Options for Near-Term Phaseout of CO_2 Emissions from Coal Use in the United States

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The global climate problem becomes tractable if CO_2 emissions from coal use are phased out rapidly and emissions from unconventional fossil fuels (e.g., oil shale and tar sands) are prohibited. This paper outlines technology options for phasing out coal emissions in the United States by ~2030. We focus on coal for physical and practical reasons and on the U.S. because it is most responsible for accumulated fossil fuel CO_2 in the atmosphere today, specifically targeting electricity production, which is the primary use of coal. While we recognize that coal emissions must be phased out globally, we believe U.S. leadership is essential. A major challenge for reducing U.S. emissions is that coal provides the largest proportion of base load power, i.e., power satisfying minimum electricity demand. Because this demand is relatively constant and coal has a high carbon intensity, utility carbon emissions are largely due to coal. The current U.S. electric grid incorporates little renewable power, most of which is not base load power. However, this can readily be changed within the next 2–3 decades. Eliminating coal emissions also requires improved efficiency, a "smart grid", additional energy storage, and advanced nuclear power. Any further coal usage must be accompanied by carbon capture and storage (CCS). We suggest that near-term emphasis should be on efficiency measures and substitution of coal-fired power by renewables and third-generation nuclear plants, since these technologies have been successfully demonstrated at the relevant (commercial) scale. Beyond 2030, these measures can be supplemented by CCS at power plants and, as needed, successfully demonstrated fourth-generation reactors. We conclude that U.S. coal emissions could be phased out by 2030 using existing technologies or ones that could be commercially competitive with coal within about a decade. Elimination of fossil fuel subsidies and a substantial rising price on carbon emissions are the root requirements for a clean, emissions-free future.

1. Introduction: The Requirement To Eliminate Coal Emissions

A startling requirement has emerged from climate science research in the past few years: The "safe" long-term level of atmospheric greenhouse gases (GHGs) is much lower than has been supposed. Indeed, the present amount of atmospheric CO_2 is already into the dangerous zone. We must reduce atmospheric CO_2, already at 387 ppm in 2009, to no more than 350 ppm (*1*). This requirement derives from improved understanding of Earth's climate history and observations of ongoing changes, such as worldwide recession of mountain glaciers, loss of Arctic sea ice, Greenland and Antarctic ice mass loss, expansion of the subtropics, rising sea level, and deterioration of coral reefs.

Implications of the low CO_2 ceiling for coal follow immediately from examination of the fossil fuel reserves of oil, gas, and coal (Figure S1) (*1, 2*). Readily available reserves of oil and gas are sufficient to take atmospheric CO_2 to at least 400 ppm. Oil and gas are such convenient fuels, and the world has developed such a strong dependence on them, that it is very likely that the large readily available pools of these fuels will be exploited. The only practical way to preserve a planet resembling that of the Holocene, with reasonably stable shorelines and preservation of species, is to rapidly phase out coal emissions and prohibit emissions from unconventional fossil fuels such as oil shale and tar sands.

Requirements of phasing out coal emissions, averting emissions and/or use of unconventional fossil fuels, and avoiding the need to extract final drops of oil from the most extreme places on the planet, together have strong policy implications. Although policy details are beyond the scope of this paper, the core requirement is for governments to make fossil fuels more expensive than clean energy alternatives, i.e., to stop allowing cost externalization of major damage to the environment, human health, etc. A first step is to remove fossil fuel subsidies. In addition, there needs to be a substantial rising fee on carbon emissions, so as to generate innovations in alternative energy and energy efficiency technologies.

We also suggest that a carbon "fee-and-dividend" approach would be best, wherein the dividend is returned fully to the public, so they have the wherewithal to invest in new carbon-free technologies and energy efficiency (for detailed arguments see refs *3* and *4*). The dividend can be computed by simply dividing the total collected fee (fossil fuel carbon times the carbon price) by the number of recipients, which may, e.g., be the number of legal adult residents with half-shares for children, up to two per family (*3, 4*). With such a dividend, people doing better than average in reducing their carbon footprints will make money. The fee-and-dividend approach can be implemented globally as well (*4*). Under this rational approach, amplifying socioeconomic feedbacks

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TABLE 1. 2008 U.S. Electric Power Generation by Source[a]

electricity source		billion kWh	EJ	% of coal	% of renewables	% of total
fossil fuels						
coal		1994	7.2			48.5
oil		45	0.2	2.3		1.1
natural gas		877	3.2	44		21.3
total		2928	10.5			71.2
nuclear		806	2.9	40.4		19.6
renewable energy						
hydroelectric		248	0.89	12.4	66.7	6.04
biomass	wood	39	0.14	1.94	10.4	0.94
	waste	17	0.06	0.86	4.6	0.42
geothermal		15	0.05	0.74	4	0.36
solar		1	0.003	0.04	0.23	0.02
wind		52	0.19	2.61	14	1.27
total		372	1.34	18.6		9.04
all sources		4110	15			

[a] Based on ref *8*; totals might not add up precisely due to rounding.

can take hold and help move the world rapidly beyond the fossil fuel era into a clean energy future.

