Chapter 15
U.S. LAW AND POLICY: ENERGY

SYNOPSIS

I. INTRODUCTION

What is the energy policy of the United States? The answer to that question is so amorphous that law scholars have devoted entire law review articles to demonstrating that the United States in fact has a national energy policy. *See* Joseph P. Tomain, *The Dominant Model of United States Energy Policy*, 61 U. COLO. L. REV. 355 (2000). Even then, the most that can be said is that the country has a "dominant model" of energy policy, but no one has argued — or, indeed, could argue — that the United States has a single, purposeful energy law governing generation, transmission, and distribution of power. To the contrary, U.S. politicians frequently tout their support for an "all-of-the-above" energy policy, and U.S. energy law consists of dozens of separate statutes and regulations administered by state, federal, and even local agencies, many of which appear to be working toward different purposes. Added to these substantive laws are subsidies, tax credits, and other financial incentives promoting coal, petroleum and natural gas, as well as wind, solar, and other renewable energy sources. Indeed, energy bills have become so laden with subsidies and tax breaks that Senator John McCain famously dubbed one the "No Lobbyist Left Behind" bill. For years now, analysts on the political left, right, and center have called for federal lawmakers to make sense of the existing disparate energy provisions sprinkled throughout the federal statutes, by developing a coherent and consistent federal energy policy. Election-year politics also often generate increased calls for a new approach to energy policy, in response to escalating energy prices and, for some, concern about climate change. Yet, whether the United States will adopt a cohesive, sustainable energy policy remains far from certain.

Since Thomas Edison first established the Pearl Street power station in 1882, supplying electricity to lower Manhattan, the overarching goal of U.S. energy policy has been to provide cheap, abundant, and reliable energy throughout the country. The approaches to achieving these goals have varied over time, from comprehensive state regulation of energy utilities, to direct federal regulation of energy production, to efforts to deregulate different aspects of energy production, to what Professor Joseph Tomain refers to as the "dominant model," which mixes regulation with market-based approaches aimed at promoting energy production and use over energy efficiency and conservation. *See* Tomain, *The Dominant Model*, 61 U. COLO. L. REV. at 355. This dominant model favors traditional fossil-fueled electricity sources, particularly coal and natural gas,[1] which are abundant and can provide large amounts of power to be distributed along the nation's electricity transmissions lines. *Id.* at 375. The dominant model also has favored energy production by large-scale, capital-intensive and centralized facilities, rather than smaller, diverse firms more likely to supply energy from alternative and renewable sources. *Id.* Finally, the dominant model of energy regulation aims to provide energy to consumers at reasonable prices established by state or, on occasion, federal regulators. *Id.* These lower costs have typically promoted energy consumption and stifled the market for higher-priced alternative energies.

[1] Natural gas plays two key roles in the U.S. energy sector. First, it is used as a fuel in power plants and thus provides electricity. Second, it often serves as a direct heating and cooking fuel for homes and businesses with natural gas furnaces and stoves. This chapter will discuss natural gas generally and will not separate the indirect electricity production from the direct uses except where the separation is necessary to clarify an issue. Oil and other liquid fuels contribute a very small amount (no more than 2%) to U.S. electricity production. Instead, they play a dominant role in the transportation sector. While this chapter will refer to petroleum to a limited extent, Chapter 16 on U.S. Transportation Policy discusses liquid fuels in greater detail.

The results of the dominant model can be seen in the country's power production and consumption patterns. In 2011, more than 67 percent of the electricity used in the United States came from fossil fuel sources, with coal providing about 42 percent of the total power. Overall electricity consumption in the United States has more than doubled since the 1970s. Excluding transportation-related energy use (which is covered in Chapter 16) and waste, the greatest increase in electricity consumption has occurred in the residential and building sectors, as Americans have built larger homes and offices with more appliances, electronics, and expansive heating and air conditioning systems. Wasted energy accounts for a shocking amount of total energy "use": electrical losses — the amounts of electricity that are lost in generating, transmitting, and distributing electric power — are higher than the total amount of natural gas, electricity, or petroleum actually used by residential and commercial customers. The U.S. electricity sector is, in short, highly inefficient and fossil-fuel intensive.

Yet the U.S. electricity sector may be in the midst of a fundamental change. Natural gas production has spurred much of this change: the deployment of advanced hydraulic fracturing technologies has made natural gas an unexpectedly abundant and affordable resource. In 2012, natural gas prices declined to unprecedented lows, spurring new investment in natural gas plants and displacing coal-fired electricity at a remarkable rate. Indeed, in the first half of 2012, natural gas and coal provided equivalent amounts of power for a period of time; this was a remarkable development, considering the fact that natural gas has historically accounted for about 20 percent of U.S. power, while coal has typically produced about half of all U.S. electricity. The rise of natural gas has also resulted in lower greenhouse gas emissions in the United States and triggered a vigorous debate about the future role natural gas should play in the U.S. power sector.

The electricity sector also appears to be undergoing significant changes regarding the role of renewable energy. Although renewable energy sources provide a small amount of U.S. electricity (in 2011, hydropower provided about 8 percent, with other renewables providing less than 6 percent), the renewable energy industry has witnessed remarkable growth since the mid-1990s. The wind industry has led the charge, with its production rates increasing more than 1,500 percent from 2001 to 2011, and solar energy production increasing by 150 percent. *See* U.S. ENERGY INFO. ADMIN., MONTHLY ENERGY REVIEW APRIL 2012, at 139 tbl. 10.1 (2012), *available at* http://www.eia.gov/totalenergy/data/monthly/archive/00351204.pdf. Other renewable electricity sources saw less growth during that time, but observers believe that geothermal, biomass, and wave energy will expand in future years. To a large extent, these changes have resulted from federal tax credits and state renewable energy mandates. Whether the same policies will continue to support renewable power in the future is uncertain, however, and it is unclear if the renewable energy sector can continue to grow absent continued regulatory intervention.

The future role of nuclear energy is also unclear. Since the late 1990s, some energy scholars, energy companies, and politicians have promoted nuclear power as the obvious alternative to greenhouse gas-intensive coal-based power. For a few years, it appeared that the nuclear power sector, which had been somewhat stagnant throughout the 1980s and 1990s, would experience a renaissance. However, the 2011 earthquake and tsunami in Japan and the resulting meltdowns at the Fukushima nuclear plant made many question the safety of nuclear power. Perhaps more significantly, the lack of a permanent storage facility for spent high-level nuclear waste has made regulators and energy companies hesitant about investing more money in nuclear power. It seems unlikely that the nuclear sector will experience anything like a renaissance for the near future.

Finally, efficiency and conservation have become increasingly important issues in electricity production, delivery, and regulation. As noted above, electrical losses eclipse actual electricity use in the residential and commercial sector. This is the result, in part, of inefficient buildings and appliances on the users' end, but it is also the result of the structure of the U.S. electricity system. Many power plants in use today came online in the 1950s, 1960s, and 1970s, and they lack modern technologies to make them more efficient. As a result, the coal fleet in the United States operates at about a 35 percent average efficiency rate, which means that about 65 percent of the energy produced through burning coal in power plants is lost as waste heat. Long-distance transmission lines also waste a lot of power; about 10 percent of electricity sent on the line is lost through the transmission system. Regulators have responded with efficiency mandates and support for localized energy production designed to avoid line losses and other inefficiencies. Whether these efforts will yield meaningful changes remains to be seen.

This chapter explores U.S. energy policy, with a focus on the electricity system, and the potential changes to it that climate change mitigation may necessitate. Section II begins with a description of electricity regulation and how the regulatory framework has led to the power system we have today. Section III then provides an overview of the electricity sources used today and discusses proposals to alter energy production. It will briefly introduce the role that natural gas, clean coal, nuclear power, and renewable energy sources might play in U.S. power production. Section IV focuses on the policies states — and to some extent, the federal government — have developed specifically to promote more renewable energy production. Finally, Section V discusses the role that energy conservation and efficiency may play in reducing greenhouse gas emissions from the U.S. electricity sector.

II. TRADITIONAL ELECTRICITY REGULATION AND FOSSIL FUELS

To understand the efficacy of policies to reduce greenhouse gas emissions from the electricity sector, it helps to have some understanding of electricity regulation. This area of law is quite complex, in that it involves the intersection of traditional state policy power regulation, monopoly regulation, economic theory, and, at least to some extent, physics. Electricity regulation also frequently involves complicated questions regarding federal versus state jurisdiction. While understanding electricity regulation can seem daunting, developing a basic understanding of the area is key to understanding some aspects of U.S. climate change policy.

A. A Brief History of Electric Utilities[2]

The fundamentals of electricity regulation date back to the 1880s, shortly after Thomas Edison began delivering power from the first centralized electricity plant, the Pearl Street

[2] For a comprehensive description of this history, *see* Richard F. Hirsh, POWER LOSS: THE ORIGINS OF DEREGULATION AND RESTRUCTURING IN THE AMERICAN ELECTRIC UTILITY SYSTEM, 12–15 (1999).

Station, to customers in Manhattan. Before that time, people in cities typically produced their own power through burning wood, coal, or natural gas to produce heat and light. With the completion of the Pearl Street Station, Thomas Edison showed how electricity itself — not just fuel — could be delivered to homes and businesses throughout a city.

In delivering this power, Thomas Edison relied on direct current (DC) power lines (when electrons flow in one direction, it is called direct current; when they flow in both directions, it is called alternating current (AC)). At the time, Edison considered them safer and more reliable, but they could only deliver power over relatively short distances and in relatively small amounts. To deal with these technological limitations, Edison and the company he founded, followed by other energy companies, would build new power plants to serve new neighborhoods. For a couple decades, most cities received power from these small, neighborhood power plants like the Pearl Street Station. For people familiar with the concept of distributed generation today — the idea that cities and homes should produce their own power — the model Thomas Edison created should be familiar.

However, a protégé of Edison, Samuel Insull, considered this arrangement inefficient. As emerging technologies developed, Insull pursued electricity production on a much larger scale. Under his system, large centralized power plants capable of producing large amounts of power came online. At the same time, Insull invested in alternating current (AC) transmission lines, which allowed for much more power to travel much further distances than DC lines. These technological changes thus allowed power plants to produce more power and send it further than ever before.

These technological developments also created economic opportunities. Electricity companies realized they could produce and deliver power more cheaply than the smaller neighborhood stations, and they began to offer discounted rates to attract customers. Over time, the centralized power plants — which benefitted from economies of scale — successfully outcompeted many neighborhood stations, driving them out of business. Indeed, the large power companies were so successful that they often achieved monopoly status as the sole power providers to various neighborhoods and even whole cities. Over time, the rise of the monopolies triggered calls for regulators to step in and regulate their practices.

B. Why Regulate Monopolies

The rise of the electric monopolies occurred at around the same time that other monopolies — such as oil companies and railroads — were facing increasing scrutiny by the public and politicians. Indeed, fears about monopolies had been a major theme in U.S. political and legal discourse since at least 1877, when the Supreme Court authorized state rate regulation of grain warehouse monopolies. Munn v. Illinois, 94 U.S. 113 (1876). With the passage of the Sherman Antitrust Act in 1890, monopoly regulation had become a key aspect of regulation designed to protect consumers from exploitative prices and poor service.

But unlike monopolies that regulators could break up, electricity was considered a natural monopoly. A natural monopoly exists when economic or technological constraints make it unlikely that competition can develop and persist in a given market. In the case of the electricity sector, common wisdom at the time — and to some extent today — held that the electricity sector would tend towards natural monopoly because the costs of building power plants and transmission lines were prohibitively expensive for anyone trying to compete with the centralized power station model developed by Insull. Because existing power plants had adequate capacity to serve most urban demand, there would be little or no economic advantage to building new large power plants to serve a relatively small population that lacked power in urban areas. In other words, the start-up costs were too high and the potential rewards too small for anyone seeking to provide electricity in areas already served by a monopoly. As for areas that lacked electricity service, some did offer potentially viable markets, but these new markets would also tend toward monopoly control over time. In short, regulators expected the electricity service to remain monopolistic.

Monopolies are considered harmful because economic theory and actual practice indicate that monopolies will typically raise prices and provide poor service when they do not fear competition. The preferred response to a monopoly is to break it up and force competition. Since economic theory says this will not work for natural monopolies, regulators generally have two other options. First, they can institute a government takeover of the monopoly to remove the profit motives that lead to price increases and service reduction. Alternatively, they can regulate monopolies to prevent them from engaging in exploitative practices. In the case of electricity monopolies, regulators chose the second approach.

C. Key Elements of Monopoly Regulation

Most of the companies providing electricity to consumers in the late 1800s and early 1900s were investor-owned utilities, i.e., companies that earn revenue and receive financing through selling stocks in their companies. These utilities have dual goals: 1) they need to ensure an adequate return for their investors; and 2) they need to provide service and earn revenue from their consumers. Monopoly regulation is primarily about customers receiving adequate and reasonably priced service, while also ensuring investors receive adequate compensation. Thus, monopoly regulation aims to harmonize these potentially conflicting goals.

Under most state electric utility laws, state public utility commissions (PUCs) oversee utilities' behavior. State utility regulation typically includes the following:

1) States establish the geographical limits of the monopoly's scope and prohibit most competition within that fixed territory;
2) States regulate utilities' investments in new facilities and other resources through rules governing utilities' electricity procurement;
3) States require utilities to provide adequate service; and
4) States regulate the rates utilities charge their customers.

While rate regulation has been the most contentious issue for utilities, the other components of utility regulation have become more important as energy law has begun to change. This section will thus briefly introduce these four aspects of monopoly regulation.

1. *Fixed Territories*

States define the geographical territories in which monopolistic utilities operate. Drawing boundaries around a monopoly's franchise protects the monopoly from competition within its geographical limits. However, state regulators may also decide to expose the investor-owned utility to competition from other service providers. For example, in many states, municipalities own and operate electricity services within areas that would otherwise be served by private utilities. Thus, fixing territories can both protect monopolies from competition within designated geographical limits and limit the scope of the monopolies' power.

2. *Procurement*

States have authority to direct utilities to procure specified amounts and types of power. This procurement authority can play out in different ways, but a few general approaches have emerged. First, some states tend to take a hands-off approach regarding the types of power utilities may use, but nonetheless require utilities to obtain authorization prior to investing in new capital facilities such as power plants and transmission lines. This blessing often appears in the form of a certificate of convenience and necessity (CCN), which basically acknowledges that a new investment is prudent and will deliver needed power to consumers. Second, some states require utilities to invest in "least cost" resources — which may include new plants or energy efficiency — and often require utilities to engage in long-term planning to ensure that the utilities' investments will be "least cost" over a long timeframe. Third, some states direct utilities to purchase or build certain types of power or power plants. Renewable Portfolio Standards, discussed below, are an example of such procurement mandates. In practice, most states use a combination of the three approaches: they may direct utilities to obtain a certain percentage of their power from specific resources, require that utilities pursue some least-cost strategies, and require utilities to receive a CCN prior to making specific investments in new resources.

3. *Service*

Because electricity is an essential service, and because monopolies have an economic incentive to skimp on service to increase their profits, states have long regulated the adequacy of the services utilities provide. In the context of climate change, adequate electricity service may involve two primary components. First, utilities must provide reliable service to ensure customers receive power on demand and to prevent blackouts and other disruptions. For intermittent renewable energy sources, such as wind and solar, reliable service can be an issue unless backup power sources or adequate electricity storage exists. Second, some states direct utilities to purchase or support investment in localized renewable energy (often called distributed generation), in which case utility service may include connecting new sources to the electricity grid and balancing thousands of new energy sources on a system designed for monopoly service. These service obligations have become increasingly complicated with the expansion of renewable energy.

4. *Rate Regulation*

Rate regulation, or ratemaking, is probably the most active area of utility regulation. While a full review of rate regulation is beyond the scope of these materials, an understanding of the basic approach to rate regulation principles and practices can help explain various aspects of utility decision-making. It can also help one understand how one might change the electricity system to mitigate climate change.

As explained above, monopolies with unchecked power will tend to increase their prices to extract "monopoly rents." They will also tend to limit service once they have captive customers. Rate regulation aims to limit these behaviors by 1) rewarding utilities for making desirable investments, 2) compensating utilities for providing necessary service, and 3) limiting the rates monopolies can charge their customers. At the same time, rate regulation aims to ensure that utilities receive adequate compensation to attract investors and maintain their financial integrity; otherwise, utilities would lose their economic viability and no longer be able to provide essential services like electricity.

Early into rate regulation, utilities and regulators developed a formula designed to accomplish the potentially competing goals of protecting consumers from exploitative rates while adequately compensating utilities. Under this formula, regulators calculate the "revenue requirement," the presumptive total amount a utility is entitled to earn per year. They establish the revenue requirement prospectively, based on the anticipated costs utilities are expected to incur annually (or during some other fixed time period). Regulators then use the revenue requirement amount to establish a price per unit of electricity sold (this is usually done on a kilowatt-hour (kwh) basis). Thus, if a utility had a revenue requirement of $10 million and expected sales of 100 million kwh, the fixed price customers would pay would be $.10/kwh.[3] Ratemaking is essentially about calculating the revenue requirement and then translating it into the final electricity rates.

To calculate the revenue requirement, regulators use a common formula:

- $R = Br + O$

Under this formula:

- R = the "revenue requirement," or the amount of revenue the utility is entitled to earn during a specified time period;
- B = the rate base, which includes the capital expenses the utility incurs to provide service to ratepayers;
- r = the rate of return; and
- O = operating expenses.

Pursuant to this formula, utilities presumptively earn their profits by investing in capital projects; they earn a profit (the rate of return) on the total amount invested in such projects (the

[3] Most states use much more complicated rate design strategies to establish different prices for different classes of customers. This example is just meant to provide a basic illustration of how the revenue requirement gets translated in electricity rates.

rate base). The "Br" component of the formula thus aims to promote investment by rewarding utilities' capital investments (the B) with a rate of return (r), or profit, on the investments they make. Since utilities are also required to provide various services to their customers — such as billing, reading meters, responding to customer calls, etc. — they are able to recover all operating expenses ("O") associated with delivering services. However, utilities cannot earn a rate of return, or a direct profit, on operating expenses. The formula thus promotes utility investment in capital-intensive, expensive facilities that have low operating expenses. In the early part of the 20th Century, when the United States was still industrializing, this incentive was seen as necessary to ensure rapid expansion of the electric system. Partly due to the formula, the United States now relies predominantly on large, capital-intensive power plants for its electricity.

Once regulators calculate the revenue requirement, they translate it into a fixed price per each unit of electricity sold. These final rates are, for all intents and purposes, the only finite aspect of the ratemaking process; although regulators use the R = Br + O formula to establish the overall revenue requirement for the utilities, utilities are not usually guaranteed recovery of the full revenue requirement nor, in most cases, prohibited from recovering more. Ultimately, a utility's actual income usually depends on how much electricity it sells at the fixed rate established by the regulators. This dynamic creates a couple of different incentives.

First, ratemaking encourages utilities to increase their revenue requirements as much as possible. In the example above, the utility's revenue requirement was $10 million. If the utility can increase the revenue requirement to $15 million but has the same anticipated amount of sales, the utility will be allowed to earn $.15/kwh. A utility can increase its revenue requirement (R) by increasing operating expenses (O), its rate base times rate of return (Br), or both. Economically speaking, a utility will want to increase its Br because that will have the greatest financial benefit for the utility. As a check against this incentive for utilities to over-invest, most states require that utilities demonstrate their investments are "prudent" and that any resulting facility becomes "used and useful," i.e., that it produces power that consumers need.

Second, ratemaking may encourage operational efficiency. Since ratemaking is prospective (i.e., regulators will set rates in 2013 for utility operations in 2014–2017), estimated expenses are usually either higher or lower than those the utility actually incurs during its annual operations. The more operationally efficient a utility can become, the more likely it will earn greater profits. For example, if a utility's revenue requirement is $10 million, based on expected operational expenses of $4 million, the utility will be able to earn greater profits if its actual expenses are lower than $4 million. However, as noted above, utilities must continue to provide adequate service. Thus, they cannot pursue operational efficiency at the expense of adequate service.

Third, traditional ratemaking likely promotes over-consumption of electricity if utilities can earn more revenue by selling more power. In the first example above, the utility is expected to sell 100 million kwh at $.10/kwh during the year. If it meets sales expectations, it will earn its revenue requirement of $10 million. But if a utility sells 120 million kwh instead, its total income will be $12 million. While selling this extra amount of power will involve some additional expense, much of the extra revenue will be pure profit. Thus, utilities have economic motivation to promote increased consumption of power.

Many electricity experts have noted that the traditional ratemaking process may not adequately serve the needs of today, particularly when climate change is concerned. Utility regulation promotes the construction of large, capital-intensive facilities with low operational costs, but renewable energy does not always fit into this model. Traditional ratemaking also tends to promote increased electricity consumption by compensating utilities based on the amount of power they sell and thus providing a disincentive to promote conservation. As explored in different parts of the rest of this chapter, policymakers have begun to develop new strategies to reward utilities for making environmentally friendly investments. Nonetheless, traditional ratemaking practices persist in many parts of the United States and thus continue to reward investments that may increase greenhouse gas emissions.

D. Electricity Regulation: Federal and State Jurisdiction

Most of the discussion above has focused on the role of state regulators because electricity regulation was historically left to the states. For the first several decades of electricity regulation, the federal government played almost no role. Most electric utilities were vertically integrated monopolies that owned and operated all aspects of the electricity system (generation, transmission, and distribution) within individual states. Over time, however, utility transactions began to cross state lines, and states began to assert jurisdiction over these interstate transactions. But in 1927, the Supreme Court ruled that states lacked the authority to regulate wholesale interstate transactions, and federal agencies at that time had no statutory authority to regulate them either. *See* Public Utilities Commission of Rhode Island v. Attleboro Steam & Electric Co., 273 U.S. 83 (1927). This gap in regulation exposed ratepayers to unchecked costs and allowed the utilities to make risky investments for which ratepayers ultimately had to pay. To address this regulatory gap, Congress passed the Federal Power Act in 1935, giving the Federal Energy Regulatory Commission (FERC)[4] regulatory authority over certain aspects of the electricity system. As a result, the federal government regulates some parts of the electricity system and states regulate others, but the lines between federal and state power are not always clear.

The jurisdictional boundaries between federal and state regulation have played a significant role in renewable energy policy development, however, and they may affect state power to limit greenhouse gas emissions directly. This section therefore briefly discusses electricity jurisdiction. It starts with an introduction to the electricity system. Then, it provides an overview of the jurisdictional lines established under the Federal Power Act. Finally, it explains how changes to the electricity system have increasingly blurred the jurisdictional lines.

1. *The Electricity System*

Electricity production and delivery include three main components: generation, transmission, and distribution.

- **Generation** refers to the actual production of electricity, from sources such as coal-fired power plants, nuclear plants, natural gas plants, hydropower facilities, wind

[4] Before 1977, FERC was known as the Federal Power Commission (FPC).

farms, and solar panels. Although electricity generation facilities vary in types and sizes, they are often divided according to whether they provide baseload power or peak power. Baseload plants provide adequate and reliable electricity during average consumption periods. Facilities that use fossil fuels, hydropower, or nuclear materials as their energy sources typically serve as baseload plants because they run all hours of the day and night to serve baseload energy needs. So long as the energy source remains available and energy needs remain consistent, baseload plants will operate continuously. When electricity needs peak during a day or season, peak power plants frequently come on line to provide supplemental electricity. Peak power plants are often smaller than baseload plants, and they may use different types of fuels as their power source. Peak power plants must start up and shut down relatively quickly and easily to respond to peaking energy needs. They often use natural gas and sometimes oil as their main fuel sources (indeed, diesel generators are sometimes used as peak power sources). In many places, intermediate plants now operate to serve load levels that are higher than baseload averages but fall short of peak demand.

- **Transmission** refers to the long-distance conveyance of electricity over high-voltage power lines. Power companies typically take power from generation facilities, use transformers to increase the voltage over the transmission lines, and then use other transformers to decrease the voltage to distribute lower voltage power to end-users. Electricity transmission requires a near-perfect and consistent balance between power supply and load (load means demand). Too little power can cause blackouts and too much power can cause transmission lines to overheat and short-circuit. Since effective and affordable electricity storage technologies do not yet exist on a broad level, transmission management is a critical and challenging component of the electricity system.

- **Distribution** refers to the delivery of electricity to end-users, including industries, commercial buildings, residences, and any other consumer of electricity.

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2. *Federal versus State Jurisdiction under the Federal Power Act*

The lines between federal and state jurisdiction have become increasingly important to understand as more states have acted to mitigate climate change and promote renewable energy. Unfortunately, these lines can become blurry at times, but there are some generally clear lines between state and federal power under the Federal Power Act. For example, the federal government has authority over wholesale electricity rates — e.g., the rates independent power producers charge utilities for electricity — while states have authority over retail rates — the rates utilities charge us. These clear distinctions, however, have gotten blurred as a result of various policies that allow states to encroach to some extent into federal wholesale territory. This section explores some of these dynamics, and the discussion of renewable energy policies will reveal how jurisdictional lines affect state authority to promote renewable power.

a. *Retail v. Wholesale Sales*

Historically, most utilities operated as vertically integrated monopolies, in which a single utility generated electricity, transmitted that electricity along its own transmission lines, and sold that electricity directly to customers. States regulated all three components of the electricity system under their power to regulate "retail" electricity transactions. Retail electricity sales are sales from any entity directly to the end user. If a utility is vertically integrated and selling power from its own power plants to end users, states have jurisdiction over the entire monopoly enterprise. If a utility is instead buying power from another producer and then reselling the power to end users, states have jurisdiction only over the retail sales (i.e., the sales from the utility to the end users), as a result of the Federal Power Act.

