels in areas where carbon monoxide is not an issue. MTBE is produced from isobutylene and methanol; ETBE, from isobutylene and ethanol (both methanol and ethanol can also be used as fuels; see below). MTBE is commercially available (made from natural gas) and when blended with gasoline (between 1% and 16% MTBE) it is an effective way to reduce carbon monoxide. Carbon dioxide emissions are about the same as unleaded gasoline. Levels of nitrogen oxides emissions and evaporative emissions are slightly higher with oxygenated fuels. There is also some concern about the toxicity of evaporative emissions.

The 1990 Clean Air Act Amendments require areas that have high levels of carbon monoxide to sell only fuels with an oxygen content of at least 2.7%. Vermont is not one of these areas and oxygenated fuels are not now sold here. Because of tax breaks, there is very little difference in the cost between gasoline blended with MTBE and unleaded gasoline.

Ethanol (CH_3CH_2OH, Ethyl Alcohol)

In addition to mixing ethanol with gasoline to form gasohol, ethanol also can be burned directly in automobiles. Ethanol boosts the performance and efficiency of engines but it requires more storage capacity or more frequent refilling because it contains less energy per gallon of fuel. With the exception of acetaldehyde, ethanol's emissions are much less than those of gasoline or a gasoline/ethanol blend. Furthermore, if the ethanol was made from renewable woody-biomass (currently, the most promising alternative to high-cost corn sources), carbon dioxide emissions from fossil carbon could be eliminated if the biomass source was managed sustainably.

In order for ethanol to gain a major share of the motor fuel market, minor modification to automobiles is required because of its corrosive nature. In addition, necessary major modification to the pipeline system or delivery by truck or rail make ethanol somewhat less attractive. Finally, methods to produce ethanol cheaply from trees, shrubs, grasses, and biomass waste need to be developed.

Ethanol has been used as a transportation energy source in Brazil for many years, but it is not widely used in the U.S. and is not currently used in Vermont.

Methanol (CH_3OH, Methyl Alcohol)

Methanol, like ethanol, is an alcohol fuel in which oxygen in the fuel helps ensure more complete combustion. Methanol can be made from natural gas, coal, oil, or biomass.

Methanol produces less carbon monoxide, destructive hydrocarbons, nitrogen oxide, and evaporative emissions than unleaded gasoline. Methanol is even more attractive as a diesel substitute, emitting much less nitrogen oxides and particulates than diesel fuel (Gordon, 1991, 85). The total level of carbon dioxide emissions depends on the source of the methanol. If coal gasification is used, the carbon dioxide emissions would be about double those of unleaded gasoline, but if it were made from renewable biomass sources, net fossil carbon emissions would be eliminated.

Methanol improves engine performance because it has a higher octane rating which allows higher compression ratios and reduces engine knocking. Like other alcohol fuels, however, its corrosive nature provides difficulties and requires modifications to both the engine and the distribution system.

The development of biomass sources and biomass technologies for producing methanol provide the best hope for methanol to become a significant, cleaner alternative to gasoline. At present, methanol is most cheaply made from natural gas. It is cheaper, however, to burn natural gas directly in automobiles than to convert it into methanol and then burn it in automobiles. Therefore, for methanol to gain a significant market share, other sources such as biomass will have to be developed.

Currently, most methanol is made from natural gas and is not burned as a pure fuel but used to create the fuel additive methyl tertiary butyl ether (MTBE is described above). Neither gasoline with MTBE or methanol is sold in Vermont.

Natural Gas

Natural gas is a very promising alternative vehicle fuel. The primary component in natural gas is methane (CH_4) (as much as 98%). Natural gas can be extracted from fossil sources, or methane can be produced from renewable sources such as biomass, cow manure, and landfills. It can be stored in vehicles either as liquid natural gas (LNG) or compressed natural gas (CNG).

Natural gas burns cleaner than unleaded gasoline with 25% less carbon dioxide emissions. It is the least expensive alternative fuel. In southern New England, it sells for about $0.70 per gallon of gasoline energy equivalent. The lower cost is due in part to lower motor fuels taxes; CNG is taxed by the federal government at approximately $0.059 per equivalent gallon of gasoline, much less than the $0.184 per gallon gasoline tax. LNG, however, is taxed at the same rate as gasoline. Natural gas already has an extensive pipeline delivery system available in many areas. In addition, it is non-toxic and non-carcinogenic.

Natural gas is not only gentler on the environment, it is also gentler on the engines that burn it. Engine, spark plug, and lubricating oil life are much greater than in gasoline engines; with natural gas, engine lives of 500,000 miles are possible (Gordon, 1991, 76-7). Another advantage is that vehicles can be modified to run on either gasoline or natural gas, although engines designed to run on natural gas alone are more efficient.

One major obstacle is the cost of converting existing automobiles to natural gas burning vehicles, which can be between $1,200 and $3,500. Vehicles designed to burn natural gas cost less than converted vehicles but more than gasoline-powered vehicles, in part because natural gas storage cylinders used in automobiles are more expensive than gasoline fuel tanks. Major auto manufacturers have begun selling dedicated natural gas vehicles at a price somewhat higher than their gasoline equivalents, but the price differential will decline as production volume increases. (More than 40 states have adopted incentives for individuals who purchase vehicles using natural gas or other alternative fuels, but Vermont has yet to approve similar legislation.) Another obstacle is the fact that adding natural gas compressors to service stations is expensive. And, while there are more than 1,000 natural gas filling stations nationwide, they are still relatively rare, making refueling inconvenient. (One can, however, drive all the way across Canada using natural gas along a certain route). For these reasons, natural gas is probably best suited for fleet applications that can have their own refilling station, at least for the near future.

It will be important for Vermont to keep abreast with natural gas vehicle development to stay current with future transportation demands. Today, there are 1,200 natural gas vehicles operating in New England, supported by 35 public and private fueling stations. In addition, the concept of a "Clean Fuels Corridor" has been studied in the Northeast region; the study evaluated market potential for alternative fuel filling stations along heavily traveled highways in the Northeast. The Interstate 89 and Interstate 91 corridors linking Montreal, Boston, and Hartford were among the routes studied.

In Vermont, the first natural gas vehicles will operate in the northwestern part of the state, served by Vermont Gas Systems. Fleet vehicles based in Vermont Gas's service area provide an opportunity to expand Vermont's use of this cleaner fuel without requiring expansion of the pipeline and therefore incurring additional costs. Groundwork is being laid for this possibility. Vermont Gas is currently testing two pick-up trucks and a sedan powered by natural gas. Furthermore, Vermont Gas Systems, Mountain Transit (a school bus contractor), and DPS are involved in a joint venture to test a natural gas school bus beginning in September 1996. Vermont Gas will build a refueling station at Mountain Transit's terminal. Mountain Transit will purchase the bus with a dedicated natural gas engine for use on a school bus route. The incremental costs related to the natural gas engine will be paid by a DOE grant. Performance, maintenance, and emissions of the natural gas bus will be monitored and compared to diesel buses.

The large-scale expansion of natural gas into the transportation market would have significant impacts in Vermont's natural gas supply. The annual consumption of natural gas per car is about the same as one house that has natural gas space and water heating, as well as a natural gas oven and clothes dryer. The potential exists to double the demand for natural gas within the current Vermont Gas service area without expanding that area or the number of customers. This, however, would require greater pipeline capacity than currently exists.

It will be several years before natural gas becomes a significant residential transportation fuel source. Currently, the closest natural gas filling stations are in the Hartford, Ct. and Boston areas. In the future, it is conceivable that cars could be refueled at homes overnight; residential fueling stations that tap into a homeowner's distribution line and slowly fill cars overnight are being tested in the Toronto area. Natural gas's low cost and the 1990 Clean Air Act Amendments requirement that 10% of fleet purchases in air quality non-attainment areas (Vermont is not currently among these areas) burn cleaner fuels such as natural gas will help to make such vehicles more common in the future. Even though these requirements do not pertain to Vermont, natural gas service stations will probably appear in Vermont as owners of natural gas vehicles from outside the state seek to use their vehicles in an expanded area.

Liquefied Petroleum Gas (LPG)

LPG is Vermont's most common, yet unheralded, alternative transportation fuel. It can be produced in two ways: as a byproduct of petroleum refining or from processing natural gas. The state's LPG supply is commonly of the petroleum variety. It is supplied from Gulf Coast refineries delivered to the Northeast via pipeline and from tanker imports directly to New England seaports. A simple hydrocarbon and clean-burning when compared with gasoline, LPG is classified as an alternative transportation fuel in the Clean Air Act Amendments of 1990 and the National Energy Policy Act of 1992.

Vehicle tailpipe tests indicate that LPG has at least 80 percent fewer emissions than the federal clean air standards for carbon monoxide, hydrocarbons and nitrogen oxides, making it about twice as clean as conventional unleaded gasoline (National Propane Gas Association, *Exhaust Emissions Data*, citing a California Air Resources Board test, 1988). As with compressed natural gas, LPG reduces certain maintenance requirements and can extend engine life. Moreover, LPG has a pump octane rating of 104. It also does not create evaporative emissions since refueling occurs in a closed system (for safety reasons).
A distribution infrastructure already exists for LPG, including production, transportation, and wholesale and

retail dealers. There are an estimated 350,000 LPG-fueled vehicles in the U.S. and 3.5 million worldwide. Commonly used as a fleet fuel, LPG is used for school buses, taxi cabs, public safety vehicles, and others. Fleet operators who buy LPG in bulk quantities receive discounts that can make LPG less expensive than gasoline, but it is more expensive in small quantities. Bulk price discounts and lower maintenance has made LPG popular with many fleet operators.

In Vermont, there were 281 LPG vehicles registered in mid-1995, far more than any other alternative fuel. Most were trucks operated as fleet vehicles by the 70-plus LPG dealers in the state. Many fleets have operated with LPG for two or more decades, proving their capability in Vermont's climate. In early 1995 there were 33 public refueling facilities for LPG vehicles making refueling fairly convenient and well-distributed statewide (Alternative Fuels Data Center, World Wide Web site, 1996). Availability of LPG vehicles from large auto manufacturers has been fairly limited; therefore LPG-fueled autos and trucks in Vermont are predominantly conversions of gasoline engines, typically costing $1,400-$1,600 per conversion.

Electricity

Electric cars have been around almost as long as automobiles and electricity, and may play an important role as an alternative to petroleum. Electric cars have no tailpipe emissions, which makes them extremely valuable in large cities or areas where pollution is a major problem. California, for example, requires that 10% of vehicles sold beginning in 2003 be "zero emitting vehicles" (ZEV), or vehicles with no tailpipe emissions.

However, the emissions of electric cars are merely shifted to the electric generating plant, so their emissions depend on the source of the electricity. With the exception of coal and nuclear power, electric plants produce less emissions and hazardous waste per unit of energy compared to an automobile. Electric vehicles offer more options, since electricity can be generated in many ways; if solar, wind, and hydro sources were used on a wide scale by utilities, for example, electric vehicles could have virtually no emissions. If biomass sources were used, there would be no net carbon dioxide emissions. In addition, if electric generation for urban vehicle power occurs away from cities, urban air quality could be improved.

In one modification of the electric car, the hybrid-car, the electricity is generated in the vehicle using a generator (and possibly fuel cells in the future). In hybrid vehicles, the on-board generator is meant to supplement the electricity stored in the batteries, boosting range and performance. Since the generator required is smaller and more efficient than current internal combustion engines, the emissions of hybrid vehicles should be less than current automobiles.

Electric vehicles have the potential to use much less energy than conventional internal combustion engines. Automobile engines use about 15% of the energy in gasoline to move the vehicle. Most of the energy is in the form of waste heat that is dissipated by the radiator or exits through the exhaust. Electric motors are much more efficient and produce very little waste heat. The inefficiencies of electric vehicles are at the generating station, which is typically 30-35% efficient for typical fossil fuel power plants (twice as efficient as the automobile engine). New power plants are more efficient and cogenerating facilities can use up to 80% of the energy in fuels (five times as efficient as the automobile engine). There are further energy losses due to electric transmission (about 8% in Vermont) and battery storage (about one-third of the energy is lost in the storage process) (MA Electric Vehicle Demonstration Program Steering Committee, *First Year Program Results*, 1995, Attachment 12). In the future when newer, more efficient generating plants replace the older, less efficient ones, electric vehicles will be substantially more energy efficient. Assuming a 50% electric generation efficiency, one vehicle in the 1995 Tour de Sol (an electric and solar vehicle road rally held in New England each summer) achieved an equivalent of 70 miles per gallon. Assuming the vehicle was charged by a fossil fuel burning plant operating at 30% efficiency, it would have achieved 42 miles per gallon.

There are several other advantages of electric vehicles. Greater use of electric vehicles reduces the danger of

EVermont was conceived in early 1994 as a demonstration project to test electric vehicles in the cold climate and rugged terrain of Northern New England. Previously, most electric vehicle (EV) operation in the United States had been confined to locations with milder weather and urban conditions. Project organizers wanted to gain experience with EVs and air quality issues, the role of EVs in the future of transportation, and their impact on the electric grid.

water pollution from oil spills and leaking underground storage facilities. It may also reduce U.S. and Vermont dependence on oil use and on foreign oil imports. Finally, electric vehicles are significantly quieter than gasoline-powered vehicles and could significantly reduce the level of traffic noise.

An extensive and reliable transmission network for electricity already exists and does not require any changes to supply electricity to automobiles. There is also enough excess electric capacity available to Vermont (without incurring additional rate increases) to allow the electric car market in the state to grow to 5% of total car sales by the year 2001 (as would be required if Vermont adopted the California Low Emitting Vehicles Standards) (Vt. DPS). Use of electricity as an automotive energy source does, however, require that automobiles undergo a major redesign. Fewer working parts are needed, extending the lifetime and reducing the complexity of vehicles powered by electricity. One to four small electric motors as well as a battery and charging system could replace the engine, fuel system, ignition system, emissions system, transmission, and differential, as well as part of a current automobile's braking system.

