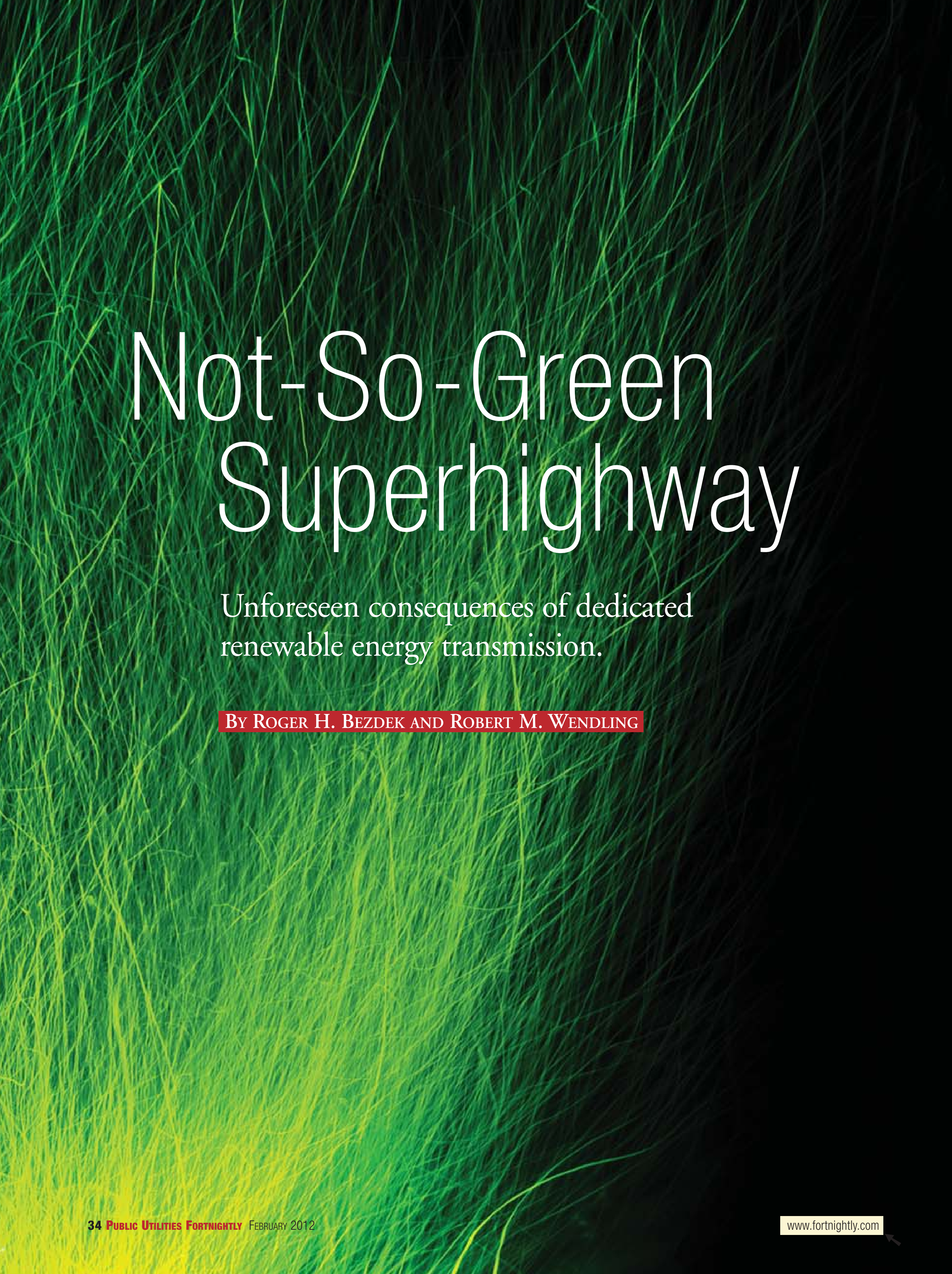


Not-So-Green Superhighway

Unforeseen consequences of dedicated renewable energy transmission.

BY ROGER H. BEZDEK AND ROBERT M. WENDLING

Growth in renewable electricity (RE) generation will require major expansion of electricity transmission grids, and in the U.S. this could require building an additional 20,000 miles of transmission over the next decade—double what's currently planned. To facilitate this, government policymakers are planning to build what are sometimes called "green" transmission lines that are restricted to carrying electricity generated by renewable sources, primarily wind and solar.

However, state and local jurisdictions are resisting siting of transmission unless it serves local constituents and existing power plants. If such transmission is built and local access is allowed, then the major beneficiaries of the added transmission might be existing power generation facilities, especially coal plants. Many of these facilities have very low electricity generating costs and their capacity factors are transmission-constrained. Their access to added transmission lines could enable them to sell electric power at rates against which RE can't compete.