The Federal Power Act (FPA) gives FERC authority over the "sale of electric energy at wholesale in interstate commerce." FPA § 201(b)(1), 16 U.S.C. § 824(b)(1). Wholesale electricity sales involve sales of electricity to any entity that intends to then sell the electricity at resale. FPA § 201(d), 16 U.S.C. § 824(d). So, for example, if a wind power company sells electricity to a utility, and that utility then sells power to you for use in your home, the wind company's sale to the utility is a wholesale electricity sale and the utility's sale to you is at retail. FERC has power over the rates charged by the wind company to the utility. The Supreme Court has made clear that this power is exclusive. Federal Power Commission v. Southern California Edison Company, 376 U.S. 205 (1964). Thus, if an electricity sale occurs at wholesale, only FERC can set rates for the transactions.[5]

It is important to keep in mind, however, that FERC's control over wholesale rates does not intrude upon a state's traditional regulatory authority over procurement. Under this traditional authority, a state may direct a utility to purchase certain types of power, such as wind power, or prohibit a state from purchasing other types of power. A state may even tell a utility to purchase wholesale power only if it can keep rates below a certain level. But once the state authorizes a utility to purchase some power at wholesale, its job is done; the rates the utility will actually pay are governed by FERC.

In practice, most wholesale rates are actually established through contracts. FERC's role in wholesale rate regulation is thus usually focused on ensuring the wholesale market is competitive and that utilities do not exercise market power at the wholesale level.

QUESTIONS AND DISCUSSION

1. Under the FPA, FERC has jurisdiction over "public utilities," which the Act confusingly defines to mean individuals and corporations, but not government entities. FPA §§ 201(e), 3(4), & 3(3). This means that government sales of electricity at wholesale are not regulated by FERC. In the case of most government-owned power plants, such as coal plants operated by the Tennessee Valley Authority (TVA) and hydroelectric dams managed by the Bonneville Power

[5] There is one important exception to the general rule that FERC has exclusive authority over wholesale electricity rates. As discussed below, under the Public Utility Regulatory Policies Act (PURPA), states may set wholesale rates for purchases of energy from "qualifying facilities," but only so long as the states adhere to FERC regulations regarding the rate setting. While states are technically engaged in the rate-setting process, they must nonetheless follow federal law in doing so.

Administration (BPA), federal legislation creating the agencies established requirements regarding the rates the agencies may charge. In the case of state or municipal utilities, FERC cannot regulate their wholesale sales, and states often regulate rates for these entities or else allow them to set their own wholesale rates for the power they sell. Rural electric cooperatives are also exempt from FERC regulation.

2. As the above discussion about procurement suggests, even the seemingly clear lines between FERC's authority over wholesale rates and states' authority over procurement can get blurry. For example, utilities may need state prior authorization (through a CCN) prior to entering into long-term contracts for wholesale power. The states use the CCN as a mechanism to guarantee that the utility's investment in wholesale power is prudent.

Utilities may actually welcome the states' involvement. For example, a Minnesotan utility successfully defeated an independent power producer's effort to compel the utility to enter into a long-term contract that would have required the utility (and its ratepayers) to purchase power and pay for any backup power from a "state-of-the-art, clean-coal power plant." Order Disapproving Petition by Excelsior Energy, Inc., for Approval of a Power Purchase Agreement under Minn. Stat. § 216B.1694, Docket No. E.-6472/M-05-1993 at 1 (Minn. Pub. Util. Comm'n Aug. 30, 2007). State legislation designed to promote clean coal technology required the utility to enter into a long-term contract to buy power from the plant, but only if the state PUC determined the contract was in the public interest. The PUC ultimately rejected the contract because it would have exposed ratepayers to potentially exorbitant retail costs. Thus, even though the contract involved the sale of wholesale electricity (from the clean coal plant to the utility), the state still had the right to use its procurement power to reject the contract. If, however, the state had tried to fix the actual rates the utility would have paid for the power, this would have involved wholesale rate setting and an impermissible intrusion into FERC's exclusive authority over wholesale rates. Do you understand the line between procurement authority and wholesale rate setting in this example? If a state directs a utility to purchase a certain amount of power from independent renewable energy sources, is that procurement or wholesale rate setting? What if a state tells a utility to purchase renewable power from certain types of facilities and to pay the facilities extra to account for the environmental benefits of renewable power?

3. An ongoing case between the states of North Dakota and Minnesota could make the line even fuzzier. *See* Memorandum Opinion and Order, North Dakota v. Swanson, No. 11–3232, 2012 U.S. Dist. Lexis 141070 (D. Minn. Sept. 30, 2012). In 2007, Minnesota enacted legislation prohibiting any person from constructing new energy facilities or buying or importing power from new energy facilities that would "contribute to statewide power sector carbon dioxide emissions." Id. at *1, citing 2007 Minn. Laws Ch. 136, art. 5, § 3. Minn.Stat. § 216H.03, subd. 3. North Dakota, the lignite coal industry, and various North Dakota utilities sued Minnesota, arguing (among other things) that the FPA preempts the state legislation because it intrudes upon FERC's exclusive jurisdiction over wholesale power. In refusing to dismiss the complaint on these grounds, the district court agreed that Minnesota's law, which prohibits utilities from procuring power from some sources, "may conflict with FERC's ability to exclusively regulate wholesale sales of electricity in interstate commerce." *Id.* at *11. The court's ruling is a deviation from the typical distinction FERC has drawn between procurement, which states traditionally have regulated, and wholesale rates, which FERC regulates. Since the court's decision came on a motion to dismiss and the district court proceedings are still underway, the court may ultimately find that the FPA does not preempt the state law.

4. ***Electricity Restructuring and Jurisdiction*****.** The electric industry has undergone profound changes in the past few decades as more independent power producers came online. The first wave of independent power production resulted from a 1978 federal law, the Public Utility Regulatory Policies Act (PURPA), which required utilities to purchase power from facilities generating power from certain renewable sources and combined heat and power (CHP) plants. Although PURPA's purpose was to promote more sustainable power, it unintentionally spurred a deregulation effort in the 1980s and 1990s when more than 1200 new, independently owned power plants came online. Supporters of electricity deregulation argued that PURPA showed that electricity generation was no longer uncompetitive and urged states to restructure their electricity sectors to make generation competitive. Since transmission was still considered a natural monopoly, most states focused their restructuring on generation.

To enable competition at the generation level, states either ordered their utilities to sell off their power plants or to create legally separate corporate entities to own and manage generation separately from transmission and distribution. In effect, restructuring divided electricity service into two components: generation, which became competitive in many states, and transmission and distribution, which remained monopolistic. (Some states further separated transmission from distribution, but these materials will not explore that aspect of restructuring.) Fourteen states have fully embraced restructuring, which means their utilities buy most or all of their electricity on a competitive market. Several other states were in the process of restructuring when California's own electricity restricting experience imploded during the 2000-2001 electricity crisis. As a result of California's crisis, many states suspended their restructuring efforts. Today, most restructured states are located in the Northeast (although Texas, Illinois, and Michigan also have restructured systems).

Legally, restructuring has two important impacts on state and federal power. First, when a state restructures, generation that used to be retail becomes wholesale. A utility that used to produce its own power for its retail customers must now buy its power at wholesale and resell it to its customers. Thus, the rates the utility will pay for power are governed by FERC, although as noted above, in practice utilities negotiate wholesale rates through contracts with generators. Second, by restructuring, states also give FERC regulatory control over transmission access and rates. In essence, one consequence of allowing competition is a loss of state power over rates and transmission.

5. Even in states that have not fully embraced restructuring, many electricity sales occur at the wholesale level and thus are regulated by FERC. Whenever a utility buys power from a wind farm, for example, it is buying power at wholesale.

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b. *Interstate Commerce under the Federal Power Act*

FERC has jurisdiction over wholesale sales and transmission in "interstate commerce" under the Federal Power Act. FERC has adopted, and the Supreme Court has approved, a very expansive definition of "interstate commerce" under the FPA. Federal Power Comm'n v. Florida Power & Light Co., 404 U.S. 453 (1972). The test for whether something is in "interstate commerce" is based on "the flow of electric energy, an engineering and scientific" test. *Id.* In effect, so long as a state is connected to an interstate transmission grid, its electricity transactions are considered to be in interstate commerce because the "elusive nature of electrons" makes it nearly impossible for a utility to demonstrate that its electricity did not actually move out of state. *Id.* Thus, even if Florida company A sells power to Florida company B to be used by a consumer in Florida, the wholesale sale of power from A to B will be in interstate commerce because Florida is connected to an interstate grid. *See id.*

QUESTIONS AND DISCUSSION

1. *Interstate Commerce under the FPA.* FERC's definition of interstate commerce subjects any utility connected to the interstate grid to FERC regulation unless the utility can demonstrate that its electrons do not cross state lines. This test is nearly impossible to meet, and, as a result, all utilities connected to an interstate grid could be subject to some type of FERC regulation over their wholesale transactions or power transmissions. There are 3 interstate transmission grids in the United States: the Eastern Interconnect, the Western Interconnect, and the Texas Interconnect. Only three states — Alaska, Hawaii, and parts of Texas — are not connected to an interstate grid. While Alaska and Hawaii's separation results from geographic isolation, Texas has intentionally kept itself free of the interstate grid to shield itself from FERC interference. What benefits do you think Texas may derive from retaining exclusive control over its transmission lines?

c. *Jurisdiction over Transmission in Interstate Commerce*

The FPA also gives FERC authority over "the transmission of electric energy in interstate commerce." FPA § 201(b)(1), 16 U.S.C. § 824(b)(1). Under the FPA's expansive definition of interstate commerce, *all* transmission outside of Alaska, Hawaii, and Texas (*see* note 1 immediately above) could be subject to FERC control. Thus far, FERC has asserted authority only over transmission of wholesale electricity and "unbundled retail" transmission. *See* New York v. Federal Energy Regulatory Comm'n., 535 U.S. 1 (2002). In essence, FERC has chosen to assert its authority over transmission as necessary to allow non-utility energy producers to get access to the transmission grid, but it has declined to assert authority over electricity transmission in states where vertically integrated electric utilities continue to operate as monopolies in supplying retail power. However, the Supreme Court has recognized that FERC could preempt states' traditional regulation of electricity transmission. *Id.*

FERC jurisdiction over electricity transmission is important for renewable energy producers and other independent power producers who need access to transmission lines to sell and deliver their power. In the United States, unlike most other countries, private utilities actually own and often operate transmission lines. To protect their monopoly status, utilities have an economic incentive to deny others access to their transmission systems, or at least have an incentive to charge monopoly rates to independent power producers. For FERC, which has long promoted opening up the electricity system to market forces, lack of adequate and fair transmission access distorts any potential market. For renewable energy producers who may not operate with large profits, exploitative transmission rates can make their businesses unviable. To mitigate against these impacts, FERC exercises its regulatory authority over transmission by directing utilities who sell power at wholesale to make their transmission lines open to other generators' power (i.e., transmission line owners must provide "open access" to their lines) and to treat all electricity transmission transactions fairly (i.e., transmission line owners may not give themselves unduly preferential treatment or discriminate against other power producers).

While FERC has expansive jurisdiction over the management and operation of the transmission grid and the rates utilities charge for use of their transmission lines, FERC has very limited authority over the siting of transmission lines. Siting is an issue for the states. This means that FERC could mandate that a utility construct additional transmission lines as necessary to ensure adequate transmission access and reliability, but it cannot typically interfere with decision-making processes regarding where a transmission line gets built. While Congress attempted to give FERC some authority over the siting process in areas designated as "National Interest Electricity Transmission Corridors," two federal appellate cases invalidated key aspects of the federal siting regulations and process. As a result, while FERC in theory could intervene in state siting decisions, in practice it plays no real role in siting.

QUESTIONS AND DISCUSSION

1. ***The Transmission Bottleneck.*** One issue that has plagued regulators, particularly as new sources of power became available due to deregulation, is the lack of available transmission capacity. When utilities were vertically integrated, they controlled the power entering transmission lines and could thus usually ensure that transmission lines had sufficient capacity to convey the utilities' own electricity. However, deregulation of power generation placed new burdens on transmission lines. Utilities initially tried to restrict access to their transmission lines, until FERC ordered the lines open to other sources of power. The introduction of new power sources can increase congestion and make managing the grid more complicated and expensive for utilities. The lack of transmission capacity has also discouraged some construction of new renewable energy sources.

2. ***FERC Regulation of Government-Owned Transmission Lines.*** In certain parts of the country, government utilities like the Bonneville Power Administration (Bonneville) and Tennessee Valley Authority own and operate a substantial portion of the transmission system. As noted above, the Federal Power Act generally exempts government-owned utilities from FERC regulation. However, Section 211A of the Federal Power Act states:

> [T]he Commission may, by rule or order, require an unregulated transmitting utility to provide transmission services: (1) at rates that are comparable to those that the unregulated transmitting utility charges itself; and (2) on terms and conditions (not relating to rates) that are comparable to those under which the unregulated utility provides transmission services to itself and that are not unduly discriminatory or preferential.

FERC has relied on this provision to require government owners of transmission lines to adhere to FERC's open access and non-discrimination requirements.

In a recent dispute, FERC also relied on Section 211A to override Bonneville's practice of ordering wind energy producers to curtail their production of wind power to ensure Bonneville's transmission lines had adequate capacity to deliver hydropower. *See* Iberdrola Renewables, Inc. v. Bonneville Power Admin., 137 FERC P 61,185 (Dec. 7, 2011). In 2011, heavy rains and snowmelt in the Pacific Northwest left much of the Columbia River swollen with water. Dam managers needed to release water from the dams to avoid flooding and had the option of either spilling the water or running the water through turbines to produce power. If they were to spill the water, they would likely have violated Washington State's water quality standards, which prohibit dissolved gases from exceeding a certain limit. They may also have violated the Endangered Species Act because excessive dissolved gases can kill endangered and threatened salmon in the Columbia River. Thus, when faced with either spilling water or producing power, Bonneville decided it needed to produce power. It then also needed to get that power on its transmission system, but many other power producers including wind energy producers had firm contracts guaranteeing them access to the grid, subject to certain exceptions. When it became clear to Bonneville that it could not accommodate both its own power and electricity from other producers, it ordered other producers to curtail their power production to free up transmission capacity. In *Iberdrola Renewables*, FERC ruled that Bonneville had violated Section 211A by failing to operate its transmission lines "on terms and conditions . . . that are comparable to those under which the . . . utility provides transmission services to itself."

Bonneville defended its decision by noting that it had agreed to deliver its hydropower, without charge to the wind producers, in lieu of the wind energy. This arrangement had worked in the past for coal plants and other thermal producers, who would benefit from not having to burn fuel to produce power. For wind energy producers, however, the arrangement would have cost them an estimated $50 million because they cannot earn revenues from tax credits or Renewable Portfolio Standards unless they deliver actual wind power to the grid. Based on this impact, FERC found Bonneville's disparate treatment a violation of Section 211A.

Since this ruling, Bonneville has struggled to develop a solution that will ensure its compliance with the Endangered Species Act and Clean Water Act. How should it meet its obligations under these statutes while also complying with the Federal Power Act? Should Bonneville have to pay wind producers for the full amount of lost revenue?

E. Addressing Carbon Dioxide Emissions through Utility Regulation

A number of PUCs have restricted power plants from building new coal-fired power plants or conditioned the construction of the plants in a number of ways. Some PUCs have also ordered the closure of existing coal-fired power plants due, at least in part, to Clean Air Act regulations that will require the plants to undertake costly retrofits. Although some PUCs have acted out of concern for the environment, most have based their decisions on the economic risks of investing in new coal plants. In particular, the PUCs fear that ratepayers may end up paying for expensive retrofits to comply with environmental laws or for expensive pollution credits under an emissions trading program. Consider the following:

IN RE PETITION FOR DETERMINATION OF NEED FOR GLADES POWER PARK UNITS 1 AND 2 ELECTRICAL POWER PLANTS IN GLADES COUNTY, BY FLA. POWER & LIGHT CO., ORDER DENYING PETITION FOR DETERMINATION OF NEED

Docket No. 070098-E1, Order No. PSC-07-0557-FOF-EI (July 2, 2007)

On February 1, 2007, Florida Power & Light Company (FPL) filed its petition for a determination of need for the proposed Glades Power Park Units 1 and 2 (FGPP) electrical power plants in Glades County . . . FPL proposed two ultra-supercritical pulverized coal (USCPC) generating units, each having summer net capacities of approximately 980 megawatts (MW) for a combined net capacity of 1,960 MW, with proposed in-service dates of 2013 and 2014. . . .

In its petition, FPL sought an affirmative determination of need as well as cost recovery for the FGPP. * * *

Florida's Electrical Power Plant Siting Act, Sections 403.501–403.518, recognizes that the selection of sites and the routing of associated transmission lines will have a significant impact upon the welfare of the population, the location and growth of industry, and the use of the natural resources of the state. To that end, the Act is designed so that a permit application is centrally coordinated and all permit decisions can be reviewed on the basis of standards and recommendations of the deciding agencies. Further, it is the intent of the Act to seek courses of action that will fully balance the increasing demands for electrical power plant location and operation with the broad interests of the public.

Pursuant to Section 403.519, this Commission is the sole forum for the determination of need for major new power plants. Section 403.519(3), sets out the factors we are to consider:

> In making its determination, the Commission shall take into account the need for electric system reliability and integrity, the need for adequate electricity at a reasonable cost, the need for fuel diversity and supply reliability, and whether the proposed plant is the most cost-effective alternative available. The Commission shall also expressly consider the conservation measures taken by or reasonably available to the applicant or its members which might mitigate the need for the proposed plant and other matters within its jurisdiction which it deems relevant.

The Legislature did not assign the weight that this Commission is to give each of these factors. The power plant siting process is designed so that final decisions will be rendered within certain statutory time frames based on the best information and evidence available at the time.

To support the cost-effectiveness of its FGPP proposal, FPL performed sixteen economic scenarios combining four different fuel and four different environmental compliance cost projections. Each scenario calculated the cumulative present value revenue requirement for two generation expansion plans, one with coal and one without coal. The difference between the two plans was intended to demonstrate each plans' relative cost-effectiveness compared to available alternatives. The four fuel price forecasts are ongoing, long-range estimates of the price differential between coal and natural gas. The four price estimates included a low, medium, and high price differential between coal and natural gas, as well as a "shocked" differential which was developed to show the impact of what a significant price increase in oil or natural gas may have on the value of adding FGPP to FPL's portfolio of assets. The relative price differential between coal and natural gas is the driving force behind the system revenue requirement calculations. FPL projected a net present value impact between the low and high cost differentials of approximately $72 billion.

FPL also provided four different environmental cost projections. These projections addressed environmental costs for three currently regulated emissions — sulfur dioxide, nitrogen oxides, and mercury — combined with various scenarios of future carbon allowance costs. The projected carbon costs were based upon Federal legislation under current debate before Congress. FPL projected the net present value impact between the low and high environmental costs to be approximately $22 billion. If more stringent regulations are enacted in the future, environmental costs will have an even greater impact on the overall cost-effectiveness of the FGPP. * * *

As with any capital-intensive project, an increase in total costs will occur until lower fuel costs overcome the higher capital costs. FPL estimated that the FGPP would not show a positive net present value benefit until the year 2022. Even after this length of time, only the two most optimistic scenarios projected ratepayer savings. FPL acknowledged that the FGPP was not a clear winner from a cost standpoint; rather, the need for the FGPP was driven by the need for increased fuel diversity on FPL's system. Such a strategic benefit is difficult to quantify.

As noted above, the Commission's decision on a need determination petition must be based on a case-by-case review of facts with underlying assumptions tested for reasonableness and certainty. Taking into account each of the factors referenced in Section 403.519, we find it is in the public interest to deny FPL's petition for determination of need. Our decision is based upon . . . our determination that FPL has failed to demonstrate that the proposed plants are the most cost-effective alternative available, taking into account the fixed costs that would be added to base rates for the construction of the plants, the uncertainty associated with future natural gas and coal prices, and the uncertainty associated with currently emerging energy policy decisions at the state and federal level. This Commission recognizes the need for fuel diversity. Section 403.519, in fact, was amended in 2005 to expressly authorize the Commission to consider fuel diversity as a factor in determining need. Nuclear and other generating technologies, as well as the use of solid fuels, may play an appropriate part in a utility's generation mix for promoting fuel diversity and affordable supply reliability. We further recognize the need for additional generation to meet current and future growth. Finally, we recognize that, in light of the inherent variability of necessary assumptions about fuel costs, capital costs, and other resource planning matters, uncertainty about cost-effectiveness alone will not necessarily control the outcome of every need determination decision. We find in this case, however, that the potential benefits regarding fuel diversity offered by FPL in support of the FGPP fail to mitigate the additional costs and risks of the project, given the uncertainty of present fuel prices, capital costs, and current market and regulatory factors.

QUESTIONS AND DISCUSSION

1. *Undertones of the Florida Decision*. Although the Florida Public Service Commission (FPSC) did not directly mention the effects of climate change on the utility's operations, the cost of carbon dioxide regulation did factor into the FPSC's decision. Some commentators also believe that climate change was an underlying concern for the FPSC:

> The FPSC's decision was the first time it rejected a new power plant since 1992. The decision . . . was couched vaguely in terms of uncertainty over fuel prices, capital costs, and unidentified "regulatory factors." Nevertheless, environmental concerns contributed to the outcome. FPL had claimed that the plants would have included filters, scrubbers, and other systems that would have cut CO_2 emissions generated by the burning of coal by as much as 90%. Still, the plants would have emitted more mercury than any of FPL's existing plants. . . . Climate change also played a role. FPSC members indicated that they were concerned that the price of coal could become unstable if Congress decides to regulate GHGs. They also indicated that they regarded CO_2 as well as mercury emissions as risks if the plant were approved. An environmental consultant testified before the FPSC that FPL could incur annual penalties for emitting CO_2 between $120 to $400 million under climate change legislation being considered by Congress. Governor Charlie Crist had previously made it clear that he preferred that no new coal-fired power plants be licensed, and had issued an executive order requiring the adoption of standards to reduce greenhouse gas emissions from power plants to 2000 levels by 2017 and to 1990 levels by 2025.

Robert L. Glicksman, *Coal-Fired Power Plants, Greenhouse Gases, and State Statutory Substantial Endangerment Provisions: Climate Change Comes to Kansas*, 56 U. KAN. L. REV. 517, 540-42 (2008). If Professor Glicksman is correct, the FPSC's decision was motivated by the costs to consumers, including the costs of future mitigation of GHG emissions. Do you think that the decision could be a harbinger of the FPSC's approach for future proposed coal-fired power plants? Does the decision provide a useful strategy for opponents of coal-fired power plants in other jurisdictions?

In other states, PUCs have denied utilities' requests to build new coal-fired power plants on the basis of need, rather than costs or environmental concerns. In Minnesota and Oregon, for example, regulators expressed concern over the GHGs emitted by proposed new coal-fired power plants, but ultimately disallowed investment in the plants because the utilities could not show energy demand justified the new facilities. *See id.* at 550–52. In the Oregon case, the utility had proposed to sell any excess power from its new coal plants to California. However, California had passed a law prohibiting its own utilities from entering into new long-term contracts for coal-based electricity. *Id.* Thus, since the Oregon utility could not show that Oregon customers needed the new plants, the PUC refused to allow them to be built. Do you see how policies promoting energy efficiency and restricting the use of certain types of power can affect utility investments?

2. For one proposed coal plant, the Texas PUC granted a utility a certificate of convenience and necessity, but conditioned it expressly on the utility not passing on high carbon prices to the customers.

> . . . Carbon Mitigation Costs.
>
> The Commission carefully studied the various price tags for carbon mitigation in the record that may be attributable to the energy generated from the Turk Plant. The amounts range from as low as \$13 to \$15 per ton of CO_2 emissions to as high as \$70 per ton. The average numbers for a coal plant range from \$30 to \$45 per ton. The lower numbers in this vast range are predictions of allowances to be mandated in the early phases of federal regulations on carbon dioxide emissions, growing to the larger numbers where the trade-off between a carbon "tax" and the implementation of carbon sequestration and capture technologies on coal and gas plants would occur sometime in the future. Based on these estimates and predictions, the Commission seeks to place a limit on the extent to which the Turk Plant's costs of carbon mitigation will be passed on to Texas retail ratepayers. It is unreasonable to expect the retail ratepayers to be responsible for these costs that exceed \$28 per ton of CO_2 emissions through the year 2030. To the extent that carbon legislation or implementation of mitigation technology results in costs that exceed that amount per ton, those costs shall not be borne by Texas ratepayers.

Application of Southwestern Electric Power Co. for a Certificate of Convenience and Necessity Authorization for Coal Fired Power Plant in Arkansas, PUC Docket No. 33891, Order, 7-8 (Aug. 12, 2008) Will these decisions encourage electricity generation from renewable sources or the continued use of older, dirtier coal-fired power plants? The Texas PUC allowed the Turk Plant to pass on costs of carbon dioxide credits valued at up to \$28 per ton, even though projected costs are between \$30 and \$45 per ton. Due to the PUC's order, if the actual costs of carbon dioxide exceed \$28 per ton, then the utility will be on the hook for those extra costs. Do you think the utility should have rethought its decision to build the facility?

3. ***PUC Authority to Consider Environmental Concerns***. Historically, PUCs were thought not to have the authority to consider environmental issues in their decision-making processes. However, a review of state utility laws by Professor Michael Dworkin shows that several laws give PUCs express authority to consider energy efficiency and environmental effects. *See* Michael Dworkin *et al.*, *The Environmental Duties for Public Utilities Commissions for 2006*, 7 VT. J. ENVTL. L. 6 (2006). Where states lack the express authority to consider the environment, should they be allowed to consider the consequences of carbon dioxide regulation to protect ratepayers from unreasonably priced power? Is that an economic cost or an environmental concern?

III. REVISING THE ENERGY PORTFOLIO IN THE UNITED STATES: CONSIDERING THE RESOURCE OPTIONS

The electricity sector contributes about 40 percent of total U.S. carbon dioxide emissions each year. Of the major electricity sources, coal contributed about 79 percent of these emissions and natural gas accounted for 19 percent in 2011, with the remaining 2 percent coming from petroleum and miscellaneous source. *See* Energy Info. Admin., Frequently Asked Questions, How much of U.S. carbon dioxide emissions are associated with electricity generation?, http://www.eia.gov/tools/faqs/faq.cfm?id=77&t=11 (Last updated: June 22, 2012). Compare these emissions to the U.S. electricity portfolio, in which coal provided about 47 percent of all electricity in 2011, natural gas provided about 20 percent and nuclear power provided another 20 percent of U.S. electricity. The link between greenhouse gas emissions and coal is evident in these figures and has made coal the focus of many climate change mitigation efforts.