Several factors currently limit the widespread use of electric vehicles. Battery technology is perhaps the greatest of these. Current batteries can power vehicles for about 60 miles, but one vehicle, produced by Solectria in Massachusetts, has achieved 238 miles on one charge due to very careful, efficient driving practices and an advanced battery. Other problems that need to be overcome are the long battery charging times and the lack of refueling stations. In addition, automakers have been slow to offer an electric vehicle designed with original equipment. Most electric vehicles are currently converted gasoline-powered automobiles. The conversion is costly and inefficient, but an original-equipment vehicle would likely cost less than a comparable gasoline-powered vehicle. All of these problems, however, are being addressed. It is unlikely that any single problem will prove insurmountable. Another problem is related to the efficiency of electric vehicles; because they produce very little waste heat, auxiliary heating systems must heat the interior in cold weather.

In spite of these problems, there are a few factors that favor the increased use of electric vehicles. Utilities which have seen their gross sales drop or level off because of increasing energy efficiency gains are anxious to develop electric cars and markets. In addition, New York and Massachusetts will require vehicles to meet the California Low Emitting Vehicle Standard beginning in 1998, and a number of other states are considering adopting the standard, which would further expand the use of electric vehicles. (See Chapter 4, Section II. Transportation, Strategy D. Reduce Transportation Related Emissions.) In spite of the limited range of electric automobiles, there is a significant potential market for electric vehicles. Electric vehicles could fit a significant niche in the current market, including use as fleets of vehicles that travel a known, limited distance and use as a second car for many families. Homes with two or more cars, one of which is used less than 50-70 miles per day, could use electric vehicles. The average Vermonter's commute to work is 22 miles and the average daily vehicle miles traveled by a Vermont household is 41 miles, so for many Vermont households an electric vehicle would make an excellent second car (Wilbur Smith Associates, 1994, 3-64, 3-65).

The State of Vermont, several utilities, and others are sponsoring an electric vehicle project called EVermont that is testing electric vehicles to see how they perform in a cold and mountainous environment. (See the text box on EVermont Tests Electric Vehicles.)

Gasoline- powered vehicles use some of their waste heat to combat moisture. EVs, because they use energy with high efficiency, produce no waste heat to warm passenger cabins and defrost windows. Electric heaters in the EVs were adequate for cold-weather operation in milder climates, but not in Vermont's climate.

With continued support from the federal Advanced Research Projects Agency (ARPA), the EVermont sponsors entered a second phase of the project in 1995. Six commuter cars, using AC technology, were built, each with unique heating and cooling systems and other prototype features whose testing will help evaluate how manufacturers should make the cars ready for consumer markets in cold climates. Fossil-fueled heaters, which operate at high efficiency, have been installed. One vehicle will feature a heat pump for cabin heating and cooling. Humidity-defeating desiccant and heat-retaining cabin insulation are also under study. The states of New Hampshire and Massachusetts, along with several more electric utilities, have joined the project. The vehicles are in daily use and are brought together once a month for side-by-side testing in sub-zero weather to compare performance of their individual components.

A third phase of the EVermont project is under development and is expanding to attract partners from the Northeast region. More vehicles will be added to the project in 1996 and 1997. Continued evaluation of EV technology that will enhance operation in cold weather will remain the project's focus. Combined with battery improvements under development elsewhere, ongoing refinements to electric vehicles should bring them into the transportation mainstream by the end of the decade.

3. Energy Technologies for the Present and Future

Cogeneration

Cogeneration, combustion turbines, and combined cycle plants are electric generation technologies that have the potential to be much more efficient, to release fewer emissions, and to reduce fuel and overall costs compared to traditional generation technologies. While the newest versions of these technologies are not yet in widespread use, they are being improved at a rate that virtually guarantees their use will grow in the near future.

Cogeneration is the simultaneous production of electric power and heat energy. For example, a cogeneration system might include a combustion turbine (see below) that produces electricity and a boiler or heat recovery steam generator that recovers waste heat from the turbine and produces hot water or steam for heating or industrial processes. Because cogeneration systems produce both electrical and heat energy, they can achieve substantial savings in fuel costs, overall costs, and total air emissions. For example, a conventional generating system is about 25%-30% efficient; if waste heat is used in a cogeneration system, the efficiency can increase to around 80%. Cogeneration systems are most efficient and successful when the heat energy is used on a continuous basis. Thus, cogeneration systems are generally used at an industrial or other facility that needs constant, year-round thermal energy.

Often, cogeneration systems are owned and operated by industrial or commercial customers who use the heat energy and some electricity and sell the excess electricity back to the grid or electricity transmission network. Cogeneration systems also are frequently owned by an independent entrepreneur who sells the electricity to the utility and the heat energy to an industrial or commercial customer under separate contracts. Cogeneration facilities are eligible for special treatment under federal law (PURPA) and can require utilities to purchase their output if they produce less than 80 MW and if at least 5% of the energy output is used for heat energy. (See the text box on Independent Power Producers and Qualifying Facilities.)

The concept of cogeneration is not a new one; it was in widespread use earlier in the century when industrial plants generated their own power. As electricity became cheaper and as backup power systems became more important for industries, many of them switched to electric power purchased from a utility. However, the increase in energy prices in the 1970s and the passage of the federal Public Utilities Regulatory Policy Act (PURPA) in 1978 that defined Qualifying Facilities stimulated a renewed interest in cogeneration technology.

In Vermont, about 9 MW of power from a cogeneration system is produced by Vermont Marble, about 3 MW is produced by a paper company, and smaller amounts are produced from other sources. Because Vermont does not have a large industrial base, cogeneration is more prevalent around other parts of New England and the U.S. Maine, for example, produces much more power from cogeneration because of the large number of paper plants located there. There is also the potential, however, for cogeneration plants to be used in non-industrial settings. For instance, a 160-unit elderly housing complex in Burlington, Vermont has used a natural gas cogeneration system since 1989 for water heating and electricity. Currently, Burlington Electric Department in conjunction with the city of Burlington is considering a possible cogeneration facility of about 5 MW that would provide heat through a district heating system to the waterfront area of the city.

<u>Combustion Turbines</u>

Turbines have been used to generate electricity for many years. Hydroelectric plants use water turbines, a modified form of the water wheel, to turn the force of flowing water into mechanical energy that drives generators. Conventional power plants also use turbines to convert the steam from their boilers into the mechanical energy that drives generators. Modified jet engines and diesel engines have been used for peaking needs by electric utilities and industrial customers.

Recently, engineers have found new and more efficient ways to apply turbine technology to the production of electricity with combustion turbines. Combustion turbines operate in the same manner as jet engines in aircraft. In a combustion turbine, fuel is introduced into a combustion chamber together with compressed air. The fuel burns and the expanding exhaust gases pass out through the turbine, turning the blades to provide power. Most combustion turbines currently use distillate oil or natural gas, but work is advancing on ways to extend the same technology to fuels such as coal and wood using gasification processes.

In Vermont, as around the country, turbines see their greatest use currently at times of peak electricity loads; this is because they are relatively inexpensive to build but more expensive to operate. Vermont has 124.2 MW of in-state peaking facilities that run on combustion turbines or internal combustion engines. These turbines do not make use of the design improvements of the 1980s and 1990s.

The design of combustion turbines is continuing to improve. Smaller, more versatile, more efficient turbines that use advanced metals, new blade designs, and high compression ratios similar to today's jet engines are in the works. The efficiency of these turbines is already at 39% and is expected one day to approach 60%. These advanced turbines have relatively short installation times, and their varying sizes (between 48 MW and 1 MW) suit a range of applications. For example, a large apartment building could use one in a cogeneration system (Flavin, *Powering the Future*, 1994, 21). In addition, combustion turbines in the future could run more frequently or whenever power is needed in certain niche applications.

<u>Combined Cycle Plants</u>

Combined cycle power plants utilize the most efficient large-scale thermal electric generation technology available today. Combined cycle technology uses the excess heat produced by a combustion turbine to power an additional turbine that produces even more electricity. Using the waste heat from the combustion turbine to produce more electricity dramatically improves the efficiency of the plant. By the late 1980s, this technology had achieved an efficiency of 40%, and that level rose to 50% for a new plant opened in 1993 and 53% for a new design announced that same year.

Combined cycle plants and advanced combustion turbines have environmental advantages over conventional oil- or coal-fired generators. Since they are more efficient, they require less fuel and have fewer emissions per unit of electricity produced. When burning natural gas, they emit virtually no sulfur oxides and only negligible particulates. They also cut emissions of nitrogen oxides by up to 90% and carbon dioxide emissions by up to 60% compared to conventional plants (Flavin, *Powering the Future*, 1994, 20-1).

At present, there are three utility-owned combined cycle plants in New England. The Stonybrook facility in Massachusetts is the largest of these, and Vermont utilities own 57 MW of its capacity. In addition, there are a number of independent power producers in New England that use combined cycle systems. DOE projects that 61% of the new U.S. electric generation capacity needed by 2010 will be gas-fired or oil- and gas-fired combined cycle or combustion turbine technologies (U.S. DOE/EIA, *Annual Energy Outlook*, 1995, 29).

Combined cycle technologies have not yet replaced conventional technologies partly because they use distillate oil or natural gas, fuels that are not as cheap as the coal that fires most of the conventional plants in the country. Engineers are working to develop technologies that would use coal and wood as fuels for combined cycle plants by "gasifying" the fuels so that they can power a combined cycle system. (Vermont is involved in a wood gasification demonstration project. See the Electricity from Wood section above.) Wood and other biomass sources have the potential to be used sustainably with combined cycle plants. Using coal, however, will remain a less environmentally sound option even when used in a combined cycle system. Compared to a conventional steam cycle coal plant with scrubbers, a coal combined cycle system can achieve 91% fewer nitrogen oxide emissions and 65% fewer sulfur dioxide emissions, but only 14% fewer carbon dioxide emissions. A natural gas combined cycle plant would emit 54% fewer carbon dioxide emissions than a coal combined cycle plant, with about the same amount of nitrogen oxide emissions and no sulfur dioxide emissions. Thus, while coal combined cycle plants offer an improvement in emissions over conventional coal plants, they still are much more polluting than a natural gas combined cycle plant, or even a natural gas turbine plant (Flavin, *Powering the Future*, 1994, 23). As efficiencies for all fuel sources improve in the future, coal will remain one of the most polluting sources.

Distributed Generation

Traditionally, utilities have developed their electricity generation system based on the assumption that large central power stations are the most economical way to provide power to customers. (This assumption relies on economies of scale in building generation plants and on the ability to build whatever power lines are necessary to get power to customers.) But the advent of new technologies, combined with public policy initiatives, rising costs in certain areas, and other factors, has brought this assumption into question. In the future, utilities may rely increasingly on a mix of large central stations and small dispersed generating plants.

Distributed generation is a concept in which small-scale generation and modular storage facilities are located throughout the region (in the distribution network) instead of at a central power station. The technologies envisioned as distributed generation include fuel cells, photovoltaics, solar thermal systems, wind turbines, small hydroelectric plants, landfill methane systems, biomass gasification, cogeneration systems, and battery storage units. (Some of these technologies could also be used without the involvement of utilities; see above sections.) Distributed generation units potentially have environmental advantages, higher efficiencies, shorter construction times, and lower construction costs than centralized stations; in addition, such units are well-suited to the use of locally available fuels.

One of the most attractive advantages of a distributed generation system is that it would reduce the need to build and upgrade transmission and distribution lines. Utilities annually invest substantial amounts of money in transmission and distribution. U.S. utilities currently spend some $11 billion each year to build and upgrade transmission and distribution lines, which is one-third more than they spend on new power generation (Flavin, *Powering the Future*, 1994, 44). The transmission and distribution system is designed to meet large peak demand requirements, and because peak demands occur infrequently, the lines are most often under-utilized. Distributed generation units could be strategically located to relieve existing or anticipated transmission and distribution constraints. In this way, distributed generation would provide utilities with value both as a generation investment and as a transmission and distribution investment. Because transmission and distribution is expensive, it might be economical in some cases to pay more for electricity from small decentralized generators located near customers than to purchase bulk power for less but pay more to get it to customers.

One issue that needs to be explored before distributed generating units can be widely used is that of reliability. The current, centralized generation system is reliable because if a power plant temporarily shuts down, backup power from other locations can be sent to customers through the transmission lines. However, with a distributed generation system, such backup might not exist if the transmission and distribution system was not capable of handling it. On the other hand, smaller units on an integrated grid would be easier to back up than large units due to the smaller amount of energy required, and thus necessary reserve margins could decrease.

The move to a distributed generation system could improve efficiency, utilize more local fuel resources, give people more local control and involvement over their electric energy, and (in some cases) lower the environmental burden of energy use.

Energy Storage Technologies

In order for our energy future to be sustainable, our use of renewable energy sources will need to grow and our energy storage technologies will need to improve. Many renewable sources are available only at certain times, which may not coincide with the times when we need energy. For example, wind turbines produce energy whenever it's windy, which may or may not coincide with our electricity demand; similarly, solar systems collect energy only when it's sunny, but we need heat energy during winter nights. Energy storage technologies allow us to capture energy from renewable sources at any time and store it for later use.

There are a number of energy storage methods currently used, and others being developed. Batteries are one of the most familiar; they can store electric energy from any source. Battery technology is quickly improving for both traditional lead-acid batteries and for newer types such as nickel-cadmium batteries. With non-electric thermal storage systems, heat is absorbed by a mass that will store it and release it later on. For example, masonry walls or floors can absorb heat in a passive solar home during a winter day, and release it slowly after the sun goes down. Other thermal storage systems include indoor pools, rock beds, or at a larger scale, molten sodium. Companies in Sweden are experimenting with solar storage in underground ponds or piles of buried and insulated crushed rock that release the heat in the winter that was initially captured and stored in the summer. Utility-scale storage technologies include compressed air energy storage and superconducting magnetic energy storage. Pumped or "ponded" hydropower are other options; with pumped hydropower, water is pumped into a storage reservoir during off-peak, low cost hours, and then falls back through the dam when needed (although energy losses in the pumping cycle have limited the value of this type of storage); with ponded hydropower, river water collects in a reservoir behind a dam and is released through the dam when needed. Finally, hydrogen energy could act as a versatile energy storage carrier in conjunction with renewables. Renewables such as wind, solar, and hydro could produce electricity when demand is high and create hydrogen when demand is low, as described above.