2. Building Sector Energy Reductions and Energy Conservation

2.1. Building Sector Energy Reductions. Energy reduction strategies and material, equipment, and efficiency improvements in buildings hold great potential for offsetting GHG emissions in the near and long-term, both in the U.S. (*5*) and globally (*6*). Numerous studies (e.g. refs *6* and *7*) have shown that these measures can provide net economic gains per ton of carbon emissions reduced. Improved efficiency is generally defined by the ability to do more with less, i.e., to reduce energy consumption while maintaining or improving services provided by the energy. Given our focus on near-term reduction of emissions from coal burning, we are primarily concerned with available, off-the-shelf building energy reduction and efficiency improvements related to electricity use, as that is the primary use of coal.

According to the Energy Information Administration (EIA), in the U.S., approximately 93% of coal usage in 2008 was for electric power generation, with virtually all the remainder used in industrial processes (*8*). Conversely, as of 2008, coal burning generated almost half (49%) of all U.S. electric power (which totaled approximately 4100 TWh, or 15 EJ, of energy), with natural gas contributing another 21% (Table 1). Most of the remainder is provided by low-carbon sources, primarily nuclear and hydroelectric plants. Overall, electricity consumption accounts for about 40% of U.S. CO_2 emissions, and almost 75% of electricity generation is used for building operations (*9*). Building operations represent by far the largest portion of energy use in the life cycle of buildings (*10*).

The latest EIA energy "reference case" projects that coal-fired electric power in the U.S. will increase by about 20% or 400 TWh (1.4 EJ) between 2007 and 2030 (*11*) and that residential and commercial buildings will account for most of this increase. Regardless of whether or not the EIA reference case is realistic, mitigating anthropogenic climate change requires that high priority be given to reducing electricity consumption and increasing the efficiency of electricity use via improvements in the building sector.

Numerous measures that are currently deployable would allow significant improvements in building energy consumption (*6, 12, 13*). In the commercial and residential sectors, these include appropriate planning and design strategies, improved material and building envelope design and insulation; more efficient lighting, equipment and appliances; site and community-scale renewable energy technologies; and recovery and recycling of fluorinated gases used in refrigeration. In the industrial sector, currently available efficiency improvement measures include more efficient end-use electrical equipment and heat/power recovery.

Large-scale implementation of these strategies is hindered mainly by a lack of appropriate education, policies, and market incentives. In broad terms, suitable policy measures would include adoption of more rigorous energy codes and standards for buildings and electrical appliances, improved professional design education, and increased investment in building energy reduction measures and incentives. Such measures have already been proven to be very effective in reducing electricity consumption on a statewide scale in California (*14*) as well as many other areas.

Development and implementation of new building codes between 2010 and 2030 that satisfy the "2030 Challenge" would greatly reduce building sector GHG emissions (*15*). A key market incentive should be the decoupling of utility profits from the sale of electricity (thereby decreasing GHG emissions) and providing a financial incentive for energy reduction and efficiency improvements. Additional suggestions are outlined by Mazria and Kershner (*16*), who assert that the building sector could become largely or entirely carbon-neutral by 2030, thereby potentially leading to very large reductions in coal emissions (Figure 1). Measures that would allow significant energy reduction and efficiency improvements, and are available today, include (but are not limited to) the items listed in Table S1.

2.2. Energy Conservation. It is self-evident that in addition to improvements in energy efficiency, energy conservation - defined simply as lowered absolute consumption of energy - can also provide substantial reductions in GHG emissions from coal (as well as the other fossil fuels). Incentives such as tax credits, energy efficient mortgages, and block grants can be provided to developers and state and local governments who facilitate and build transit and pedestrian-oriented developments, and infill, mixed use and location efficient housing. Lifestyle consumption changes can also be encouraged by demand-side management programs (*13*) as well as the use of household energy information systems and building energy labeling, to name just a few. In addition, household energy consumption and peak energy demand can be reduced by over 30% and 40% (respectively) via ground-coupled heat pumps (*5*), although their economic favorability depends on the location.