While the electricity system is a major greenhouse gas contributor, it has undergone several profound changes that could lead to significant and permanent reductions in greenhouse gas emissions. Most notably, coal-fired power plants seem to be on the decline, while natural gas-based electricity production has increased. In the early 2000s, more than 100 new coal-fired power plants had been proposed for construction in the United States; by the end of 2012, utilities had scrapped plans to build almost all of the proposed plants. Perhaps even more significantly, utilities announced their intentions to retire an unprecedented number of older coal plants. A number of factors contributed to these changes, including new regulations under the Clean Air Act that would require pollution control upgrades on many newer plants, lower electricity consumption during the Great Recession and anemic recovery that followed, and the rise of cheap natural gas as an alternative fuel. While renewable energy policies may have also contributed to some extent to reduced demand for coal, few analysts draw a clear link between renewable energy and any decline in coal-fired power.

The question facing the electricity industry, regulators, consumers, and environmental advocates is what might replace coal as a viable power source. In 2008, “clean coal” and nuclear power seemed like strong candidates, notwithstanding their significant costs and regulatory and legal uncertainty about where to store their byproducts (CO_2 in the case of coal and high-level nuclear waste in the case of nuclear). In 2012, natural gas — which many had promoted as an ideal bridge fuel between coal and a carbon-free electricity future — emerged as the fuel of choice. But natural gas is not carbon free, and controversy regarding the impacts of hydraulic fracturing and the costs of expanding the gas transportation system may impede its growth. As for renewables, many have dismissed their potential to provide a significant source of affordable and reliable power. Yet, their use and production continue to expand. The question is whether they will continue to grow and improve at a rate that would allow them to lead into a carbon-free electricity system.

The materials in this section thus discuss the resource options available to power the U.S. electricity system. Although this section discusses some policies that promote different energy resources, it focuses much more on the technologies involved in producing power and the technological and practical hurdles involved in their use. Part A begins with a short discussion of the dominance of fossil fuels in the electricity system we have today. Part B then explores the role that traditional electricity resources — namely natural gas, clean coal, and nuclear power — might play to reduce greenhouse gas emissions from the U.S. power system. Last, Part C introduces renewable energy technologies and their potential to power the grid. Once readers have an understanding of the options available, Section IV of this chapter will review the predominant policies used to promote renewable energy.

A. The Dominance of Fossil Fuels

Why are fossil fuels so dominant in our electricity system? To some extent, it is probably because they got there first (well, second, after wood). Under a theory called the endowment effect, once a commodity is established as useful or a facility becomes operational, it gains a stronghold in society that is difficult to replace absent significant economic or social disruption. Although we have seen dramatic shifts in resource use in the energy sector (for example, oil used to provide a significant amount of electricity, and many cities once used natural gas to directly supply urban lighting), they have typically occurred over a matter of decades. The nature of fossil fuels also makes them difficult to replace. Fossil fuels are highly concentrated and potent sources of power; it takes comparatively little coal or natural gas to provide power, whereas it takes much more sun or wind to produce the same amount. Fossil fuels are also easily deployable and scalable, making them ideal for an electricity system built around the centralized power station model of the United States. Once the infrastructure to deliver fuel to a plant through coal trains or natural gas pipelines and the electricity to consumers through transmission lines is built, getting power from fossil fuels simply requires adding more fuel. Fossil fuels are also reliable, in that they can provide electricity on demand, while many renewable energy sources are intermittent. Finally, U.S. energy policy has always been about supplying more power at lower prices. Whenever prices increase, the political response in the United States is usually to call for the production of cheap fuels. In a country like the United States, where fossil fuels are abundant, this strategy has usually worked.

Subsidies have also advanced fossil fuels' dominance in the U.S. energy system. Over the years, the federal government has committed billions of dollars to fossil fuel energy sources, although the exact amounts are difficult to track. Indeed, estimates of fossil fuel subsidies vary significantly. The Environmental Law Institute conservatively estimated that subsidies for fossil fuels from 2002-2008 totaled approximately $79 billion, while renewable energy sources received $29 billion (about half of which went to corn ethanol, a controversial renewable fuel discussed more in Chapter 16). *See* ENVTL. L. INSTITUTE, ESTIMATING U.S. GOVERNMENT SUBSIDIES TO ENERGY SOURCES: 2002-2008 3 (2009). Other estimates of U.S. fossil fuel subsidies range from $10 billion to $52 billion annually. *See* Fossil Fuel Subsidies in the U.S., OilChange.org, http://priceofoil.org/fossil-fuel-subsidies/ (last visited Jan. 7, 2012) (linking to various reports from, among other entities, the Organization for Economic Cooperation and Development (OECD)). According to a study by an organization called Earth Track, oil and gas companies received $41 billion and coal received $8 billion annually. *See* Mark Clayton, *Budget Hawks: Does US Need to Give Gas and Oil Companies $41 Billion a Year*?, CHRISTIAN SCIENCE MONITOR, Mar. 9, 2011, at http://www.csmonitor.com/USA/Politics/2011/0309/Budget-hawks-Does-US-need-to-give-gas-and-oil-companies-41-billion-a-year. Renewable energy sources have, of course, also received significant subsidies in the past decade or so, but the amount and duration of fossil fuel subsidies — some of which began as early as 1918 — have helped fossil fuels remain dominant.

Finally, the "hidden" subsidies fossil fuels receive through being able to externalize their environmental and public health costs have likely also contributed to fossil fuels' comparative strength. The National Research Center, for example, calculated that the hidden costs of coal, when considering only its impact on human health as a result of a few regulated pollutants and some limited environmental factors (excluding climate change), totaled more than $50 billion per year. NATIONAL ACADEMIES OF SCIENCES, HIDDEN COSTS OF ENERGY: UNPRICED CONSEQUENCES OF ENERGY PRODUCTION AND USE (2010). A study by Harvard, which included the impacts of climate change, other environmental impacts from coal mining, and broader human health impacts, calculated the full cost of coal at more than $345 billion per year. Paul Epstein et al., *Full Cost Accounting for the Life Cycle of Coal*, 1219 ANN. N.Y. ACAD. OF SCI. 73, 91 (2011). While these are not direct subsidies, they can have a similar impact, in that the failure to reflect the costs of externalities leads to lower market prices for coal and thus may make it harder for other, less harmful, fuels to compete.

QUESTIONS AND DISCUSSION

1. ***The Underlying Purposes of Energy Tax Incentives***. Congress has used tax incentives and subsidies to promote energy development for about ninety years. *See* Mona Hymel, *The United States' Experience with Energy-Based Tax Incentives: The Evidence Supporting Tax Incentives for Renewable Energy*, 38 LOY. U. CHI. L.J. 43, 43 (2006). Two theoretical reasons underlie why lawmakers subsidize energy production. First, incentives promote new technologies during their initial development, and, second, government subsidies are meant to "pay the differential between the value of an activity to the private sector and its value to the public sector." *Id.* at 43 n.1. Do these reasons justify continued subsidization of fossil fuels? If yes, how so? If not, why? Why would Congress continue to provide subsidies if their underlying purpose has eroded?

2. Fossil fuel subsidies tend to be sprinkled throughout the tax code and various statutes, and they are notoriously difficult to quantify and track. *See* Mark Clayton, *Budget Hawks*, *supra*. In contrast, renewable energy subsidies are more concentrated in a few key laws and are easier to monitor. This has made subsidies for renewables easier to target and critique, particularly as subsidies for renewables have increased. For example, when the Energy Information Administration (EIA) reported that renewables (including corn ethanol) had received nearly $15 billion in subsidies in 2010, this launched a firestorm of protest against the subsidies, particularly the $5 billion that had gone to the wind energy. *See* Robert J. Bradley, Jr., *Where the Federal Energy Subsidies Really Go*, FORBES.COM, Aug. 9, 2011, at http://www.forbes.com/sites/realspin/2011/08/15/where-federal-energy-subsidies-really-go/. Even though total energy subsidies according to the EIA exceeded $37 billion (and thus provided significant support to fossil fuels), opponents of the renewable energy subsidies emphasized the cost per unit of production. *Id.* Subsidies to the failed solar power company Solyndra only added fuel to the flames.

Advocates of renewable energy companies argue that focusing on a single year of subsidies distorts the picture. Historically, fossil fuels have received far more in subsidies than renewable power. Several traditional fuel sources, including nuclear power and natural gas, also benefitted from direct government involvement in technological developments necessary to make them commercially viable. Thus, renewable energy advocates assert, it is only fair that renewable energy should benefit from the same degree of support until renewable power technologies mature. What do you think of these arguments? Are you surprised to read that wind energy received $5 billion in subsidies in 2010?

3. The role that existing infrastructure plays in supporting fossil fuels in the electricity sector cannot be overstated. Existing infrastructure not only eases the burdens involved in transporting fuels to power plants; it can negate opposition that resources might face in providing electricity. Consider, for example, the existing railroad infrastructure that supplies most coal plants. Railroad tracks transect public lands, private lands, urban properties, and many areas that would be difficult (if not impossible) to develop today. Having the tracks in place allows the coal industry to avoid contentious debates and legal battles regarding the siting of new rail lines. This makes it easier, quicker, and cheaper for coal companies to increase production when energy demand soars because they can simply increase the number of coal cars without having to worry about building new railways. Similarly, most transmission lines in operation today were built in the 1950s and 1960s, when the United States was much less populous and before most environmental laws existed. Transmission lines and power plants were also often planned and built simultaneously, ensuring that electricity from the plants could easily reach urban consumers. Moreover, a single utility usually owned the generation and transmission facilities, allowing for streamlined planning and construction of the electricity infrastructure. Finally, once a utility has built a power plant and the transmission lines, it can add onto the plant or build a replacement plant to readily hook up to the existing transmission infrastructure. While replacing a coal plant with a natural gas plant might require investment in natural gas pipelines, the new plant will at least be able to use existing transmission infrastructure.

Now consider the infrastructure needs of large renewable facilities. To build a wind farm, for example, a company cannot simply replace an existing facility due to the need to locate in areas with wind resources. A company thus needs to purchase or lease property, secure permits to build the facility, install roads and other infrastructure to allow continued access to the site, and ultimately connect to the transmission system. The siting and construction process requires compliance with multiple local, state, and federal statutes, which takes time and money and may involve litigation. Successfully siting a facility is only part of the battle, however, because the wind farm needs access to transmission lines, which often do not extend into the areas best suited for wind development. The wind developer also therefore needs to build transmission infrastructure or convince a utility to do so, costing more time and money and likely generating more opposition. Finally, for renewable energy sources to become viable replacements for fossil fuels, they eventually require storage technologies to mitigate the intermittency limitations of most renewable resources. Fossil fuels have never required storage because they are deployable on demand and thus have an added infrastructure advantage.

4. ***Will Energy Exports Be the New Frontier for Fossil Fuels?*** As domestic consumption of some fossil fuels has declined, even as production for some has increased, fossil fuel producers are seeking to expand their export markets. Consider coal, which as noted in the introduction to this chapter, is in a major state of upheaval and perhaps decline in the United States. Clean Air Act regulations mandating installation of new pollution controls, combined with low natural gas prices, have prompted many energy companies to announce their plans to retire coal-fired power plants. For example, on January 7, 2013, Georgia Power announced its intent to close several coal-fired power plants. *Jeremy P. Jacobs, Georgia Power to Shutter 15 Coal- and Oil-Fired Power Plants*, ENV'T & ENERGY NEWS PM, Jan. 7, 2013. As the U.S. coal market contracts, coal companies have begun efforts to export coal to energy-hungry countries like China and India. Natural gas companies are also seeking to increase exports of liquefied natural gas (LNG) from the United States to countries with much higher natural gas prices. Petroleum producers may also increase their exports if the pace of their development continues; in November 2012, some projections indicated that the United States might become a net petroleum exporter by 2030 if production of shale gas continues to expand at the same rates it witnessed from 2000 to 2012. What are the political, economic, and environmental implications of the United States increasing these exports? Will it make domestic and international climate change mitigation more difficult if the United States becomes a significant player in the export market?

B. Traditional Fuels as Sustainable Energy Sources?

Can traditional fuels provide the United States with low-carbon, sustainable energy sources? Many energy experts believe that efforts to expand renewable energy production and use are misguided, and that natural gas, "clean coal," and nuclear power provide the best hope for the United States to meet energy demands, protect the U.S. economy, and reduce overall greenhouse gas emissions. For those who believe that the United States should be "energy independent," coal, natural gas and nuclear power have additional promise because the country has ample coal, gas, and uranium supplies and would therefore not need to import any of its energy. Moreover, use of these traditional fuels would not require a major redesign of the electricity system, since it is already designed to deliver power from large, capital-intensive facilities. This section explores some of these issues.

1. *Natural Gas*

For several years, many people have promoted the use of natural gas as a bridge fuel toward a carbon-free electricity system. The promise of natural gas, they argue, is that its direct power plant CO_2 emissions are about half those of coal. If the United States were to abandon efforts to bring new coal-fired power plants online and instead built new natural gas power plants, this would reduce new greenhouse gas emissions by half. Advocates of natural gas — most famously, T. Boone Pickens — have also argued that natural gas could replace petroleum as a transportation fuel and thus free the United States from dependency on foreign oil. Finally, some have promoted natural gas as a source of backup power for intermittent renewable energy sources, thereby allowing renewable energy production to grow while storage technologies continue to develop. In essence, many people view natural gas as an essential transitional fuel from coal to renewables, allowing the U.S. electricity sector to become carbon-free.

Others have challenged this idea of natural gas, for three main reasons. First, the climate benefits of natural gas may not be what they appear. When the lifecycle emissions of greenhouse gases are included in the emissions calculations of gas-fired power plants, natural gas may actually be worse than coal. Second, the idea that natural gas production would ramp up and then rapidly decline ignores the significant impact that infrastructure development and investment have over the long term: once natural gas pipelines and power plants are built, we will use them. This means that natural gas will not act as a bridge to renewables, but instead will simply serve as a substitute for coal. Even if lifecycle emissions estimates from natural gas are lower than some estimates indicate, building up natural gas infrastructure will delay the transition to a carbon-free electricity sector. Finally, investing in natural gas may stifle development of renewable energy, so the natural gas bridge could be a bridge to nowhere.

Of the arguments supporting natural gas as a bridge fuel, Professor Pierce's perspective, excerpted below, probably offers the most realistic perspective of what that bridge would look like.

RICHARD J. PIERCE, JR., NATURAL GAS: A LONG BRIDGE TO A PROMISING DESTINATION,

32 UTAH. ENVTL. L. REV. 245 (2012)

Introduction

Supporters of efforts to replace hydrocarbons with carbon-free renewable resources as our primary source of electricity often refer to natural gas as a "bridge fuel." That reference reflects a reluctant recognition that renewable resources cannot replace hydrocarbons as our primary generating fuel in the near term. It also reflects recognition that, while natural gas is a hydrocarbon, it is less damaging to the environment than other fossil fuels. In particular, displacement of coal with natural gas as a generating fuel reduces emissions of greenhouse gases, such as carbon dioxide, by about 50%. Thus, the "bridge fuel" metaphor refers to the expectation of many policy makers that we can move in the direction needed to mitigate climate change in the near term by displacing coal with natural gas, but that we will replace all hydrocarbons with carbon-free renewable resources in the long term.

* * * I conclude that, while the "bridge" will not take the U.S. everywhere we would like to go, it is likely to take the U.S. to a destination that is a major improvement over the status quo, measured with reference to any plausible set of national or international goals.

How Long Is the Bridge?

New uses of two old technologies — horizontal drilling and hydraulic fracturing — have enabled the U.S. to increase its natural gas reserves by 75% during the period 2004-2011. The supply of gas from fracturing of shale formations has increased at a rate of 48% per year since 2006, and the Energy Information Administration (EIA) predicts a continuation of that trend for many more years. In the short-term, that increase in reserves has increased deliverable quantities of gas by 14% and allowed the U.S. to displace 10% of the coal we were using to generate electricity just three years ago. It has also resulted in a price of gas that is only about 30% the price of oil, and approximately equal to the price of coal. This remarkable change in conditions in the U.S. gas market is likely to yield more significant results in the future. Most experts believe our gas resource base is now sufficient to meet U.S. demand for over a century and will allow the U.S. to use gas as our primary generating fuel for the foreseeable future. As President Obama has recognized, fracking has turned the U.S. into the Saudi Arabia of gas.

The contrast between the prospects for gas and the prospects for carbon-free renewable resources is stark. It costs two to five times as much to generate electricity through use of renewable resources such as solar and wind as through use of gas. Moreover, because most renewable resources can generate electricity only on an intermittent basis, a unit of electricity generated through use of a renewable resource is worth only about 25% as much as a unit of electricity generated through use of gas. * * *

Renewable resources have major disadvantages in addition to their high cost. They require installation of thousands of miles of new transmission lines. It is extremely difficult to obtain both the regulatory approvals needed to site transmission lines and the financing needed to construct transmission lines. * * *

Efforts to develop electricity projects that use renewable resources to generate electricity and to market the electricity produced by such projects are entirely dependent on the continued availability of extraordinarily generous federal and state subsidies and state renewable resource portfolio mandates. Those subsidies and mandates are unlikely to continue. * * *

Given the financial and fiscal crises that now afflict the U.S., it is highly unlikely that either the federal government or most states will choose to retain their extraordinarily expensive subsidies and mandates for renewable resources. Thus, I am confident there will be a critical need to use gas as a bridge fuel for the indefinite future. Fortunately, the gas resource base appears to be adequate to that task for at least the next century.

Where Does the Bridge Lead?

The policy makers who coined the phrase “bridge fuel” believe both that the “bridge” will be relatively short, and that it will lead to replacement of all hydrocarbons with carbon-free renewable resources. In the prior section, I explained why I believe the “bridge” that natural gas must create will be long — at least many decades and probably a century. I will turn next to the question of what lies on the other side of that bridge. It is possible that technological developments over the next several decades will create a situation in which carbon-free renewable resources will become economically viable and in which developers of renewable resource projects will be able to overcome the other formidable obstacles to replacement of hydrocarbons with renewable resources. It is more likely, however, that technological breakthroughs will create an environment in which natural gas remains the best available means of meeting our needs for electricity for many more decades after we cross the present long “bridge.” In other words, the long natural gas “bridge” is likely to lead to more natural gas. * * *

In the U.S., replacing coal with gas would reduce total emissions of green house gases attributable to electric generation by 45%. That is well-short of the 80% reduction in global emissions that climate scientists believe to be needed to mitigate global warming, but it is a major step in the right direction. * * *

Moreover, we could extend the benefits of the U.S. gas boom to the transportation sector by increasing the direct use of compressed natural gas in vehicles and/or by increasing the indirect use of natural gas by increasing the number of vehicles that are powered by gas-generated electricity. * * *

Economic conditions have improved significantly in the states where the drilling is taking place. Pennsylvania estimates that gas drilling has increased economic activity in the state by billions of dollars and has created thousands of new jobs in the state over the last three years. Ohio is expected to enjoy a similar gas-based economic boom in the near future. New York has the potential to enjoy similar economic benefits when, and if, it lifts its moratorium on horizontal drilling and hydraulic fracturing. President Obama estimates fracking will create 600,000 new jobs in the US. * * *

QUESTIONS AND DISCUSSION

1. ***Climate Benefits of Natural Gas?*** For years, many people assumed natural gas was more climate-friendly than coal because the direct combustion emissions from natural gas are much lower. In 2011 and 2012, however, various studies began to assess the lifecycle emissions of natural gas and produced surprising results. The studies considered the fugitive emissions of methane from natural gas drilling operations and pipelines and concluded that, when those emissions were included in the carbon footprint of natural gas, natural gas might have a larger carbon footprint than coal. When natural gas leaks, it releases methane, with a 100-year global warming potential of approximately 25, directly into the atmosphere. Each methane molecule is thus 25 times more effective at trapping heat than each carbon dioxide molecule. So, even if combustion emissions of carbon dioxide are lower for natural gas than coal, the methane emissions may eclipse any benefits of reducing the CO_2 emissions.

A study from the National Center for Atmospheric Research (NCAR) concluded that methane leakage rates would need to be lower than 2% for natural gas to have a climate benefit (and even that benefit would be quite small). Tom M.L. Wigley, *Coal to Gas: The Influence of Methane Leakage*, 108 CLIMATE CHANGE 601, 607 (2011). But the use of hydraulic fracturing in shale deposits results in higher leakage rates; studies show leakage rates in many areas range from 4 to 9%. This means that natural gas's perceived benefits may not only be overstated; natural gas may be worse for the climate than coal. *See* Joe Romm, Bridge To Nowhere? NOAA Confirms High Methane Leakage Rate Up To 9% From Gas Fields, Gutting Climate Benefit, Climate Progress, Jan. 2, 2013, at http://thinkprogress.org/climate/2013/01/02/1388021/bridge-to-nowhere-noaa-confirms-high-methane-leakage-rate-up-to-9-from-gas-fields-gutting-climate-benefit/?mobile=nc. In fact, the International Energy Agency concluded that a "Golden Age of Gas," in which natural gas replaces coal to a large extent, could lead to a long-term temperature increase of 3.5˚C (or 6˚F) temperature increase. INT'L ENERGY AGENCY, GOLDEN RULES FOR A GOLDEN AGE OF NATURAL GAS: WORLD ENERGY OUTLOOK SPECIAL REPORT ON UNCONVENTIONAL GAS 91 (2012). Americans, as a society, seem less troubled by expanding infrastructure for natural gas than for renewable energy. Why do think that is so?

2. Natural gas infrastructure and permanence. Natural gas infrastructure development will also affect whether natural gas acts as a bridge fuel. Professor Pierce's article acknowledges this to a large extent, noting that whatever bridge natural gas builds will be a long one. But that basically means, as the International Energy Agency has noted in various reports, that emissions associated with natural gas will likely be "locked in" so long as the infrastructure exists. Consider the following:

> Building a natural gas bridge will require a significant expansion of infrastructure: drilling wells for production, pipelines for distribution, and a range of devices for consumption including power plants, home furnaces, and industrial ovens. Investing in these systems will increase the supply of natural gas and lower its costs through economies of scale. As a result, consumers will find it cheaper and easier to use natural gas. This is a straightforward account of what infrastructure does — it facilitates certain types of behaviors.

Christopher F. Jones, Natural Gas: Bridge or Dead End?, HuffingtonPost.com, Aug. 29, 2012, at http://www.huffingtonpost.com/christopher-f-jones/bridge-or-dead-end_b_1837015.html. The infrastructure buildup will have at least two likely impacts. One, as noted in the discussion of utility regulation above, the costs of infrastructure will likely be passed onto consumers, and once they pay for the infrastructure, they will want to see the infrastructure used. This makes it more likely that natural gas will be locked in as a fuel. Two, investment in infrastructure now, when natural gas prices are very low, should allow natural gas to remain competitive for a long time even if the fuel prices increase. So long as the infrastructure costs are recovered before fuel prices increase, consumers bills will remain relatively stable and natural gas will continue to be comparatively cheap.

3. ***Will Natural Gas Outcompete Renewables?*** Low natural gas prices may also detrimentally affect renewable energy development by driving down the price of electricity. If natural gas appears much more affordable than renewable power, some observers fear that political and public will to support renewable energy may decrease. On the other hand, natural gas provides an important source of backup power for intermittent renewables. What are your thoughts about the benefits and risks to the renewable energy industry of natural gas development?

4. ***Localized Impacts of Hydraulic Fracturing.*** Beyond the climate impacts, recent studies have begun to report other harmful impacts of "fracking" technologies, including groundwater contamination, air pollution, and even earthquakes. If the natural gas industry could control its methane leaks, would these other impacts be worth the climate benefits?

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2. *"Clean Coal"*

The term "clean coal" generally refers to coal energy technologies that achieve substantial reductions in conventional air pollutants, such as sulfur dioxide, mercury, and nitrogen compounds. More recently, "clean coal" has also been equated with carbon capture and sequestration (CCS) technologies, which promise to collect carbon dioxide emissions from coal-fired power plants and then store the collected carbon dioxide underground. Whether CCS can become a viable technology remains an open question. In addition, the use of CCS technology has generated considerable debate within and beyond the environmental community.

For CCS to succeed, scientists must develop technologies to first capture carbon dioxide as it is released from coal-fired power plants and then to permanently sequester (i.e., store) the carbon dioxide underground. New coal-fired power plants are being built to enable capture of carbon dioxide from the emissions stack. While older coal-fired power plants will require retrofitting for carbon capture to become feasible, it appears likely that retrofitting will become feasible in the future as well.

However, technologies for carbon sequestration remain much more elusive. While different strategies exist, perhaps the best known involves the use of geologic formations composing porous rock deep underground into which to inject pressurized CO_2 with layers of non-porous rock above the non-porous layer for "capping" the CO_2.

The viability of CCS technology to mitigate climate change has generated considerable controversy. Not surprisingly, those in the coal industry support CCS technology as a means to continue coal use while reducing greenhouse gas emissions. Environmentalists, however, are divided on the issue. Some organizations view CCS as a necessary technology to address the inevitable use of coal throughout the world. Other organizations believe the focus on CCS diverts attention and funding away from renewable energy technologies.

BEN BLOCK, U.S. ENVIRONMENTAL GROUPS DIVIDED ON "CLEAN COAL,"
(Worldwatch Institute, Mar. 19, 2008)

Environmental organizations agree that global warming is a serious concern and that emissions from coal-fired power plants must be drastically curtailed. To do so, many support carbon capture and sequestration, commonly known as CCS. CCS technology is designed to trap and store (either in the Earth's crust or the deep oceans) the massive quantities of carbon dioxide spewed from coal power plants.

Groups like the Natural Resources Defense Council (NRDC) and Environmental Defense Fund are already lobbying on behalf of CCS. Others, such as the Sierra Club and the World Wildlife Fund, are more cautious about promoting CCS. They insist that affordable and proven technologies, such as energy efficiency and wind or solar energy, should be more fully implemented before CCS is considered. Greenpeace specifically opposes the technology.

A divided environmental community is reflective of a still unproven technology. Although CCS is almost certainly technically feasible, both the timing and the cost are highly uncertain. A Massachusetts Institute of Technology report released last year, *The Future of Coal*, concluded that the U.S. CCS program is not on track to achieve large-scale commercial operation for at least a decade.