All energy storage technologies have a similar shortcoming; energy is lost in storage, so less energy is available later. Still, they provide a way for our energy supply to be much more versatile, especially when used in conjunction with renewables.

Fuel cells

Fuel cells convert chemical energy into electrical energy or electricity. Like batteries, they consist of an electrolyte and two electrodes. They differ from batteries in the following ways: they are not generally used to store energy, and they are used to convert a steady flow conventional fuel into electricity.

Until recently, fuel cells were an exotic technology, most familiar in their use to generate energy and drinking water for the space shuttle and the Gemini, Apollo, and Skylab spacecraft. They are, however, neither new nor limited to space applications. The British lawyer and inventor Sir William Grove conceived of fuel cells in 1839, and today there are 55 200 kW fuel cell power stations worldwide.
Fuel cells combine hydrogen and oxygen to produce water, electricity, heat, and carbon dioxide (the amount of CO_2 depends on the amount of carbon in the hydrogen source). The source of hydrogen can be hydrogen gas or hydrogen-rich fuels such as natural gas, LPG, or methanol. Most fuel cells currently run on hydrogen-rich

fuel because of cost, supply, and storage problems associated with pure hydrogen. When the hydrogen and oxygen are combined to form water, they release electrons that are captured to provide electrical energy. Heat and carbon dioxide are also released. The heat can be captured and used for space or water heating needs.

Fuel cells have many advantages over conventional generation technologies and methods.

- Fuel cells are very efficient, producing more electricity from each unit of fuel than technologies that require burning the fuel. Typical generating facilities burn fuel, then use the heat and expanding gases released from the burning to turn a mechanical generator which generates electricity. Fuel cells eliminate these steps and the inefficiencies of capturing the heat and operating a generator. Conversion efficiencies, therefore, are very high -- up to 80% in an ideal system. Practical efficiencies, however, are currently about 40% due to various internal losses. This is better than most currently operating power plants and about the same as new combined cycle plants.

- Waste heat can be utilized for space or water heating, further increasing a fuel cell's theoretical efficiency to nearly 85%.

- Emissions are quite low since no combustion of the fuel takes place.

- Fuel cells produce very reliable high quality power just as larger central generation plants do, but because of their small size and ability to be located at a customer's site, there is less chance of interruption or impairments in quality caused by other users (such as fluctuations in voltage and interference).

- Fuel cells can displace the need for upgrading transmission and distribution systems by being located along and near the end of over-stressed transmission lines.

- Siting of units is easier because fuel cells are modular and can fit into many settings, including industrial settings.

- Fuel cells can utilize many energy sources, including gasified fuels.

In addition to fuel cells' advantages over conventional generation technologies and methods, they are also very versatile. Smaller-scale prototypes power buses at Los Angeles International Airport. Larger units for electric generation are modular and can be assembled building block style to create a power plant, so utilities can tailor an installation to match growth needs and site limitations. Also they could be appropriate for distributed generation because of their quiet operation, minimal emissions, and capability to quickly match demand levels. Sizes could range from home-sized 5-10 kW modules to 10-25 MW generating units. There are several different technology types currently being developed.

The greatest current disadvantages to fuel cells are their novelty and cost. The only production model presently available is a 200 kW unit about the size of a single car garage. These power plants now cost about $3,000 per kW, but their cost is rapidly declining. Technology improvements and production economies are expected to reduce the costs to $2,000 per kW before the year 2000. Even without these cost reductions, niche markets are developing for customers who need reliable, high-quality power for sensitive applications.

Fuel cells have the potential to change the electric utility industry. It is conceivable that during the 20-year scope of this plan, electricity generated from fuel cells could become cheaper than or competitive with electricity produced at large central power plants. If that happened, most new buildings could have natural-gas-powered fuel cells providing their electricity, heating, and hot water needs. The results of a decentralized power generation process competing directly against a large, centralized, capital-intensive, regulated utility with long power plant life times are uncertain and such a possibility should be carefully monitored and explored.

H. Current and Future Issues in Energy Use

Two energy use issues deserve special attention because they will increasingly form the context for future energy decisions. These issues, as discussed below, include reflecting the full cost of energy use in energy prices, and competition and restructuring in the electric utility industry. Both an overview of these topics and a summary of Vermont's experience with them are outlined.

1. Full Cost of Energy Use

Currently, individuals and firms who benefit from energy use usually do not bear all the costs associated with that energy use. Instead, some of those costs are shifted onto other members of society, future generations, and the environment. This occurs because consumers usually pay for the cash production and distribution costs of using energy, but do not pay directly for other costs of using energy. These other costs include the indirect, negative consequences of energy use that are or eventually will be borne by someone. Because these consequences are borne by people who are outside or "external" to the contract between the energy provider and the energy user, they are called external costs. Examples of external costs or impacts include the human health costs associated with air pollution, with uranium and coal mining, and with radioactive nuclear power accidents; military expenditures for protecting foreign oil interests; local job losses or other negative economic effects due to switching from a localized energy source to a non-localized one; the displacement of communities due to building hydroelectric dams and flooding tracts of land; crop losses from air and groundwater pollution; damage to buildings and other structures due to acid rain from sulfur dioxide emissions; mercury and lead contamination of lakes and fish; and perhaps one of the riskiest and most unknown external costs, the unknown climate change effects from placing more and more carbon dioxide into the atmosphere by burning fossil fuels.

The failure of markets to include external costs in the prices of energy distorts the choices of policy makers and consumers. If the full cost of energy use were included in prices, less energy and cleaner energy would be consumed, with less harm to present and future generations and the environment. Moreover, the pattern of energy use would change if prices and public policy better accounted for the relative costs, risks, and benefits associated with each type of energy and technology. For example, if the costs and risks from air pollutants are factored into the price of coal energy, coal is much less cost-competitive because of the costs resulting from acid rain and global warming. If the full cost of energy was reflected in the price of all fuels, market forces would ensure that cleaner energy sources with less associated costs to society would eventually displace more expensive and dirtier fuels. The advantages of renewable energy sources would become more obvious as these sources became more affordable compared to other sources.

The practice of "discounting the future" further complicates and distorts the true cost of energy. Our market system doesn't naturally reflect external costs and benefits in energy prices partly because the system discounts the future, or assumes that money, goods, and resources available today are worth more now than they are in the future. In the case of money, discounting the future is valid; one dollar today is worth more than one dollar in the future because of inflation and the ability to earn a profit through investment. However, in the case of the earth's biological capital (air, water, rivers, lakes, soil, forests, and species that are healthy and have the ability to regenerate themselves and remain healthy indefinitely), discounting the future is not valid if Vermont's energy goal of sustainability is to be met. That is, biological capital is not worth more to Vermonters today than it will be worth to Vermonters in the future, although the market operating independently assumes this through discounting. Social scientist Garrett Hardin has called the overuse of natural resources "the tragedy of the commons," claiming that public goods held in common by all will unavoidably be overused if they are underpriced in the marketplace. In the case of depletable energy sources

Many of the external costs of oil are paid for by U.S. taxpayers. The most important subsidy for American oil companies is the foreign tax credit, through which companies have received about $5 billion per year in tax breaks since 1987. Oil companies also receive another tax break through a percentage depletion deduction which will cost an estimated $4.2 billion over the 1995-99 period (for both oil and gas). In addition, oil companies are allowed to classify most of their intangible drilling costs as expenses instead of capital for tax purposes. This tax loophole will cost the U.S. an estimated $1.2 billion between 1995-99. The Overseas Private Investment Corporation, which insures companies against adverse changes in foreign political conditions, is also paid for by U.S. taxpayers (Rothschild, 1995, 2, 4, 10, 12).

such as fossil fuels, it is not clear whether discounting the future is valid if the goal of sustainability is to be met. Future generations may not need fossil fuels to meet their energy needs; on the other hand, they may need fossil fuels even more than we do now. Because we can never know for certain to what degree future generations will value resources such as fossil fuels, it is probably best to err on the side of caution and assume they will value it at least as much as we value it. Once again, the market operating independently does not reflect these values in the price it places on energy sources.

In response to the failure of the market to include all the external costs and benefits of energy use, regulators in some states and on the national level have attempted to "internalize" or encompass such externalities in the price of some energy sources. In Vermont, as well as in some other states, electric and natural gas utilities must reflect externalities in cost-benefit analyses through the least cost integrated planning process. Usually external costs are reflected by including adjustments (sometimes called "adders") to the costs of polluting energy sources during the decision-making process. Twenty five states plus the District of Columbia currently require consideration of environmental externalities in electric utility decision-making, with two more states considering such requirements.

On the national level, regulations that limit fuel emissions internalize some external costs. For example, the Clean Air Act Amendments of 1990 made steps toward internalizing the costs of sulfur dioxide emissions (a pollutant that causes acid rain) by giving utilities a certain number of emission allowances that effectively place a cap on how much they can emit. The allowances can be bought or sold among utilities, offering an incentive to utilities to cut their emissions and earn a profit by selling their allowances. In addition to this allowance method, there are other ways of internalizing external costs and benefits. For instance, a carbon tax would internalize the costs of emitting carbon dioxide; this would make renewable and non-polluting resources more cost-competitive. An energy tax would internalize the costs of using all forms of energy, encouraging consumers and utilities to use energy as efficiently as possible. Gasoline taxes already in place are generally intended to internalize the costs of maintaining public roadways, although these taxes in Vermont do not internalize all the costs of maintaining roadways or internalize any other costs. If tax revenues are dedicated to mitigating external effects, they can provide a double benefit. However, with the current dissatisfaction among the American public for government solutions funded by taxes, the feasibility of setting new taxes is uncertain. Efficiency standards on equipment, vehicles, appliances, generation plants, and other technologies also could internalize some of the costs of inefficient energy use and limit emissions.

One barrier to fully internalizing external costs into energy prices is that it has proven difficult to come up with a complete system that assigns meaningful relative costs and benefits to each energy source. Each fossil fuel emits different types and different amounts of pollutants; even the same fuel can produce different emissions depending on how it is burned. Each pollutant, in turn, has varying effects on humans and the environment and makes varying contributions to air pollution, acid precipitation, and potential climate change. This makes it difficult to sort out the relative dangers of each fossil fuel. Non-fossil fuel energy sources also present threats to humans and the environment. Hydroelectric plants release no air pollutants, but they alter river environments and fish habitats. The relative amount of environmental damage caused by hydroelectric dams compared to the damage caused by air emissions from fossil fuels is difficult to determine. And although the cost of occupational exposures at nuclear plants has been quantified and dollars are being collected to dismantle and dispose of nuclear power stations and their fuel, the risks imposed by radioactive nuclear waste on the environment and future generations is much harder to quantify into a meaningful price. In addition to

There are significant costs borne by taxpayers to maintain a secure oil supply. The U.S. military protects the sea lanes of the Persian Gulf, and fought Desert Storm in 1990 partly to protect the oil fields of Saudi Arabia and Kuwait. Edwin Rothschild, in a recent study, estimates that the national security costs of maintaining the U.S. oil supply are $57 billion per year, or approximately $9.19 per barrel of oil used in the U.S. Costs from Desert Storm are expected to total $61 billion (of which $52.4 billion has been contributed by other nations) (Rothschild, 1995, 13, 15). U.S. taxpayers also pay for the Strategic Petroleum Reserve, which would be used to provide oil companies with crude oil and to stabilize prices in the case of a worldwide oil disruption or shortage. Taxpayers have spent $16.7 billion to purchase oil that is stored in the reserve and $4.4 billion to maintain and manage it (Rothschild, 1995, 12, 15).

When external costs are considered, the total cost of oil use is extremely high. Oil users do not directly pay for these external costs, but taxpayers and future generations pay for many of them. When costs remain external to the price of oil, they act as a subsidy to oil use; as a result, inaccurate market signals are sent to oil consumers and resources are used inefficiently. If the external costs of oil use were included in the price of oil, consumers would use less oil, use oil more efficiently, and replace oil with fuels that are more cost-effective and efficient.

these human health, human safety, and environmental costs, there are other costs such as decreased national security from reliance on Persian Gulf oil imports, risk to coal miners of contracting black lung disease, and displacement of a local population due to hydroelectric dam reservoirs. How to assign costs to such social problems is not at all clear. And, coming up with a method of valuing costs not only involves finding analytical solutions, but also involves defining and weighing social values (Hubbard, 1991, 37).

Despite these difficulties, there will be increasing pressure in the future to internalize the costs of global climate change, resource depletion, and land, air, and water pollution into the price of energy. The U.S. and about 150 other countries committed to stabilizing greenhouse gas emissions at 1990 levels during the 1992 U.N. Environmental Summit in Rio. This commitment was refined at the 1997 Kyoto Conference with an agreement that global emissions should be reduced by at least 5% below 1990 levels. The U.S. is now working toward ratification of the Kyoto Protocol, which sets U.S. emissions reductions at 7% below 1990 levels. (See Chapter 3.I.B.1 International Energy Efforts.) As the impacts of global climate change become more evident, the push to limit greenhouse gas emissions is likely to increase.[xliv] (For more about the potential costs and impacts of global climate change, see Chapter 2.) Similarly, as fossil fuel supplies become more depleted and the environment becomes more stressed from land, air, and water pollution, pressure to solve these problems is likely to escalate.

Fully internalizing or eliminating the external costs of energy use is likely to significantly impact energy prices. It is difficult to predict the full impacts of future taxes, standards, and regulations on energy prices, but it is likely that the fuels with the highest full costs will have higher prices in the future. For example, in addressing the costs of global climate change, the price of coal (which has 2.04 pounds of carbon per BTU) will likely be more affected than the price of natural gas (at 1.20 pounds of carbon per BTU) (Repetto, 1992, 55). We should take external costs into consideration in planning for our energy needs, and be prepared for the possibility that in the future the price of fuel is likely to more fully reflect all of its costs. Although higher energy prices are difficult for consumers in the short run, decisions made today when energy prices do not reflect the full cost of energy use could have long term ramifications that commit Vermont and the nation to higher-than-necessary energy prices in the future.