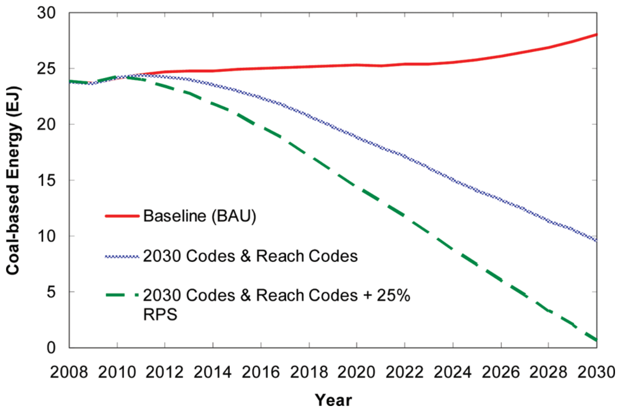

FIGURE 1. Potential coal energy reductions by 2030 from building energy reduction and efficiency measures over the baseline business-as-usual (BAU) case of EIA (*11*). 25% RPS = renewable portfolio standard in which 25% of national power is generated by renewable sources by 2030. Assumptions are as follows: First, new residential and commercial building codes become effective in years 2010, 2016, 2022, and 2028, with corresponding improvements over American Society of Heating, Refrigerating and Air-Conditioning Engineers (ASHRAE) code 90.1−2004 for commercial buildings and the 2006 International Energy Conservation Code (IECC) for residential buildings of 30%, 50%, 75%, and 100% (carbon-neutrality), respectively. Second, 25% of all new buildings meet or exceed the new code the first year it becomes effective, 50% of all new buildings meet or exceed the new code the year after, and 100% of all new buildings meet or exceed the new code every following year until a new base code is adopted. Third, the amount of existing building square footage renovated annually is equal to the square footage built new, and this renovated square footage meets the same requirements and timelines as new buildings in the second assumption above. And fourth, at the beginning of each new code cycle, the codes for the remaining cycles, or "reach codes", are expected to be adopted and implemented for a small percentage of the buildings in the second and third assumptions above. For a complete description of 2030 building codes and 'reach' codes see ref *91*.

Policies related to carbon emissions pricing are vitally needed to encourage energy conservation. Global bottom-up analyses across all emissions-generating human activities reveal that appropriate carbon pricing would lead to substantial GHG emissions reductions in all sectors, and the building sector represents by far the greatest potential source of emissions reductions (*6*). Furthermore, such analyses show that the higher the carbon price in a given amount of time, the greater the GHG emissions reductions.

3. Renewable Energy Sources

3.1. Geothermal Power. Geothermal power is derived from naturally occurring heat energy in the Earth's crust. One of its greatest benefits is provision of base load power, thus it can directly displace coal-fired power. There are currently three main types of conventional geothermal power plants in use in the world (*17*): dry (or direct) steam plants, flash steam plants, and binary-cycle plants. All three types generally produce far lower life-cycle GHG emissions than coal power (Figure 2). However, emissions of lithospheric CO_2 from direct steam and flash steam plants can be substantial. Although such emissions vary widely and depend on the nature of the particular geothermal field, on average they are much lower than CO_2 emissions from fossil fuel plants (Figure 2) (*18, 19*), and they are nonexistent in binary-cycle plants (*20*). In addition, geothermal power causes relatively few other environmental problems; properly managed, the resource

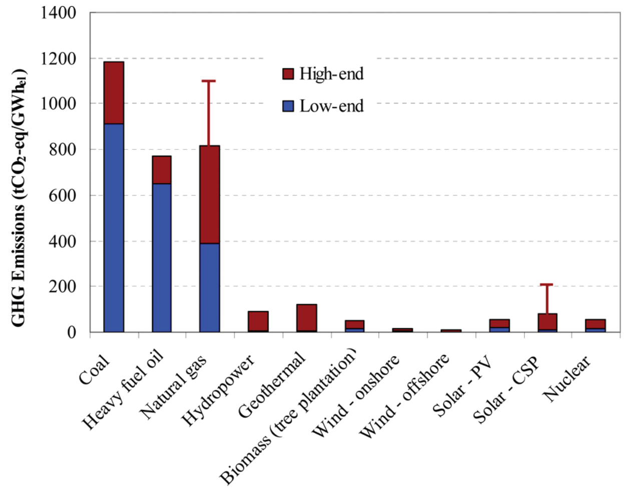

FIGURE 2. Life-cycle GHG emissions from fossil and alternative sources of electricity. Values based on refs *18*−*20*, *47*, *59*, and *92*−*96*. Error bar for natural gas denotes liquified natural gas plants (*95*); emissions from plants using syngas (produced from coal gasification) can range from about 950−2300 tCO_2-eq/GWh (*95*). Error bar on CSP denotes hybrid plants employing cofiring with natural gas (*47*). High-end geothermal value denotes an approximately global average for lithospheric CO_2 emissions from direct steam and flash steam plants (*19*). Improperly designed biomass-based approaches could result in much higher emissions than shown here (*34, 35*).

base lasts the life of the plant, and the most common types of plants can currently generate electricity at competitive costs (*5*).