20,000 Miles of Wire

JP Morgan studied a possible federal renewable energy standard (RES) and its impact on the growth rate of RE.[1] We used JP Morgan data to estimate the potential impact of an RES and the transmission required to facilitate it on the existing fleet of power plants. The analysis focused primarily on coal plants because they can increase their capacity factors, whereas U.S. nuclear plants already have capacity factors above 90 percent. Given the location of the coal plants throughout the U.S. and their current capacity factors, we estimated the impact of expanded electricity transmission lines on RE generation and costs and on conventional electricity generation and costs.

The locations of the RE central station technologies and their distances from major load centers largely determine the new transmission that will be required. Geothermal will be installed in a small number of Western states,[2] while biomass will be installed primarily in the northern Great Plains, the Pacific Northwest, and perhaps parts of the South. Solar thermal (ST) and photovoltaics (PV) will be installed in some Western and Southwestern states, and wind will be installed primarily in the northern Great Plains.

The major load centers are primarily metropolitan areas in the coastal states, the Boston-Washington corridor, the West Coast corridor, and major Midwestern cities. In general, increased transmission capability is desirable, because a robust interstate electric transmission system is in everyone's interest—consumers, power producers, and governments. An expanded transmission network will allow for power system growth, provide greater flexibility in expanding generation at existing plant sites, and facilitate construction of new generating plants at optimal locations.

However, there's a mismatch between RE resources and load centers: Most of the best RE sites are west of the Mississippi river, but most of the load centers are east of the river or on the West Coast. Even West Coast load centers are far from the best RE sites. We estimated how much new transmission needs to be built to transmit RE electricity to the load centers, and made assumptions as to what RE electricity will be transmitted to which load centers. While some RE plants can serve load centers in Southern California, Phoenix, Denver, Salt Lake City, etc., most of the RE electricity produced will have to be transmitted to load centers east of the Mississippi. Thus, major new transmission lines will be required from the Southwest and northern Great Plains states to load centers in the Midwest and the East. Most of these lines don't currently exist, and much new transmission will have to be built over the next decade to transmit renewable energy *(see Figure 1)*.

New transmission required by renewable energy could enable expansion of coal-fired generation by the equivalent of 30 new plants by 2020.

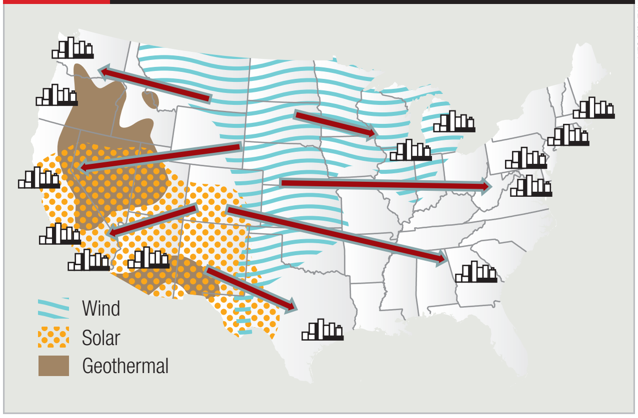
The distances involved are significant; for example:

- 700 to 1,000 miles from the northern Great Plains to the Midwestern load centers;
- 1,200 to 1,500 miles from the northern Great Plains to the load centers in the Boston-Washington corridor;
- 1,000 to 1,300 miles from the northern Great Plains to the West Coast load centers;
- 1,100 to 1,400 miles from the Southwest to the Midwestern load centers;
- 1,600 to 2,000 miles from the Southwest to load centers in the Boston-Washington corridor; and
- 1,600 to 1,900 miles from Iowa to the West Coast load centers.

It's difficult to estimate precisely how much additional transmission a mandated RES would require. Nevertheless, given the distances between RE generation sites and major load centers, the new transmission required to enable an RES could total

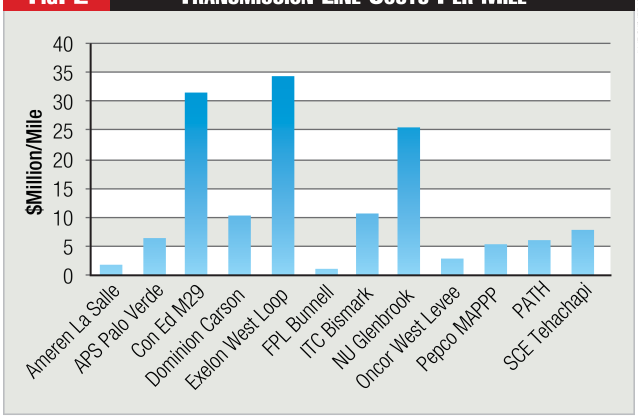
Roger H. Bezdek (rbezdek@misi-net.com) is president of Management Information Services Inc., and **Robert M. Wendling** is a vice president with the firm.