Vermont's Experience with External Costs

Vermont's experience with internalizing costs (like the experience of most states) has been mainly restricted to the electricity and natural gas utility sectors and the gasoline tax. The Vermont Public Service Board (PSB) Order in 1990 that required least cost integrated planning (LCIP) of all Vermont electric and natural gas utilities also found that environmental externalities must be included in determining which energy resources were "least cost" on a societal basis (Docket 5270). In the 1991 statute passed by the legislature that supported the Board Order, "least cost" was defined to mean minimizing "economic and environmental costs" among supply, transmission, and demand side options (30 V.S.A. §218c). Requiring least cost integrated planning of electric and gas utilities represents Vermont's biggest success thus far in accounting for external costs. One goal of least cost integrated planning is to allocate utilities' and ultimately society's financial resources in ways that minimize the *full* costs of energy acquisition, transport, and use. Because of the inclusion of least cost integrated planning, energy decisions in Vermont better reflect the societal costs of energy use.

The PSB's 1990 Order determined that external environmental costs should be added on to an energy source's cost to account for externalities in the decision-making process. The PSB authorized a default "adder" value of 5%, which was intended to be refined later to more accurately recognize the attributes of specific resources; as such, the 5% value was set as a "rebuttable presumption" that could be rebutted by offering a better estimate. Also for decision-making purposes, demand side management (DSM) measures receive a 10% credit because they have little risk compared to the construction of power plants, and they help to diversify a utilities' mix of resources.

In 1992, the PSB opened an investigation to develop and establish a more refined and complete set of environmental externality values to replace the 5% adder value (Docket 5611). The investigation attracted the interest and involvement of many parties, including utilities, independent power producers, environmental advocates, low income customer advocates, industrial customers, and commercial customers. After nine months of negotiations, a consensus on a method for valuing external costs was not reached. Proceedings are currently on hold.

The Department of Public Service (DPS) is currently examining the externality adders used by utilities on a case-by-case basis. Some utilities have agreed through settlement cases to use higher values than the 5% value set by the PSB for the purpose of calculating costs in their integrated resource plans (IRPs). DPS has argued in a number of recent IRP cases before the PSB that the air emission externality values proposed in Massachusetts are applicable for all Vermont utilities because these values apply to the same set of NEPOOL power plants that serve Vermont. DPS has recommended the use of the Massachusetts externality values for all pollutants except particulates, for which a higher value was proposed.

Vermont's struggle to find a system for valuing external costs highlights the obstacles and dilemmas facing this process. There are many issues that must be resolved before a complete valuation system can be found. Some of the issues encountered in Vermont during the formal investigation of valuation methods or during cases before the PSB are summarized below.

One issue that arose was how to weigh competing costs and benefits of a proposed energy source. For example, a utility whose hydroelectric dam was due to be relicensed argued that the dam provided economic value and avoided air emissions. Some local citizens argued that there would be economic value in restoring the popular salmon sport fishery that was destroyed when the dam complex was built on the river. State environmental regulators, including the Vermont Agency of Natural Resources (ANR), tried to balance water quality values, including fish habitat preservation, against the value of avoided air emissions. The tension between short run economic costs, site-specific ecological, recreational, and economic impacts, and remote air emissions proved extremely difficult to sort out.

Another issue is how to determine the numeric value assigned to external costs. This is an important matter, because a small difference in the rates can lead to very different conclusions about which energy sources are "least cost." For instance, in 1994 the carbon dioxide value per ton was about $24 in Massachusetts, $15 in Wisconsin, $10 to $40 in Oregon, $7.64 in California, and $1.10 in New York (Steinhurst, Docket 5826, 1995, Exhibit WS-2). Obviously, which value is chosen could make a radical difference in long term decisions about energy sources. And, when neighboring states adopt radically different values, it can affect the economy of different states in negative or positive ways.

A more technical issue is whether to calculate electric utility air emissions based on utilities' "ownload" or "pool" resource mixes. (A utility's "ownload" resource mix represents what the utility would have used if it had operated independently. The "pool" resource mix, in Vermont's case, is what all the New England utilities actually used by combining their resources through the New England Power Pool (NEPOOL). See the Electric Energy section for a description of NEPOOL.) Using the NEPOOL resource mix to calculate external costs would reflect the actual air emissions impacts of utility resources and loads and would seem to be the better choice. However, individual utilities that have already anticipated environmental and societal costs in their decision-making may be disadvantaged by this choice. These utilities suggest that they should receive credit for their efforts to include external costs, perhaps by using their ownload resource mix to calculate air emissions.

An issue that came up early in Vermont's struggle with externalities is whether to consider environmental externalities that occur outside Vermont. In 1990, the PSB considered a controversial proposal of a long term power purchase from Hydro-Québec (Docket 5330). Much of the controversy focused on the environmental effects of the purchase compared to alternatives that included purchases from within New England, natural gas combined cycle cogeneration, and demand side measures. The PSB ruled that it lacked jurisdiction under the existing statute to consider almost all environmental externalities occurring outside Vermont, and that the "public good" (a term appearing as a standard in relevant statutes) was restricted to the good of Vermont and its citizens. Thus, many of the environmental considerations surrounding hydroelectric developments generally and Hydro-Québec in particular were not allowed as evidence in the proceedings. However, the air emissions and a few other impacts from alternative purchases within New England were allowed as evidence insofar as they affected Vermont's air quality or "public good." These proceedings left a number of questions unanswered. No resolution satisfactory to all parties was reached on valuing out-of-state energy effects or site-specific environmental effects of hydro development. A more recent statute (30 V.S.A. §218c), has significantly broadened the range of externalities to be considered in utility resource selection, however. This law requires consideration of both economic and environmental costs without expressing a geographic limitation.

Relatively little attention has been paid to non-environmental external costs in the regulation of the U.S. electric industry, and the same is true in Vermont. Although this is beginning to change, non-environmental externalities appear to be even harder to value than environmental ones. Questions that have arisen include: Should the societal benefit of job creation be factored into various forms of energy use, and if so, how? How should an increase in economic activity due to energy use be measured against an increase in health or other social costs or impacts? In addition, there are non-environmental externalities which have consequences for people in other states or countries. For example, uranium and coal mining, oil and natural gas exploration and development, and energy resource transport can affect the health and safety of people outside Vermont; but the way in which Vermont's regulators can or should account for these externalities is unclear.

In the face of these challenging issues, it is no surprise that Vermont and other states have found it difficult to resolve how to value environmental and social external costs. Even if government regulators, policy-makers, and economists are eventually able to create a complete valuation system for externalities in the electricity sector, the forces behind the push for increased competition and restructuring in the utility sector could hinder progress toward internalizing costs unless a method to meld competition and internalized energy costs is found. (See the following section on Increasing Competition and Restructuring for more information.) In the non-utility energy sector, even fewer external costs are currently internalized than in the utility sector. In many respects, a national system of taxation that internalizes energy costs for electric and non-electric fuels could be the easiest, most equitable, and most reasonable approach to reflect the full costs of energy use. This approach has been used successfully in many European nations. (See Chapter 4, Energy and Taxation section, for energy tax impacts in Vermont and the U.S.).

Eventually, the public will pay the external costs of energy use. If consumers begin to pay those costs now (or avoid them), they will spend more for energy, but they will also encourage energy efficiency and renewable energy sources. If consumers do not pay now, they keep current energy prices low but create situations that will require much more money and more drastic action in the future. Although it has proven difficult to quantify and include the full costs in energy prices, if we do not do so, the market assumes such costs do not exist -- a valuation we *know* is wrong. Internalizing the costs of energy use allows the market to efficiently allocate resources at the least cost to society, and to deal effectively with problems such as energy security, global climate change, and air pollution.

2. Increasing Competition and Restructuring in the Electric Utility Industry

Historically, utilities have accepted the obligation to provide electricity service to customers in exchange for exclusive rights to service territories and an opportunity to earn a reasonable return on investment capital. Government regulators act in place of market forces, limiting utilities' monopoly power, mandating rules of operation, and providing an opportunity to earn a fair rate of return. This regulated monopoly system between utilities and the government has allowed customers to receive adequate, reliable electric service at reasonable rates.

Fundamental changes are being considered in the electric utility industry that can significantly alter this system. Increasing competition in many areas of the utility industry may offer lower rates than can be accomplished under the regulated monopoly system between utilities and government. This has encouraged some to push for even more competition of the utility industry.

Wholesale competition within the electric industry generally means that each utility can purchase wholesale power from a variety of sources; in turn, suppliers or producers of power can sell to each utility. Movement toward competition has been a growing part of the electric utility scene for decades. In 1978, federal legislation called PURPA (Public Utility Regulatory Policies Act) broadened competition in the electric generation market by mandating that utilities purchase power from independent producers if the power comes from renewable sources or cogeneration. PURPA spurred the development of Independent Power Producers (IPPs) across the nation. (See the text box on Independent Power Producers.) Recent federal legislation will broaden the wholesale power market even more. The Energy Policy Act of 1992 created a new class of IPPs called Exempt Wholesale Generators (EWGs), who would have access to utility-owned transmission lines. The legislation allows EWGs to market the power they generate to the utilities, which will lead to an increase in the number of supply options available to utilities to meet customers' needs. When it takes full effect, this portion of the Energy Policy Act will to some degree lead to a restructuring of the electricity industry. In March 1995, the Federal Energy Regulatory Commission issued the Notice of Proposed Rule Making (NOPR) which investigates ways to promote wholesale competition through open access, non-discriminatory transmission services and methods to allow recovery of stranded costs by public utilities and transmitting utilities. The NOPR lays the foundation for open and competitive wholesale power markets by separating or "unbundling" the transmission of electric power from the established set of services that utilities normally provide.

Until now, utilities have retained much of their monopoly power because they are granted exclusive service territory and because they own the local distribution lines necessary for providing service to customers. One proposed aspect of increased competition, "retail wheeling" (or more precisely, direct retail access), could change that. (In a sense, increased opportunities by some larger energy users to make their own electricity by using new power producing systems have decreased utilities' monopoly already.) Direct retail competition would give other power producers access to a utility's transmission lines and distribution system for the purpose of selling electric power directly to the utility's customers. Electricity customers could then choose among different power suppliers. Not surprisingly, retail wheeling proposals are quite controversial. The stated goals of retail competition are to increase efficiency and lower costs by spurring competition. However, it is not clear whether retail competition would achieve those goals without significant new rules and protections.

Supporters of retail competition see an opportunity to lower their power bills. They argue that retail competition will offer customers a choice of electricity producers, placing competitive pressure on monopolistic utilities to lower electricity rates and encouraging innovation and offerings of service packages that meet the needs of particular customer groups.[xlv] Furthermore, they point out that there are large electric rate differences in different electric service territories and across the country. (New England electricity rates are higher than the national average.) This gives an advantage to the industries located in lower electric rate territories. Proponents believe that in the global marketplace, competitive purchasing of all supplies including electricity is necessary in order to compete successfully, and market forces represent the most effective way to impose efficiency in the electric utility industry. They observe that most other costs of market inputs (labor) have come under intense downward cost pressure. Finally, supporters point out that there are (and in the future, there will be more) financially attractive options for industrial customers to generate their own electricity, so competition is inevitable for the future anyway. In addition, some supporters think utilities deserve a penalty of stranded costs if they made imperfect supply decisions in the past.

Opponents of unfettered retail competition believe it will force utilities to focus on short-term cost reductions to compete effectively. This would jeopardize the coordinated planning efforts of utilities that have evolved over the past several years. Least cost integrated planning (LCIP) would be difficult to maintain in its current state. The short term focus of the competitive market would discourage utilities from investing in long term measures such as reliability, energy efficiency, renewable energy, and environmental improvement programs. Retail competition would discourage utilities from investing in anything that costs even slightly more than the cheapest power plant, even if that power plant were significantly more inefficient and environmentally destructive. In short, there would be no simple way of guaranteeing that utilities and other electricity suppliers follow statutory energy goals, and that social and environmental costs are included in the price of energy. (See Chapter 2 and Appendix 2 for Vermont's statutory energy goals; see the section above on Full Cost of Energy Use.) In addition, retail competition could conceivably have negative safety and reliability implications. If increased competition leads to greater economic pressure and efforts at cost-cutting at nuclear power plants, for example, safety standards could suffer.

Opponents also argue that retail competition could affect smaller electricity customers negatively. In an unregulated, competitive environment, commercial and residential customers who use small amounts of electricity could have a difficult time getting service and sharing the benefits expected from an open access market unless provisions are made to assure that there is a way for any customer to get on the system and to stay connected to the system. Furthermore, prices for electric service may increase for residential and small commercial customers as we move from the process of rate design, as defined under regulatory requirements, and "cost-based prices" to allowing freer interplay of market forces for determining price. And currently, regulators assure that companies providing electric service are accountable to their customers by advocating for the public interest and establishing channels for registering and resolving consumer complaints. As the role of the regulator is reduced, customers' opportunities to resolve concerns with their electricity providers in a mutually agreeable fashion may also diminish. These concerns suggest the conditions which will be desirable or essential if electric industry restructuring is adopted.

A further factor that could change the monopoly environment of the utility industry is the emergence of new, smaller generation technologies. Technologies such as the fuel cell are becoming less expensive and will eventually be built in many sizes and will be easy to install next to customers' industrial, commercial, or residential sites. When this occurs, customers will be able to purchase fuel cells for their power needs and eliminate their need for a utility. Fuel cells are not the only technology that could be used in this way. Photovoltaic cells could function in the same way as they become cheaper, and technologies such as cogeneration can already function in this way for industrial customers. A movement toward on-site electricity generation could have some of the same effects as retail competition on electricity customers who cannot afford to switch to an on-site system.