Currently the U.S. has about 3 GW of installed geothermal power capacity (Figure S2), and an additional 6.4 GW is under development (*21*). In 2008 this provided 15 TWh/yr (0.05 EJ/yr), accounting for approximately 4% of total renewable electricity production, and thus less than 0.4% of total electricity production, and 0.7% of electricity production from coal (Table 1).

However, the national geothermal resource base is very large. All current plants use hydrothermal resources, i.e., naturally occurring hot fluids (liquid water or steam) contained in rocks with relatively high permeability. These plants typically operate at a capacity factor (ratio of average power output to rated power output) of greater than 90% (*5*). Geothermal resources of the U.S. are concentrated in the west (Figure 3a). A recent analysis by the U.S. Geological Survey (USGS) estimates a mean national hydrothermal electric power potential of about 9 GW (providing 70 TWh/yr or 0.3 EJ/yr) in identified resources and an additional 30 GW in unexplored resources (*22*). However, there is a large uncertainty in these estimates - they range from 4 to 16 GW for identified sources and 8 to 73 GW for undiscovered resources.

An additional type of geothermal power, known as enhanced geothermal systems (EGS), has the potential to vastly expand the geothermal resource base (Figure 3b) (*22*−*24*). EGS involves the use of hydrofracturing to add water and permeability to underground regions that lack either but have high temperatures. Major technological barriers include site selection and engineering of sustainably large fluid reservoirs that avoid water loss and short-circuiting between injection and production wells. The potential for fracturing to induce microseismicity is also a concern, although there has been little or no damage to EGS projects or their surrounding communities (*25*). Thus far the highest achieved continuous water flow rate at an experimental EGS site has been 25 kg/s (*23*), but a reasonable goal is to obtain a rate of 80 kg/s at 200 °C. Economically, although capital