Carbon liability concerns have led major investors and the U.S. government to rein in financing for coal-fired power plants. As a result, the coal industry has embraced CCS as essential to its survival. Some environmentalists say CCS is critical to creating a political deal that would dissuade power companies from blocking new climate legislation. "Congress should require planned new coal plants in the United States to employ CCS without further delay," NRDC said in a statement last year.

According to NRDC science fellow George Peridas, as long as China continues its surge in coal emissions and the U.S. coal industry wants to build new plants, the coal industry must be presented with an alternative. "There are cheaper ways and cleaner ways and preferable ways to meet energy demands, but I think CCS will ultimately be needed too," Peridas said. "I'd love to be actively campaigning against all use of coal, but I don't think that's the best way to reduce emissions."

U.S. Representatives Henry Waxman of California and Edward Markey of Massachusetts introduced a bill last week that would ban any coal plants that do not capture and store at least 85 percent of carbon dioxide emissions. The Sierra Club supports the legislation because it places a moratorium on coal plants until CCS is ready. The group's support, however, does not reflect an embrace of CCS.

"We need to make sure that the technology to capture and store carbon is feasible and in place," said Bruce Nilles, The Sierra Club's national coal campaign director. "While we are evaluating the role coal should play in our energy future, we should continue to move forward with the clean, affordable energy solutions that are available today, like wind and solar power."

Greenpeace has taken a hard-line approach against CCS. "We are opposed to CCS technology," said Kate Smolski, Greenpeace USA global warming campaigner. "The No. 1 reason is it's a way the dirty polluting coal industry can prop itself up. It's an unproven technology. And it takes resources away from solutions that we can use right now."

The main concern with CCS is whether carbon stored inside empty aquifers would leak and pollute groundwater reserves. "If people think this is *the* solution, think again. A lot of research is needed," said Steven Chu, director of the Lawrence Berkeley National Laboratory at last week's "Summit on America's Energy Future," sponsored by the National Academies of Sciences and Engineering.

Researchers are calling for "urgent" expansion of CCS research and development funding. Massachusetts Institute of Technology physicist Ernest Moniz, also director of the Energy Initiative, said experimental CCS power plants are needed to improve cost and performance. The U.S. government's plans for its first large CCS plant were halted in January when the Department of Energy canceled major pilot program FutureGen after concluding that the costs had mushroomed out of control. "What we need is several demonstrations in parallel," Moniz said at the Academies' summit. * * *

For his part, Worldwatch Institute President Christopher Flavin is skeptical of CCS. "It will be many years before we know for sure whether large-scale carbon sequestration is practical and affordable," Flavin says. "The only thing that's certain today is that we shouldn't assume CCS will be a major solution to climate change-unlike solar, wind, and energy efficiency, all of which are being deployed on a significant scale today."

QUESTIONS AND DISCUSSION

1. If you headed an environmental organization, what position would you take regarding CCS? Would it matter if, like the Sierra Club, your organization was actively seeking to block all new coal plants and retire many old ones in the United States? Is it realistic for organizations to oppose CCS when coal provides such a large percentage of energy in the United States and the world?

2. One of Greenpeace's major concerns with CCS is that it will deflect research, development, and investment away from renewable energy sources. Greenpeace, False Hope: Why Carbon Capture and Storage Won't Save the Climate 7 (May 2008). Do you think Greenpeace's concerns are valid?

3. Recent research suggests that carbon sequestration may require significant amounts of energy and perhaps as much as 20 percent of the electricity a power plant generates would be used for carbon sequestration. Reuters News Service, Power Needed to Bury CO_2 a Coal Issue — Experts (June 30, 2008), *available at* http://www.planetark.org/dailynewsstory.cfm?newsid=49079. Does this change your analysis of CCS technology?

4. ***Potential Leakage from CCS Sites.*** One risk of geological sequestration is that carbon dioxide may leak from sequestration sites. Under certain conditions, leakage could contaminate drinking water sources or exacerbate the effects of other environmental contaminants.

> Leaking CO_2 may affect [underground sources of drinking water] overlying the sequestration reservoir or reach the land surface where it could accumulate in soil and affect biotic respiration, or in structures where it could harm human health. The most probable routes of human exposure to CO_2 leaking from [onshore geological sequestration] sites are through inhalation or skin contact. Although CO_2 is harmless at low concentrations it can displace air and asphyxiate or cause chronic health effects at high concentrations. In areas where radon gas is prevalent, rising CO_2 could displace radon gas causing radon to accumulate in structures exacerbating human health concerns.

Jeffrey W. Moore, *The Potential Law of On-Shore Geologic Sequestration of CO_2 Captured from Coal-Fired Power Plants*, 28 ENERGY L.J. 443, 452 (2007). Do these concerns outweigh the risks from climate change? If CO_2 leaks into drinking water supplies or leaks into the atmosphere, who should be liable? What existing principles of liability would apply to a leak?

5. The property regime regarding carbon sequestration is also unsettled. Under the *ad coelom* doctrine, property boundaries typically extend up to the sky and down to the earth's core. Property owners can also separate their surface estates from mineral estates to either sell or lease access to underlying resources while maintaining ownership of their land. Moreover, when parties exploit underground resources like oil and gas, they are entitled under the rule of capture to take fugitive resources that might underlie multiple surface parcels so long as they do not physically invade the mineral estate of another party. However, a property owner may not drill underground in a way that would result in a physical intrusion, or trespass, onto another party's property.

How should carbon sequestration fit into this regime? If a coal plant pumps carbon dioxide underground and the carbon dioxide moves below the surface estate of a nearby land owner, is this a trespass or would the rule of capture allow someone to fill a common "reservoir" of empty space with carbon dioxide? And who owns the carbon dioxide underground? What if the carbon sequestration site sits above valuable oil, gas, or other mineral deposits? Would it be permissible for one property owner to fill an underground reservoir with carbon dioxide and thereby effectively prohibit adjacent property owners from drilling for valuable resources?

6. Congress has dedicated hundreds of millions of dollars to a CCS facility known as the FutureGen facility. For a brief time, the Department of Energy suspended funding for the FutureGen plant because DOE thought the project economically wasteful and technologically unachievable. Congress, however, reinstated the funding. In December 2012, the Illinois Commerce Commission (the electricity regulatory body in that state) approved a prospective power purchase agreement for the FutureGen facility to sell power to utilities in the state. The CCS facility may come online by 2017. *See* Julie Wernau, *Chicago Electric Bills Set to Rise $1 a Month Next Year*, CHICAGO TRIB., Dec. 19, 2012.

3. *Nuclear Power*

Energy experts have long engaged in a heated debate regarding the role of nuclear power in the United States. On the one hand, nuclear advocates believe that nuclear energy — which emits no carbon dioxide — presents the most realistic option for providing sufficient baseload energy. On the other hand, nuclear opponents believe that the use of nuclear energy will perpetuate a flawed centralized energy program and present other environmental risks. Despite this debate, nuclear power appeared to be entering a renaissance of sorts until March 2011, when the Fukushima Daiichi nuclear plant in Japan experienced meltdowns due to an earthquake and resulting massive tsunami. Whether concerns about nuclear safety and nuclear storage will affect nuclear power's future still remains to be seen. Consider the following articles summarizing nuclear energy policy and the potential benefits of a nuclear renaissance.

MARK HOLT, CONGRESSIONAL RESEARCH SERVICE, NUCLEAR ENERGY POLICY

(May 10, 2011)

<u>Most Recent Developments</u>

The earthquake and resulting tsunami that severely damaged Japan's Fukushima Daiichi nuclear power plant on March 11, 2011, raised questions in Congress about the accident's possible implications for nuclear safety regulation, U.S. nuclear energy expansion, and radioactive waste policy. The tsunami blacked out all electric power at the six-reactor plant, resulting in the overheating of the reactor cores in three of the units and overheating of several spent fuel storage pools at the site. The overheating caused major hydrogen explosions and releases of radioactive material to the environment. Several House and Senate hearings have been held on the accident, and several bills on nuclear safety have been introduced. Proposed bills would delay all new nuclear licenses and permits until stronger safety standards were in place (H.R. 1242), expand evacuation planning around U.S. nuclear reactors (H.R. 1268), and initiate U.S. efforts to strengthen international nuclear safety agreements (S. 640, H.R. 1326).

* * *

President Obama's State of the Union Address on January 25, 2011, called for nuclear power to be included in a national goal of generating 80% of U.S. electricity "from clean energy sources" by 2035. Along with nuclear power and renewable energy, "clean energy" would include "efficient" natural gas plants and clean coal technologies, to the extent that they reduced carbon emissions from conventional coal-fired plants. The President's proposed Clean Energy Standard could provide a significant boost to U.S. nuclear power expansion, particularly in areas of the country with relatively limited renewable energy resources.

The Administration's FY2012 budget request would nearly triple the current ceiling on federal loan guarantees for nuclear power plants, to $54.5 billion, as had also been proposed but not approved for FY2011. The Administration announced the first conditional nuclear power plant loan guarantee on February 16, 2010, totaling $8.33 billion for two proposed new reactors at Georgia's Vogtle nuclear plant site. . . . Seventeen applications for combined construction permits and operating licenses (COLs) for 26 new nuclear power units have been submitted to the Nuclear Regulatory Commission (NRC), although work on several applications has been suspended. * * *

<u>Nuclear Power Status and Outlook</u>

After nearly 30 years in which no new orders had been placed for nuclear power plants in the United States, a series of license applications that began in 2007 prompted widespread speculation about a U.S. "nuclear renaissance." The renewed interest in nuclear power largely resulted from the improved performance of existing reactors, federal incentives in the Energy Policy Act of 2005 (P.L. 109-58), the possibility of carbon dioxide controls that could increase costs at fossil fuel plants, and volatile prices for natural gas — the favored fuel for new power plants for most of the past two decades.

However, only a handful of proposed U.S. reactor projects currently appear to be making progress toward construction in the near term. High construction cost estimates — a major reason for earlier reactor cancellations — continue to undermine nuclear power economics. An unexpected obstacle to nuclear power growth has been the recent development of vast reserves of domestic natural gas from previously unproducible shale formations, which has held gas prices low and reduced concern about future price spikes. Moreover, uncertainty over U.S. controls on carbon emissions may be further increasing caution by utility companies about future nuclear projects.

The March 11, 2011, earthquake and tsunami that severely damaged Japan's Fukushima Daiichi nuclear power plant could also affect plans for new U.S. reactors, although U.S. nuclear power growth was already expected to be modest in the near term. Following the Fukushima accident, preconstruction work was suspended on two planned reactors at the South Texas Project. Tokyo Electric Power Company (TEPCO), which owns the Fukushima plant, had planned to invest in the South Texas Project expansion, but TEPCO's financial condition plunged after the accident. The Fukushima accident could also lead to new U.S. safety requirements and raise investor concerns about higher costs and liability. However, after the accident the Obama Administration reiterated its support for nuclear power expansion as part of its clean energy policy.

The recent applications for new power reactors in the United States followed a long period of declining nuclear generation growth rates. No nuclear power plants have been ordered in the United States since 1978, and more than 100 reactors have been canceled, including all ordered after 1973. The most recent U.S. nuclear unit to be completed was TVA's Watts Bar 1 reactor, ordered in 1970 and licensed to operate in 1996. But largely because of better operation and capacity expansion at existing reactors, annual U.S. nuclear generation has risen 28% since the startup of Watts Bar 1.

The U.S. nuclear power industry currently comprises 104 licensed reactors at 65 plant sites in 31 states and generates about 20% of the nation's electricity. * * *

Annual electricity production from U.S. nuclear power plants is much greater than that from oil and hydropower and other renewable energy sources. Nuclear generation has been overtaken by natural gas in recent years, and it remains well behind coal, which accounts for about 45% of U.S. electricity generation. Nuclear plants generate more than half the electricity in six states. The record 807 billion net kilowatt-hours of nuclear electricity generated in the United States during 2010 was about the same as the nation's entire electrical output in the early 1960s, when the oldest of today's operating U.S. commercial reactors were ordered.

Reasons for the 30-year halt in U.S. nuclear plant orders include high capital costs, public concern about nuclear safety and waste disposal, and regulatory compliance issues.

High construction costs may pose the most serious obstacle to nuclear power expansion. Construction costs for reactors completed since the mid-1980s ranged from $2 to $6 billion, averaging more than $3,700 per kilowatt of electric generating capacity (in 2007 dollars). The nuclear industry predicts that new plant designs could be built for less than that if many identical plants were built in a series, but current estimates for new reactors show little if any reduction in cost.

Average U.S. nuclear plant operating costs, however, dropped substantially since 1990, and costly downtime has been steadily reduced. Licensed U.S. commercial reactors generated electricity at an average of 89% of their total capacity in 2009, according to industry statistics.

Sixty-six commercial reactors have received 20-year license extensions from the Nuclear Regulatory Commission (NRC), giving them up to a total of 60 years of operation. License extensions for 17 additional reactors are currently under review, and more are anticipated, according to NRC. The FY2010 Energy and Water Development Appropriations Act provided $10 million for DOE to study further reactor life extension to 80 years, and DOE requested $21.4 million for that program in FY2012.

Existing nuclear power plants appear to hold a strong position in electricity wholesale markets. In most cases, nuclear utilities have received favorable regulatory treatment of past construction costs, and average existing nuclear plant operating costs are estimated to be competitive with those of fossil fuel technologies. Although eight U.S. nuclear reactors were permanently shut down during the 1990s, none has been closed since 1998.* * *

FRED BOSSELMAN, THE ECOLOGICAL ADVANTAGES OF NUCLEAR POWER,

15 N.Y.U. ENVTL. L. J. 1 (2007)

Will a new generation of nuclear plants be built in the United States? The United States is the world's largest supplier of commercial nuclear power. In 2005, there were 104 U.S. commercial nuclear generating units that were fully licensed to operate, and they provided about 20% of the Nation's electricity. But no new nuclear plants have been built in the United States for over twenty years. * * *

This article concentrates only on one issue related to that decision--an issue that often receives less attention than it deserves: How will the decision affect ecological processes and systems, both in the United States and globally? The article makes three arguments: (1) if nuclear power plants are not built, the gap will be filled by more coal-fired power plants; (2) the impact of coal-fired power plants on ecological processes and systems is likely to be increasingly disastrous; and (3) nuclear power's ecological impacts are likely to be neutral or even positive.

I. Coal and Nuclear Power Are the Realistic Choices to Meet the Need for Reliable Base-Load Electric Generation in the United States

A. Electric Utilities Need Access to an Assortment of Different Types of Power Plants

Electric utilities need to be able to have access to a "portfolio" of different types of generating plants. Because electricity cannot be stored on a large scale, power generators must continually produce power as it is consumed. Some users of electric power produce a relatively constant and predictable demand for electricity, and this amount is known as "base-load." Electric utilities need reliable generation sources with low operating costs for meeting base-load needs. Base-load power plants run virtually without interruption to supply the continuous portion of electricity needs, as compared to the needs that expand and contract seasonally or diurnally. Base-load plants are often called "must-run" plants, because they will run for as long as possible at full load, and will produce the lowest overall power-generating costs for this type of use. Today, many observers consider coal and nuclear power to be the only reliable future sources of base-load power. * * *

B. Conservation Will Not Prevent the Need for New Power Generating Capacity

Demand for electricity is influenced by many different factors, including the weather, the strength of the economy, the price of electricity, and the use of high-demand equipment and buildings. The history of the last fifty years has provided many examples of over- and under-estimation of demand growth, but no evidence of any decline in demand for any multi-year period. * * *

D. Renewables Can Play a Valuable but Limited Role

The goal of a completely renewable system of electric generation appeals to almost anyone who does not have vested interests in the continued use of non-renewable energy sources. The currently available renewable sources of electrical energy on a large scale are primarily hydroelectric power (hydro), wind, and solar. The United States and individual states have provided some incentives for the creation of renewable generating systems, and some European countries have provided even more, but renewable energy resources can meet only a small fraction of reliable base-load electricity needs within the next decade because: (1) their availability depends on external factors beyond human control, requiring backup by reliable generation; (2) their potential location is also dependent on factors beyond our control; and (3) new renewable technologies, although promising, are more than ten years away from large scale production. * * *

II. From an Ecological Standpoint, Nuclear Power Is Much Better than Coal

Examining coal and nuclear power solely from an ecological standpoint, the advantages of nuclear power are clear.

A. The Ecological Impacts of Every Stage of the Use of Coal Are Disastrous

Virtually all of the coal mined in the United States is used as boiler fuel to generate electricity, and although few users of that electricity realize it, half of the nation's electric energy is provided by coal. In his recent book, Big Coal, Jeff Goodell points out that in the United States, the mining and combustion of coal typically occur in such remote locations that most Americans have no idea "what our relationship with this black rock actually costs us." This is particularly true with regard to public understanding of ecological systems that are being destroyed in remote places or through chains of causation that only experts understand. Coal is ecologically destructive through (1) mining, (2) air pollution, (3) greenhouse gas emissions, and (4) water pollution; and (5) while so-called "clean-coal" technology is a long-range hope, it is not likely to be common in the next decade. * * *

5. Large-Scale Use of "Clean-Coal" Technology Is Decades Away

Scientists and engineers believe that it is technologically possible to create a process for burning coal which creates no conventional air pollution and stores all of the potential carbon emissions in the earth's underground layers. In 2003, such a proposal was part of the President's

State of the Union speech, and the coal industry has been talking about this idea without rushing to adopt it.

Whether the needed carbon storage and sequestration will ever come about, however, is another question. The Intergovernmental Panel on Climate Change has released an extensive study of the potential methods of carbon capture and storage. They concluded that capturing carbon dioxide before it is released as power-plant emissions is possible but expensive with current technology. Once captured, existing technologies can be used to inject the gas into underground layers, such as existing or depleted petroleum reservoirs. But the risk of sudden escape of the injected gas needs to be evaluated; the release of large amounts of carbon dioxide into the atmosphere can asphyxiate all oxygen-dependent organisms enveloped by the cloud of carbon dioxide. * * *

B. Nuclear Power Has Much Less Effect on Ecological Systems than Coal

Like coal, nuclear power is made from a mineral substance that comes from a mine, is transported to the power plant and removed from the plant when its usefulness has ended. The uranium used in nuclear power plants, however, has only a small fraction of the ecological impact of coal at any stage of its cycle, both in total effect and per unit of power produced. The nuclear industry claims that:

> Nuclear energy has perhaps the lowest impact on the environment — including air, land, water, and wildlife — of any energy source, because it does not emit harmful gases, isolates its waste from the environment, and requires less area to produce the same amount of electricity as other sources.

The evidence supports these claims, as will be shown below. Moreover, the risk of a serious accident or terrorist attack on the next generation of nuclear plants will be slight.

1. The Amount of Uranium Used Is a Tiny Fraction of the Coal Used

The mining of uranium admittedly can create some of the same adverse ecological impacts as the mining of coal. The difference, however, is that while the coal-fired power plants in the United States used slightly over a billion tons of coal in 2005, nuclear power plants used only 66 million pounds of uranium oxide. Thus the scale of the impact from uranium mining is not in the same ball park as the impact of coal mining. Virtually all uranium mines currently operating in the United States are underground mines or use the in situ leaching method, which both have much less impact on the environment than open pit uranium mining. Moreover, coal-fired power plants produce half the electricity in the United States while nuclear power plants produce one-fifth.

In addition, unlike coal, uranium used in power plants can be recycled and used again. At the present time, the United States does not reprocess its nuclear fuel, but countries such as Great Britain, France, Japan, and Russia do so on a regular basis. * * *

2. Nuclear Power Plants Cause No Air or Radiation Pollution

Whereas coal burning creates large amounts of sulfur dioxide and nitrogen oxides, nuclear power generation emits none. The reason that nuclear power plants produce no air pollutants when generating power is that in a nuclear power plant, nothing is burned; the heat used to spin the turbines and drive the generators comes from the natural decay of the radionuclides in the fuel. It is the burning of fossil fuels, and particularly coal, that causes air pollution from electric power plants.

Nor does a nuclear power plant pollute its surroundings with dangerous radiation, as its opponents often imply. The population exposure from the normal operation of nuclear power plants is far lower than exposure from natural sources. "The civilian nuclear power fuel cycle, involving mining, fuel fabrication, and reactor operation, contributes a negligible dose [of radiation] to the general public." Life cycle air pollutant emissions from nuclear plants are comparable to those of the wind, solar, and hydro facilities--in other words, minimal.

Concern is sometimes raised about the possibility of releases of large amounts of radiation from an accident at a nuclear power plant. In the four decades of commercial power plant operation in the United States, such a release has never occurred. The only serious accident at a commercial nuclear reactor in the United States caused no radiation damage to people outside the plant and little environmental damage. * * *

4. Dry Cask Storage Is a Safe Way to Store Spent Fuel

In the United States, one of the most common arguments against nuclear power relates to the current proposal to bury spent fuel from power plants in a permanent storage facility at Yucca Mountain, Nevada. In my opinion, resolution of this debate is really unnecessary for the construction of new nuclear power plants because recent studies have shown that dry cask storage is a safe and secure method of handling spent fuel for the next century. Dry casks are designed to cool the spent fuel to prevent temperature elevation from radioactive decay and to shield the cask's surroundings from radiation without the use of water or mechanical systems. Heat is released by conduction through the solid walls of the cask (typically made of concrete, lead, steel, polyethylene, and boron-impregnated metals or resins) and by natural convection or thermal radiation. The cask walls also shield the surroundings from radiation. Spent fuel is usually kept in pools for five years before storage in dry casks in order to reduce decay heat and inventories of radionuclides. As the bipartisan National Commission on Energy Policy recently explained, dry cask storage "is a proven, safe, inexpensive waste-sequestering technology that would be good for 100 years or more, providing an interim, back-up solution against the possibility that Yucca Mountain is further delayed or derailed — or cannot be adequately expanded before a further geologic repository can be ready."

At present, most spent fuel is initially stored in water-filled pools on each nuclear power plant site. After five years, the fuel has cooled enough to be transferred to dry casks for storage, and many plants have built such casks onsite. The National Research Council has pointed out that the temporary storage of spent fuel in a retrievable form, such as dry cask storage, might provide opportunities for re-use of the material if new ways of using it were developed in the future. In any event, the current availability of dry cask storage means that the problem of spent fuel no longer appears to be an insurmountable barrier to building new nuclear plants. * * *

C. "But What About Chernobyl?"

In 1986, an explosion at the Chernobyl nuclear power plant in the Ukraine caused the release of large amounts of radiation into the atmosphere. Initially, the Soviet government released little information about the explosion and tried to play down its seriousness, but this secrecy caused great nervousness throughout Europe, and fed the public's fears of nuclear power all over the world. Now a comprehensive analysis of the event and its aftermath has been made: In 2005, a consortium of United Nations agencies called the Chernobyl Forum released its analysis of the long-term effects of the Chernobyl explosion.

The U.N. agencies' study found that the explosion caused fewer deaths than had been expected. Although the Chernobyl reactor was poorly designed and badly operated and lacked the basic safety protections found outside the Soviet Union, fewer than seventy deaths so far have been attributed to the explosion, mostly plant employees and firefighters who suffered acute radiation sickness. The Chernobyl reactor, like many Soviet reactors, was in the open rather than in an American type of pressurizable containment structure, which would have prevented the release of radiation to the environment if a similar accident had occurred.

Perhaps the most surprising finding of the U.N. agencies' study was that "the ecosystems around the Chernobyl site are now flourishing. The [Chernobyl exclusion zone] has become a wildlife sanctuary, and it looks like the nature park it has become." Jeffrey McNeely, the chief scientist of the World Conservation Union, has made similar observations:

Chernobyl has now become the world's first radioactive nature reserve. . . . 200 wolves are now living in the nature reserve, which has also begun to support populations of reindeer, lynx and European bison, species that previously were not found in the region. While the impact on humans was strongly negative, the wildlife is adapting and even thriving on the site of one of the 20th century's worst environmental disasters.

QUESTIONS AND DISCUSSION

1. What do you think of Professor Bosselman's analysis? Is nuclear power the best choice for climate-friendly energy production? Does his article sufficiently address the ecological concerns surrounding nuclear production? For example, the U.N. Report, Chernobyl's Legacy: Health, Environmental and Socio-Economic Impacts, reports that Chernobyl caused 4,000 cases of thyroid cancer, mostly in children. While most have recovered, nine died. In addition, Ukraine, Belarus, and Russia withdrew 784,320 hectares of agricultural land and 694,200 hectares of timberland from production. Moreover, the nature reserve exists because an area of roughly 30 kilometers surrounding the reactor is highly contaminated and thus closed to public access.

2. ***Skepticism about Nuclear Power.*** Not everyone agrees that nuclear energy has a bright future ahead of it. *See* Joseph P. Tomain, *Nuclear Futures*, 15 DUKE ENVTL. L. & POL'Y F. 221

(2005). Professor Tomain argues that nuclear energy "does not appear to pass a market test, has increasing safety concerns, and does not have great promise for replacing fossil fuels." *Id.* at 246. Regarding the market power of nuclear energy, Professor Tomain notes that nuclear energy has never been financially competitive. Instead, even during the heyday of nuclear production, the nuclear industry relied heavily on government subsidies and tax breaks. *Id.* at 241–43. Studies show that any revival of the nuclear energy industry will require substantial government assistance. *Id.* Concerns regarding waste disposal and weapons proliferation also lead many observers to doubt the political viability of nuclear energy. *Id.* at 244–46. How should policymakers address these concerns? Do the benefits of carbon-free power production justify the risks that nuclear power may present?

3. Professor Benjamin K. Sovacool and Christopher Cooper dispute whether nuclear power is really carbon-free:

> From a climate-change standpoint, nuclear power is not much of an improvement over conventional coal-burning power plants, despite recent claims by the Nuclear Energy Institute that nuclear power is the "Clean Air Energy." Reprocessing and enriching uranium requires a substantial amount of electricity, often generated from fossil fuel-fired power plants, and uranium milling, mining, leeching, plant construction, and decommissioning all produce substantial amounts of greenhouse gas. In order to enrich natural uranium, for example, it is converted to uranium hexafluoride, UF6, and then diffused through permeable barriers. "In 2002, the Paducah [uranium] enrichment plant [in Kentucky] released over 197.3 metric tons of Freon[, a greenhouse gas far more potent than carbon dioxide,] through leaking pipes and other equipment."