A few governments around the world have committed to retail competition to date. Great Britain authorized retail competition when it sold its government-owned utility system (except nuclear power plants) to private investors during the Thatcher administration. The new British system is still in its early stages, but consequences thus far include a boom in construction of gas-fired power plants, a bust in the British coal industry, skyrocketing profits for the government-regulated regional distribution companies, falling and rising prices for different customers, and little investment in demand-side management or decentralized generation. However, debate is still ongoing about how to restructure the reforms, so Britain's power industry will likely change in the future. Norway has adopted a narrower version of retail competition, and other countries are considering similar moves. In early 1994, the California Public Utilities Commission proposed retail competition for large industrial customers beginning in 1996, extending to all customers in 2002. This proposal resulted in heated public debates not only in California but across the country, due to the fact that California has set the direction of nationwide utility reform for 20 years (Flavin, 1994, *Powering the Future*, 47-50). California, New York, Michigan, Massachusetts, and Wisconsin led the way with restructuring the electric utility industry and offering retail competition, and most of the other states are actively considering some form of retail competition. Currently all the New England states except Vermont have addressed restructuring and retail competition through regulatory proceedings or legislative action. (See Chapter 4, Section I, Strategy G. Increase Competition in the Electric Utility Industry.)

Vermont's Experience with Utility Restructuring

In order to plan for increased competition and to promote cooperation among stakeholders in Vermont, the Department of Public Service joined with the Public Service Board to form a roundtable group and a smaller working group on electric utility restructuring in November 1994. These groups include utility and industry members, low-income and environmental advocates, and government regulators. The working group met about every three weeks through the summer of 1995 to identify the concerns of each stakeholder and to develop agreed-upon principles for increased competition.

In July 1995, the working group reached agreement on a set of basic principles that they believed should guide restructuring in Vermont. The principles include:

1. Maintaining high-quality, reliable service.
2. Assuring public health and safety.
3. Continuing to increase efficiencies in the production, delivery, and use of electric services.
4. Promoting non-discriminatory open access to the electric system for wholesale transactions.
5. Exploring restructuring methods that allow for retail choice.
6. Ensuring a high level of environmental quality and reduced environmental cost.
7. Preserving public benefits of the current system, including cost-effective end-use efficiency, research and development, and the development and use of renewable resources.
8. Honoring existing commitments of utilities arising from past utility decisions.
9. Empowering all consumers, especially low-income consumers, to assume responsibility and accountability for their electrical services.
10. Extending the benefits of restructuring equitably to all classes of consumers.
11. Incorporating a clear system of public accountability and public participation into the restructured environment.
12. Enhancing the ongoing competitiveness of businesses and the economy.
13. Assuring safe, efficient, and reliable electric service to all customers, with no reduction in customer access, customer service, or customer protections.
14. Maintaining and improving upon customer service safeguards and protections.

Most working group members believed that these principles were not specific enough to guide a transition to a more competitive environment and thus they endorsed another, more detailed set of principles. This second set of principles includes particular ways to ensure environmental protection, low-income energy affordability, energy efficiency, renewable energy, and the recovery of stranded utility costs, and as such, expands upon principles 6, 7, 8, and 9 above. (See Chapter 4, Section I.G. for the full text of the Vermont Principles on Electric Industry Restructuring.)

In September 1995, with the vocal support of Governor Howard Dean, the DPS petitioned the PSB to adopt principles for restructuring and to direct all electric utilities to present plans consistent with those principles that would guide restructuring in their service areas. DPS recommended that these plans should be prepared by May 1996, with the goal of achieving restructuring by the end of 1997.

In October 1995, the Board opened Docket 5854 - Investigation into the Restructuring of the Electric Utility Industry in Vermont. Under this docket a multi-party negotiating group and several subcommittees are working rapidly first on negotiation and consensus-building to "solidify and further strengthen the principles" of the workgroup and to "identify the elements that should be addressed in every utility restructuring plan"

(Order in Docket 5854, 4). Then each electric utility will develop its plan for how it will be organized and how it will function in the new environment.

Some other New England states are currently at similar stages as Vermont in their move toward increased competition and utility restructuring. Massachusetts and Rhode Island are steadily moving toward competition and restructuring. Connecticut has not been moving as quickly in the same direction. Several states have ongoing cases before judiciary boards or commissions to rule on various aspects of restructuring. Some states, like Vermont, convened roundtable groups of stakeholders to discuss restructuring and increased competition. This approach is desirable because there are many disparate interests which are best resolved by negotiation rather than litigation. It will be advantageous for Vermont to continue to move toward restructuring at the same pace as the rest of New England in order to take benefit from the new environment.

Vermonters and citizens from around the country must decide how competition and utility restructuring can best benefit society as a whole. Society benefits from increased competition only if cheaper electricity comes while maintaining appropriate social obligations which the utilities now carry, including long-term planning, consideration of environmental and social costs, equitable pricing to all customers, and other obligations. The task of working out how to reap the benefits from increased competition while retaining the benefits of the current utility structure is a formidable one, and it requires that citizens, planners, regulators, and utilities decide what is most important to society in our electric energy use.

III. FUTURE ENERGY USE

There is little doubt that today's generations live in a period of rapid and accelerating change. What our world will be like 50, 20, even 10 years from now will likely be very different from today's world. Many of the forces that will bring about changes are already in progress; others depend on choices that individuals and governments around the world make in the near future. Vermont's future energy situation will occur within and be affected by a larger national and global context, and as such, it is helpful to place discussions of energy use within this larger social context. Thus, the section below outlines the major worldwide and nationwide social and economic trends already shaping our future. The next section examines economic and demographic projections for Vermont, and finally, a future energy use scenario for Vermont is presented: the base case forecast.

A. Future Social and Economic Trends

Energy consumption affects or is affected by nearly every social and economic trend that will shape our future. Worldwide and national trends involving our growing population, changing economy, and declining natural resources (outlined below) represent some of the forces driving our societal and energy future.

The world's increasing population has significant consequences for our energy use. Since 1985, between 86 and 89 million people have been added to the world's population every year (Brown, 1994, 98-9). This means that the equivalent of the population of Vermont is added to the world about every 2.5 days. In addition, worldwide life expectancy continues to rise; currently, the average human life expectancy is 65 years, an increase of almost 20 years since 1950 (Brown, 1994, 134-5). This growing population leads to a growing demand for more energy, products, and services to meet people's basic needs. As a result, more stress is placed on environmental systems and energy resources.

U.S. population is expected to continue to grow much more slowly than world population in the future. However, longer life expectancies and the aging baby boom generation will contribute to a rise in the average age of our population. The segment of the U.S. population aged 35-54 will increase sharply during the 1990s. As the labor force continues to grow older, society will be faced with providing more services for the elderly, and employers could be faced with a declining labor pool (*The Futurist*, July-August 1990, as quoted in Vt. AOT, *Vt. on the Move*, 1992, 32).

Not only are there more people consuming resources today compared to the past, but each person consumes more resources now than in the past. This trend is likely to persist as the number of industrialized nations in the world continues to grow. Nations tend to use more energy as they industrialize, as was the case in the U.S. in the 1800s and in developing countries today. This occurs not only because energy systems in such nations are likely to be more inefficient, but also because countries may be experiencing the growth of energy-intensive industries, the growth of large infrastructure such as roads, the growth of personal energy consumption levels, and a shift from energy sources for which statistics are not kept toward those that are tracked (such as a shift from fuelwood to coal for cooking, from bicycles to buses for transportation). If all developing countries continue to use more energy as they industrialize, global energy use will increase substantially. However, if developing countries follow a less energy-intensive development path, many of the negative impacts could be avoided (Brown, 1994, 126-7).

The globalization of the economy is one of the most sweeping economic trends affecting the world's future. The movement of products, capital, and information continues to become more global. As the U.S. depends more on the global market to both buy and sell goods, our prosperity will become more linked to trade with other nations and the economic well-being of those nations. The trend toward segmentation of the world into regional trading blocs may also continue, with the Pacific Rim, the European Community, and the U.S./Canada/Mexico blocs representing the early indicators of this change. As the economy becomes more global, more energy will be needed to transport goods and people around the globe.

The global movement toward an information-based economy is a major countervailing trend. Telecommunications will increasingly be used as a gateway to an expanding array of sophisticated communication services, leading to increased decentralization of the workplace (*The Futurist*, July-August 1990, in Vt. AOT, *Vt. on the Move*, 1992, 32-4). The decentralization of the workplace may reduce energy consumption, as fewer people commute to work on a daily basis. However, it also has the potential to transform presently rural locations into suburbs, as people start to live farther from their workplaces and towns. Sprawled land use patterns currently result in greater energy consumption than more dense land use patterns, and this could be an impact of the decentralization of the workplace as well.

Other trends that will continue to change the global economy include the rapid pace of technology development, the shift towards a service economy (primarily in the Western world), increased competition and deregulation of industries (including the electric utility industry), the development of new, specific market niches, and rapidly changing consumer preferences.

In the U.S., the pressure to reduce the federal budget deficit and the size and role of the federal government could have significant impacts on the economy and energy use. Funding for energy planning, renewable energy, and energy programs -- including low income energy assistance programs -- may decline. If the influence of the federal government decreases, there could be an increase in state government activity and influence, and growing diversity among states' activities and priorities.

The health of the environment will increasingly define and dominate our future. Dealing with the problems resulting from global climate change, the destruction of the ozone layer, the loss of biological diversity from worldwide habitat destruction and deforestation, and the depletion of limited resources will be central issues in the years ahead. As the environment becomes less able to absorb increasing stresses from human impacts, including stresses from energy use, environmental cleanup efforts will become more necessary. The world's three food supply systems (oceans, rangelands, and croplands) are already over-stressed from human demand, and increasing population places additional pressure on these systems. The global fish catch is declining; all 17 of the world's major fishing areas have either reached or exceeded their natural limits, with nine of these areas in serious decline (Brown, 1994, 32-3).

The earth's rangelands are being grazed at or beyond sustainable use almost everywhere, and cropland use is becoming unsustainable in many countries due to extensive soil erosion, the declining response of crops to additional fertilizer use, and the declining availability of fresh water for irrigation. Growth in cropland productivity has been slowing and world grain production per person has been falling since 1984 (some of which may be due to market forces or government policy) (Brown, 1994, 18-20, 26-7). The stress on natural systems from an increased population, increased consumption, and increased energy use will lead to more stress on human health. As the earth's natural systems become more pressured, human health will become even more linked to the health of the environment, and health care costs are likely to reflect this. The ways in which energy is used in the future will increasingly affect both human health and health care costs.

Changes in world population, the economy, and natural resources will continue to shape our energy future. Balancing population and economic growth, both of which usually require more energy use, with the stresses that increasing energy use places upon the natural systems sustaining human life will be a major challenge in the future. Energy efficiency and sustainable energy supplies will become increasingly more important in meeting that challenge.

in transmission and distribution costs in Vermont as new infrastructure is installed (Vt. DPS, *Vermont Comprehensive Energy Plan*, 1991, 35; Energy Ventures Analysis, 1995).

Total energy use is projected to be about 3.4 TBTU or 2.4% higher in 2010 in this 1998 Plan compared to the 1991 Plan. Among sectors, however, residential energy use shows lower values in the 1998 Plan, while the commercial, industrial, and transportation sectors show higher values. Residential energy use is projected to be about 3 TBTU lower in 2010 in the 1998 Plan, largely because less energy is forecast for space heating due to improving efficiencies. The combined commercial and industrial sectors show a value that is about 4.8 TBTU higher in 2010 in the 1998 Plan, perhaps due to lower projected fuel prices, leading to more intensive energy use in production processes. Transportation energy use is projected to be about 1.6 TBTU higher in 2010 in the 1998 Plan. Oil, LPG, and natural gas use are higher in 2010 in the 1998 Plan, partly due to lower price projections in the forecast. Wood use remains about the same in both forecasts, and electricity use is about 2 TBTU lower in 2010 in the 1998 Plan (Vt. DPS, *Vermont Comprehensive Energy Plan*, 1991, 36-7; see also Figures 3.III.11 and 3.III.13).

Total predicted energy expenditures in Vermont are lower in 2010 in the 1998 Plan in all sectors, due mostly to the lower price projections. Expenditures in 2010 in the 1998 Plan are substantially lower for oil, electricity, and wood, slightly lower for natural gas, and higher for LPG, perhaps due in part to LPG's increasing share of the residential space and water heating market.

Emissions data between the two forecasts are difficult to compare because the 1998 Plan uses updated emissions factors. These factors are used to calculate how much of each pollutant is emitted by each fuel from an average mix of appliances, machinery, vehicles, etc. found in Vermont. For a summary of the emissions factors used in the 1998 Plan, see Part II of this chapter.

B. Economic and Demographic Projections for Vermont

In addition to global and national trends, Vermont's political, economic, demographic, and energy price trends will shape our future energy use. Figures 3.III.1 - 3.III.5 show how the state's economic and demographic characteristics are projected to change through 2015, and Figure 3.III.6 presents an estimate for future oil prices. The data from these forecasts is used as input to the base case forecast of energy use presented below. Vermont's population and employment, as illustrated in Figure 3.III.1, are projected to rise moderately into the future, with employment increasing at a slightly faster rate than population. As shown in Figure 3.III.2, real personal income and Gross State Product (GSP) are predicted to rise at virtually the same rate, about 1.8% per year between 1990 and 2015. Figure 3.III.3 compares Vermont's per capita real personal income with U.S. values. Vermont's per capita personal income has traditionally been lower than the U.S. average; however, in the 1980s, the gap between Vermont and U.S. values narrowed, with each projected to increase at virtually the same rate, about 1% per year, into the future. Vermont's real Gross State Product per capita, shown in Figure 3.III.4, also moved closer to the U.S. average in the 1980s. In the future, Vermont's GSP per capita is expected to increase by 29% between 1990 and 2015, a slightly higher growth rate than the U.S. rate of 24%. The commercial and industrial output projections in Figure 3.III.5 indicate that real output from both sectors will increase between 54%-56% between 1990 and 2015.

Future energy prices, especially oil prices, will play a large role in determining future energy use in the state. As shown by Figure 3.III.6, crude oil prices have fluctuated in the past several years, and are currently relatively low. However, the price is projected to rise into the future, reaching about $25 per barrel by 2015 (in 1994 dollars), about the same as the 1990 price.