FIG. 1 REQUIRED GREEN POWER SUPERHIGHWAYS



Source: AWEA and SEIA

FIG. 2 TRANSMISSION LINE COSTS PER MILE



Source: EEI and EPRI

10,000 to 20,000 miles of lines. To put this in perspective, NERC estimates that planned transmission additions in the U.S. will total about 20,000 miles through 2019.[3] Thus, the transmission lines required by an RES could nearly double transmission requirements over the next decade.

There are two major problems associated with the required new lines. First, they will have to cross numerous states to reach the load centers. Permitting would require approval of the states, local authorities, and impacted landowners, who have often thwarted transmission expansion in the past. To avoid delays, the federal government would need authority to mandate routes and to declare eminent domain. While FERC has some authority, it isn't clear how long challenges to federal preemption might last, slowing final route approvals and transmission construction. Granting this kind of federal preemption likely will cause substantial political controversy, the duration of which isn't predictable.

Second, investors won't commit funds to install RE without the assurance that the necessary transmission lines will be available, and federal exercise of eminent domain ahead of RE facility construction might prove to be essential.

Coincident with the construction of the transmission and RE plants must be the addition of backup power supplies,[4] firm demand-response capacity, or both. If those resource additions are delayed, then the RE power generated might have difficulty accessing markets, because large quantities of widely varying electric power from wind and solar facilities might exceed the ability of existing power grids to accommodate.

The costs of backup power resources, as well as the new transmission capacity, ultimately will be charged to power consumers. The capacity of the transmission lines needed to move RE power must be sized to at least the nameplate capacity of the RE technologies, if the maximum amount of RE power is to reach markets. However, the average capacity factor of, for example, wind in the Great Plains is less than 40 percent, which means that more than 60 percent of the transmission capacity would be unused, resulting in much higher transmission costs than if the lines were more fully loaded. Locating backup power generating capacity near RE sites can make greater use of transmission capacity and reduce cost penalties.

In principle, once the approximate number of miles of required new transmission is estimated, the total cost can be projected by multiplying by the average cost per mile. Unfortunately, transmission costs per mile vary greatly *(see Figure 2)*. Most of the new RE transmission will be through rural or semi-rural areas, but as transmission lines approach major load centers costs will escalate rapidly.