Benjamin K. Sovacool & Christopher Cooper, *Nuclear Nonsense: Why Nuclear Power Is No Answer to Climate Change and the World's Post-Kyoto Energy Challenges*, 33 WM. & MARY ENVTL. L. & POL'Y REV. 1 (2008).

4. Just as with CCS technologies, environmental groups are split with respect to nuclear power's role in a green energy economy. How would you advise an environmental organization regarding whether to support the growth of nuclear power?

5. How should the nuclear meltdown at the Fukushima Daiichi nuclear power plant in Japan influence U.S. policymakers? One reason the Fukushima plant caused so much concern was because, like many U.S. plants, it stored its spent fuels onsite in water pools. Nuclear waste remains radioactive for many years after it is removed from a power plant, and waste storage strategies aim to keep spent nuclear materials from resuming their reactions, overheating, and releasing uncontrolled amounts of radiation. A common storage strategy involves taking nuclear waste and binding it into glass rods. The glass rods are then stored in large pools of cold water until the wastes lose enough of their potency to become eligible for dry cask storage or permanent storage. The cold water is necessary to keep the nuclear wastes stable, but because the spent fuel rods continue to generate heat, safe waste storage requires a constant influx of cold water to prevent the water from boiling away and the rods from overheating. When the tsunami hit the Fukushima plant, it shut down the nuclear reactors and backup power used to pump fresh water into the storage pools. Eventually, the heat from the fuel rods boiled off the water in the pools, and without electricity, workers at the plant were unable to add additional cold water to the pools. Experts believe that significant amounts of radiation ultimately escaped due to the loss of cooling water.

In the United States, many nuclear plants also store spent fuel rods in cold water pools. While pool storage was initially considered a temporary strategy, long-term storage options do not yet exist. Although the Department of Energy and the Nuclear Regulatory Commission have spent decades and billions of dollars working to find and develop a long-term storage site for spent nuclear waste, they appear further than ever from achieving this goal. It is possible that nuclear facilities can store some of their waste in dry storage casks (basically cement-encased storage units), and nuclear reprocessing may some day become a viable option. How should these waste storage issues affect future investment in nuclear power?

B. Renewable Energy Sources

Americans have become increasingly concerned about volatile energy prices, climate change, and the United States' dependence upon foreign oil. As a result, American support for, and investment in, renewable energy has continued to grow. Wind energy, in particular, has boomed, and the solar energy industry has similarly experience substantial growth. Yet, at the same time, local opposition to some renewable energy facilities has increased out of fears that large-scale renewable energy sources will destroy the scenery, threaten wildlife, or otherwise create unintended consequences. This section highlights the potential and limitations of the dominant renewable energy resources.

1. *Wind Power*

On August 5, 2008, the American Wind Energy Association (AWEA) announced that the United States had become the world's largest wind energy producer, surpassing Germany's production rates for the first time. Press Release, AWEA, Looming Expiration of Federal Incentive Threatens Wind Power's New-Found Growth: AWEA Second Quarter Market Report Solar (Aug. 5, 2008). Wind energy has quickly become the dominant renewable energy source in the United States, having increased by more than 1,500% from 2001 to 2011, and it has room to grow. The Department of Energy estimates that the Midwest states alone (including all states in the Great Plains) have the capacity to support energy generation for the entire country. *See* U.S. GOV'T. ACCOUNTABILITY OFFICE, RENEWABLE ENERGY: WIND POWER'S CONTRIBUTION TO ELECTRIC POWER GENERATION AND IMPACT ON FARMS AND RURAL COMMUNITIES 17 (2004). While development of this capacity will take time, most experts agree that the U.S. capacity for wind energy is more than sufficient to meet the nation's energy needs.

Wind power technology is also readily available. Indeed, wind turbines are the modern equivalent of centuries-old technology — windmills. Stand-alone wind turbines can be used for water pumping or communications, two applications that might otherwise require electricity, as well as by property owners to generate electricity. They can also be connected to power grids, combined with other electrical systems, including solar power systems, and connected to each other to form wind plants.

Some of the advantages of wind power are obvious. Because they are emissions free, they do not generate GHG emissions (or other pollution emissions). In addition, wind energy is among the least expensive renewable energy technologies, costing between 4 and 6 cents per kilowatt-hour, depending upon the wind resource and project financing of the particular project. National Renewable Energy Laboratory, *Wind Power Basics* (2008).

Despite its low cost relative to other renewable energy sources, it still must compete with cheap, and often subsidized, fossil fuels. Wind power technology also requires a higher initial investment than fossil-fueled generators. Department of Energy, *Wind Energy Basics* (2008). In addition:

> The major challenge to using wind as a source of power is that the wind is intermittent and it does not always blow when electricity is needed. Wind energy cannot be stored (unless batteries are used); and not all winds can be harnessed to meet the timing of electricity demands.
>
> Good wind sites are often located in remote locations, far from cities where the electricity is needed.
>
> Wind resource development may compete with other uses for the land and those alternative uses may be more highly valued than electricity generation.
>
> Although wind power plants have relatively little impact on the environment compared to other conventional power plants, there is some concern over the noise produced by the rotor blades, aesthetic (visual) impacts, and sometimes birds have been killed by flying into the rotors. Most of these problems have been resolved or greatly reduced through technological development or by properly siting wind plants.

Id.

QUESTIONS AND DISCUSSION

1. *Wind Farm Siting Controversies*. Despite the dominance of wind power, debates regarding siting of wind generation facilities have been particularly contentious. Wind opponents have particular concerns about the impacts of large-scale wind facilities on migrating bird and bat populations. Early wind farms, most notably a massive facility located in Altamont Pass, California, have caused the deaths of thousands of birds. While technology in the wind power sector has advanced to avoid many bird deaths, wind energy facilities do nonetheless cause some migratory bird and bat mortality. Statutes like the Endangered Species Act and Migratory Bird Act can make wind farm siting and operation difficult because of these impacts.

Aesthetic concerns can also lead to wind development opposition from those who think wind facilities will mar otherwise pristine views or cause noise disturbance. Concerns about aesthetics have spurred opposition to wind projects in Maine, where a wind project was planned in a location close to the Appalachian Trail; Montana, where local residents fear that wind development will diminish the Big Sky state's scenic vistas; and, most famously, Massachusetts, where the Cape Wind project in Nantucket Sound, off the coast of Cape Cod, has generated years of dispute and litigation. It is unclear, however, whether siting opposition presents a significant hurdle to wind development, or whether a few high-profile cases give the impression that it is becoming increasingly difficult to site wind farms. The growth rate of wind capacity suggests that siting may be a hurdle in some cases but that many wind farms experience little to no opposition.

Nonetheless, many people have called for changes to wind facility siting processes. In many states, local governments have the ability to veto wind projects under local land-use laws or energy facility siting laws. One scholar has proposed to limit the power of local governments — and thus the force of "Not in My Backyard" (NIMBY) decision-making — by giving state agencies the power to permit wind facilities. *See* Ronald H. Rosenberg, *Making Renewable Energy a Reality — Finding Ways to Site Wind Power Facilities*, 2 WM. & MARY ENVTL. L. & POL'Y REV. 635, 670-84 (2008). Is this a good idea? Should local governments be denied the ability to control what happens in their jurisdiction?

2. ***Economic Impacts of Wind in Rural Areas***. Wind farms may face less opposition from rural communities that welcome the economic boost wind power can provide. In many areas where rural landowners have leased their lands for wind turbines, they may command $3,000-$4,000 in lease fees per turbine per year. Am. Wind Energy Ass'n., *Wind Energy for Your Farm or Rural Land*, 1, *available at* http://www.awea.org/pubs/factsheets/WindyLandownersFS.pdf. At the same time, landowners can continue to use their land for farming or ranching. Finally, wind power may provide rural communities with other economic resources, from construction jobs associated with installation of the wind facility to long-term employment associated with maintaining the wind turbines:

> Assembling the pre-fabricated wind turbines and towers employs construction workers at an estimated rate of 4.8 job-years (direct and indirect employment) per 1 MW of wind power construction. Using this ratio, a 50 MW wind farm would produce 240 job-years of employment for those workers who constructed the facility. A 2005 estimate of employment impact suggested that by 2015 wind energy projects in California alone would produce 2,690 construction jobs and 450 permanent operational jobs just for facilities built on U.S. Bureau of Land Management lands.
>
> After the construction phase of the wind farm project, a smaller number of permanent jobs would be added to local economies usually experiencing little job growth. It has been estimated that between 9 to 10 full-time service personnel would be needed to maintain a 100 MW wind farm. Although this continuing employment benefit would not be extremely large, it would occur in rural areas

> with small populations and few incoming job opportunities, and it would be distributed over a large rural area.

Rosenberg, *Making Renewable Energy a Reality*, at 664. Not surprisingly, given wind power's benefits for rural areas, the top ten states in terms of wind energy production — Texas, California, Minnesota, Iowa, Washington, Colorado, Oregon, Illinois, Oklahoma, and New Mexico — all have significant amounts of rural land.

While it might seem wise for wind energy companies to focus their efforts only on rural areas to avoid costly and time-consuming siting battles, long-term development strategies will require a significant expansion of wind facilities throughout the United States.

> The optimistic goal of the federal government's Wind Powering America initiative is to have at least 24 states with at least 1,000 MW of installed wind power capacity by 2010. In 2007, there were 16 states that already meet that goal with an additional 6 states currently meeting the 1,000 MW goal when projects under construction were considered. Although achieving the 10,000 MW milestone in 2006 represented a ten-fold growth in 20 years, it must be kept in mind that American wind power still accounts for approximately 1% of existing, domestic electricity generation. This total may be small but it is still significant. Providing 48 billion kWh of electricity, which is sufficient to power 4.5 million American homes, represents a significant accomplishment for the wind power industry. However, achieving the proclaimed national goal of reaching the 5% level by 2020 will require substantial expansion of American wind power even beyond these levels and continued government encouragement. To reach this achievement, thousands of wind turbines must be sited across the country and in offshore locations.

Rosenberg, *Making Renewable Energy a Reality*, at 657-58.

3. Renewable energy sources also face a myriad of regulatory hurdles as companies seek to locate them on public or private lands. Depending on the energy source, energy producers may need to comply with the Outer Continental Shelf Lands Act, the National Environmental Policy Act, the Surface Mining Control and Reclamation Act, among many others. In addition, at least six different federal agencies could regulate various aspects of wind energy development according to the Department of Energy. DEPARTMENT OF ENERGY, 20% WIND ENERGY BY 2030: INCREASING WIND ENERGY'S CONTRIBUTION TO U.S. ELECTRICITY SUPPLY, 120–21 (2008).

4. *Transmission Access for Wind Power Facilities*. Inadequate transmission line capacity also affects the development of new wind energy facilities. Many places in the country that have abundant wind resources either lack transmission lines or adequate transmission capacity. RYAN WISER & MARK BOLINGER, U.S. DEP'T OF ENERGY, 2009 WIND TECHNOLOGIES MARKET REPORT 60, 70 (2010). The cost of building new transmission lines may be prohibitively expensive for wind energy companies and discouraged by regulators. However, a recent FERC regulation (Order 1000) requires transmission planners to accommodate renewable energy sources, which may provide wind and other renewable energy sources better access to the transmission grid in the future. *See* Adam James & Whitney Allen, *FERC Order No. 1000: The Most Exciting Energy Regulation You've Never Heard Of*, THINKPROGRESS.ORG (Oct. 22, 2012).

5. *Intermittency*. Wind energy is vulnerable to intermittency problems. Although many places in the United States (particularly offshore locations) provide nearly constant wind speeds to enable reliable utility-scale wind energy production, many others can provide adequate wind only during specific times of the year or day. And in some places, the best times for reliable and abundant wind energy production are late night and early morning before the dawn when most people are sleeping. Wind energy therefore often provides supplemental power, but in many places cannot serve as a reliable source of baseload or peak energy. Moreover, because winds can suddenly subside, wind energy usually requires backup power sources to immediately replace any sudden loss of wind power. In some places, hydropower can serve as a backup source, but natural gas is also often used as the go-to backup supply. This can undermine the climate benefits of wind energy if large numbers of natural gas-fired power plants must be kept in standby mode (in which they remain online, albeit at a much lower production level) to support wind power.

Intermittency also undermines the economic value of wind power. First, as noted above, most wholesale sales of electricity are negotiated through contracts between sellers (i.e., the owners of wind power facilities) and buyers (i.e., utilities). Intermittency makes it less certain that a utility will receive the amount of power it needs at a particular time. But utilities must provide reliable service to their consumers, so the utilities will need to obtain backup power from other sources or else the wind energy sellers will need to have their own backup sources to deploy. If the utilities obtain their own backup supplies, they will insist on paying less for the wind energy they do buy. If wind facility owners obtain their own backup energy, this will eat into their profits from the wind sales. Second, as described in greater detail below, the main programs (tax credits and renewable portfolio standards) designed to support wind energy development apply to the production of wind power. If the wind does not blow, the facilities will not produce power and thus will not receive the benefits of renewable energy programs.

6. *Pumped Hydro Storage.* One storage technology available for wind energy is pumped hydroelectric storage. A pumped hydro system often uses a closed-loop system for producing hydropower. Basically, under this system, water is pumped uphill into a storage reservoir until power demand triggers the need for electricity production. The water from the reservoir is then released to run through turbines at the bottom of the hill. Once energy demand subsides, the water is then pumped back uphill into the reservoir until its next use. Since water is heavy, it can take significant amounts of power to pump the water back uphill. This is where the wind comes in: if wind turbines that would typically operate at night or during off-peak periods could provide the power to pump the water uphill, they could displace fossil fuels otherwise used for the pumping process. The hydroelectric production, meanwhile, could provide reliable power on demand.

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2. *Solar Power*

Since 2000, the United States and several states have launched programs aimed at increasing the use of solar power and improving solar technology. As a result of these efforts, the solar industry has experienced significant growth. Between 2001 and 2011, solar production grew by about 150 percent. Most of the growth came from increased installations of solar photovoltaic (PV) systems, particularly rooftop solar arrays and some larger PV systems installed in both urban and rural areas. While analysts expect PV deployment to continue to increase, they also expect concentrated solar power (CSP) facilities — which can function more like thermal power plants that boil water to produce power — to contribute much more power in the future.

For solar energy, four main hurdles have stood in the way of its growth. First, solar technology is expensive, and while PV costs have declined significantly since 2010, solar power's costs still exceed the direct costs of other traditional and renewable sources. Second, as with wind, the lack of storage capacity makes solar power vulnerable due to its intermittency. In some places, however, solar energy has an advantage over wind because it can usually supply reliable power during peak energy periods, particularly in the summer when air conditioning use contributes to peak demand during the daytime. Third, uncertainty regarding continued access to sunlight discourages investment in solar arrays; homeowners are unlikely to invest in solar facilities if they believe future development or growing trees might shade out the arrays in the future. Finally, integration with the distribution and transmission system can present hurdles for solar facilities distributed throughout urban areas.

QUESTIONS AND DISCUSSION

1. ***Solar and Nighttime Energy***. Solar energy has long been viewed as a daytime-only power source, due to the inefficient and prohibitively expensive solar energy storage options in existence. However, in July 2008, scientists with the Massachusetts Institute of Technology (MIT) announced a breakthrough in solar technology that could allow for highly efficient, and cheap, storage of solar energy through a process that mimics photosynthesis. Press Release, Massachusetts Institute of Technology, "Major Discovery" from MIT Primed to Unleash Solar Revolution: Scientists Mimic Essence of Plants' Energy Storage System (July 31, 2008), *available at* http://web.mit.edu/newsoffice/2008/oxygen-0731.html. If the technology succeeds, the MIT scientists believe that homes could be powered solely through solar technology and no longer dependent upon centralized power delivery for nighttime electricity. *Id.* While it may take years for these technologies to advance, the benefits of independent solar power became evident during Hurricane Sandy in November 2012, when homes that had solar arrays were able to restore electricity service much quicker than homes that received all their power from the grid. In some cases, however, the owners of solar arrays had technology installed that prohibited them from operating independently of the grid. For those owners, they remained without power (because the transmission system was down), even though their solar arrays were intact and operational.

2. ***Public Lands and Energy Development.*** The use of public lands for solar energy development has been particularly contentious and often pits renewable energy advocates (many who would describe themselves as environmentalists) against wildlife and wilderness advocates.

It has also revealed the differential treatment that different types of energy resources on public lands often receive.

For example, on June 26, 2008, the United States announced a freeze on the development of solar energy projects on public lands managed by the Bureau of Land Management (BLM) in six western states so that the agency could prepare a programmatic Environmental Impact Statement (PEIS). *See* 73 Fed. Reg. 30907 (May 29, 2008). According to BLM officials, a number of factors required assessment, including the impact of construction and transmission lines on native vegetation and wildlife, water use because certain solar plants may require water to condense the steam used to power the turbine, and reclamation of land after the 20- to 30-year life span of the solar plant. Dan Frosch, *Citing Need for Assessments, U.S. Freezes Solar Energy Projects*, N.Y. Times, June 27, 2008. A week later, however, BLM announced that it would lift the ban on solar energy applications, citing concerns by commenters who thought the ban would stifle renewable energy development. Press Release, BLM, BLM to Continue Accepting Solar Energy Applications (July 2, 2008), *available at* http://www.blm.gov/wo/st/en/info/newsroom/2008/July/NR_07_02_2008.html.

The agency initially thought the freeze necessary to address the 125 current proposals submitted by solar companies to develop solar energy on BLM-managed lands in Arizona, California, Colorado, Nevada, New Mexico and Utah. The proposals covered almost one million acres with the potential to generate 70 billion watts of electricity, or enough to power more than 20 million average American homes. BLM, BLM Initiates Environmental Analysis of Solar Energy Development (May 29, 2008, updated June 12, 2008), at: http://www.blm.gov/wo/st/en/info/newsroom/2008/may_08/NR_053008.html.

Taken at face value, the PEIS seemed essential as the projects range across a vast amount of land and could have significant cumulative impacts. Yet, others considered the solar freeze unwarranted or, worse, a “spiteful” move by the Bush Administration to slow the development of alternative energy resources while at the same time promoting fossil fuels. David Sassoon, *U.S. Freezes Solar Projects to Study Environmental Impact of Collecting Sunshine in the Desert* (SolveClimate, June 27, 2008). Ultimately, the BLM issued a final PEIS indicating its support for solar energy development. While renewable energy advocates were pleased with the outcome, those concerned about the impacts of utility-scale solar development on public lands decry the use of public lands as industrial energy production sites.

The temporary ban also raised questions about the role public agencies should play in managing public lands for energy production. Public lands have long served as oil and gas production and coal mining sites. How should BLM prioritize energy development on public lands? BLM is charged under the Federal Land Policy and Management Act to manage public lands for multiple uses. Its mission under FLPMA is to sustain the health and productivity of the public lands for the use and enjoyment of present and future generations. Does this mission provide BLM any meaningful guidance?

3. ***Balancing Solar Production with Other Uses.*** It can be difficult for policy makers to protect solar access without undermining other legitimate uses of the land and sky. Consider, for example, a dispute that arose in California.

Under California's 1978 Solar Shade Control Act, Cal. Pub. Res. Code §§ 25980-25966, tree owners may not allow their trees to cast a shadow over more than 10 percent of a solar collector during the hours of 10 a.m. to 2 p.m. *Id.* § 25982. Tree owners who violate the law are subject to both civil and criminal prosecution. If a tree owner receives an abatement notice from a prosecuting attorney ordering removal or alteration of the tree, a tree owner may be held liable for $1,000 per day for each day the owner retains the tree in violation of the abatement notice. *Id.* § 25983. Among its various exemptions, the law exempts trees planted before 1979 from the shading prohibition. *Id.* It also exempted trees that cast shadows over the solar panels within one year of installation of the solar panels. *Id.* However, other trees that would ultimately grow high enough to cast the offending shade were not exempt. *Id.*

In May 2008, the Solar Shade Control Act received attention when a California court convicted a couple for violating the Act. The couple had planted eight redwood trees in 1993. Their neighbor had installed rooftop solar panels in 2001. In 2005, a deputy district attorney initiated a prosecution against the couple, and the judge ultimately found that 3 trees violated the Act. The other trees, the judge found, were exempt because they had cast shadows over the solar panels within a year of the panels' installation. *See* Felicity Barringer, *Trees Block Solar Panels, and a Feud Ends in Court*, N.Y. TIMES, Apr. 7, 2008, at A14. In response to the dispute, the California legislature amended the law to establish a first-in-time, first-in-right system that would allow trees that shade solar panels to remain in place if they were planted before the installation of the solar panels. S.B. 1399 (Jul. 22, 2008), codified at Cal. Pub. Res. Code §§ 25980–25966.

Do you think the California legislature's amendment is the correct response? California has enacted a "million solar roofs" program to encourage the installation of residential solar arrays. While the revision to the Solar Shade Control Act will, as the bill's sponsor suggested, avoid "a million neighborhood arguments," *see* Barringer at A14, doesn't it also have the potential to stifle solar installations? Is there a better way to promote neighborhood harmony while encouraging solar development? Do common law rules of property and nuisance inform this discussion? *See* Tenn v. 889 Associates Ldg, 500 A.2d 366 (N.H. 1985) (addressing rights of homeowners to sunlight). In many cases, homeowners may obtain easements protecting their solar arrays from shading by later development, but these easements require the consent of neighbors who may not agree to constrain their future development rights. If a state or local government passes a law authorizing prescriptive easements, it may face takings challenges. How should states promote solar development without unduly interfering with others' property rights?

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3. *Hydropower and Ocean Energy*

Hydropower currently supplies about 63 percent of the renewable energy produced in the United States. Most of the nation's hydropower facilities were constructed during the middle part of the 20th century, often without full consideration of the impacts that dams could have on aquatic ecosystems. As the consequences of large dams became clearer, public opposition to major dam projects increased. No major hydropower dam has been built in the United States since the 1970s. Indeed, the trend in the U.S. has been to remove dams in order to provide migratory fish passage to upstream spawning grounds. While some lawmakers have begun to explore the possibility of building additional hydropower facilities in an effort to expand the U.S. renewable energy portfolio, it seems likely that the era of major dam building in the United States is over.

Other types of hydropower, however, have much greater promise. Micro-turbines for use in small streams and even irrigation canals could provide opportunities for reliable small-scale power production in rural environments. Wave and tidal energy development have the potential to provide significant amounts of baseload power, but technologies are still emerging to make these sources viable. This section provides a brief overview of the technologies and the potential legal hurdles for these resources.

U.S. DEPARTMENT OF ENERGY, HYDROPOWER BASICS

(2008)

Advantages * * *

Hydropower is generally available as needed; engineers can control the flow of water through the turbines to produce electricity on demand.

Hydropower plants provide benefits in addition to clean electricity. Impoundment hydropower creates reservoirs that offer a variety of recreational opportunities, notably fishing, swimming, and boating. Most hydropower installations are required to provide some public access to the reservoir to allow the public to take advantage of these opportunities. Other benefits may include water supply and flood control.

Disadvantages

Fish populations can be impacted if fish cannot migrate upstream past impoundment dams to spawning grounds or if they cannot migrate downstream to the ocean. Upstream fish passage can be aided using fish ladders or elevators, or by trapping and hauling the fish upstream by truck. Downstream fish passage is aided by diverting fish from turbine intakes using screens or racks or even underwater lights and sounds, and by maintaining a minimum spill flow past the turbine.

Hydropower can impact water quality and flow. Hydropower plants can cause low dissolved oxygen levels in the water, a problem that is harmful to riparian (riverbank) habitats and is addressed using various aeration techniques, which oxygenate the water. Maintaining minimum flows of water downstream of a hydropower installation is also critical for the survival of riparian habitats.

Hydropower plants can be impacted by drought. When water is not available, the hydropower plants can’t produce electricity.

New hydropower facilities impact the local environment and may compete with other uses for the land. Those alternative uses may be more highly valued than electricity generation.

Humans, flora, and fauna may lose their natural habitat. Local cultures and historical sites may be impinged upon. Some older hydropower facilities may have historic value, so renovations of these facilities must also be sensitive to such preservation concerns and to impacts on plant and animal life.

U.S. DEPARTMENT OF ENERGY, ENERGY INFORMATION ADMINISTRATION, OCEAN ENERGY

(2008)

Tidal Energy

Tides are caused by the gravitational pull of the moon and sun, and the rotation of the earth. . . . The simplest generation system for tidal plants involves a dam, known as a barrage, across an inlet. Sluice gates on the barrage allow the tidal basin to fill on the incoming high tides and to empty through the turbine system on the outgoing tide, also known as the ebb tide. There are two-way systems that generate electricity on both the incoming and outgoing tides.

Tidal barrages can change the tidal level in the basin and increase turbidity in the water. They can also affect navigation and recreation. Potentially the largest disadvantage of tidal power is the effect a tidal station can have on plants and animals in the estuaries. . . .

Tidal fences can also harness the energy of tides. A tidal fence has vertical axis turbines mounted in a fence. All the water that passes is forced through the turbines. They can be used in areas such as channels between two landmasses. Tidal fences have less impact on the environment than tidal barrages although they can disrupt the movement of large marine animals. They are cheaper to install than tidal barrages too.

Tidal turbines are a new technology that can be used in many tidal areas. They are basically wind turbines that can be located anywhere there is strong tidal flow. Because water is about 800 times denser than air, tidal turbines will have to be much sturdier than wind turbines. They will be heavier and more expensive to build but will be able to capture more energy.

Wave Energy

. . . There is tremendous energy in the ocean waves. The total power of waves breaking around the world’s coastlines is estimated at 2-3 million megawatts. The west coasts of the US and Europe and the coasts of Japan and New Zealand are good sites for harnessing wave energy.

One way to harness wave energy is to bend or focus the waves into a narrow channel, increasing their power and size. The waves can then be channeled into a catch basin or used directly to spin turbines. . . . Small, on-shore sites have the best potential for the immediate future; they could produce enough energy to power local communities.