C. Base Case Forecast

In order to better understand what Vermont's future energy use may be like, this Plan includes a base case forecast of future energy demand. The base case forecast is an integral part of the Plan; in this chapter, it is used to outline future energy demand under a business-as-usual scenario and to show where opportunities lie provide services, and the residential sector requires housing. These buildings and their occupants require energy for heating, cooling, and appliance uses. The amount of energy used is based on the energy efficiencies of the buildings and the devices used in the buildings. Changes in energy efficiency are simulated using a consumer preference mechanism, which estimates efficiency-fuel tradeoff curves from survey data that show how consumers actually perform in the marketplace.

Investments add new buildings and new devices with their own (usually higher) efficiencies to the existing capital stock. The gradual accumulation of these investments then changes the average efficiency of the stock. New technologies (developed through research and development) also affect the new investment decisions by increasing the efficiency of using a particular fuel.

Once new capital stock is installed, the energy requirement of the existing capital stock can be changed only by new investments, retirements, or retrofits. The maximum amount of efficiency that can be incorporated in new capital stock depends on technological and physical constraints. The amount of efficiency actually installed depends on a simulation of the consumer's tradeoff between higher capital costs with lower operating costs (higher efficiency) and lower capital costs with higher operating costs (lower efficiency). In evaluating this tradeoff, the consumer takes into account not only differing efficiency levels within devices using a single fuel type, but also the relative costs of using alternate fuels where fuel substitution is feasible. These choices are also influenced by efficiency programs, incentives, tax policies, and other policies. Final energy demand is determined in the model not only by the capital stock, but by weather, economic conditions, and socio-economic conditions.

Environmental Impact Simulation

ENERGY 2020 determines emissions from the projected fuel use and from pollutant emissions factors for end uses developed from several sources, including U.S. EPA publications, various reports from test results, and local data sources (U.S. EPA, 1982, 1992). No attempt is made, however, to calculate indirect emissions.

Electric Supply Simulation

The electric utility sector of ENERGY 2020 can be operated either endogenously (with values determined within the model) or exogenously (with values determined outside the model). In this study it was operated endogenously, reflecting the plant characteristics of generating facilities owned by Vermont utilities. The electric sector incorporates the contracts and generating facilities that are currently a part of Vermont's resource mix along with those Vermont already has committed to acquire. In addition to existing and committed resources, the model also simulates construction of new generic sources of capacity (mostly gas-fired combined-cycle plants), based on demand from the model forecast. The usage and associated emissions characteristics of these facilities is based on an algorithm for simulating how the system would operate in the real world.

Vermont's electric resource mix includes contracts and generators located outside the state, and some power produced in Vermont is consumed in other states. This study presents the energy use and emissions created by Vermont's electricity use no matter where the power was produced.

for energy savings and environmental improvement. In Chapter 4, it provides a point of comparison for the energy savings impacts and environmental improvements of various policies.

Because the base case forecast represents a business-as-usual scenario, it does not describe Vermont's most likely future. Instead, it describes what would most likely happen if current trends continue and if no changes occur in state and national energy policy. Future energy consumption and environmental impacts in the forecast are based on three sets of assumptions. The first set is an economic and demographic forecast, developed by the Department of Public Service's economic model of Vermont. Highlights from that forecast were outlined above. The second set of assumptions comes from a fuel price forecast, produced for the DPS by Energy Ventures Analysis. Finally, a set of standards and efficiency levels for buildings, equipment, appliances, and vehicles, as well as a set of utility efficiency measures, also act as input to the base case forecast. The standards include, for example, the appliance efficiency standards (for residential and commercial appliances) which reflect current law, mobile home efficiency standards, vehicle efficiency (CAFE) standards, and auto emissions standards. In addition, the efficiency measures installed by utilities through 1994 are reflected in the base case forecast.

The base case forecast does not contain assumptions about impacts from possible future legislation, future utility efficiency measures, or future appliance or vehicle efficiency standards legislation. It also does not forecast economic business cycles, and assumes historic normal weather patterns. Because it doesn't include such assumptions, the base case forecast does not represent DPS's estimate of what *will* occur. Instead, its usefulness lies in its portrayal of what the future would be like if "nothing new happened." As such, the base case forecast provides a reference point for examining and comparing various policies for the future. See the text box on the Energy 2020 and REMI Models for more information on development of the base case.

D. Base Case Forecast Overview

The base case forecast projects delivered energy consumption in Vermont to increase by 54% between 1990 and 2015, from about 98 trillion BTU (TBTU) to 151 TBTU.[xlvi] Primary energy use is expected to increase at a similar rate, from 121 TBTU to 187 TBTU during the same time. (Primary energy use includes the energy required to generate electricity, and the energy lost in transmission and distribution of electricity and natural gas.)[xlvii] These growth rates mirror projected growth rates in Vermont's Gross State Product (55% between 1990 and 2015), and in statewide energy expenditures (54% or $678 million in 1995 dollars during the same time period). Primary energy use per capita also continues to rise in the base case forecast, from 214 million BTU per person in 1990 to 274 million BTU in 2015.

Vermont's delivered energy consumption in the transportation sector increases substantially in the forecast, by 69% between 1990 and 2015, while consumption in the residential sector increases only very slowly. The commercial and industrial sectors each experience strong growth in energy use -- 84% and 58% respectively over the same time period; however, the absolute amounts these sectors use remain much lower than either the residential or transportation sectors.

Delivered energy consumption increases among virtually all end uses in the base case forecast. Consumption in road transportation end uses increases by a total of 72% between 1990 and 2015. Several other end uses are projected to experience growth rates between 50%-60%, including water heating, process heat (industrial), motors (industrial), lighting, drying, and miscellaneous electric loads. Most other end uses experience lower growth rates, except for air conditioning energy use which is projected to increase 80% during the same time-frame.

Oil remains the dominant fuel in the base case forecast, with its delivered use increasing by 52% between 1990 and 2015. Electricity, the second largest energy source, increases by 42% during the same time-frame. Non-electric uses of natural gas and LPG (propane) increase substantially into the future, by 108% and 83% respectively, but remain dwarfed by oil use. The gap between consumption of non-renewable and renewable energy sources continues to widen into the future, as use of hydroelectric power remains fairly constant and wood use increases slowly, while fossil fuel sources increase significantly in this base case forecast.

Emissions of eight pollutants from the state's energy use are analyzed in the base case forecast. Vermont's energy use produces significant emissions of carbon dioxide, carbon monoxide, nitrogen oxides, volatile organic compounds (VOCs), and sulfur oxides. In addition, smaller amounts of particulates (those less than 10 microns or PM-10), nitrous oxide, and methane are emitted. Emissions of carbon dioxide, nitrogen oxides, nitrous oxide, and methane are projected to increase between 1990 and 2015. Three of these pollutants, carbon dioxide, nitrous oxide, and methane, contribute to global warming, and Vermont is expected to experience a 67% increase in emissions of these greenhouse gases between 1990 and 2015 (in CO_2 equivalent terms). The state's projected increasing nitrogen oxides emissions will cause both ground-level ozone and acid precipitation precursors to increase, by 9% and 10% respectively, during the same time-frame. Vermont's air emissions are also analyzed among sectors and fuels in sections below.

The sections below outline these and other conclusions in more detail. In addition, Figures 3.III.7 - 3.III.29

and Tables 3.III.1 - 3.III.4 present base case forecast results in a detailed visual format.

E. Base Case Energy Projections

The base case forecast presents projections for energy expenditures, energy consumption, and air emissions for Vermont through 2015. The projections can be analyzed according to sector (residential, commercial, industrial, transportation), end use, or fuel type. All of these divisions are used to present the data that follows. Because transportation is both a sector (in this forecast) and an end use, it is both separated as a sector in some graphs and included as an end use in other graphs.

1. Energy Expenditures

As shown in Figure 3.III.7, Vermont's total energy expenditures have been rising slowly since the mid-1980s. Future expenditures are expected to rise more quickly, at 1.7% per year or 54% between 1990 and 2015, due to rising energy prices and increasing consumption levels. In 1995, Vermont's energy expenditures are an estimated $1,313,100,000 (in 1995 dollars). Energy expenditures are about 8.1% of gross state product in 1995, and are expected to increase to 8.6% by 2015, a significant increase in monetary terms.

The transportation sector claims the largest portion of Vermont's energy expenditures, as shown in Figure 3.III.8. Transportation expenditures are currently only slightly greater than expenditures in the residential sector, at $448 million and $437 million respectively (in 1995 dollars). However, this gap is expected to increase substantially in the future as transportation expenditures increase by 66% while residential expenditures increase by only 25% between 1990 and 2015. Expenditures in the commercial and industrial sectors are also projected to grow quickly in the future, by 73% and 70% respectively; however, energy outlays in these two sectors will still remain lower than in the other sectors.

Figure 3.III.9 illustrates that oil and electricity expenditures are currently similar in Vermont, at about $595 million for oil and $555 million for electricity (in 1995 dollars), but are expected to draw apart in the future as oil prices and expenditures rise. Oil and electricity purchases together are expected to comprise between 86%-87% of Vermont's total expenditures through 2015. Expenditures for natural gas and LPG are expected to rise 139% and 66% respectively between 1990 and 2015, but these expenditures remain small in comparison to oil and electricity expenditures.

2. Total Energy Use

As shown in Figure 3.III.10, Vermont's total delivered energy consumption fell in the late 1970s and early 1980s in response to high oil prices, but rose again later in the 1980s. After falling in response to the 1990 recession, statewide energy consumption is expected to resume its increasing trend, increasing from 98 TBTU to 151 TBTU or 54% between 1990 and 2015. The state's energy consumption is also presented in terms of primary energy use. Primary energy use includes the energy required to generate electricity, and the energy lost in transmission and distribution of electricity and natural gas. About 19% of our total primary energy use is lost in the generation, transmission, and distribution of electricity and natural gas, both now and in the future. Vermont's primary energy use per capita is projected to increase in the future, from 214 million BTU in 1990 to 274 million BTU in 2015. As outlined below, this increase stems largely from growth in transportation energy use due to increasing vehicle miles traveled and dispersed land use patterns, and growth in commercial and industrial energy use due to projected economic output from these sectors.

3. Energy Use Among Sectors

Figure 3.III.11, depicting the state's delivered energy consumption by sector, shows trends similar to those for energy expenditures by sector. The gap between transportation and residential energy consumption will continue to widen, as transportation energy use increases by 69% while residential use grows by only 21% between 1990 and 2015. Residential use increases slowly in the future partly as a result of gains made by appliance efficiency standards and the fact that new homes are usually more efficient than old ones. Energy consumption in the commercial and industrial sectors increases fairly quickly, but remains low compared to use in the residential and transportation sectors. In terms of primary energy use, the residential, commercial, and industrial sectors' levels of use are all closer to the transportation sector's level of use due to the additional energy used for electricity generation.

4. Energy Use Among End Uses

Figure 3.III.12 illustrates Vermont's energy consumption by end use, including transportation as an end use. Energy consumption increases among virtually all end uses in the base case forecast, but increases faster for road transportation than for any other major end use. Road transportation energy use rises 72% between 1990 and 2015; by contrast, energy consumption for the next largest end use, heating, rises only 30% during the same time-frame. Several end uses are projected to experience growth rates between 50%-60%, including water heating, process heat (industrial), motors (industrial), lighting, drying, and miscellaneous electric loads. A few additional end uses experience slower growth rates (between 27% and 39%), including refrigeration, cooking, and as mentioned above, space heating. The end use that experiences the largest growth in energy use is also the one which uses the least amount of energy (among those that are tracked): air conditioning, which is projected to increase 80% between 1990 and 2015. These increases occur over a time period in which population increases by about 21%; thus, the state's per capita energy use grows substantially. The only end use category to decrease in energy consumption during the base case forecast is the plane, train, and marine vehicles category.

5. Energy Use Among Fuels

Vermont's delivered energy use by fuel, as shown in Figure 3.III.13, depicts the dominance of oil in our energy consumption. Oil consumption is projected to increase 52%, from 62.8 TBTU to 95.2 TBTU, between 1990 and 2015. While use of other fuels is also expected to increase (most notably, natural gas at 108% and LPG at 83%), the total usage of these other sources remains small compared to oil. In terms of primary energy consumption, natural gas and wood energy use increase dramatically as these sources replace other electric energy sources in the future. Nuclear energy use is projected to decline as Vermont Yankee nuclear plant's license expires in 2012. Both coal and hydroelectric energy use are also expected to decrease due to electricity contract purchases that are scheduled to expire in the years ahead.

Although Vermont currently uses more hydroelectric power and wood energy than many other states, our total use of renewable energy sources is still much smaller than our use of non-renewable sources, as shown in Figure 3.III.14. This presentation of renewable and non-renewable sources depicts renewable resources in two ways. The first total for renewables (in the table) gives the amount of renewable energy used. The second total reflects the amount of oil required to generate the same amount of electricity that comes from hydropower sources. While the first total more accurately describes the amount of renewable energy consumed, the second total shows the advantage of hydroelectric power: large amounts of depletable energy resources are not lost in the conversion of hydropower to electricity, as is the case with fossil fuel sources. (The same advantage is captured by solar and wind energy.) No matter how renewable resources are depicted, it is clear that if present trends continue, the gap between renewable and non-renewable sources in Vermont's energy supply will grow even wider in the future.

6. Energy Intensity

To help measure the importance of energy use on the state's economy, the intensity of energy use is presented in Figures 3.III.15 and 3.III.16, indicating how our energy use per person or per dollar of GSP has changed over time. Energy use in the residential sector per person fell dramatically in the late 1970s and early 1980s due to higher energy prices, lower oil use, and conservation efforts in heating end uses. It experienced another decline in 1990 due in part to milder weather. In the future, however, the residential energy intensity is expected to rise in the late 1990s, then level off, and eventually begin to decline.

Energy use in the commercial and industrial sectors per dollar of real GSP showed a similar decline in the late 1970s and early 1980s, rose in the mid-1980s in response to a strong economy, and fell again as the 1990 recession hit. The forecast shows a growth pattern similar to residential energy intensity, in which growth is greatest early on, but eventually levels off around 2005, ebbing slightly in the last few years of the forecast. Energy demand will increase as output grows in the future, but eventually rising fuel prices will dominate, leading businesses to adopt more efficient processes and devices and slowing the growth in energy use relative to output.