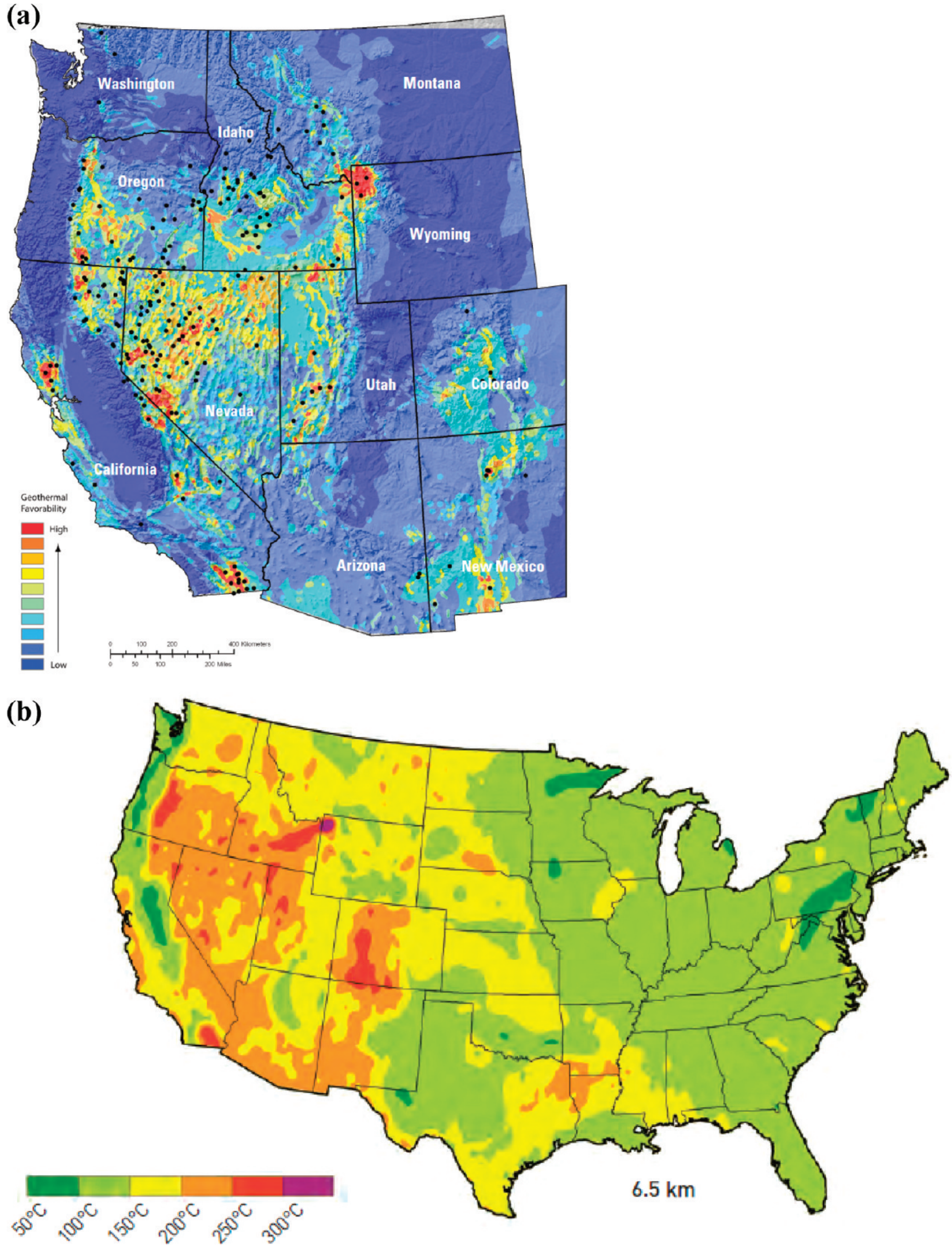

FIGURE 3. Geographic distribution of (a) known geothermal systems and favorable geothermal areas (from ref *22*) and (b) potential enhanced geothermal (EGS) resources in the U.S. based on average temperatures at 6.5 km depth (from ref *24*). (Both figures are reproduced with permission.)

costs of geothermal power are currently competitive with fossil fuels (*26*), there are substantial costs and risks associated with exploration, drilling, and plant development. Because depths of 3 to 10 km are required to reach sufficient temperatures, drilling costs are especially important. Until recently, there was limited federal funding for EGS projects; however, the Obama administration has announced that \$80 million from the American Reinvestment and Recovery Act would support the research and development of EGS (*27*).

EGS is attractive despite the high risks and technical challenges, for two main reasons: the resource potential is enormous, and EGS plants would provide base load power that could directly displace coal-fired plants. As with hydrothermal resources, the USGS estimates of the EGS resource span a wide range: 345 to 728 GW, with a mean of 518 GW (*22*). This mean value translates to about 4000 TWh/yr or 14 EJ/yr, which is equivalent to almost all current U.S. electricity generation and 70% more than projected total coal-fired generation in 2030 in the EIA reference case (*11*). A 2006 Department of Energy (DOE)-sponsored study estimated that the potential economically viable EGS power supply by midcentury could be 100 GW (*24*). A subsequent DOE review did not dispute this potential but indicated that significant advancements must be made in drilling and reservoir production/maintenance to achieve economic viability (*23*). A separate study by the American Solar Energy Society (*5*) concluded that there is potential for 50 GW (about 400 TWh/yr or 1.4 EJ/yr) of geothermal power by 2030 without relying on deep EGS resources.

In summary, geothermal power has the potential to offset significant U.S. demand for coal-fired power in the near term and a very large long-term potential, and thus it can make an important contribution to carbon emissions reductions. And because of the extremely large resource potential of EGS, an aggressive research and development (R&D) effort to develop EGS resources is warranted despite the consider-