QUESTIONS AND DISCUSSION

1. ***Greenhouse Gas Emissions from Large Hydropower Projects***. In 2000, a study published in *BioScience* reported that hydropower dams could contribute up to seven percent of global greenhouse gas emissions. Vincent L. St. Louis, *et al*., *Reservoir Surfaces as Sources of Greenhouse Gases to the Atmosphere: A Global Estimate*, 50 BIOSCIENCE 766 (2000). In particular, the study noted that reservoirs behind hydroelectric dams could release significant amounts of methane and carbon dioxide, and that annual emissions from twenty-one of the studied dams would equal emissions of greenhouse gases as three large coal-fired power plants. The exact type and nature of the emissions from dams depends, however, on factors such as climate, soil type, and vegetation in the water body. Nonetheless, dam opponents have cited this study as a reason why climate change should not augur a new era of dam construction. How do you think climate policies should treat large hydropower development?

2. ***Jurisdiction over Wave Energy Facilities.*** For a few years, wave energy development got caught up in a jurisdictional battle waged between the Minerals Management Service (MMS) of the Department of Interior, which has jurisdiction over resource development on the Outer Continental Shelf, and FERC, which has jurisdiction to issue licenses for hydroelectric facilities. Ultimately, the agencies entered into a memorandum of understanding (MOU) to resolve their jurisdictional fight. Pursuant to the MOU, developers of wave energy facilities on the Outer Continental Shelf will need to obtain a lease from MMS prior to seeking a hydroelectric facility license from FERC. Developers in state waters (which extend three miles out from the coastline) will have to obtain state permission and a FERC license.

3. ***The Promise of Wave Energy?*** Although a few wave farms have operated in other countries, U.S. wave power development has faced economic and technological hurdles, particularly because the Pacific Ocean's stormy seas and large swells present significant challenges for wave energy developers. In 2012, however, wave developers announced the deployment of some utility-scale wave energy devices off the coast of Oregon, and a research facility deployed a testing platform that will allow developers to test new devices off of Oregon's coast without facing the risk of losing their devices to the Pacific. *See* David Ferris, *Oregon Races to Catch Up to Europe in Wave Energy*, FORBES.COM (Oct. 3, 2012), http://www.forbes.com/sites/davidferris/2012/10/03/in-wave-energy-oregon-races-to-catch-up-to-europe/. While many promoted these developments as a sign of wave energy's emergence, it will likely take some time before any wave energy facilities begin producing reliable power and even longer before wave energy systems become profitable.

4. The generation of energy from renewable sources may create significant adverse environmental impacts, just not climate change impacts. How should the tradeoffs among these impacts be made? In light of these tradeoffs, how should governments promote renewable energy sources?

4. *Biomass*

Biomass is also re-emerging as an important power source in some parts of the country. Biomass can provide electricity and, when it is converted into ethanol or biofuels, may serve transportation needs. Biomass has the advantage of potentially providing consistent baseload power. However, the growth of raw materials necessary to produce biomass can involve significant inputs of fertilizers, pesticides, and water, all of which can offset the potential climate benefits of moving away from fossil fuels.

NATIONAL RENEWABLE ENERGY LABORATORY, BIOMASS ENERGY BASICS

(2008)

We have used biomass energy, or "bioenergy" — the energy from plants and plant-derived materials — since people began burning wood to cook food and keep warm. Wood is still the largest biomass energy resource today, but other sources of biomass can also be used. These include food crops, grassy and woody plants, residues from agriculture or forestry, oil-rich algae, and the organic component of municipal and industrial wastes. Even the fumes from landfills (which are methane, a natural gas) can be used as a biomass energy source.

Benefits of Using Biomass * * *

- The use of biomass energy has the potential to greatly reduce greenhouse gas emissions. Burning biomass releases about the same amount of carbon dioxide as burning fossil fuels. However, fossil fuels release carbon dioxide captured by photosynthesis millions of years ago — an essentially "new" greenhouse gas. Biomass, on the other hand, releases carbon dioxide that is largely balanced by the carbon dioxide captured in its own growth (depending how much energy was used to grow, harvest, and process the fuel). . . .

- Biomass energy supports U.S. agricultural and forest-product industries. The main biomass feedstocks for power are paper mill residue, lumber mill scrap, and municipal waste. For biomass fuels, the most common feedstocks used today are corn grain (for ethanol) and soybeans (for biodiesel). In the near future — and with NREL-developed technology — agricultural residues such as corn stover (the stalks, leaves, and husks of the plant) and wheat straw will also be used. Long-term plans include growing and using dedicated energy crops, such as fast-growing trees and grasses, and algae. These feedstocks can grow sustainably on land that will not support intensive food crops.

NREL's vision is to develop technology for biorefineries that will convert biomass into a range of valuable fuels, chemicals, materials, and products — much like oil refineries and petrochemical plants do.

Biopower

Biopower, or biomass power, is the use of biomass to generate electricity. Biopower system technologies include direct-firing, cofiring, gasification, pyrolysis, and anaerobic digestion.

Most biopower plants use direct-fired systems. They burn bioenergy feedstocks directly to produce steam. This steam drives a turbine, which turns a generator that converts the power into electricity. * * *

Co-firing refers to mixing biomass with fossil fuels in conventional power plants. Coal-fired power plants can use co-firing systems to significantly reduce emissions, especially sulfur dioxide emissions. Gasification systems use high temperatures and an oxygen-starved environment to convert biomass into synthesis gas, a mixture of hydrogen and carbon monoxide. The synthesis gas, or "syngas," can then be chemically converted into other fuels or products, burned in a conventional boiler, or used instead of natural gas in a gas turbine. * * *

The natural decay of biomass under anaerobic conditions produces methane, which can be captured and used for power production. In landfills, wells can be drilled to release the methane from decaying organic matter. Then pipes from each well carry the methane to a central point, where it is filtered and cleaned before burning. This produces electricity and reduces the release of methane (a very potent greenhouse gas) into the atmosphere. * * *

Gasification, anaerobic digestion, and other biomass power technologies can be used in small, modular systems with internal combustion or other generators. These could be helpful for providing electrical power to villages remote from the electrical grid — particularly if they can use the waste heat for crop drying or other local industries. * * *

QUESTIONS AND DISCUSSION

1. ***The benefits of biomass.*** Biomass sources have various advantages. Plants take up carbon dioxide when they grow and release carbon dioxide when they burn. Thus, assuming the plants can grow without the addition of too many fertilizers or pesticides (which contain petroleum) or pumped irrigation water (which uses electricity), biomass may represent a climate-friendly source of power. Biomass sources also provide new and/or increased markets for forest and agricultural products. Alternatively, they may facilitate waste management when they are part of methane capture systems. Finally, unlike most wind and solar sources, biomass plants can produce electricity constantly and therefore avoid the problems associated with intermittency.

2. ***The disadvantages of biomass.*** Biomass sources have some important downsides: they are often inefficient when compared to fossil fuels and they produce pollution that makes siting difficult. Biomass is inefficient when compared to oil and gas because the solar energy concentrated in plants is much less potent than the energy concentrated in oil and gas. Consequently, biomass power derived from raw materials often requires a significant amount of space (and other inputs, such as fertilizers and pesticides) to produce. Thus, biomass can have a large carbon footprint and may actually emit more greenhouse gases than fossil fuels. Biomass derived from agricultural and organic waste, in contrast, has a smaller footprint. Biomass power plants also emit various pollutants, such as particulate matter and volatile organic compounds. Well-designed biomass power plants can often reduce emissions significantly, but biomass is by no means pollutant-free.

5. *Geothermal Energy*

Geothermal energy is a final renewable energy source that may provide an alternative to fossil fuels. Geothermal energy is simply heat from the earth, usually in the form of hot water or steam. Shallow reservoirs provide a ready source of energy, while deeper sources usually require drilling to access. Geothermal sources have the potential to provide baseload power for electricity systems because geothermal sources release heat constantly. The Energy Information Administration estimates that geothermal sources could provide approximately 22,000 megawatts (MW) of power. While this figure is significantly higher than the current 2,200 MW of power currently produced by geothermal sources, it is a small fraction of the existing capacity of the U.S. electric power system, which is currently more than one million MW. Geothermal may offer greater promise in providing direct heating; both shallow reservoirs and deeper heat sources can produce hot water and steam for residential and commercial heating, as well as some industrial uses. However, while geothermal power has been promoted for decades, its development is relatively stagnant in the United States.

IV. POLICIES TO PROMOTE RENEWABLE ENERGY

The federal government and many states have enacted a number of policies to promote and even mandate renewable energy production. The federal government has played a critical role incentivizing renewable energy production through tax credits and subsidies. The U.S. government also passed one of the first renewable energy purchasing mandates, the Public Utility Regulatory Policies Act (PURPA), which launched the U.S. renewable energy industry and continues to affect renewable power development today. On the state level, key policies include Renewable Portfolio Standards (RPSs), net metering, and, more recently, feed-in tariffs. This section reviews these different policies and considers their potential and limitations. It also considers whether these policies can lead to a fundamental transformation of the U.S. electricity system or whether other structural forms must occur for the power system to become carbon-free.

A. Tax Credits and Incentives

Tax credits and other financial incentives are the predominant tools Congress has used to spur renewable energy development. Since the 1970s, Congress has established a number of tax incentives for solar, biomass, and geothermal energy production. Most studies show that tax incentives are necessary for the renewable energy industry to establish itself and compete with other fossil fuel energy sources (all of which also receive substantial subsidies and credits as well). Mona Hymel, *The United States' Experience with Energy-Based Tax Incentives: The Evidence Supporting Tax Incentives for Renewable Energy*, 38 LOY. U. CHI. L. J. 43, 74–75 (2006). Two types of federal subsidies — the Investment Tax Credit (ITC) and the Production Tax Credit (PTC) — are particularly important for renewable energy investors. The ITC has primarily promoted investment in solar energy, while the PTC has served as the main tax credit for wind energy facilities:

> The ITC has long served as the dominant subsidy for large solar thermal plants and other large solar energy facilities. The ITC gives investors a tax credit based on the amount of money they invest in qualifying renewable installations. Investors can receive the credit for five years after a facility is placed in service. The amount of credit depends on the type of power and size of the investment, rather than the amount of electricity produced, with credits beginning at 10 percent of the investment in geothermal and maxing out at 30 percent for solar energy and small wind farms. For many years, the ITC has served as the dominant program to promote solar thermal energy installations because Congress excluded solar energy from eligibility under the PTC in 2005. Moreover, the ITC offers greater certainty for developers of large power facilities with high upfront capital costs and uncertain production forecasts. Investors in solar facilities, therefore, have benefitted from the certainty of the ITC while solar technology has developed and capital-intensive facilities have undergone construction.
>
> The PTC, in contrast, rewards actual production and delivery of renewable electricity to the power grid. Wind energy is particularly suited to the PTC because wind turbine technology was already quite mature when the U.S. wind energy industry began its buildup in the late 1990s. For wind energy developers, the question was not whether they could build operational facilities, but whether they could sell power at rates that were competitive with fossil fuel-based electricity. The PTC enables this competition by allowing qualifying facilities to earn a specified inflation-adjusted amount in tax credits for each kilowatt of electricity they deliver to the grid. The credits are available for the first ten years of a facility's operation. Although the value of the credits may decline if the market price of electricity reaches a certain level (and the subsidy is therefore no longer necessary), production levels do not affect the availability or value of credits. . . . Renewable energy experts attribute a substantial amount of the growth in renewable energy facilities, and particularly wind farms, to the PTC.

Melissa Powers, *Small is (Still) Beautiful: Designing U.S. Policies to Increase Localized Renewable Energy Production*, 30 WISC. INT'L L. J. 595, 607–08 (2012).

Perhaps the biggest concern with the use of tax credits and subsidies is their temporary nature. Since 1978, when Congress enacted tax incentives for wind power and solar power, those industries have expanded and contracted as tax incentives have varied. As Professor Hymel explains:

> [I]n 1992, Congress enacted the production tax credit (PTC) to further encourage the production of electricity from wind. At the time of enactment, Congress indicated that the credit was "intended to enhance the development of technology to utilize the specified renewable energy sources and to promote competition between renewable energy sources and conventional energy sources." After enactment, the wind industry took off and the United States quickly became the world leader in the development of wind technologies. In large part due to

> Congress's failure to make the production tax credit permanent and to adopt renewable production standards, the United States has since fallen behind while other countries have recognized the immense benefits from this renewable energy source.

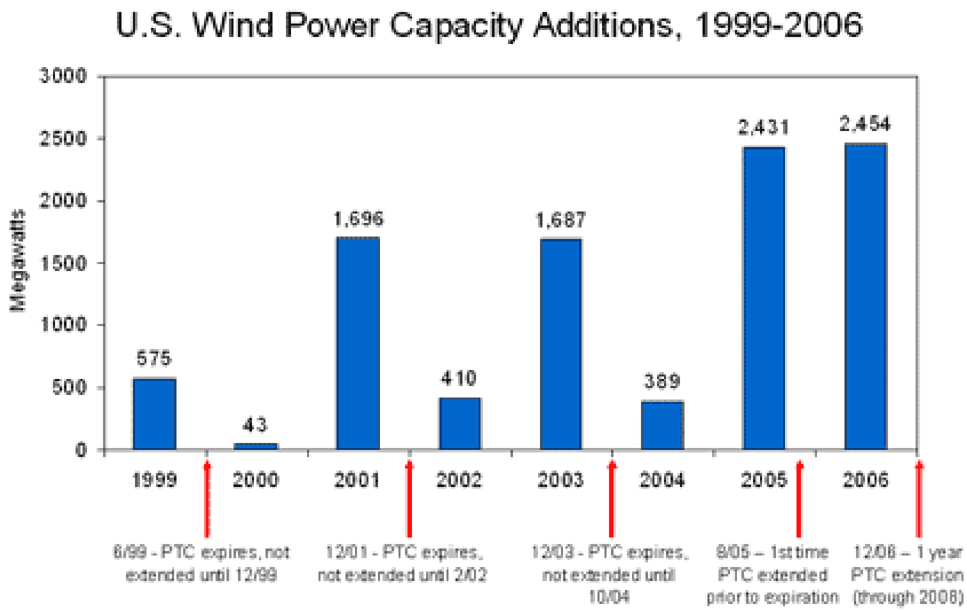
Hymel, at 75–76. Congress has since allowed the PTC to expire multiple times, only to renew it after investment in wind energy has plummeted. As of this writing, the PTC is in effect at least until the end of 2013. Wind advocates argue that the "on-again, off-again" nature of the PTC disrupts the industry's growth and puts it at a disadvantage to fossil fuel energy sources, all of which receive consistent tax incentives.

UNION OF CONCERNED SCIENTISTS, RENEWABLE ENERGY TAX CREDIT EXTENDED AGAIN, BUT RISK OF BOOM-BUST CYCLE IN WIND INDUSTRY CONTINUES

(Feb. 14, 2007)

From 1999 until 2004, the PTC had expired on three separate occasions. Originally enacted as part of the Energy Policy Act of 1992, the PTC — then targeted to support just wind and certain bioenergy resources — was first allowed to sunset on June 30, 1999. In December of 1999, again due to the efforts of UCS and other organizations, the credit was extended until December 31, 2001. The PTC expired at the end of 2001, and it was not until March 2002 that the credit was extended for another two years. Congress allowed the PTC to expire for the third time at the end of 2003. From late 2003 through most of 2004 attempts to extend and expand the PTC were held hostage to the fossil-fuel dominated comprehensive energy bill that ultimately failed to pass during the 108th Congress. In early October 2004, a one-year extension (retroactive back to January 1, 2004) of the PTC was included in a larger package of 'high priority' tax incentives for businesses signed by President George Bush. A second bill — extending the PTC through 2005 and expanding the list of eligible renewable energy technologies — was enacted just a few weeks later. [Editors' Note: Congress ultimately renewed the PTC at the last minute in 2007 and extended it a few times after that, usually at the eleventh hour. Most recently, Congress allowed it to expire at the end of 2012. It then renewed the PTC on January 3, 2013, for one more year.]

Combined with a growing number of states that have adopted renewable electricity standards, the PTC has been a major driver of wind power development over the past six years. Unfortunately, the "on-again/off-again" status that has historically been associated with the PTC contributes to a boom-bust cycle of development that plagues the wind industry (see Figure below). The cycle begins with the wind industry experiencing strong growth in development around the country during the years leading up to the PTC's expiration. Lapses in the PTC then cause a dramatic slow down in the implementation of planned wind projects. When the PTC is restored, the wind power industry takes time to regain its footing, and then experiences strong growth until the tax credits expire. And so on.



Source: American Wind Energy Association, 2007.

The last lapse in the PTC — at the end of 2003 — came on the heels of a strong year in U.S. wind energy capacity growth. In 2003, the wind power industry added 1,687 megawatts (MW) of capacity — a 36 percent annual increase. With no PTC in place for most of 2004, U.S. wind development decreased dramatically to less than 400 MW — a five-year low. With the PTC re-instated, 2005 marked the best year ever for U.S. wind energy development with 2,431 MW of capacity installed — a 43 percent increase over the previous record year established in 2001. With the PTC firmly in place, 2006 was another near record year in the U.S. wind industry. Wind power capacity grew by 2,454 MW — a 27 percent increase. The American Wind Energy Association projects similar growth in 2007.

Extending the PTC [for a short time] will allow the wind industry to continue building on previous years' momentum, but it is insufficient for sustaining the long-term growth of renewable energy. The planning and permitting process for new wind facilities can take up to two years or longer to complete. As a result, many renewable energy developers that depend on the PTC to improve a facility's cost effectiveness may hesitate to start a new project due to the uncertainty that the credit will still be available to them when the project is completed.

QUESTIONS AND DISCUSSION

1. The latest expiration and last-minute renewal of the PTC occurred at the end of 2012. Under the PTC in place at the time, facilities that came online by December 31, 2012 were eligible for the PTC. Practically speaking, this looming expiration date stifled investment in new development throughout 2012 because wind energy companies had no idea whether facilities that came online after January 1, 2013 would receive the tax credits. As part of the "fiscal cliff" negotiations of December 2012 and the beginning of January 2013, Congress agreed to another temporary extension of the PTC until December 31, 2013. However, unlike the previous PTC provisions, which required a facility to become operational by the deadline, the 2013 renewed PTC simply required development to begin by the end of 2013. Whether that alteration will change the boom-bust cycle is debatable.

2. The on-again, off-again subsidies have industry-wide impacts on costs and operations. For example, turbine prices often skyrocket during the last years of a multi-year PTC or during short-term extensions because turbine manufacturers know that wind developers are under the gun to get their wind farms built. The manufacturers might be seen as taking advantage of the developers, but they also have a rational economic incentive to hike up their prices, since the expiration of the PTC also results in declining turbine sales. Property owners can similarly demand significantly higher royalties if they know the wind developer must meet the PTC's deadline. Finally, laborers can command high prices during boom times but often face layoffs when subsidies expire. This can contribute to labor shortages and thus delayed development when the subsidies get renewed. Stability in the subsidies may keep prices lower overall and contribute to more sustainably paced development.

3. ***Should Credits Be Based on Production?*** Allowing wind developers to earn credits based on their amount of production can have positive and negative implications. On the positive side, production credits reward those facilities capable of delivering power to the grid and can promote significant growth in emerging industries. Indeed, the wind energy industry grew more than 1,500% from 2001 to 2011 partly because of the PTC.

However, production-based credits can have downsides as well. First, lack of adequate access to the transmission system can have significant impacts on wind companies. For example, during the spring of 2011, wind energy companies in Oregon lost an estimated $50 million in tax credits and other revenue when the Bonneville Power Administration curtailed wind companies' electricity deliveries due to an overabundance of hydropower and a lack of transmission capacity to deliver both hydro and wind power on the same lines. Second, production-based credits promote the development of large-scale facilities, even where a combination of large- and small-scale renewable sources might offer greater reliability and balance to the electricity system. Third, companies can become reliant on production-based credits, particularly when wholesale power prices decline and the market is otherwise soft. In other words, production-based credits can create a cycle of dependency for emerging technologies trying to compete in a system dominated by fossil fuels and price volatility.

4. In the American Recovery and Reinvestment Act of 2009 (ARRA), Congress gave renewable energy facilities that were normally eligible for the PTC the option of instead taking advantage of the ITC or a one-time Treasury Grant, both of which basically awarded qualifying renewable facilities a tax credit equivalent to 30 percent of their upfront costs (although there were differences between the programs). *See* Howard A. Cooper, *Tax Credits for Electricity from Renewables — Updated*, 125 TAX NOTES 221, 229-30 (Oct. 12, 2009). Many wind developers who did not think they could meet the December 2012 deadline for the PTC chose the ITC credit instead. Does this suggest that the ITC is a better policy? Should developers have the option of picking and choosing the subsidy that works best for them?

5. More generally, how should the federal government structure tax incentives for the renewable energy industry? On the one hand, renewable energy advocates argue that tax credits and other incentives are necessary to level the playing field with other industries, and that so long as other industries receive tax assistance, so should renewable. On the other hand, some policymakers believe that tax credits for renewable sources distort the market and drive up overall energy prices. Should renewable energy sources receive tax credits for an indefinite period of time? If not, what time frame is appropriate?

B. PURPA

The Public Utility Regulatory Policies Act (PURPA) was the first significant U.S. policy designed to promote renewable energy production. At the time of its passage, in 1978, the United States had struggled through several years of skyrocketing fuel prices and what appeared to be a persistent shortage of affordable electricity. Utilities, meanwhile, had spent the decade investing in nuclear power plants, most of which faced enormous cost overruns and many of which were ultimately canceled when energy forecasts proved over-ambitious and when the nuclear accident at Three Mile Island made the public turn away from nuclear plants. At the time of PURPA's passage, the nation still needed more power, but not enough to justify investment in large, capital-intensive, risky power plants. PURPA thus aimed to promote development of small efficient power plants, including renewable power facilities.

PURPA promotes power production from "qualifying facilities" (QFs), which include combined heat and power (CHP) plants and renewable energy facilities with a maximum capacity of 80 megawatts. 16 U.S.C. §§ 824a-3, 796(17)(A). To promote QF development, PURPA establishes three main requirements. First, utilities must purchase electricity from QFs. PURPA thus guarantees that QFs will have a market for their power. Second, under PURPA utilities must connect the qualifying facilities to the grid, to ensure that their electricity actually gets online, and sell electricity back to the QFs when they need supplemental power. Finally, PURPA establishes the presumptive rates utilities must pay for the power. These rates must equal the "full avoided costs" the utility would otherwise pay to produce or purchase the last unit of power it needs to buy. At the time of PURPA's passage, avoided cost rates were very high because most utilities would have needed to build new power plants to produce the last unit of power QFs would otherwise supply. Although FERC's regulations allowed QFs and utilities to enter into contracts that set different rates, QFs had significant bargaining power due to the avoided cost provision. Consequently, many new QFs came online after the enactment of PURPA, due to the favorable rates QFs could earn and the purchasing mandate for QF power.

PURPA had another important regulatory impact on the jurisdictional boundaries between states and FERC under the Federal Power Act. As noted above, FERC has exclusive jurisdiction over wholesale sales of power. Under PURPA, however, states are responsible for setting the avoided cost rates, so long as they adhere to FERC regulations establishing the factors states must consider. Since sales from QFs to utilities are wholesale sales (QFs sell the power to utilities which then resell the power to end users), PURPA creates an important exception to the otherwise exclusive role FERC plays in wholesale setting. As explored below in the discussion of feed-in tariffs, this exception may afford states considerable latitude for states to promote renewable energy production from smaller facilities.

QUESTIONS AND DISCUSSION

1. *The Role of States in Setting Avoided Cost Rates.* The states' role in implementing PURPA rests on somewhat shaky legal grounds under the Tenth Amendment of the U.S. Constitution. Under Section 210(f), PURPA directs states to implement FERC's rules regarding the purchasing and interconnection obligations for QFs. 16 U.S.C. § 824a-3(f)(1) ("after any rule is prescribed by the Commission . . . each State regulatory authority shall, after notice and opportunity for public hearing, implement such rule . . . for each electric utility for which it has ratemaking authority"). Mississippi challenged this provision, arguing it intruded on state sovereignty under the Tenth Amendment. *See* U.S. Const., Amdt. 10. "The powers not delegated to the United States by the Constitution, nor prohibited by it to the States, are reserved to the States respectively, or to the people." The Supreme Court, however, upheld PURPA on the basis that FERC's rules allowed states to simply resolve disputes between QFs and utilities and, since utilities have long played a role in dispute resolution, PURPA's implementation mandate was constitutionally permissible. Federal Energy Regulatory Commission v. Mississippi, 456 U.S. 742 (1982). Ten years later, however, the Supreme Court invalidated a federal law that "commandeered" the state into implementing federal law. New York v. United States, 505 U.S. 144 (1992). Although the Court in *New York* distinguished *FERC v. Mississippi*, the distinction largely focused on a different part of the PURPA unrelated to QFs. *Id.* at 161–62. It is unclear if PURPA's requirement that states implement it would survive another direct look by the Supreme Court.

This may make FERC wary of pushing states to aggressively implement PURPA. As a consequence, PURPA seems to have had the greatest impact in those states friendly to renewable energy and CHP development. QFs are concentrated in a handful of states that have had a long history of promoting renewable energy development. This may be because avoided cost calculations tend to be higher in states that want to support renewable power.

2. *PURPA Reform.* Many utilities entered into long-term contracts with QFs in the early- and mid-1980s, when avoided costs were quite high and projected to climb. By the late 1980s and early 1990s, however, avoided costs had declined and the utilities found themselves locked into 20-year contracts paying well above the market price for power. Frustrated with the contracts, many sought repeal of PURPA. Congress did not agree to a full repeal, but the 2005 Energy Policy Act did give FERC authority to waive PURPA's requirements in areas with competitive wholesale markets. FERC has exercised this authority in several instances.

3. *Feed-in Tariffs and PURPA.* As explored below, some renewable energy advocates have promoted the use of feed-in tariffs to promote new renewable power development. Feed-in tariffs have successfully spurred development of renewable energy in Germany and Spain, among other places. As you read about feed-in tariffs below, consider their similarities to PURPA.

C. Renewable Portfolio Standards

Renewable Portfolio Standards (RPSs) have become an increasingly common tool to promote renewable energy production. RPSs are state-level policies that direct utilities to produce or purchase a certain percentage of electricity from renewable energy within a specific period of time. These programs usually set interim targets as well, thereby ensuring progressive increases in renewable energy development. As of May 2012, twenty-nine states had RPSs, and another eight states had goals for renewable energy production or procurement. Despite (or perhaps because of) the growth of RPSs at the state level, many people have called for the development of a federal RPS system. This section thus introduces different aspects of state RPSs and then explores the arguments for and against a federal RPS.