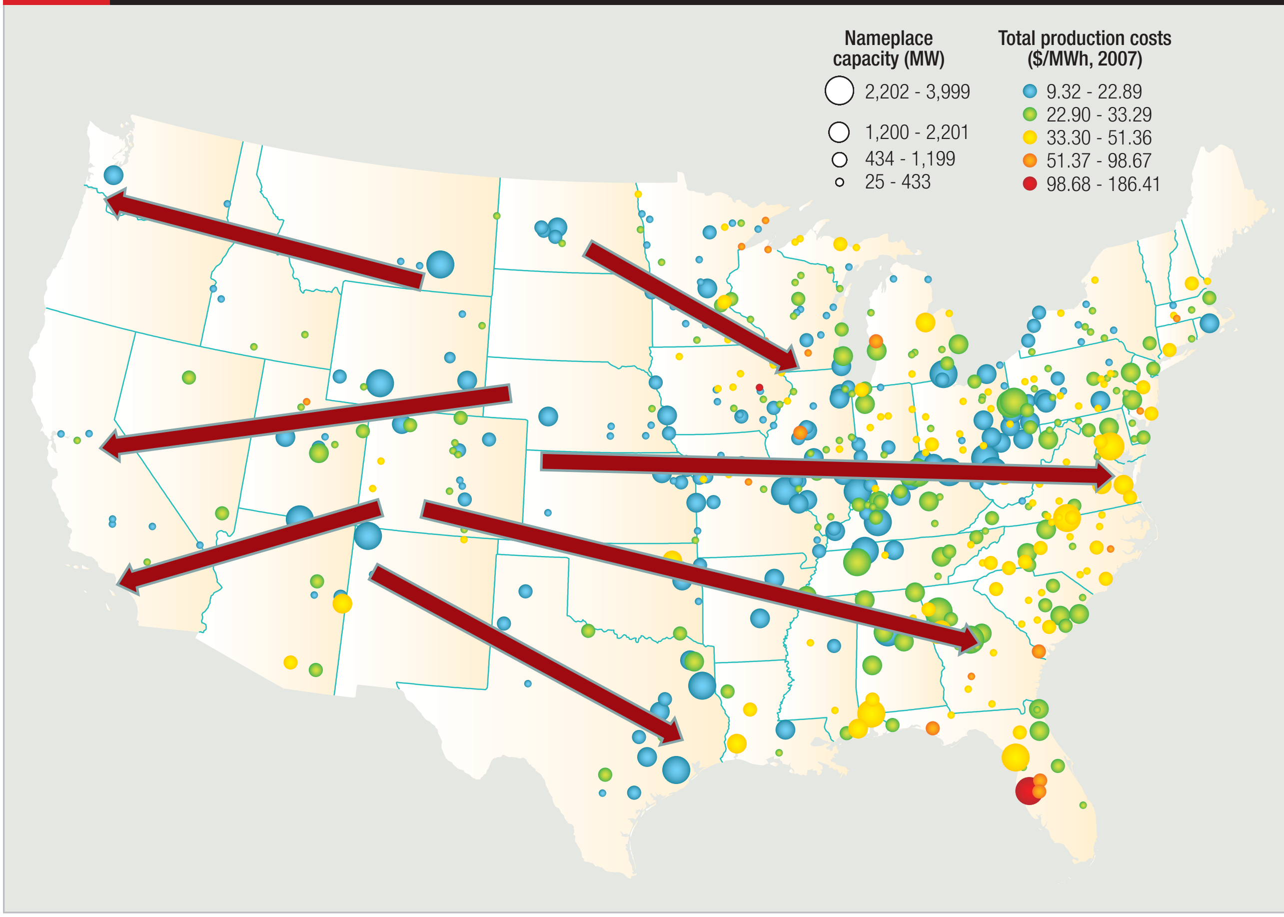
Using FERC estimates of required new transmission and independent figures for transmission costs, analysis yields an estimated cost of about $80 billion to construct the 14,500 miles of new transmission that FERC expects will be necessary by 2016.[5] With this estimate as a benchmark, the new transmission required by an RES could cost between about $50 and $100 billion.

However, even this estimate might be conservative, and transmission costs to enable an RES might be much higher.[6] Nevertheless, this estimate is generally comparable to others that have been developed.[7]

Coal Plants and Green Transmission

If additional transmission is built to accommodate an RES, a key question involves whether these transmission lines will be restricted to carrying only RE-generated electricity. Green transmission bills have been introduced in Congress to restrict new transmission exclusively to RE-generated electricity.[8] Congress also has enhanced the power of the federal government to enable transmission projects with multi-state importance to be assessed on more broadly based national interests, and the *Energy Policy Act* of 2005 (EPAct) provided FERC "backstop" transmission siting authority. States retain primary siting responsibility, but under certain circumstances the applicant may seek siting authority from FERC.[9] However, it isn't clear that EPAct provides a meaningful federal alternative if a state denies a transmission project.

FIG. 3 **GREEN POWER SUPERHIGHWAYS AND COAL PLANTS**



Source: Management Information Services Inc.

For example, Arizona regulators rejected a transmission line to connect Arizona generation with California electric consumers. In 2005, Edison International proposed a power line that would stretch from a substation 50 miles west of Phoenix, Ariz., to Palm Springs, Calif. Edison contended that the line would ensure reliable supplies of electricity for Southern California and bring the region renewable energy. However, Arizona opposed Edison's proposed power line. The dispute over the $774 million project initiated a struggle in Washington, D.C., over whether the federal government should seize more authority from states over the approval of transmission lines, since state regulators want to protect their authority.[10] Notably, after Arizona regulators rejected the proposal, Edison offered concessions to give Arizona utilities access to the line. This might indicate the ultimate fate of green transmission mandates.

Further, a federal court ruling might have negated FERC's backstop authority, and this decision could enable states to deprive FERC of backstop siting authority by timely rejection of a transmission project application.[11] Thus, there might be no way to prevent existing coal plants from using transmission lines built to serve RE facilities that can use them, on average, only about 30 percent of the time—nor is it economically desirable to do so, especially if that capacity allows otherwise inaccessible generation to reach power markets.

It isn't known precisely how much unused coal plant generation capacity would be available for use if current transmission constraints were alleviated. A meaningful calculation would require detailed analysis of the entire electric power system and how it's likely to evolve. Further, proper electric system management requires a 15 percent excess capacity margin, and a detailed analysis of the whole system would be needed to determine how much of the reserve capacity in various parts of the country is assigned to coal plants versus other power sources.