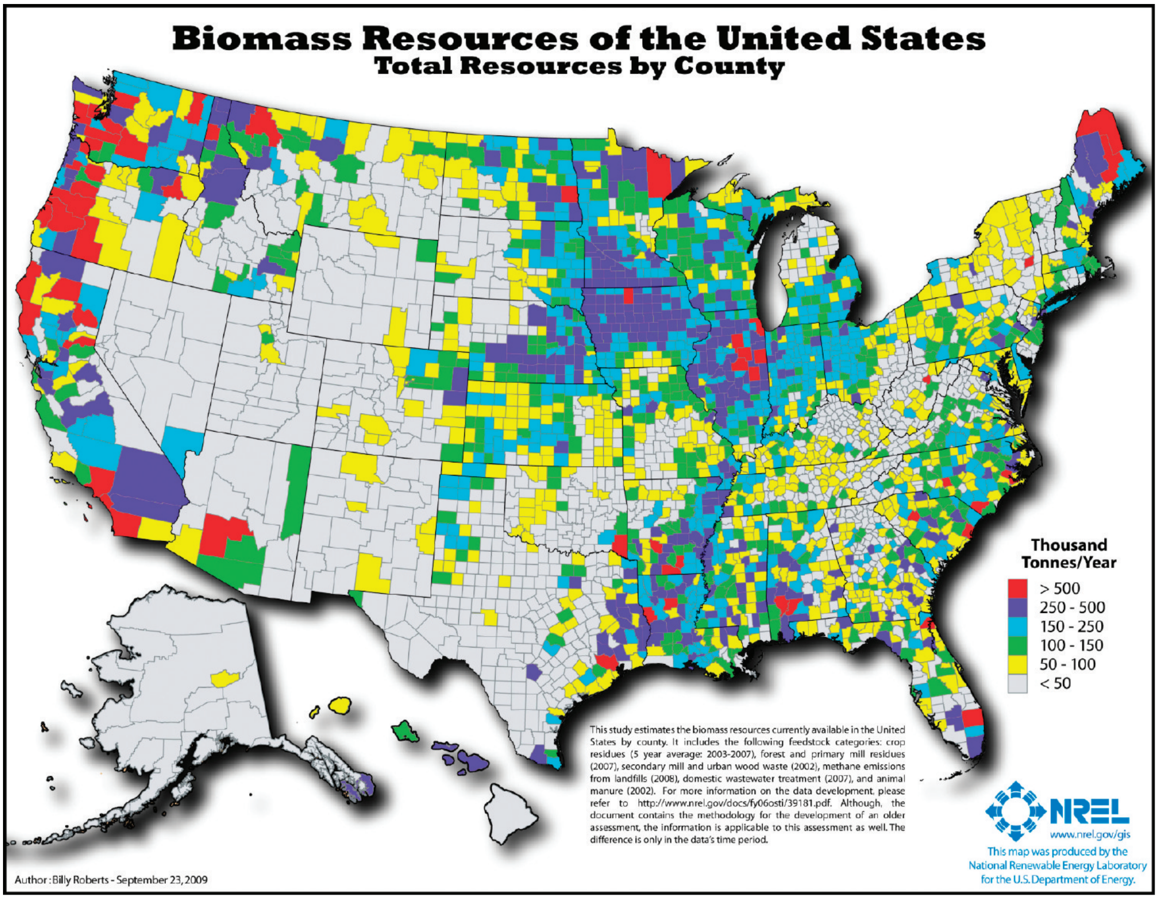

FIGURE 4. Geographic distribution of biomass resources in the U.S. by county (from ref *97*; reproduced with permission).

able technological risks and challenges. Similar conclusions apply to the global scale as well. By some estimates (e.g. ref *6*) the world's geothermal resource base is 5000 EJ/yr (~175,000 GW), which is about 10 times greater than current total annual energy use worldwide.

3.2. Biomass Power. Electricity is produced in biomass-fired power plants in three basic ways: by direct combustion, by cofiring with a fossil fuel (usually coal), or by integrated gasification combined cycle (IGCC), which involves gasification via pyrolysis followed by combustion of the gas. Typical biomass sources are plant matter, agricultural crop residues (e.g., corn stover), and urban or industrial wastes (e.g., pulp from paper mills, municipal solid waste, and landfill gas). Along with geothermal energy, bioenergy is the only nonhydro renewable energy source that can generate reliable base load power (without requiring energy storage), thereby potentially allowing direct displacement of coal. If used properly and with careful accounting of full life-cycle impacts, bioenergy can be a low-carbon source (Figure 2) or even carbon-negative, i.e., a net carbon sink (*28*).

Biomass power capacity in the U.S. is currently about 10 GW (78 TWh/yr or 0.3 EJ/yr) (Figure S2). In 2008 it provided approximately 1.4% of total electric power generation, 15% of renewable power generation, and 3% of coal-fired power generation (Table 1). Wood and wood-derived fuels comprise about 2/3 of the supply and urban waste and agricultural byproducts comprise about 1/3 of the supply (*8*). Unlike other renewable resources, the major costs of biomass power are associated with the resource itself (*5*). These include vegetation planting and management; harvesting and collection; and transportation of biomass products to power plants. Capital costs and resulting electricity costs can currently be competitive with fossil fuels (*6, 26*). Typical operating efficiency for biomass power plants ranges from 20% for direct combustion plants to 40% for IGCC plants, and biomass power plants can operate with capacity factors of 90% (*5*).