1. *An Overview of State RPSs*

The specific requirements for RPSs vary from state-to-state according to each state's needs and, often, the type of power already available in the state. Some of the different approaches include the following.

- States have different quantitative targets and deadlines. California has the nation's most aggressive RPS, requiring utilities to obtain at least 33 percent of their power from renewable sources by 2020 (as interim goals, renewable energy must provide 20 percent of utilities' power by 2013 and 25% by 2016). Utilities in Illinois must obtain 25 percent of their power from renewables by 2026. Indiana establishes a voluntary goal of 10 percent clean energy by 2025. For a summary of all state RPSs, *see* the Department of Energy, Database of State Incentives for Renewables and Efficiency (DSIRE) website, http://www.dsireusa.org/incentives/allsummaries.cfm?SearchType=RPS&&re=1&ee=1.

- States also have different definitions of the type of energy that qualifies for the RPS. While most states include solar and wind power, some limit hydropower to certain types or sizes of facilities. Coastal states are more likely to include wave and tidal power than inland states. Some states include nuclear power, but many do not. Some states also include fossil fuels as eligible fuels. Indiana, Ohio, and Pennsylvania, for example, include coalbed methane and clean coal as eligible sources. Pennsylvania also makes waste coal an eligible source. The DSIRE website summarizes these requirements as well.

- Some states include "carve-outs" in their RPSs. Carve-outs specify that certain amounts of renewable power must come from particular resources, like solar power, or types of power, like distributed generation (generation at or near the location of consumption).

Beyond these different state requirements are the compliance tools states use to track compliance with RPSs. Most states require utilities to use Renewable Electricity Credits ("RECs") to demonstrate compliance with their RPSs. A REC usually represents either one kilowatt-hour or megawatt-hour of renewable power. Depending on a state's RPS, a utility may purchase either "bundled" or "unbundled" RECs.

Bundled RECs are identification numbers that demonstrate the electricity actually comes from an eligible renewable source. By requiring utilities to obtain bundled RECs, states are essentially requiring utilities to either produce or procure renewable electricity that actually reaches instate customers (or at least makes it onto the electricity grid). The RECs are considered "bundled" because the utility must obtain both the renewable electricity and the credits representing the renewable properties of the electricity. Bundled RECs may incentivize renewable electricity production closer to the site of consumption and therefore may be more likely to convey the benefits of renewable power to the utilities' own customers. However, bundled RECs reduce flexibility for utilities by forcing them to buy power from facilities located in close proximity to the state. Reduced flexibility may mean less availability and higher prices for renewable power.

In contrast to those states that require bundled RECs, many states allow utilities to purchase unbundled RECs — which are certificates representing the "renewable" component of the electricity — rather than the renewable electricity. Utilities can thus meet their RPS obligations simply by purchasing certificates without actually delivering renewable energy to their customers. Unbundled RECs thus typically emphasize cost control and flexibility over efficiency and localized benefits. States that allow unbundled RECs may authorize utilities to buy RECs from facilities located thousands of miles away from the utilities' customers. The utilities' customers may not receive any of the renewable electricity or localized benefits associated with renewable energy production; instead, these consumers receive the generalized benefit of supporting renewable electricity, even if the renewable power never enters the state. The cost of the unbundled RECs should be lower as a consequence because the utilities have greater flexibility to purchase the lowest-priced RECs. Moreover, for utilities in states with few renewable energy facilities, unbundled RECs present a good way for utilities to satisfy their RPS obligations without building their own renewable energy systems or paying a premium for the limited renewable energy that is available.

Many states allow utilities to trade RECs as well. Much like carbon credits under a cap-and-trade system, tradable RECs are sellable commodities used to comply with RPSs. RECs can also be used in voluntary programs in which commercial, industrial customers, or even residential consumers buy RECs in lieu of renewable power to be able to show their support renewable energy. Tradable RECs are by definition unbundled, in that the "renewable" component of the electricity is stripped from the power itself. While the power gets used immediately, the unbundled REC can be bought and sold multiple times until an entity uses it to demonstrate compliance with a mandatory RPS or relies on it to demonstrate support for renewable entity. Tradable RECs are meant to incentivize renewable energy production by allowing utilities to earn revenue when they purchase more power than they need to comply with a given RPS. They also assist renewable energy producers directly, which benefit from being able to sell two commodities: the electricity itself and the "renewable" aspect of the power. Some states increase these incentives by offering "multipliers" that reward producers with additional RECs when they produce certain types of power (such as solar energy) or produce power from certain locations.

QUESTIONS AND DISCUSSION

1. On a basic level, RPSs are quite simple: utilities must show that a specific percentage of their power comes from renewable sources. But in an effort to add flexibility to RPSs, state legislatures have made them increasingly complicated. Should regulators allow utilities to use unbundled RECs, or should they have to actually purchase renewable power? Should regulators allow utilities to trade RECs? What are the benefits and risks of creating new markets in renewable energy certificates? Consider the discussion of carbon markets in Chapters 7 (discussing international carbon markets) and 18 (discussing U.S. regional and state markets). Do you think REC markets require the same oversight and rules as carbon markets do?

2. *RECs and Utility Ratemaking Rules.* RPSs have complicated the regulatory landscape for utilities and public utility commissions (PUCs). Under the traditional ratemaking formula (R = Br + O), utilities earn a rate of return on capital investments in the rate base (Br), but not on operating expenses (O). Fuel costs, including wholesale electricity purchases, are considered operating expenses. So when a utility buys electricity from a renewable energy producer to comply with an RPS, the utility will be allowed to pass the costs of the electricity onto ratepayers, but it cannot put the cost of the mandatory purchase in the rate base. If the utility were to build its own renewable energy facility, however, it would be able to charge ratepayers the cost of building the plant times a rate of return. Despite this economic incentive for utilities to build their own facilities, most have chosen to simply purchase the renewable energy at wholesale. Why do you think that is? Should utilities be allowed to put the costs of complying with RPSs in the rate base? Why or why not?

Another issue regulators must resolve is how to treat tradable RECs. If a utility purchases more renewable power than it needs to comply with an RPS, it may be allowed to resell surplus RECs at a profit to other utilities that have yet to comply with their own RPSs. So, imagine Utility A purchases 100,000 RECs at $.10/kwh, but it only needs 80,000 RECs to comply with its RPS. At the end of the compliance period, Utility A sells 20,000 RECs to Utility B for $.20/kwh, earning Utility A $2,000 in profit. May Utility A keep the profit? Presumably, Utility A included the original cost of the RECs in its operating expenses and thus billed the ratepayers. If so, is it fair for the utility to charge the ratepayers for the original RECs and keep a profit? Some states say no and require any revenues utilities earn through REC trading to go back to the ratepayers. Is this a good idea? If utilities have no economic incentive to trade RECs, why have tradable RECs at all?

3. *More about Multipliers.* Multipliers can provide investors additional incentives to build certain types of facilities. But they may also present problems under the dormant Commerce Clause if, for example, a state provides multipliers for instate production or for production of certain types of power abundant in that state. Chapter 18 explores these dynamics in greater detail.

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2. *Is It Time for a National RPS?*

For a number of years, some renewable energy advocates have called for a federal RPS to further promote renewable energy production. Yet, Congress has repeatedly declined to enact one. In 2007, Congress considered and then rejected a bill that would have required electricity utilities to purchase a certain percentage of the energy from renewable energy sources. Only after this RPS provision was stripped from the Energy Independence and Security Act of 2007 did Congress pass, and the President sign, major federal energy legislation. Two years later, the House of Representative passed an RPS as part of the Waxman-Markey bill that would have created a domestic greenhouse gas emissions trading program, but the bill died in the Senate. Despite these failures, some people believe a national RPS will become law.

But is a national RPS a good idea? Scholars have debated this idea extensively. Those who favor a national RPS emphasize the complications involved in harmonizing REC markets between states with varied mandates, multipliers, and definitions of "renewable" energy. *See* Lincoln L. Davies, *Power Forward: The Argument for a National RPS*, 42 Conn. L. Rev. 1339 (2010). They also note that a federal standard could result in a much faster rate of renewable energy development. *Id.* Opponents of a national RPS fear it would result in a wealth transfer from states with relatively few utility-scale renewable resources to those with significant wind and solar resources. *Id*. Finally, they also fear it would erode state sovereignty, either by requiring states to purchase more renewable energy than they want or else by preempting more aggressive state RPSs.

QUESTIONS AND DISCUSSION

1. ***Are States Better Equipped to Manage RPSs?*** One of the arguments against a federal RPS is that most states already have renewable requirements, and a federal RPS would merely be redundant or conflict with the goals underlying state RPSs. Many states that have adopted their RPSs have done so to boost their own renewable energy industries or to reduce local pollution. If the federal government were to adopt its own RPS, there could be the potential for utilities to purchase RECs from out-of-state sources and thereby stifle their own state's industry or environmental goals. Does this suggest that federal lawmakers who want an RPS may be misguided in their approach?

2. ***Political Costs of a National RPS?*** Some people worry that the political costs of a national RPS may be too high and may result in federal preemption of more ambitious state mandates. Although Congress often passes legislation that establishes federal floors, rather that state ceilings, state RPSs have already led to a potential backlash by fossil fuel producers and customers who attribute renewable energy mandates to rising energy prices. For example, in November 2012, The Washington Post reported, "The Heartland Institute, a libertarian think tank skeptical of climate change science, has joined with the conservative American Legislative Exchange Council to write model legislation aimed at reversing state renewable energy mandates across the country." Juliet Eilperin, *Climate Skeptic Group Works to Reverse Renewable Energy Mandates*, WASH. POST, Nov. 24, 2012. How should efforts to reverse state RPSs influence the debate about a national RPS?

3. ***Stifling the Long-term Market.*** Another risk with existing state and proposed federal RPSs is their potential to stall out once utilities achieve existing targets. For example, under the proposed Renewable Energy and Energy Conservation Tax Act of 2007, once utilities attained the goal of purchasing 20 percent of their electricity from renewable sources by 2020, the RPS would have remained at 20 percent until 2039. The EIA found that the RPS would initially have spurred entry into the renewable energy market as it climbed from 2.75 percent to 15 percent. However, as the 15 percent goal neared, renewable energy producers would have little incentive to enter the market unless Congress enacted another RPS requirement extending beyond 2020. This uncertainty, which is also present in state RPSs that run through 2025, has been a primary concern of the renewable energy industry as it plans to move forward. Should policymakers start planning for the next phase of renewable energy development after 2025, or do you think the market should lead the way after then?

4. The 27 member States of the European Union have agreed to a mandatory target to derive 20 percent of their energy needs from renewable energy by 2020, including a 10 percent biofuels target. While setting an overall EU goal, the EU directive establishes specific targets for each Member State. Each Member State's share will be determined based on the amount of energy produced from renewable resources in 2005, as well as that country's population and Gross Domestic Product. Moreover, it allows trading of renewable energy through a "guarantee of origin" regime. This facilitates domestic or international trade in renewable electricity by creating a system to ensure that the electricity was created from renewable energy sources. Should the United States develop a similar regime?

D. Net Metering, Feed-in Tariffs, and Distributed Renewable Generation

States have generally used two policies, net metering and feed-in tariffs, to incentivize distributed generation. Distributed generation is power generation at or near the site of consumption; in other words, it is local power. Many renewable energy advocates, as well as the Department of Energy, have touted the potential benefits of distributed renewable energy generation to expand renewable energy development in urban areas. Net metering and feed-in tariffs are the two primary laws aimed at supporting distributed generation development. Net metering laws allow ratepayers to offset their electricity bills by producing their own renewable power and selling it back to the utility. Feed-in tariffs require utilities to pay incentive rates for power produced from certain types of renewable energy facilities. The following excerpt provides an overview of these policies and their potential legal and practical limitations.

MELISSA POWERS, SMALL IS (STILL) BEAUTIFUL

30 WISC. INT'L L. J. at 635–46

1. Net Metering

Net metering has thus far served as the dominant tool to promote distributed generation in the country. Almost every state has some form of net metering policy, and distributed generation advocates typically turn to net metering as a key policy to promote distributed renewable energy production.

Net metering laws provide an incentive for the installation of renewable electricity facilities by allowing existing utility customers to lower their overall electricity bills and, in some states, earn a profit by selling electricity back to the utility. The term "net metering" refers to the process by which utilities bill customers for their net electricity consumption. Net metering allows consumers to discount the amount of energy they deliver to the grid from their total electricity consumption. * * *

a. The Advantages of Net Metering

Net metering's primary advantage is that it pays participants retail electricity rates for some of the power they consume. An electricity bill charges a consumer a retail price for each kilowatt-hour of power consumed. This price includes the cost of producing or obtaining the actual power, plus the costs of managing and operating the grid, balancing supply and demand, providing other utility operations, and covering the utility's profit, if any. Without net metering, a consumer who also produced electricity would pay full retail price for any power consumed and sell any power it produced at lower wholesale rates. The existence of net metering thus allows a homeowner to earn full retail rates (which are often at least 3 times higher than wholesale rates) for much of the power she produces from her rooftop solar system.

Net metering also benefits from legal certainty. FERC has sanctioned the use of net metering, even though utilities had argued that it improperly forces them to pay retail rates for wholesale electricity sales. Under the Federal Power Act, FERC has exclusive authority over wholesale electricity rates except where states are implementing the Public Utilities Regulatory Policies Act ("PURPA"), in which case states have the authority to set the [avoided cost] rates for [qualifying] facilities. When states began developing net metering programs, utilities objected on the basis that any power sold from a distributed generation producer qualified as wholesale power and thus fell within FERC's jurisdiction or PURPA's avoided cost limitations. FERC, however, concluded that net metering laws could redefine the "sale" of electricity as occurring after deliveries of power to and from a distributed generation facility were netted out. Each delivery of power is not a sale under this rationale; instead, the relevant inquiry is what occurs in the aggregate.

FERC's ruling makes net metering an attractive incentive for distributed generation. If, in the aggregate, a distributed generator produces as much power as she consumes, she can zero out her electricity bill and effectively earn retail electricity rates for her power production. If she produces less power than she consumes, she can discount her self-produced power — again at retail rates — from the amount she owes the utility. Finally, if she produces more power than she consumes, she can earn retail rates on any power produced up to the amount of her consumption. Excess power delivered to the utility will be considered a wholesale sale, subject either to FERC wholesale rates or avoided cost rates set by the state. Under any of these scenarios, the key point is that distributed generators can earn retail rates for a significant amount of the power they produce. This is the primary advantage of net metering.

b. The Limits of Net Metering

Although net metering provides a significant benefit to distributed power producers by allowing them to offset their retail electricity rates, it nonetheless has limits that can impede its effectiveness as a stand-alone renewable energy policy. First, net metering offers rewards to those who have the initial capital to install distributed generation systems and thus serves a limited group of producers. Yet it offers no guarantee that investors will recover their costs or earn a profit on the power they produce. Second, most net metering programs limit eligibility and thus have only limited impact in many areas. Third, net metering does not always guarantee easy interconnection to the electrical grid or streamline transactions. . . .

First, net metering does not cover the upfront costs of the investment in renewable energy technology or interconnection. Instead, property owners must make the initial upfront investment in renewable technology, negotiate contracts securing delivery of power to the grid, and actually begin producing power before they receive any financial benefits from net metering policies. Although tax breaks and other financial incentives may assist property owners in purchasing the renewable energy technology, net metering itself does not support the development of renewable energy until the system becomes operative. Installation costs for the most common technologies, rooftop solar PV systems, start at $10,000 and range as high as $60,000. Under some net metering programs, the payback period for the system will be between fifteen and seventeen years, if the homeowner has received tax credits offsetting the installation costs. Indeed, without additional incentives, such as direct rebates or tax credits covering the cost of installation, net metering may not provide any economic benefit during the warrantee period of the facility. For many people, the upfront costs of renewable technology are prohibitively expensive. . . .

Second, net metering typically works for only a subset of potential distributed generators. Many states impose limits on net metering that reduce its effectiveness. Some states limit participation in net metering programs to certain customers, such as residential homeowners and commercial businesses, and thus exclude industrial entities that might have greater incentives and capacity to build distributed generation systems. Many states limit the size of eligible facilities and effectively discourage the development of commercial-scale distributed renewable energy systems. Finally, several states establish a low fixed cap on the aggregate amount of electricity net metering may support. . . .

Third, net metering policies do not necessarily insure easy access to the electricity grid or recovery of net metering payments. While some states have created standard contracts for net metering participants that ease the administrative hurdles of interconnecting distributed generation to the electricity system, many states require net metering participants to negotiate complex interconnection agreements and to secure permits that increase costs and decrease access to the system. * * *

2. Feed-in Tariffs

In recognition of the limits of net metering, many distributed generation advocates have turned to feed-in tariffs (“FITs”). FITs attempt to address the problems associated with high upfront costs of renewable energy development by providing a guaranteed rate of return on the investment in renewable energy technology and ensuring interconnection to the grid. FITs have become the dominant method of incentivizing renewable energy development in many other countries, most notably Germany. Motivated by the results FITs have achieved in these other countries, some renewable energy advocates have sought to import FITs to the United States. However, while FITs provide many advantages over net metering, they do not readily conform to federal law.

a. The Advantages of FITs

FITs have the potential to incentivize significant development of distributed renewable power. The specific designs of recommended FIT policies vary, but nearly all proposed FITs have a few common elements that distinguish them from net metering programs. First, FITs guarantee full recovery of the investment in the capital project plus a specific rate of return on that investment within a specified period of time. Unlike net metering programs, which may or may not repay the full costs of renewable energy facilities, FITs provide for complete repayment. Second, most FITs set the rate of return high enough to make an investment in renewable energy facilities attractive to a wide array of investors. Third, FITs provide certainty regarding the revenue investors will earn over a period of years. . . . Finally, FITs guarantee renewable energy developers streamlined access to the electricity grid. Collectively, these features make FITs economically and administratively attractive, as evidenced by their success in promoting renewable power in Germany, Spain, and other countries.

b. The Limits of FITs

While FITs seem to have worked quite well in Europe to incentivize renewable energy development, they may not meet the same success in promoting renewable energy development in the United States. Most significantly, state efforts to adopt the European FIT model face federal preemption. * * *

California's attempts to develop a feed-in tariff illustrate the potential and limitations of FITs within the current regulatory system. In 2009, California passed a law that guaranteed certain efficient combined heat-and-power ("CHP") plants premium rates and interconnection access. In an effort to avoid federal preemption, California's law required utilities to "offer" contracts to eligible CHP facilities. The utilities and other entities challenged the law, arguing that the requirement that utilities "offer" contracts was equivalent to wholesale price regulation. FERC agreed and held (as it has consistently held) that the federal government has exclusive jurisdiction over wholesale electricity rates except where QFs are involved. If, however, the facilities covered under the FIT qualified as QFs, FERC noted that states could set avoided cost rates for the facilities. In other words, FERC affirmed that PURPA limits state power over wholesale sales and therefore constrains states' efforts to establish FITs that might establish incentive rates for distributed generation.

A few months later, however, FERC issued a clarification that provides room for states to develop a type of FIT that could conform to avoided cost requirements under PURPA. Specifically, FERC acknowledged that states could establish different categories of avoided costs based on state rules governing renewable energy development, transmission line loss, and other state policies affecting energy efficiency and sustainability. As FERC explained:

> [I]n determining the avoided cost rate, just as a state may take into account the cost of the next marginal unit of generation, so as well the state may take into account obligations imposed by the state that, for example, utilities purchase energy from particular sources of energy or for a long duration. Therefore, the

> CPUC may take into account actual procurement requirements, and resulting costs, imposed on utilities in California . . .
>
> The Commission has previously found that an avoided cost rate may not include a "bonus" or "adder" above the calculated full avoided cost of the purchasing utility, to provide additional compensation for, for example, environmental externalities above avoided costs. But, if the environmental costs "are real costs that would be incurred by utilities," then they "may be accounted for in a determination of avoided cost rates."

Under this ruling, states do not have to tie all avoided cost calculations to prevailing wholesale market rates, which are currently driven by low natural gas prices. Instead, if states have RPSs in place requiring utilities to obtain a certain amount of power from renewable sources, they can calculate avoided costs for renewable energy separately. If the RPSs include specific mandates for distributed generation or solar energy, the avoided cost calculation can narrow in on the costs for those types of power. Additionally, if development of renewable sources will displace some need for transmission line construction, the avoided cost calculation can factor in these savings. In other words, avoided cost does not have to equal the least-cost resource, so long as states can show that the costs being avoided fit within the same pool of energy and so long as the costs are in fact "avoided," rather than externalized.

This ruling gives states that want to push up avoided cost rates many opportunities to do so. However, it also likely requires states to enact a number of other policies to justify their enhanced avoided cost calculations. For example, if a state wants to ensure that distributed generation receives adequate revenue, a state might need to establish a distributed generation carve-out that requires utilities to meet a portion of their RPS obligations with energy or RECs obtained from distributed generation resources. Distributed generation could then become a separate category for avoided cost calculations. Similarly, a state could include in the avoided cost calculation the avoided expenses associated with transmission line congestion and foregone transmission line construction. But this would require the state to gather data and actually do the calculations to justify higher avoided cost rates for distributed generation. The effort involved in revising RPSs and calculating avoided costs could dissuade many states from embarking on this path.

QUESTIONS AND DISCUSSION

1. ***Distributed Generation***. Distributed generation used to be the model of electricity generation before scientists discovered how to move electricity over high-voltage, long-distance transmission lines. The term simply refers to localized, small-scale distribution of power from a wider number of power sources. While the concept is simple, PUCs are only now beginning to adjust their regulatory policies to enable distributed generation to become a more prevalent element of electricity service.

In 1992, Amory Lovins published the seminal policy document outlining the benefits of distributed generation. *See* AMORY B. LOVINS ET AL., SMALL IS PROFITABLE: THE HIDDEN

ECONOMIC BENEFITS OF MAKING ELECTRICAL RESOURCES THE RIGHT SIZE (2002). The benefits of distributed generation include: siting flexibility, lower upfront costs (and thus less economic risk), reduced demand on transmission lines and thus greater transmission efficiency, and adaptability. *See generally id.* Since his article, the Department of Energy has endorsed distributed generation as a potentially important component of the U.S. electricity system. Notably (and perhaps counter-intuitively), distributed generation may improve the reliability of the electricity system by providing multiple sources of electricity capable of backing each other up. With better grid management and integration services, this vision of distributed generation could make the electricity system much more resilient overall. *See* Powers, *Small is (Still) Beautiful*, *supra*; *see also* U.S. DEP'T OF ENERGY, THE POTENTIAL BENEFITS OF DISTRIBUTED GENERATION AND RATE-RELATED ISSUES THAT MAY IMPEDE THEIR EXPANSION: A STUDY PURSUANT TO SECTION 1817 OF THE ENERGY POLICY ACT OF 2005 (2007); Garrick B. Pursley & Hannah J. Wiseman, *Local Energy*, 60 EMORY L. J. 877, 899–900 (2011).

2. *Understanding Net Metering.* Do you understand how net metering promotes renewable power and how FERC's ruling allows net metering to work? Recall from above the FERC generally has power over wholesale rates, while states have power over retail rates. Retail rates are usually three times as expensive as wholesale. Without net metering, a homeowner's sale of electricity to a utility would be a wholesale sale, for which a homeowner would receive very low payments. For example, imagine a homeowner buys 1,000 kilowatt-hours (kwh) from a utility at a retail price of $0.10 per kwh and sells a utility 1,000 kwh at a wholesale price of $0.03 per kwh. The separate transactions would look like this:

Homeowner's retail costs = 1,000 kwh * $0.10/kwh = $100.00
Homeowner's wholesale revenue = 1,000 kwh * $0.03/kwh = $30.00
Homeowner's net costs = Retail costs – whole revenue = $70.00

With net metering, the transactions are not separate. Instead, the homeowner will only pay for the net amount of energy it consumes. In this case, the homeowner's net costs will be zero because consumption = production:

Homeowner's energy use minus energy production = 1,000 kwh – 1,000 kwh = 0

If the homeowner used 1,000 kwh and produced 800 kwh, it would have a net retail purchase. Its electricity bill would look like this:

Amount of net energy = 1,000 kwh used – 800 kwh sold to utility = 200 kwh used
Homeowner's total retail costs = 200 kwh * $0.10/kwh = $20.00 owed to utility

If the homeowner used 1,000 kwh and produced 1,200 kwh, it would have net wholesale sale. Its electricity bill would look like this:

Amount of net energy = 1,000 kwh used – 1,200 kwh sold to utility = - 200 kwh = net sale to utility
Homeowner's total wholesale revenue = 200 kwh * $0.03/kwh = $6.00 owed from utility

In each of these examples, the homeowner has effectively earned retail rates for the power it produces and sells to the utility, up to the point the homeowner's consumption equals its production. Do you see how this works? Do you understand how this can provide a good incentive for homeowners to install renewable power?

3. *Utilities' Opposition to Net Metering*. California has one of the more substantial net metering programs in the country, which requires the state's three investor-owned utilities to allow up to 5 percent of peak energy demand to come from net metering. In 2012, the California Public Utility Commission (CPUC) determined that the utilities were calculating peak demand differently and thereby effectively capping net metering at about 3 percent of peak demand. When the CPUC proposed (and ultimately finalized) an order requiring utilities to achieve the 5 percent peak demand mandate, utilities pushed back, arguing that net metering was unfair for two reasons. First, they argued that net metering basically requires poor ratepayers who cannot afford the upfront costs of rooftop solar panels to subsidize wealthy ratepayers who can. Second, they argued that net metering is unfair because it requires utilities to provide distribution and transmission services for free to those customers who are able to use net metering to zero-out their electricity bills.

Professor Steven Weissman and Nathaniel Johnson produced a report challenging both arguments. STEVEN WEISSMAN & NATHANIEL JOHNSON, THE STATEWIDE BENEFITS OF NET-METERING IN CALIFORNIA & THE CONSEQUENCES OF CHANGES TO THE PROGRAM 2–3 (2012). First, they demonstrated that most people who have participated in California's net metering program come from median income neighborhoods. *Id.* at 11–13. They also argued that net metering should lower overall electricity costs in California because solar energy production promoted by net metering can provide distributed energy during times when utilities would otherwise need to pay high peak power prices elsewhere. *Id.* at 2–3. Moreover, while utilities may not be compensated for some net metering services, they are also avoiding costs of long-distance transmission and peak power management. *Id.* at 7, 10. What do you think of these arguments? If your neighbor installs solar panels on her home, do you think it is fair for her to be able to zero out her electricity bill when poorer customers likely cannot afford the upfront costs of their own solar panels? Should your neighbor have to pay for some utility services associated with delivering power to and from her house? If not, do you think net metering could be sustainable on a broader level?