Any excess generation capacity that currently exists likely will become more fully utilized as the economy recovers, and eventually new generation capacity will be required.[12] The potential implications of new transmission lines for existing coal plant capacity factors depend on geographic factors related to RE resources in each region *(see Figure 3)*.

- For biomass and wind generation going from the northern Great Plains states to the Midwest load centers, lines would have to pass close to coal plants in North Dakota, Minnesota, Wisconsin, Iowa, Missouri, Illinois, Indiana, Kentucky, Ohio, and West Virginia.
- For biomass and wind generation going from the northern Great Plains states to load centers in the Boston-Washington

corridor, lines would have to pass close to coal plants in North Dakota, Minnesota, Wisconsin, Iowa, Missouri, Illinois, Indiana, Kentucky, Ohio, West Virginia, and Pennsylvania.

- For biomass and wind generation going from the northern Great Plains states to West Coast load centers, lines would have to pass close to coal plants in North Dakota, Minnesota, Montana, Utah, Colorado, Wyoming, and Arizona.
- For geothermal, ST, and PV generation transmitted from the Southwest to the Midwestern load centers, lines would have to pass close to coal plants in Arizona, New Mexico, Utah, Colorado, Kansas, Nebraska, Missouri, Illinois, Indiana, Kentucky, Ohio, and West Virginia.
- For geothermal, ST, and PV generation transmitted from the Southwest to the West Coast load centers, lines would have to pass close to coal plants in Arizona, New Mexico, Utah, and Colorado.

What does the proximity of new transmission lines to many existing coal plants imply for utilization of these plants? Ideally, an analysis would estimate the carrying capacity of the different lines, how close they are to which coal plants, the capacity utilization of each plant, the cost of electricity output from each plant, and projections for all of these, etc.

Alternately, a simpler analysis can use estimates of the average coal plant capacity factor and an average coal levelized cost of electricity (LCOE). Existing coal plants are, except for some large hydro projects, the least expensive means of electricity production. Coal plants produce about 50 percent of U.S. electricity, and 23 of the 25 power plants in the U.S. with the lowest operating costs are coal-fired. In states where coal is widely used, electricity production costs and rates are the lowest, and states using coal to generate most of their electricity have electric rates that are only about half those of other states. Thus, the current fleet of coal plants produces cheap electricity—4 to 6 cents per kWh, the average used in this analysis.

Real Costs of Renewables

Deriving accurate, comparable LCOE estimates for RE is difficult, and it might not even be possible to meaningfully compare the LCOEs of dispatchable and non-dispatchable energy sources. Renewables suffer from problems of low and highly variable capacity factors, intermittency, unreliability, need for storage and backup, requirements for expanded transmission, and reliance on government subsidies and government-mandated utility quotas.

For example, while coal plants can have capacity factors above 85 percent, the estimated capacity factor the Department of Energy's Energy Information Administration (EIA) uses for wind is 34 percent. EIA assumes 31 percent for ST and 22 percent for PV. In its RES study, JP Morgan used slightly lower capacity factors: 30 percent for wind, 30 percent for ST, and 20 percent for PV. While these might be reasonable as national averages, they also might be somewhat high.[13] An accurate LCOE for RE must take into account these low capacity factors, but even such an adjustment might not fully account for the fact that few renewable resources actually might be available when they're needed most.[14]

EIA's levelized cost estimates for RE use a 31 percent capacity factor for wind, 31 percent for ST, and 22 percent for PV.[15] However, if actual capacity factors are lower than this, these LCOE estimates have to be increased.

Further, it isn't clear how backup power costs should be incorporated into RE LCOE estimates. Given the fact that many RE technologies are variable and non-dispatchable, near 100 percent backup might be required—as it is in Germany.[16] Further, given that RE resources might not be reliably available when they're needed most, 24x7 spinning reserve or dedicated, firm demand response resources often might be required. This need for backup translates into a large RE premium—paying once for the RE system and again for either load-shedding capabilities or fossil fuel systems, which must be kept continually running at a low level to be able to quickly ramp up when needed. Thus, the total cost of such a system should include the cost of the RE system and the cost of the backup power system.[17]

If coal-dependent states are exempt from renewable energy costs, then electricity costs in other states would increase all the more.

Backup charges for RE can be substantial and are being imposed. For example, in 2009 BPA ruled that a new wind integration charge will be levied on all wind generators at a rate of 5.7 cents per kWh.[18] In July 2011, the agency reduced that rate to 5.43 cents. Previously, BPA charged some of its utility customers for conventional power reserves to back up intermittent wind power; however, the amount of wind on BPA's system has grown rapidly, increasing both the need for reserves and the risks to system reliability. BPA found that increased size of the wind fleet was compounded by wind generators' inability to accurately account for wind ramp events in their schedules, thereby requiring BPA to hold a significantly larger amount of reserves to provide balancing services. 5.43 cents per kWh is a significant increase; EIA estimates that the average annual electricity price in 2010 was 9.8 cents per kWh, so adding 5.43 cents per kWh would represent an increase of 43 percent. Current electricity rates in the Pacific Northwest are between 5 and 6 cents per kWh, so a surcharge of 5.43 cents effectively would double the delivered cost of power.