Figures 3.III.17 - 3.III.22 portray Vermont's residential, commercial, and industrial energy use by end use and fuel, while Figures 3.III.23 and 3.III.24 show transportation energy use by sector and end use. These breakdowns are especially helpful in learning where our greatest opportunities for energy savings lie.

7. Residential Energy Use

Within the residential sector, transportation and space heating end uses have utilized similar amounts of energy through the early 1990s, as shown in Figure 3.III.17. However in the future, the two end uses are expected to take different courses, with residential transportation energy use increasing by 62%, while space heating use increases by only 4% between 1990 and 2015. This occurs because while homes are becoming increasingly efficient, automobile efficiency is not climbing. In addition, rising personal income in the forecast creates demand for new homes (among other things), and while new homes tend to be more efficient, their locations generally require more transportation energy use. Water heating is the next largest end use in the residential sector, and its energy use is projected to increase by 53% between 1990 and 2015. Other end uses are also expected to increase, but their total energy requirement will remain relatively low.

Residential energy consumption by fuel (excluding transportation use), shown in Figure 3.III.18, is expected to undergo some changes into the future. Oil use (for space and water heating) is expected to fall as other sources, including as electricity, wood, LPG, and especially natural gas, take its place. Natural gas use in the residential sector is expected to increase markedly -- by 211% between 1990 and 2015. The next highest growth rate among fuels is for solar power, with a 195% growth rate between 1990 and 2015; however, even at this growth rate solar power remains such a small portion of total energy use that it is still hardly noticeable in 2015.

8. Commercial Energy Use

Similar to the residential sector, the commercial sector's fastest growing end use is transportation, which climbs by 72% between 1990 and 2015 (as shown in Figure 3.III.19). Heating energy use in the commercial sector experienced a decline in the late 1970s and early 1980s, probably due to conservation efforts and efficiency gains. Into the future, however, it is expected to increase substantially (99% between 1990 and 2015), unlike space heating in the residential sector which barely increases. This is partly due to the fact that commercial output (and, hence, space heating) increases steadily into the future, and because commercial energy use more closely parallels economic trends. All other commercial end uses are expected to increase by 56%-75%. As illustrated in Figure 3.III.20, oil and electricity use in the commercial sector were comparable from the mid-1980s to the present. However, the gap widens in the future as oil use (excluding transportation) increases 121% between 1990 and 2015. Other energy sources also grow significantly, especially LPG and natural gas, but remain overshadowed by oil use. The increased oil use in the commercial sector parallels the increase in commercial heating and other end uses.

9. Industrial Energy Use

In the industrial sector, process heat remains the dominant energy end use into the future, increasing 54% between 1990 and 2015 (as shown in Figure 3.III.21). Transportation, the second-highest end use grows by 90% during the same time period. Industrial motors and transportation have used similar amounts of energy in the past, but in the future this gap widens, as energy use for motors increases at a slower rate of 59% between 1990 and 2015. As illustrated in Figure 3.III.22, oil and electricity use (excluding transportation) continue to rise in the future in the industrial sector, similar to the commercial sector. While electricity energy use continues to rise steadily into the future, oil and natural gas use increase in the near future and then flatten. Energy use from other fuels also rises, mirroring the predicted growth in industrial output.

10. Transportation Energy Use

Within the transportation sector, residential use accounts for a higher proportion than commercial and industrial use and is projected to remain higher, as shown in Figure 3.III.23. Transportation energy use is expected to increase 62% in the residential sector, 72% in the commercial sector, and 90% in the industrial sector, although usage in the industrial sector remains small in comparison with use in the other two sectors. As illustrated in Figure 3.III.24, virtually all transportation energy is used by cars and trucks, and all growth is expected to occur in those end uses. Planes, buses, trains, and marine vehicles together represent only 4% or less of the total transportation energy use, and energy used by planes and trains is projected to decrease in the future in Vermont.[xlviii]

11. Total Air Emissions from Energy Use

Figures 3.III.25 - 3.III.29 and Tables 3.III.1 - 3.III.4 present the amounts of air emissions that Vermont's energy use produces. Emission levels are given in tons per year; these tonnage comparisons best illustrate trends rather than the relative impacts of each emission. For example, each ton of nitrous oxide emissions traps 270 times more heat in the atmosphere than a ton of carbon dioxide emissions, leading to a much greater impact on global warming. See Chapter 2, Environmental Soundess section, and Chapter 3, Part II for more information about the impacts of emissions from Vermont's energy use.

As shown in Figure 3.III.25, the most significant pollutants (in terms of tonnage) resulting from Vermont's energy use are carbon dioxide, carbon monoxide, nitrogen oxides, volatile organic compounds (VOCs), and sulfur oxides. Vermont's energy use also emits smaller amounts of particulates (those less than 10 microns or PM-10), nitrous oxide, and methane.

Our emissions of four of these eight pollutants are projected to decrease between 1990 and 2015 (carbon monoxide, VOCs, sulfur oxides, and PM-10), but emissions of the other four are projected to increase (carbon dioxide, nitrogen oxides, nitrous oxide, and methane). Carbon dioxide, nitrous oxide, and methane contribute to global warming, and Vermont is expected to experience a 67% increase in these greenhouse gases between 1990 and 2015 (in CO_2 equivalent terms). Nitrogen oxides are precursors of both ground-level ozone and acid precipitation; thus, increasing nitrogen oxides emissions cause both ozone and acid precipitation precursors to increase (by 9% and 10% respectively) during the same time-frame. In 1998, Vermont is expected to experience a slight decrease in emissions of acid precipitation precursors due to the expiration of a power generation contract with Merrimack II, a coal plant in New Hampshire. Between 2011 and 2012, an increase in greenhouse gases and ozone and acid precipitation precursors is expected due to the expiration of Vermont

Yankee nuclear plant's license and the projected replacement of that power with fossil fuel sources. If renewable generation and energy efficiency options were in place in 2012 when Vermont Yankee's license expires, emissions of greenhouse gases and ozone and acid precipitation precursors would decline, remain stable, or increase much more slowly.

12. Air Emissions among Sectors

The residential sector currently emits more carbon dioxide, carbon monoxide, VOCs, nitrogen oxides, PM-10, and methane than the commercial or industrial sectors, as shown in Figures 3.III.26 - 3.III.28. Carbon dioxide, nitrogen oxides, nitrous oxide, and methane are all projected to increase in the residential sector. Most notably, nitrogen oxides experience an increase of 173% between 1990 and 2015 due to greater use of fossil fuels after Vermont Yankee's retirement. Greenhouse gases in the residential sector are expected to increase from 2.75 million tons to 3.66 million tons or 33% between 1990 and 2015, mirroring the increase in residential primary energy use of 27%. Ground-level ozone precursors are also expected to increase (by 4%), while acid precipitation precursors are expected to decrease (by 3%) over the same time-frame. While acid precipitation precursors decrease over the short term due to the expiration of Vermont's contract with the Merrimack II coal generation plant, they begin to increase again by the end of forecast due to growing emissions of nitrogen oxides from the replacement of Vermont Yankee with fossil fuel sources.

While Vermont's commercial and industrial sectors emit smaller amounts of most pollutants compared with both the residential and transportation sectors, their emissions are expected to increase at some of the highest rates among all sectors, paralleling expected economic growth. Greenhouse gas emissions will increase 125% and 100% respectively in the commercial and industrial sectors, a much greater rate of increase than the rate for primary energy use in these sectors (at 77% and 62%). This difference in rates of increase is caused largely by the high use of electricity in these sectors, which causes a large increase in several pollutants when Vermont Yankee nuclear plant is replaced by fossil fuel sources in 2012 (according to assumptions in the forecast). Ground-level ozone and acid rain precursors also increase in these sectors at very high rates, most notably ozone precursors at 248% and 176% respectively in the commercial and industrial sectors. The pollutants projected to decrease for these sectors are sulfur oxides and PM-10.

The transportation sector emits more carbon dioxide, carbon monoxide, nitrogen oxides, and VOCs than any other sector, as illustrated in Figure 3.III.29. As of 1995, Vermont's transportation energy use accounted for an estimated 43% of all greenhouse gas emissions, 72% of all ground-level ozone precursors, and 54% of all acid precipitation precursors. Carbon dioxide emissions from transportation are projected to increase from 3.3 million tons to 5.6 million tons or 69% between 1990 and 2015. This rate of increase is the same as the increase in total energy use in the transportation sector. Carbon monoxide and nitrogen oxides, both of which are major pollutants in the transportation sector, are projected to decrease in the future due to federal emissions regulations; however emissions of VOCs and sulfur oxides (smaller emitters but still significant) are expected to increase. Both ozone and acid precipitation precursors are projected to decrease slightly in the future, mirroring the decrease in nitrogen oxides due to federal controls. Although the transportation sector shows decreases in important pollutants into the future, the most important trend in the sector is the large increase in greenhouse gases, which increase by 70% between 1990 and 2015.

13. Air Emissions among Fuels

Vermont's emissions from energy use can also be analyzed by fuel. Tables 3.III.1 - 3.III.4 present data of emissions from oil, LPG (propane), natural gas, and wood, the primary fuels of concern for emissions in the state. Coal use also causes significant emissions, and Vermont uses some coal for electric generation; however, the contract that Vermont utilities hold with Merrimack II, the primary supplier of electricity from coal, will expire in 1998. Vermont's increase in energy use by fuel (as outlined in previous sections) is often proportional to the increase in emissions by fuel.

Vermont's use of oil (distillate fuel, gasoline, and oil for other transportation purposes) emits much larger amounts of carbon dioxide, carbon monoxide, nitrogen oxides, sulfur oxides, and VOCs than any other fuel. The state's use of oil in 1995 accounted for 72% of all greenhouse gas emissions, 79% of all ground-level ozone precursors, and 89% of all acid precipitation precursors. Emissions of all pollutants from oil increase into the future except for carbon monoxide and nitrogen oxides emissions, which decrease due to federal emission regulations. Greenhouse gas emissions from oil are projected to increase by 47% between 1990 and 2015, mirroring the 51% increase in oil energy use over that same time period. Between 1990 and 2015, ground-level ozone precursors from oil use are expected to decrease (by 4%) as a result of federal controls. Acid precipitation precursors are projected to increase (by 8%), because emissions of one important precursor, sulfur oxides, are proportional to oil energy use (which is expected to increase).

Vermont's use of and emissions from LPG and natural gas are low compared to other fuels and emissions, but are expected to increase at some of the highest rates among all fuels. All emissions from LPG are expected to increase by fairly large amounts into the future, paralleling the 88% growth in LPG primary energy use between 1990 and 2015. Although all emissions increase at high rates, total emissions from LPG by 2015 remain small compared to oil, wood, and natural gas. All pollutants from natural gas are expected to increase at extremely high rates between 1990 and 2015 as natural gas is used for greater amounts of electric generation in the future (according to base case forecast assumptions). Greenhouse gas emissions from natural gas are expected to increase 743% between 1990 and 2015, similar to the 706% increase in natural gas primary energy use over the same time period. By 2015, greenhouse gas emissions from natural gas are expected to comprise 23% of the state's total greenhouse gas emissions. Ground-level ozone and acid precipitation precursors from natural gas also experience very large increases, from 483 and 473 tons in 1990 to 9,185 and 9,063 tons in 2015. While natural gas and LPG burn cleaner than oil and coal, and would result in a decrease in total emissions if they replaced more polluting fuels, their increasing use leads to higher levels of total emissions in the base case forecast.

Vermont's use of wood energy currently emits significant amounts of carbon dioxide, carbon monoxide, VOCs, and PM-10. However, these pollutants are projected to decrease in the future (except for carbon dioxide), as older wood stoves are replaced with lower-emitting EPA-certified stoves. VOCs and PM-10 will experience healthy decreases in the future, but carbon monoxide emissions only decrease slightly. Between 2005 and 2015, carbon monoxide emissions actually increase slightly. Carbon dioxide emissions from wood comprise 12%-13% of Vermont's total carbon dioxide emissions and are expected to grow in the future, paralleling the 99% growth in wood primary energy use between 1990 and 2015 due largely to greater use of wood for electric generation (according to forecast assumptions). However, if wood resources are managed sustainably, as is usually the case in Vermont, no net carbon dioxide emissions are attributed to wood burning. (See the wood energy use sections of Chapter 3, Part II for more on sustainable harvesting and CO_2 emissions.) As shown in Table 3.III.4, greenhouse gas emissions from wood are much lower (about 99% lower) if CO_2 is not attributed to wood burning.