4. *Solar Utilities?* Professor Joel Eisen has argued that net metering cannot succeed on a larger scale because it offers a very weak incentive when one considers the upfront costs of solar arrays combined with the long payback periods under most net metering programs. *See* Joel B. Eisen, *Residential Renewable Energy: By Whom?*, 31 UTAH ENVTL. L. REV. 339, 354–61 (2011). He also doubts that existing utilities will make serious efforts to promote solar power development. One solution, then, is the creation of new utilities whose sole missions are to deploy solar energy. *See* Joel B. Eisen, *Can Urban Solar Become a "Disruptive" Technology?: The Case for Solar Utilities*, 24 NOTRE DAME J.L. ETHICS & PUB. POL'Y 53 (2010). Like existing investor-owned utilities, the solar utilities would be able to bill ratepayers for the power and services they provide, but unlike investor-owned utilities who often favor traditional fuels, the solar utilities would focus exclusively on deployment of solar power, particularly in urban areas.

Some states have created energy efficiency utilities because traditional utilities lack the incentive to invest in energy efficiency. Should new solar utilities be created as well?

5. *PURPA and Feed-in Tariffs.* PURPA and feed-in tariffs have a few similar elements. Both require utilities to purchase power from specified facilities and both require utilities to provide the facilities access to the transmission grid. The main difference between PURPA and feed-in tariffs are the prices utilities must pay. Under PURPA, the utilities' avoided costs establish the presumptive rates for qualifying facilities. If avoided costs are low due to an abundance of supply and thus low wholesale rates, qualifying facilities may not receive much revenue for their power. Feed-in tariffs attempt to ameliorate this risk by guaranteeing renewable energy producers either a fixed price for their power or at least certainty that they will recover their full investment plus a profit on renewable energy facilities. Which solution do you think is better over the long term?

6. *Distributed Generation Carve-outs and RPSs.* Another option some states have pursued is mandating that utilities obtain, under RPSs, a certain amount of electricity from distributed generation. Utilities may then choose either to buy power and RECs from distributed generation sources or to build and install their own distributed generation facilities. If a utility builds its own facilities, it should be able to include the costs of the facilities in its rate base and thus earn a rate of return on those costs. Despite this economic incentive, most utilities have avoided building their own distributed generation systems. It is unclear why, but most observers think the nature of corporate culture at utilities contributes to this dynamic: simply stated, utilities tend to be large companies that lack experience in developing small-scale distributed power, and the economic incentives that exist are insufficient to reverse the inertia many corporations experience.

V. ENERGY EFFICIENCY AND CONSERVATION

Energy experts believe the United States could reduce its energy consumption by 25 to 40 percent simply through improving energy efficiency throughout the United States. Energy conservation efforts work to reduce overall energy use and to shift energy use out of peak usage periods and into off-peak times. These "peak-shaving" strategies have the potential to reduce overall energy production because U.S. energy generation is targeted at providing peak energy; to the extent peak energy demand declines, so will overall energy production.

The U.S. electricity system is not structured to encourage widespread energy conservation. In part, this is because prices established by PUCs reflect average costs of energy production. Since energy consumers are protected from paying the highest costs associated with providing electricity during peak use times, they are generally shielded from price signals that would otherwise encourage lower energy use. The following article identifies ways that regulators could restructure energy pricing to encourage energy conservation.

SIDNEY A. SHAPIRO & JOSEPH P. TOMAIN, RETHINKING REFORM OF ELECTRICITY MARKETS,

40 WAKE FOREST L. REV. 497, 528–41 (2005)

V. The Smart Consumption Model

A smart electricity generation policy will not displace the Traditional Model. It is, however, responsive to protecting the environment and serving other important national interests. The evaluative test for the success of the smart generation alternatives will come in the market, and, for this reason as well as others, the market must contain a pricing mechanism that is cost sensitive. We therefore turn next to new thinking about electricity pricing.

More specifically, this section investigates the potential of marginal cost pricing to promote energy conservation. Our analysis reveals that marginal cost pricing requires the installation of new meters that should result in significant energy conservation, which in turn will reduce some of the environment harm associated with electricity generation, and that the benefits of reduced consumption should outweigh the problems of achieving it.

A. Meters and Prices

Most retail consumers purchase electricity according to how much electricity they consume over some period of time, usually a month. The price usually does not vary, except possibly for fuel costs, even if the cost of producing the electricity goes up because retail prices are based on the average cost of producing and delivering electricity. By comparison, electricity production costs vary significantly by hour in almost all systems across the country.

Average cost pricing is used in large part because marginal cost pricing requires the use of meters that measure the time of day that electricity is consumed. If electricity prices are based on marginal costs, consumers will have an incentive to reduce electricity use during periods of peak demand or to switch to less expensive sources of energy because the cost of generating and delivering electricity is normally greater during such peaks. There is little marginal cost pricing in both regulated and unregulated generation markets because neither market generally employs meters that measure time-of-day demand.

1. Regulated Markets

Consumers do not pay any more for electricity when the costs of generating and delivering it increase in regulated markets (except for fuel costs) because the normal method of setting utility prices uses average cost. Regulators, however, could adopt marginal cost pricing if they required utilities to install time-of-use meters.

a. Traditional Regulation. Under cost-of-service ratemaking, regulators first determine the revenue requirement of a utility. Regulators calculate the revenue requirement by estimating the cost of producing electricity and how much money the utility must earn to provide a sufficient rate of return for stockholders and bondholders who invest in the company. Once the revenue requirement is determined, regulators determine the price that the utility can charge for each unit of electricity. Regulators can do this by dividing the revenue requirement by the quantity of electricity that they estimate the utility will sell, but regulators may also make adjustments to reflect differences in the cost of producing and transmitting electricity. For example, a commission will set a lower price for large industrial users because it is less expensive for a utility to deliver a large volume of electricity to one location than much smaller amounts to thousands of households. None of these prices reflect actual marginal costs since they are based on regulators' estimates of the differences in cost of providing service to different classes of customers. More importantly, once a price is established for a class of customers, it does not change over the period of time in which it is in effect. In other words, price is the average cost of producing electricity for that class of customers. Thus, even after these adjustments, other than the actual fixed price paid, there is no further incentive for any class of consumers under this regulatory system to use less electricity when the cost of producing it rises.

The current method of structuring prices does not take into account that the cost of producing electricity normally increases during periods of peak demand. The cost goes up for several reasons. During periods of peak demand, electrical utilities typically include older, more inefficient generation plants in their portfolio of generators, which are not normally used because they are more expensive to operate and because they cause more air pollution than other generation units. In restructured electricity markets, local utilities can purchase additional supplies of electricity from other generators, but the cost of electricity purchased from other suppliers can be expected to rise as demand increases unless there is sufficient excess efficient generation. Furthermore, the marginal transportation costs rise according to the distance over which electricity is transported because megawatts are lost in the act of transmitting electricity. In addition, the cost of transmission increases because high demand for electricity creates transmission congestion.

The cost differences between peak and non-peak demand can be substantial * * *

b. Regulatory Reform. If regulators decided to employ marginal cost pricing, there are a number of difficult issues that they will have to overcome. These include the choice of a pricing method, the scope of the marginal cost pricing, and methods to protect consumers who still purchase electricity from monopoly suppliers.

<u>*i. Pricing Method.*</u> Regulators have two general options to adopt marginal cost pricing: consumers receive rebates for reducing electricity usage during periods of peak demand or retail prices are actually based on the marginal cost of producing electricity.

a. Rebates. Under this approach, consumers are rewarded for reducing electricity use during periods of high demand. Thus, in this approach, consumers reduce their electricity loads in response to actual or forecasted demand. In return, they are entitled to rebates based on the amount that they reduce their electricity use during these periods of high demand. For example, a consumer might receive fifty percent of the amount of money a utility saves because the consumer reduced its electricity use during a period of high demand. The utility saves money because it does not have to generate (or buy) electricity for that customer at a time when the cost of producing the electricity (or buying it) has increased.

As compared to marginal cost pricing, this approach creates less incentive for consumers to reduce their electricity use because consumers capture only some percentage of the amount of money that the utility saves because it does not have to pay higher marginal costs to generate and deliver electricity. If, by comparison, marginal cost pricing is used, the consumer can save the full amount of the increase in cost. For example, if the marginal cost of producing electricity during a period of high demand is 50¢ per kilowatt ("kW") and the consumer is entitled to fifty percent of that amount, the consumer is entitled to a 25¢ rebate per kW. If, however, the consumer will have to pay the entire 50¢ per kW for any electricity used during a peak period, the consumer can save 50¢ for each kW that electricity usage is reduced or deferred to a period when prices are lower. Marginal cost pricing therefore provides more incentive for consumer to engage in conservation efforts. Nevertheless, this plan may be attractive to regulators because it protects consumers from a run-up in prices during periods of peak demand while still providing an incentive for consumers to reduce their electricity usage.

b. Variable prices. Regulators can also pursue marginal cost pricing through use of "time-of-use" or "real-time" pricing. In time-of-use pricing, meters record when consumption occurs (for example, hourly), and rates are assigned to time blocks much like monthly rates are presently assigned. For example, Florida Gulf Power normally charges customers three different rates (low cost, medium, and high cost) depending when the electricity is used. Real-time pricing, in contrast, uses an even smarter meter than the time-of-use meter to communicate the actual price of electricity in real time.

The biggest advantage of time-of-use pricing is that it is easier for consumers to understand and therefore for utilities and their regulators to embrace. Nevertheless, the incremental benefits of real-time pricing over time-of-use pricing may be significant relative to the small incremental cost of a real time meter over a time-of-use meter. Unlike real-time pricing, time-of-use pricing does not distinguish between hot days and cool days because the rate for blocks of time is set in advance. In addition, a key issue is how consumers will react to each type of pricing. Assuming that the time periods are designed such that the average customer consumes half of his demand during peak hours at 10¢ per kilowatt-hour ("kWh") and half during off-peak hours at 4¢ per kWh, consumers may behave as if they are charged 7¢ per kWh regardless of when power is consumed. By comparison, real time pricing seems more likely to cause consumers to engage in conservation efforts since they are immediately aware of the costs of not doing so.

Nevertheless, some critics claim real-time pricing will not work unless consumers have smart devices that shut off appliances when electricity costs rise or reduce the amount of electricity that they use. There are, however, a number of studies that indicate residential and small business consumers are able to shift their electricity demand in response to prices that vary by time.

Moreover, consumer response can be enhanced if utilities and regulators alert consumers to potential price increases. This would be similar to efforts to inform people about the quality of air during periods of potentially unhealthy smog. Most morning newspapers and television broadcasts convey this information to consumers. Similarly, the news media can warn consumers about weather conditions that will result in high demand for electricity and therefore higher electrical prices. Regulators could require utilities to maintain websites that indicate current prices, or even send email alerts, which may make it easier for consumers to keep abreast of changes in price.

The adoption of real-time pricing would also create a market demand for devices to assist consumers in reducing their energy costs. Utilizing a Smart Grid, as discussed earlier, real-time pricing meters can be designed to give consumers immediate information on the rate of consumption and the current cost per hour. It will also be possible to automate some consumer responses. For example, the meter can be connected to "smart" appliances that shut off or cut back on electricity use when they receive a signal of higher prices.

ii. Consumer Protection. When marginal cost pricing is used in monopoly electricity markets, regulation of prices will remain necessary to protect consumer interests. Regulators face three general challenges.

First, regulators will have to use ratemaking to establish a revenue requirement for a utility's costs other than the cost of producing electricity. The retail price would be composed of the marginal cost of producing and delivering the electricity plus the price set by regulators to permit the utility to recoup its other costs. Regulators would also need to verify that the marginal costs a utility charged were its actual marginal costs. For this purpose, regulators would need to establish in advance how marginal costs were to be calculated.

Second, regulators will have to address the problem that marginal cost pricing creates economic risks for consumers that did not exist previously because retail rates will vary, sometimes by substantial amounts. Economic theory would dictate that prices should be based on marginal costs regardless of volatility, but this result may not be consistent with a regulator's legal obligation to design regulation in a manner that protects the public. Moreover, the adoption of marginal cost pricing may not be politically feasible if consumers are exposed to price spikes and market volatility. At the same time, efforts to protect consumers against price spikes will reduce the extent to which marginal cost pricing creates an incentive to engage in conservation.

Regulators have a number of options to address this issue. They can make marginal cost pricing voluntary. Or, as noted earlier, they can adopt a rebate plan. Under this approach, consumers are protected against price spikes because they pay regulated rates for electricity. At the same time, they receive rebates for reducing the electricity load during peak periods, which encourages conservation or deferral. Regulators can also adopt a price ban that limits the amount that prices can be increased or decreased based on the marginal cost of producing the electricity, protecting consumers and utility investors. Whichever approach is adopted, regulators ought to make the ultimate objective to move as many consumers as politically and legally possible to marginal cost pricing.

Finally, regulators will need to consider the potential burden on low-income electrical consumers, who will be less able to afford to install energy saving products, such as better insulation, as compared to wealthier consumers. More accurately, these consumers would not be in a position to pay higher rents for housing if landlords took additional conservation measures and passed the costs on to their tenants. This reality suggests that low-income consumers will end up paying higher electrical bills. However, because low-income consumers generally live in small housing units, the amount of the increase may not be very great. Moreover, low-income consumers can avoid higher prices to the extent that they conserve electricity during periods of high demand. Nevertheless, even a small increase in price may be highly detrimental to low-income consumers. Some low-income consumers may not be able to reduce electrical use because, for example, they are unable to work and, therefore, are not in a position to conserve on air conditioning during the middle of the day, as compared to persons who leave for work.

There are a number of potential solutions to this problem. Regulators could exempt low-income consumers from installing more expensive meters, low-income consumers could be entitled to purchase electricity at lower rates, or they could receive a discount when they paid their bills. All of these methods, however, would require a subsidy from either other ratepayers, which could be part of the regulated portion of the price that utilities would charge, or taxpayers in the form of direct subsidies. Since welfare reform seems unlikely, regulators should attempt to address the issue of low-income consumers during regulatory reform.

2. Unregulated Markets

In competitive markets, sellers will continue to sell a product or service as its marginal revenue exceeds its marginal costs. Thus, short-run prices in competitive markets reflect marginal costs. In competitive generation markets for electricity, however, sellers cannot always charge consumers for electricity according to the time of day that electricity is produced. As in regulated markets, many consumers still have meters that measure only the total electricity consumed, but not the time during which it was consumed.

As a result, the market price does not fully reflect the marginal cost of producing electricity for consumers who lack new meters. Instead, they purchase electricity at a fixed price for some period of time, such as one month. A utility will calculate this fixed price based on an estimate of its average marginal costs for that month. While this approach is closer to marginal cost pricing than occurs under traditional cost-of-service ratemaking, it still does not reflect changes in the cost of producing electricity at different times of day or on different days within the billing period.

B. Prices and Conservation

Economic theory predicts that consumer demand will fall as the price of a product or service goes up. Thus, if consumers pay higher prices for electricity during periods of higher demand, the demand for electricity should fall. This “economic law,” however, is subject to some important caveats. The extent to which consumers will reduce demand depends on the elasticity of demand. If consumers do not have a readily available substitute for a product or service, demand will not fall as rapidly as when less expensive substitutes are available. Consumers have three potential substitutes for purchasing electricity: They can reduce demand during peak periods when prices are higher, invest in products that reduce energy use, or switch to lower cost sources of energy. According to economic theory, consumers will choose these options only if they cost less than paying for more electricity, and the consumer will choose among these options based on their comparative costs.

While all three of these options will reduce the demand for electricity, the last may not produce an environmental improvement if consumers switch to an alternative source of energy that creates as much or more pollution. For example, some consumers may switch to a diesel unit that produces pollution emissions that greatly exceed those produced by the plant whose electricity the consumer is replacing. Most households, however, are unlikely to keep a generator in the backyard, and most industrial users will likely rely on less expensive sources of energy, such as natural gas, to fuel self-generation.

Since marginal cost pricing is not widely used, there is only limited evidence concerning the extent to which consumers will reduce demand in response to higher prices. The results of voluntary programs, however, suggest that it will be possible to obtain significant reductions of demand during periods of peak usage. A program offered to industrial users by the Georgia Power Company, for example, has produced as much as a 500 MW reduction in the utility's load, which represents about ten percent of the utility's total industrial demand. When the utility charges its highest prices, it gets an eighteen percent reduction in demand. Similarly, a voluntary program for industrial users in New York took an average of 668 MW in load off the grid during the hottest summer days, which is the equivalent of the generating capacity of a large turbine power plant.

There have also been positive results concerning residential consumers. Residential consumers who volunteered for a variable rate program offered by Gulf Power in Florida consumed only 20% of the power they purchased during high-cost periods, producing an annual average 14% savings in their electricity bills. An experimental plan in California that used marginal cost pricing including a very high price for critical peak periods resulted in a reduction of over 12% in peak demand. A marginal price plan that did not include a critical rate produced a 4% decrease in demand during peak periods. Prices during the peak period were about three times higher under the plan with the higher prices.

These results suggest that at least some industrial and residential consumers will reduce demand in response to price increases or rebates. The critical issue is how many consumers are sensitive to price and how they will act when prices go up (or when there is an opportunity to earn a rebate). Some commentators predict that many residential consumers will not react to high prices by reducing electrical use during peak periods of demand, at least in the short run. This will happen if the purchase of more energy-efficient appliances or of more insulation costs more than paying higher electricity bills, which may be the situation for persons who do not consume much electricity, even during periods of peak demand. Since, however, the benefits of lower demand are benefits for everyone using electricity, these commentators argue regulators may be justified in using additional financial incentives to encourage conservation. This argument anticipates that the cost of the incentives will be substantially less than the benefits of protecting the environment and having a more reliable and less expensive generation and delivery system. Fifteen states currently have established benefit funds for this purpose funded by a small charge of all kWh flowing through the transmission and distribution grids.

C. Capital Costs

There are good reasons to believe that marginal cost pricing (or some variation of it) will lead to conservation efforts by at least some consumers. Marginal cost pricing will cause consumers to use less electricity during periods of high demand and, to the extent that such use cannot be rescheduled to periods of lower cost, to purchase energy saving products. Nevertheless, for this reform to succeed, regulators will need to require utilities to install new meters in millions of homes and small businesses. Although this is by no means an inexpensive proposition, it does appear to be cost-effective. * * *

The actual total cost, however, would be less since it would be offset by the amount of money that consumers would save by decreasing peak purchases in favor of cheaper power during non-peak periods. While it is difficult to estimate how much money people will save, rudimentary calculations suggest consumers should quickly recoup the cost of the new meter. For a ballpark estimate, assume that the capital markets require a 10% internal rate of return on the investment in metering over a ten year period. Annual savings of about $4 billion per year would be necessary to generate such a return on investment. Since residential consumers spent over $100 billion on power in 2002, a 4% reduction in energy costs would be sufficient to amortize the investment in metering. * * *

This analysis suggests that large electricity consumers should be able to recoup the cost of the meters without much difficulty. For example, the Marriott Hotel in New York saved more than $200,000 in the first summer of experimental testing of Consolidated Edison's real time pricing by reducing its use of energy during peak periods of demand. The experience of residential consumers, however, indicates that they also will be able to recoup the cost of a new meter through decreased demand or shifts in the use of electricity. Customers of Gulf Power in Florida who purchased electricity under a voluntary variable rate plan saved, on average, 14% on their annual electricity costs.

There are additional savings. Capital costs will be saved as peak day loads grow less rapidly than total demand due to consumption switching away from peak periods. It is difficult to know how much money will be saved by additional conservation by consumers, but the United States is facing a very large bill for construction of new generation and transmission facilities in the next decade. A study commissioned by Edison Electric Institute estimates that $56 billion of transmission investments will be required during the current decade. The Energy Information Agency, an arm of the U.S. DOE, estimates that 88 gigawatts ("gW") of generation will be required by the year 2010. Using industry rules of thumb, 88 gW of capacity would require an investment of between $26 billion and $44 billion.

Moreover, the potential to save money is substantial because this household use of electricity in the residential segment is the largest consumer of power, and more importantly, it has the lowest load factor of the three major market segments. The residential segment accounts for about 37% of annual electricity consumption, while the commercial and industrial segments represent 32% and 28%, respectively, of demand. The amount of electricity consumed, however, understates the true burden that the residential segment places on the power grid. Since power cannot be stored, each utility must have the ability to generate or purchase enough power to meet peak day demand; therefore, peak usage is a better indicator of the demand that a segment makes upon the power grid. Assuming 40%, 60%, and 80% load factors for residential, commercial, and industrial consumers, respectively, residential consumers represent 51% of peak day demand, while commercial and industrial consumers represent 30% and 19%, respectively.

Experimental programs appear to confirm the previous analysis. A pilot program in Little Rock, Arkansas found that each new real-time pricing customer helped to avoid the installation of 1.5 kW of electricity, saving $1,200 in capital costs. The net savings was $350 per customer after paying $850 to install the necessary metering.

QUESTIONS AND DISCUSSION

1. *Real-time Pricing*. What are the conservation benefits of real-time pricing? Policymakers believe real-time pricing sends consumers price signals that will encourage them to reduce their energy use that consumers will restrict their energy use during the times of the day when energy rates are highest. But does this necessarily mean that overall energy use will decline, or simply that consumers will use the same amount of energy but adjust the times when they use it?

2. *Real-time Pricing and the "Smart Grid."* For real-time pricing to work, many analysts believe consumers must have instantaneous feedback on their power consumption and prices; after-the-fact information about the prices consumers paid in the past does not have the same impact in changing consumers' behavior. The development of real-time information and energy use is part of the broader concept of the "Smart Grid." The term basically refers to a modern, digitized, integrated, and efficient system of transmitting and delivering electricity. It also often includes the use of smart meters to provide consumer information. While most policy analysts support the development of a smart grid and smart meters, it is an incredibly expensive and time-consuming endeavor.

3. *Conservation and Efficiency Programs.* The federal government has employed a number of programs to promote energy conservation. For example, the Energy Star program identifies products, such as appliances, that meet certain efficiency requirements. The Environmental Protection Agency and Department of Energy oversee the program, establish the efficiency requirements, and certify those products that meet the requirements. The agencies estimate that Energy Star resulted in a 40 million metric ton reduction in greenhouse gas emissions in 2007. Green building techniques, which focus on resource efficiency, are also promoted through the Energy Star program. In addition, the U.S. Green Building Council has promoted sustainable building through its Leadership in Energy and Environmental Design (LEED), which sets rigorous requirements and rewards "green builders" with LEED certifications for qualifying buildings. Public utilities and many state governments also promote energy efficiency through rebates and other financial incentives.

4. *The Jevons Paradox*. In 1865, the English economist William Stanley Jevons turned his attention to the increasing use of coal to power England's industrial revolution. Given the possibility of diminishing coal supplies, Jevons concluded that "we cannot long continue our present rate of progress." In searching for ways to prolong the use of coal, he rejected efficiency as a policy strategy: "It is a confusion of ideas to suppose that economical use of fuel is equivalent to diminished consumption. The very contrary is the truth." THE COAL QUESTION (1865). Jevons neatly captured this paradox by noting that energy efficiency may increase energy consumption:

> The number of tons of coal used in any branch of industry is the product of the number of separate works, and the average number of tons consumed in each.

> Now, if the quantity of coal used in a blast-furnace, for instance, be diminished in comparison with the yield, the profits of the trade will increase, new capital will be attracted, the price of pig-iron will fall, but the demand for it increase; and eventually the greater number of furnaces will more than make up for the diminished consumption of each. And if such is not always the result within a single branch, it must be remembered that the progress of any branch of manufacture excites a new activity in most other branches, and leads indirectly, if not directly, to increased inroads upon our seams of coal. . . . [T]he more we render it efficient and economical, the more will our industry thrive, and our works of civilization grow.

Id. The extent or even existence of the Jevons Paradox, since recast as the "Khazzoom-Brookes postulate," after the economists Daniel Khazzoom and Leonard Brookes, has been quite acrimoniously debated. *See* Horace Herring, *Does Energy Efficiency Save Energy: The Economists Debate*, OPEN UNIVERSITY ENERGY AND ENVIRONMENT RESEARCH UNIT REPORT, 74, (July 1998). For example, energy efficiency may be relatively large compared to the increase in use of fuel. Nonetheless, there is mounting evidence that at the national level it is not uncommon for total resource consumption to grow even while efficiency improves, suggesting at least that improvements in efficiency are not necessarily sufficient for curtailing consumption (although, once again, this does not necessarily demonstrate that resource consumption grows *because of* improvements in efficiency). Moreover, what might be true at the microeconomic level may not be true at the macroeconomic level:

> . . . At this microeconomic level, for instance in the case of an individual household, savings that are made through, for instance, improved insulation, release money that will be spent on other goods. These will entail some energy consumption, creating a "rebound effect," but in practice the money that has been released, which was previously being spent essentially on either primary fuel (e.g. gas or oil) or on electricity, is unlikely to be spent on anything equally energy intensive. Absolute reductions in energy consumption are thus possible at the microeconomic level.
>
> However, this does not mean that an analogy can be made with macroeconomic effects. Apart from anything else, the substitution effects observable at the macroeconomic level cannot be replicated by households, where demand for a range of goods is relatively inelastic. If energy becomes, in effect, cheaper, there is very limited scope for the individual simply to divert money, say from food to energy. A business, on the other hand, could respond to cheaper energy by deliberately increasing consumption — using a more energy intensive process, which would allow savings to be made elsewhere, for instance in manpower.

United Kingdom, Parliament, SELECT COMMITTEE ON SCIENCE AND TECHNOLOGY, SCIENCE AND TECHNOLOGY: SECOND REPORT, paras. 3.8–3.9 (2005). Assuming, despite these uncertainties, that the Jevons Paradox is true, what policies can be employed to avoid it?