Thus, actual costs must include the costs of RE plus the imputed costs of backup power. Including backup would provide a dispatchable system, whose costs could be legitimately compared with coal and other baseload options, and if such costs are incorporated into the RE LCOE, these cost estimates would increase significantly.

There's also the question of how the costs of increased RE transmission should be included in the RE LCOE. This issue is often framed as the difficulty of getting power from RE sites to the major demand centers on the coasts. Costly transmission lines will be needed to move RE to the major population centers, and there must be considerable redundancy in the new transmission lines to guard against damage due to natural disasters and terrorism. All of this entails considerable additional costs. As noted, legislation has been introduced for “green transmission” lines that would be restricted exclusively to renewable electricity.[19] While the feasibility of such proposals is questionable, if such lines are actually built it might be that all of their costs would have to be included in the RE LCOE.

Coal Utilization Scenarios

Added transmission could greatly impact the existing coal fleet.[20] Utilization of the existing coal fleet is currently about 72 to 74 percent. However, this can be increased to about 85 percent if there's enough transmission to transmit the added coal generation to the load at nights and weekends.[21] Much current night and weekend load is handled by natural gas. Natural gas isn't cost-competitive with coal, and is only used due to lack of adequate transmission from coal plants. Most of the underutilized coal capacity is in the middle U.S. and is stranded from the East Coast. U.S. coal capacity is about 310 GW, coal furnishes about 2 trillion kWh annually, and the U.S. consumes about 1.1 billion tons of coal annually.

If added transmission increases utilization of existing coal plants by 10 percent, coal could provide an additional 200 billion kWh and coal demand would increase by 100 million tons—even assuming no new coal plants are built.[22]

Analyzing two scenarios, and performing two sensitivity analyses for each, allows the potential impact of additional transmission on coal plant utilization to be estimated. The analysis assumes that additional RE transmission would enable capacity increases in between 25 and 50 percent of the plants in the existing coal fleet, with potential capacity increases of 5 percent and 15 percent.

If additional transmission built for RE generation enabled capacity increases in 25 percent of the existing coal fleet, the average capacity of the entire coal fleet could be increased by about 1.5 to 4 percent—4 GW to 12 GW. This could increase annual coal-fired generation by about 30 to 80 billion kWh, and increase annual coal demand by 25 to 75 million tons—even assuming no new coal plants are built.

If the additional transmission built for RE generation enabled capacity increases in 50 percent of the existing coal fleet, the average capacity of the coal fleet could be increased by about 3 to 8 percent—10 GW to 25 GW. This could increase annual coal-fired generation by about 60 to 160 billion kWh and increase coal demand by about 50 to 150 million tons—even assuming no new coal plants are built.

Using the means of these estimates, the expanded transmission required by RE would enable an increase in the average capacity of the existing coal fleet of about 15 GW (5 percent); an increase in annual coal-fired generation by 100 billion kWh; and an increase in annual coal demand of 57 million tons.

Thus, the new transmission required by RE could enable expansion of coal-fired generation by the equivalent of about 30 new coal plants by 2020. This expansion could be very rapid, since no new siting, permitting, or construction would be required. And the electricity produced would be inexpensive—about 5 cents per kWh.

Green Policy Dilemmas

An RES mandate could cause serious economic and policy dilemmas. A mandated RES requires not only a massive build of RE generating facilities over the coming decade but also, of necessity, a very large increment in transmission and requirements for near-100 percent backup. This will be very costly; the total, actual costs of achieving an RES by 2020 could exceed $500 billion—instead of the JP Morgan estimate of $275 billion. These are actual cost estimates and include the implicit costs of RE, such as federal and state government subsidies and mandated utility cross-subsidies.

This raises the question of what the actual, unsubsidized cost of the RE-generated electricity in 2020 is likely to be. Taking reliability, capacity factors, transmission requirements, and backup power requirements into account, the actual 2020 costs of the RE technologies could be twice as high as EIA estimates. The actual 2020 levelized cost of energy, in 2010 dollars, could be as high as 30 cents per kWh of onshore wind, and 50 cents for offshore wind; 80 cents for PV and 55 cents for ST; 16 cents for geothermal; and 17 cents for biomass.

This presents some interesting dilemmas.