Figure 3.III.1 Vermont Population and Employment
Thousands of people

Figure 3.III.2 Vermont Personal Income and Gross State Product
Billions of 1995 dollars

Figure 3.III.3 Vermont and U.S. Personal Income Per Capita
1995 dollars

Figure 3.III.4 Vt. GSP and U.S. GDP Per Capita

1995 dollars

Figure 3.III.5 Vermont Commercial and Industrial Output

Billions of 1995 dollars

Figure 3.III.6 Crude Oil Prices

1994 dollars per barrel

Figure 3.III.7 Vermont Energy Expenditures

Millions of 1995 dollars

Figure 3.III.8 Vermont Energy Expenditures by Sector

Millions of 1995 dollars

Figure 3.III.9 Vermont Energy Expenditures by Fuel

Millions of 1995 dollars

Figure 3.III.10 Vermont Primary and Delivered Energy Use

TBTU

Figure 3.III.11 Vermont Delivered Energy use by Sector
TBTU

Figure 3.III.12 Vermont Delivered Energy Use by End Use
TBTU

Figure 3.III.13 Vermont Delivered Energy Use by Fuel

TBTU

Figure 3.III.14 Vt. Non-renewable and Renewable Primary Energy Use
TBTU

Figure 3.III.15 Vermont Energy Intensity, Residential Sector

Million BTU per person

Figure 3.III.16 Vt. Energy Intensity, Commercial and Industrial Sectors

Thousand BTU per dollar of real GSP (1995 dollars)

Figure 3.III.17 Vt. Residential Delivered Energy Use by End Use
TBTU

Figure 3.III.18 Vt. Residential Delivered Energy Use by Fuel
TBTU

Figure 3.III.19 Vt. Commercial Delivered Energy Use by End Use

TBTU

Figure 3.III.20 Vt. Commercial Delivered Energy Use by Fuel
TBTU

Figure 3.III.21 Vt. Industrial Delivered Energy Use by End Use

TBTU

Figure 3.III.22 Vt. Industrial Delivered Energy Use by Fuel
TBTU

Figure 3.III.23 Vt. Transportation Delivered Energy Use by Sector

TBTU

Figure 3.III.24 Vt. Transportation Delivered Energy Use by End Use

TBTU

Figure 3.III.25 Vermont Emissions from Energy Use

Tons

Figure 3.III.26 Vermont Emissions from Residential Energy Use
Tons

Figure 3.III.27 Vermont Emissions from Commercial Energy Use

Tons

Figure 3.III.28 Vermont Emissions from Industrial Energy Use
Tons

Figure 3.III.29 Vermont Emissions from Transportation Energy Use

Tons

Table 3.III.1 Vermont Emissions from Oil

Tons

Table 3.III.2 Vermont Emissions from LPG (Propane)

Tons

Table 3.III.3 Vermont Emissions from Natural Gas
Tons

Table 3.III.4 Vermont Emissions from Wood
Tons

ENDNOTES:

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i. Vermont Yankee is one of a group of nuclear plants built in New England with diverse ownership. Others include Yankee Rowe (MA), Connecticut Yankee, and Maine Yankee. The lead Vermont Yankee owner was CVPS.

ii. For information on the scientific basis for global climate change, see the following reports produced by the Intergovernmental Panel on Climate Change: *Scientific Assessment of Climate Change*, 1990; *Climate Change 1992: The Supplementary Report to the IPCC Scientific Assessment*, 1992; and the update of the 1990 report.

iii. The energy required to extract, refine, and transport energy sources for electric generating plants is not included in the calculation of primary energy use (except transportation within Vermont). Similarly, the energy required to extract, refine, and transport non-electric fuels such as gasoline, LPG, etc. to customers is not included (except transportation within Vermont). The energy required to transport electric and non-electric fuels within Vermont is included in the calculation of primary oil use.

iv. There are a few other petroleum products, including asphalt oil, road oil, and lubricants, that are not typically burned for energy use but are necessary for our energy use (and the energy embedded within them represents energy we cannot use for other purposes). These products accounted for an additional 1.2 TBTU in Vermont in 1993 (U.S. DOE/EIA, *State Energy Data Report*, 1995, 299).

v. Calculated by dividing 1993 U.S. petroleum use (33,842.2 TBTU) by 1993 population (257.6 million) (U.S. DOE/EIA, *State Energy Data Report 1993*, 1995, 21; U.S. DOE/EIA, *International Energy Annual 1993*, 1995, 113). Vermont value calculated by dividing 1993 petroleum use (78 TBTU) by population (576,000) (Vt. DPS).

vi. Proven reserves are those quantities which geological and engineering information indicates with reasonable certainty can be recovered in the future from known deposits under existing economic and operating conditions.

vii. Calculated using the 1992 worldwide oil use (66.7 million barrels per day), the worldwide growth rate in oil use of 1.596% per year predicted by the U.S. Energy Information Administration (U.S. DOE/EIA, *International Energy Outlook*, 1995, 81), and the proven world oil reserves (1.1 trillion barrels) as of January 1993 (Masters, et. al., 1994, 531). Annual new discoveries of oil have been three times lower than annual oil production during the early 1990s (Masters, et. al., 1994, 537). Because the proven reserves data is up-to-date as of January 1993, the equivalent of approximately one year's worth of annual oil production was likely discovered between 1993 and 1995. Therefore, the year of depletion of proven reserves was adjusted by one year. This information does not change the estimates of world ultimate reserves of oil.

viii. Calculated using the United Nations population projections indicating that world population growth will level off at 11.6 billion people in 200 years, and assuming that the current worldwide petroleum use per capita linearly increases during the next 100 years from .01195 barrels per day (the current worldwide per capita use) to .06691 barrels per day (the current U.S. per capita use). Sources: Brown, 98; U.S. DOE/EIA, *International Energy Annual 1993*, 1995, 4-6, 114-116.

ix. OPEC (Organization of Petroleum Exporting Countries) includes Algeria, Gabon, Indonesia, Iran, Iraq, Kuwait, Libya, Nigeria, Qatar, Saudi Arabia, the United Arab Emirates, and Venezuela.

x. Vermont and U.S. oil consumption projections are based on different oil price forecasts.

xi. Algeria, Iraq, Kuwait, Libya, Qatar, Saudi Arabia, and United Arab Emirates, as well as imports from the "Neutral Zone," located between Saudi Arabia and Kuwait.

xii. There was an additional 3.09 million barrels per day of natural gas plant liquids and other domestic supply produced in the U.S. in 1994. Other domestic supply includes benzol, other hydrocarbons, oxygenates, gasoline blending components, finished petroleum products, hydrogen, alcohol, processing gains, and unaccounted-for crude oil.

xiii. Supply of SPR in terms of net imports was calculated by dividing 1993 end-of-year SPR stocks (592 million barrels) by annual average daily net imports of all petroleum (7.99 million barrels). Supply of SPR in terms of OPEC imports was calculated by dividing 1993 end-of-year SPR stocks by annual average daily imports from OPEC (4.22 million barrels).

xiv. Calculated by dividing barrels of motor gasoline used in Vermont in 1993 (7,094,000) by population (576,000) (U.S. DOE/EIA, *State Energy Data Report*, 1995; VT DPS). U.S. value calculated by dividing barrels of motor gasoline used in 1993 (2,729,000,000) by population (257.6 million) (U.S. DOE/EIA, *State Energy Data Report*, 1995; U.S. DOE/EIA, *International Energy Annual*, 1995).

xv. Vermont and U.S. gasoline consumption projections are based on different oil price forecasts.

xvi. Heating oil and diesel fuel are both distillate fuels. Like gasoline, distillate fuel is refined from crude oil. Heating oil is sometimes called "light fuel oil" or "number two heating oil."

xvii. Vermont and U.S. LPG consumption projections are based on different fuel price forecasts.

xviii. Energy use among these end uses, added together with the numbers reported above for kerosene, LPG, distillate fuel, and motor gasoline, come to slightly more than the 78 TBTU given earlier for total petroleum use in Vermont. This is due to the fact that values for motor gasoline, distillate fuel, kerosene, jet fuel, aviation gasoline, and residual fuel come from the State Energy Data Report of the U.S. Department of Energy, while values for LPG and total petroleum use come from estimates of the Vermont Department of Public Service. Vt. DPS values were used whenever possible for consistency with other non-petroleum energy consumption values which are also DPS estimates.

xix. Vermont and U.S. jet fuel consumption projections are based on different fuel price forecasts.

xx. Calculated using 1992 worldwide natural gas use (74.7 trillion cubic feet), the 2.027% usage growth rate per year predicted by the U.S. Energy Information Administration, and the proven reserves (4,980.3 trillion cubic feet) as of January 1, 1995 (U.S. DOE/EIA, *International Energy Outlook*, 1995, 37, 82).

xxi. Vermont and U.S. natural gas consumption projections are based on different fuel price forecasts.

xxii. Vermont and U.S. wood consumption projections are based on different fuel price forecasts.

xxiii. The Use Value Appraisal tax program taxes forest and farm land of a minimum acreage at the rate of its current use rather than at the rate of its development value, encouraging landowners to keep their land undeveloped. Under this program, landowners pay a lower tax rate and the state makes up the difference in lost revenue. However, this program has not been fully funded in recent years.

xxiv. Most conventional fireplaces, masonry stoves, furnaces, boilers, cookstoves, and some pellet-burning appliances are exempt from the regulation. These appliances may or may not have high efficiencies and low emission rates.

xxv. Vermont utilities also received about $2 million for generation related to Hydro-Québec compared to what they would have spent operating independently.

xxvi. On an ownload basis; see Figure 3.II.38 for an explanation of ownload. In addition, Vermont purchased about 275 GWh from Ontario Hydro and NEPOOL "system power" in 1993; some small fraction of this power was likely generated from nuclear sources.

xxvii. On an ownload basis; see Figure 3.II.38 for an explanation of ownload.

xxviii. On an ownload basis; see Figure 3.II.38 for an explanation of ownload. In addition, Vermont purchased about 275 GWh of power from Ontario Hydro and NEPOOL "system power" in 1993; some of this power was likely generated with coal.

xxix. Calculated using the 1992 coal use of 5,001 million short tons, the worldwide growth rate in coal use of 1.5% per year predicted by the U.S. Energy Information Administration, and the proven coal reserves of 1,145 billion short tons as of January 1, 1991 (U.S. DOE/EIA, *International Energy Outlook*, 1995, 44, 83).

xxx. On an ownload basis; see Figure 3.II.38 for an explanation of ownload. In addition, Vermont purchased about 275 GWh from NEPOOL "system power" in 1993; some of this power was likely generated by oil.

xxxi. Calculated using the 1992 worldwide oil use (66.7 million barrels per day), the worldwide growth rate in oil use of 1.596% per year predicted by the U.S. Energy Information Administration (U.S. DOE/EIA, *International Energy Outlook*, 1995, 81), and the proven world oil reserves (1.1 trillion barrels) as of January 1993 (Masters, et. al., 1994, 531). Annual new discoveries of oil have been three times lower than annual oil production during the early 1990s (Masters, et. al., 1994, 537). Because the proven reserves data is up-to-date as of January 1993, the equivalent of approximately one year's worth of annual oil production was likely discovered between 1993 and 1995. Therefore, the year of depletion of proven reserves was adjusted by one year. This information does not change the estimates of world ultimate reserves of oil.

xxxii. OPEC (Organization of Petroleum Exporting Countries) includes Algeria, Gabon, Indonesia, Iran, Iraq, Kuwait, Libya, Nigeria, Qatar, Saudi Arabia, the United Arab Emirates, and Venezuela.

xxxiii. These two projections of worldwide oil consumption assume different rates of growth for future oil prices.

xxxiv. Calculated using 1992 worldwide natural gas use (74.7 trillion cubic feet), the 2.027% usage growth rate per year predicted by the U.S. Energy Information Administration, and the proven reserves (4,980.3 trillion cubic feet) as of January 1, 1995 (U.S. DOE/EIA, *International Energy Outlook*, 1995, 37, 82).

xxxv. Vermont and U.S. natural gas consumption projections are based on different natural gas price forecasts.

xxxvi. On an ownload basis; see Figure 3.II.38 for an explanation of ownload.

xxxvii. The Northeast includes Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Pennsylvania, Rhode Island, and Vermont.

xxxviii. Vermont and U.S. wood consumption projections are based on different fuel price forecasts.

xxxix. Calculated assuming the typical Vermont residence consumes 7,000-8,000 kWh per year, and that 13,000 BTU per hour will generate 1 kWh in landfill gas generators.

xl. Eight potential sites were originally identified in Vermont. In addition to the two sites already used for landfill gas generation, the following six were identified: City of South Burlington Landfill, C.V. Landfill in East Montpelier, Palisades Landfill, Rathe Brothers Landfill in Colchester, Town of Essex Landfill, and Waste U.S.A. Landfill in Newport. These six candidate landfills were reduced to five in the study to account for potential database errors (SCS Engineers, 1994, 5-2, A-19).

xli. A DSM bidding process is effective if it is done in a way that avoids "cream-skimming." Cream-skimming occurs when a DSM program or measure is implemented that has a high energy-savings-to-investment ratio instead of implementing a DSM program or measure with a smaller ratio but with larger total energy savings.

xlii. Avoided cost comparisons are a shortcut that often gives the same result as full application of the societal test. The societal test is discussed further in the *Vermont Twenty Year Electric Plan*.

xliii. These utilities are: Enosburg Falls Water and Light Department, Green Mountain Power, Hardwick Electric Department, Hyde Park Electric Department, Jacksonville Electric Company, Lyndonville Electric Department, Ludlow Electric Department, Northfield Electric Department, Stowe Electric Department, Swanton Electric Light Department, Vermont Marble Power Division of OMYA, and Washington Electric Cooperative.

xliv. The case of CFCs and the ozone hole provide precedent for what may occur again with greenhouse gases. As evidence of the impacts of CFCs mounted, countries joined together to ban ozone depleting CFCs in the Montreal Protocol. Since carbon dioxide is a product of all combustion, it does not lend itself to an outright ban, as in the case of CFCs, but limits placed on carbon dioxide and other greenhouse gas emissions could take the form of a carbon tax, efficiency standards, or tradable permits (such as those used for sulfur dioxide).

xlv. In a restructured industry, tools that could help lower rates include meters and other technologies that allow for real-time pricing. Real-time pricing would allow electricity providers to charge different rates at different times of day as electricity demand fluctuates. In addition, customers would have information about how much they were being charged for electricity at different times of day, and could both modify their usage to occur at the least expensive times of day and monitor rates in order to compare them with rates of other electricity providers.

xlvi. A TBTU is equivalent to approximately 172,000 barrels of crude oil or roughly 8 million gallons of gasoline (enough to drive 8,000 cars 20,000 miles).

xlvii. The energy required to extract, refine, and transport (to Vermont borders) energy sources for electric generating plants was not included in the calculation of primary use. Similarly, the energy required to extract, refine, and transport (to Vermont borders) non-electric fuels such as gasoline, LPG, etc. to customers was not included. In addition, projections of future gains in electric generation technologies were not considered.

xlviii. In 1987, 27% of total U.S. transportation energy use was for vehicles other than cars, trucks, and motorcycles (Gordon, 1991, 31). In addition, airplane energy use is projected to increase in the U.S., unlike in Vermont. Vermont's usage levels and trends are different from those in the U.S. due to our small airports, small use of freight trains, and small use of buses due to the rural nature of the state.