A comprehensive interagency analysis led by DOE's Oak Ridge National Laboratory suggests that the potential resource base for bioenergy in the U.S. is very large - about 1.3 billion tons of biomass by 2025 (*29*). Of the various sources of biomass in that study, approximately 70% are from agriculture and 30% from forestry. Substantial resources are available in most states, although supplies are largest on the West Coast and the upper Midwest states (Figure 4). This resource base could be capable of generating over 230 GW (1800 TWh/yr or 6 EJ/yr) of power, of which slightly less than half, or 870 TWh/yr, might be economically viable (*5*). This amounts to approximately half of current U.S. coal-fired power generation and could offset far more than the projected 400 TWh increase in coal power by 2030 in the EIA reference case (*11*). Modest carbon prices in the range of 25–35 \$/tCO_2 would likely be needed to keep large-scale biomass power economically competitive with coal power (*30*).

Biomass power also offers an important option that other renewables do not: the potential to incorporate carbon capture and storage (CCS), thereby making biomass power substantially carbon-negative (e.g. refs *30–32).* Whether or not CCS is employed, it is crucial to consider the full spectrum of climate as well as ecological and socioeconomic impacts in evaluating the use of biomass. Specifically, crops that are specially grown for bioenergy should not indirectly lead to carbon-positive land use changes elsewhere or result in conversion of pristine ecosystems to cropland. For instance, the current approach of using the edible portion of food crops seems untenable from both a climate and sustainability standpoint (e.g. refs *33–35).* A more sound approach utilizes biomass waste products or low-input/high-diversity perennial plants grown on degraded or marginal lands (*28, 34, 35*).

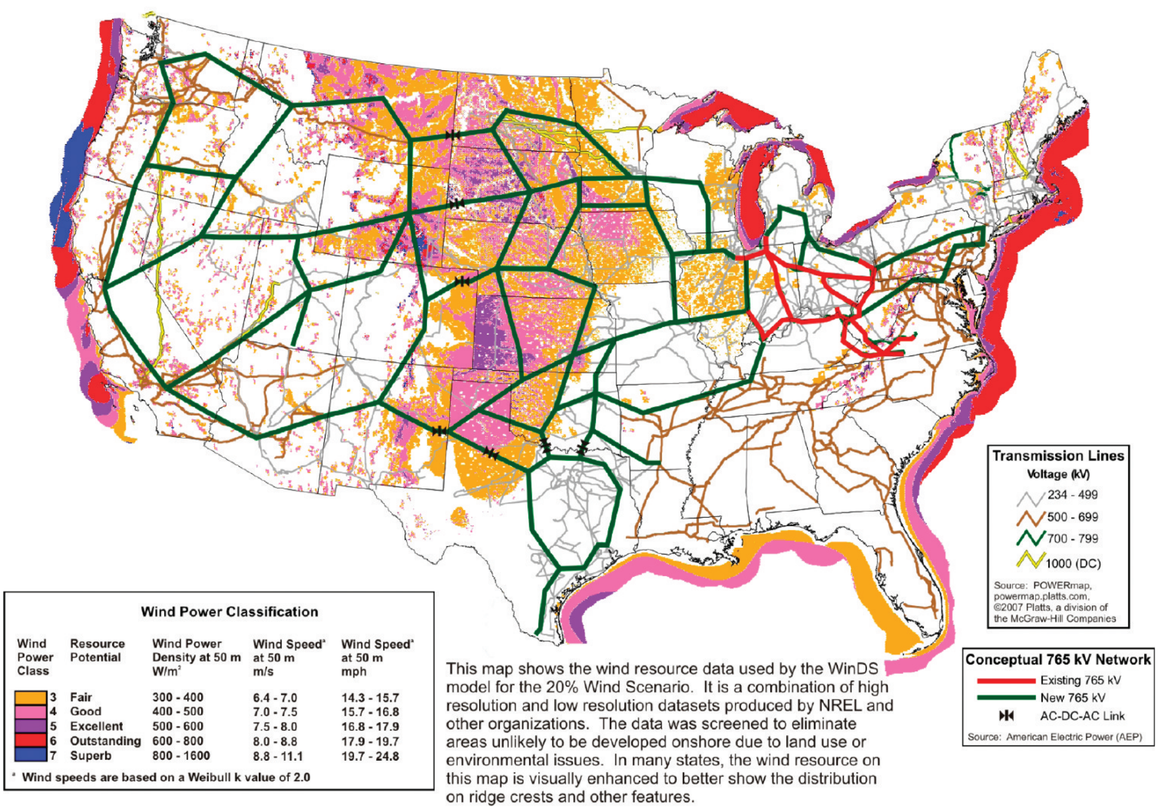

FIGURE 5. Geographic distribution of wind resources in the U.S. and additional transmission requirements to enable large-scale wind power (from ref *37*; reproduced with permission).