The increased electricity generation from existing coal plants enabled by the new transmission would probably cost about 5 cents per kWh—three to 15 times cheaper than the likely costs of the RE generation. Even if some of the coal plants had to be retrofitted with additional environmental controls, they would produce electricity at prices that would still be an order of magnitude lower than the renewable electricity. By way of contrast, EIA projects that the average price of electricity in 2020 will be 10.7 cents per kWh.[23] Thus, in 2020, the newly-enabled coal generation could be about 50 percent cheaper than the average electricity price, whereas the renewable electricity could be from 50 percent to 800 percent higher than the average electricity price.

Total RE generation in 2020, rather than the 612 billion kW estimated by JP Morgan, might be closer to about 475 billion kWh—about 11 percent of the U.S. total. Increased transmission would enable an increase in annual coal-fired generation of about 100 billion kWh—about 21 percent of the incremental RE generation.

The dilemma arises because the coal-fired electricity could sell for a price that's from three to 15 times less expensive than the renewable electricity. Based on cost alone, the rational consumer would prefer to purchase the coal-fired electricity instead of the renewable electricity, and the 100 billion kWh of coal-generated electricity could potentially displace 100 billion kWh of renewable electricity. Of course, in the real regulatory world actual electricity prices are weighted averages of costs from different sources and include various charges, fees, taxes, etc. Nevertheless, given the enormous cost differentials involved, it's obvious that consumers would prefer to purchase coal-fired electricity—and large industrial and commercial customers might have the clout to enforce their desires.

What is likely to occur, and how will regulators react? First, if an additional 100 billion kWh of coal-generated electricity comes on line, what would happen to the more-expensive renewable electricity? If regulators choose to enforce an RES mandate, how would they set overall electricity prices? Would they blend the costs of the renewable electricity with those of the enabled coal-generated electricity? Would this even be realistic in states like Indiana, Ohio, Missouri, and West Virginia, which obtain almost all of their electricity from coal, and would benefit greatly from the newly enabled expansion of existing coal generation? These states have already suffered severe job losses, and significantly increased electricity rates to satisfy an RES would make matters worse.

Once the transmission is in place, renewable energy plants won't be able to compete, giving a new definition to the term 'stranded assets.'

However, if certain large, coal-dependent states are exempt from paying for the RES costs, then electricity costs in other states would have to increase all the more. Federal RE subsidies could only disguise this fact for so long.

Another question concerns the potential impact of the new transmission on prospects for new coal plants, since even new coal plants with enhanced environmental controls could produce electricity more cheaply than RE. The expanded transmission could enable these new coal plants to achieve capacity factors in the range of 80 to 85 percent, compared to the current average of about 72 to 75 percent. EIA projects that coal costs to electric generators will become increasingly cheaper than the alternatives through 2030, and the cost advantages of new coal plants over the RE plants would thus be substantial.

Yet another question that arises concerns the relationship » between RE plants and the required backup plants—most of them likely to be natural gas fired. Once the backup plants and the expanded transmission lines are in place, there will be enormous economic pressure to maximize the less-expensive electricity generation from the backup plants and minimize generation from the RE plants. For, when actual costs are considered, RE also can't compete with natural gas in the generation of electricity. Mandates could force usage of the much more expensive renewable electricity, but how long ratepayers would be willing to pay for this is questionable.

The bottom line is that the new transmission required by an RES could enable a large new tranche of inexpensive electricity generation from existing coal plants at about 5 cents per kWh. Levelized costs of electricity from renewable power plants are between 15 and 75 cents per kWh. So, once the transmission is in place, unless RE is mandated by law, there will be strong incentives to use RE much less than anticipated.

RE may be necessary to get the additional transmission built. However, once the transmission is in place, the RE plants won't be able to compete economically and might give a new definition to the term "stranded assets." At best, they might be used as fuel savers, but the costs of the fuel saved would be very high.

In sum, a mandated RES and the vast expansion of transmission lines required to achieve it could result in a large expansion in the generation of inexpensive electricity. However, this expansion might not be from RE as the proponents of green transmission lines contend. Rather, the expanded, low-cost electricity generation would result from the increased capacity utilization of existing coal plants enabled by the building of the new transmission—and perhaps by new coal plants facilitated by the additional transmission. These plants will be able to generate electricity at prices that are significantly cheaper than those of renewable energy facilities. Once this occurs, electricity consumers will strive to obtain access to this low-cost electricity at the expense of the renewable electricity. How this inexpensive electricity and the costs of an RES are distributed among consumers, ratepayers, and taxpayers will be the subject of intense legislative and regulatory debate.

Endnotes:

1. Christopher Blansett, *The Proposed Renewable Electricity Standard and its Impact on the Growth Rate of the Renewable Energy Sector*, J.P. Morgan Securities, Inc., Sept. 1, 2009.
2. The only currently practical technology is existing geothermal steam, which is available in very few locations, most already being utilized. Hot-dry rock and other technologies aren't yet practical or economic.
3. North American Electric Reliability Corp., *2001 Long-Term Reliability Assessment: 2007-2016*, October 2010.
4. WAPA found that, due to this backup requirement, the environmental impacts of renewable energy projects approach those of the required backup facilities. See *Life Cycle Impact Assessment of Renewable Electrical Generation Technologies Compared to the WECC Baseline*, prepared by Scientific Certification Systems Inc., for the Western Area Power Administration and Tri-State Generation and Transmission Association, March 2009.
5. "U.S. Electric Reliability: Capacity and Transmission Requirements and Costs," Management Information Services Inc., September 2008.
6. For example, ITC Holdings has received FERC approval for a 765-KV transmission line to carry wind energy from Iowa and other Midwestern states from the Upper Midwest into Illinois. The approved cost for this one transmission line alone could be as high as $12 billion; see Dan Piller, "Rehearing Requested on Wind Transmission Ruling," *Des Moines Register*, Aug. 22, 2011. Transmission lines from the northern Great Plains and the Southwest to the major load centers on the East Cost would be much longer than this line.
7. See, for example, Rebecca Smith, "New Grid for Renewable Energy Could Be Costly," *Wall Street Journal*, Feb. 9, 2009.
8. H.R. 2211, *National Clean Energy Superhighways Act* of 2009, introduced by Rep. Jay Inslee (D-Wash.) on April 30, 2009; *Clean Renewable Energy and Economic Development Act*, introduced by Sen. Harry Reid in the 111th Congress.
9. See the discussion in S. F. Greenwald and J.P. Gray, "Transmission Superhighway or Interconnected Patchwork?" *Power*, April 2009.
10. S. F. Greenwald and J. P. Gray, "Can FERC Deliver Transmission?" *Power*, November 2007.
11. *Piedmont Environmental Council v. FERC*; see S. F. Greenwald and J. P. Gray, "Transmission Superhighway or Interconnected Patchwork?" op. cit.
12. Part of current capacity underutilization is associated with the recent economic recession which, officially, has ended; see. Sara Murray and Ann Zimmerman, "Bernanke: Recession 'Likely Over,'" *Wall Street Journal*, Sept. 16, 2009.
13. Other estimates of wind capacity factors are in the range of 25 to 30 percent, and they could be even lower. For example, Boccard notes, "For two decades, the capacity factor of wind power measuring the mean energy delivered by wind turbines has been assumed at 35 percent of the nameplate capacity. Yet, the mean realized value for Europe over the last five years is closer to 21 percent thus making levelized cost 66 percent higher than previously thought." Nicolas Boccard, "Capacity Factor of Wind Power: Realized Values vs. Estimates," October 2008. The actual capacity factors for wind in Germany ranged between 14 and 21 percent over the period 2000 through 2007; see *Windenergy Report Germany 2008*, ISET, Univ. Kassel, Germany, 2008.
14. During the California heat wave in July 2006, which resulted in significant increases in electricity demand, actual wind generation was at only about 5 percent of available capacity. Thus, in this case, the capacity factor for wind was closer to 5 percent than 34 percent.
15. U.S. Energy Information Administration, *Annual Energy Outlook 2009*, Washington, D.C., March 2009.
16. M. Frondel, N. Ritter & C. Vance, *Economic Impacts From The Promotion Of Renewable Energies: The German Experience;* Rheinisch-Westfälisches Inst. f. Wissenschaftsforschung, October 2009.
17. James Schlesinger and Robert Hirsch, "Getting Real on Wind and Solar," *Washington Post*, April 24, 2009.
18. Charles Redell, "NW Utilities Get Wind of Integration Charge," Reuters, August 12, 2009.
19. For example, see the *Clean Renewable Energy and Economic Development Act,* op. cit.
20. "Green Transmission and the Reid Bill," Management Information Services, Inc., March 2009.
21. This is a complex issue, since some older coal plants might not be able to operate at full capacity because of mechanical and environmental limitations. Further, upgrading older coal plants could run into regulatory restrictions via new source performance standards; see "What You Should Know About Electric Companies and New Source Review," Edison Electric Institute, July 2002.
22. This would be analogous to what happened in the U.S. nuclear power industry over the past two decades, where nuclear capacity factors increased from less than 80 percent to the current 90 percent or more.
23. U.S. Energy Information Administration, *Annual Energy Outlook 2011*, April 2011.