Although the use of biomass to produce liquid biofuels also might hold significant climate change mitigation potential, we suggest that bioelectricity used to supply base load power is likely to provide the greatest benefit, since it can offset demand for coal (see the Supporting Information [SI] for a brief discussion on the competing uses of biomass).

3.3. Wind Power. Wind power has been the fastest growing renewable energy source in the U.S. in recent years, primarily because of its low overall costs - e.g., its capital costs are much lower than almost all other sources (*26*). Consequently, wind power accounts for the vast majority of added renewable electricity capacity in the U.S. (Figure S2). The current (as of Dec. 31, 2009) nationwide wind power capacity is almost 35 GW (*36*), providing 120 TWh/yr or 0.4 EJ/yr (based on an average 40% capacity factor). In 2008 wind accounted for about 1.3% of total electric power generation, 14% of renewable power generation, and 2.6% of coal-fired power generation (Table 1). Principal costs associated with wind power generation relate to turbine construction and deployment, land costs, and grid integration costs; overall cost is roughly inversely proportional to wind speed (*5*). Life-cycle CO_2 emissions of wind power generation are trivial compared to any of the three fossil fuels and are among the lowest of all the renewables (Figure 2).

The potential onshore wind resource base in the U.S. is substantial, particularly west of the Mississippi; however the Southeast is largely lacking in onshore wind resources (Figure 5). (The Southeast does have significant offshore wind resources, but these are more expensive to tap.) A recent major study led by DOE examined the feasibility of wind energy providing 20% of electricity production by 2030 (*37*). That analysis assumed, among other things, that over 300 GW of additional wind capacity would be needed to supply 20% of the 2030 electricity supply; 10% of existing grid capacity is available for wind; and wind turbine costs would be 10% lower by 2030 while turbine capacity factors would increase by about 15% by 2030. Major relevant findings of that study are that integration of wind energy into the electric grid can be done at very low cost and without limitations by supplies of raw materials; and excluding grid integration costs, over 600 GW of onshore wind power could be economically viable by 2030, even without a production tax credit. In addition, the scenario leads to a decrease of about 18% of coal consumption and 50% of natural gas consumption by electric utilities, thereby offsetting construction of over 80 GW of new coal-fired power plants (from a baseline projection of 140 GW of added coal power).

It is important to bear in mind that the above DOE study was based on consideration of additional wind capacity only, i.e., it excluded integration of other renewables and effects of efficiency/conservation measures. It is much more likely - and advisable - that the country would deploy a combination of efficiency, renewable energy, and nuclear power. For example, the ASES study (*5*), which found wind energy to be the largest renewable energy contributor by 2030, estimated that 20% grid penetration by wind would require only 245 GW when reduced electricity demand from efficiency improvements is taken into account. In any case, both the ASES and DOE studies demonstrate that wind power holds great potential to significantly reduce near-term U.S. electricity requirements from fossil fuels.

The most fundamental drawbacks of wind power (as with solar power) are its variable nature and the distances between resource locations and population centers. Wind power is variable both on a diurnal basis (wind speeds are generally higher at night) and a seasonal basis (winter is windier than summer). Solar energy experiences the opposite effects. Thus, deploying wind and solar together is complementary.

The variable nature of the wind ostensibly hinders its ability to provide base load power. Thus it is not surprising that utilities currently give little capacity credit to wind. However, these shortcomings could be significantly overcome by deploying a large fleet of plug-in hybrid electric vehicles (PHEVs) or all-electric vehicles (EVs) (Figure S3). The batteries from such a fleet would provide distributed electrical storage, which, when coupled with a "smart grid" (see Section 4), could enable higher integration of variable renewables into the electric grid (*5*). Wind power could charge batteries mostly at night, when most electricity is currently provided by coal. Furthermore, aside from reductions in coal emissions, this approach could also significantly reduce oil emissions, which have been the largest anthropogenic source of CO_2 in the U.S. for years (*38*).

3.4. Solar Photovoltaic Power. Like wind turbines, solar photovoltaics (PVs) have been in use around the world for several decades. There are two basic types of PVs: thin film and wafered crystalline silicon. The latter type accounts for the vast majority of PVs in current use. Life-cycle GHG emissions of PVs are much lower than all fossil fuels (Figure 2).

Solar PVs currently account for about 2 GW of electric capacity in the U.S. (3 TWh/yr or 0.01 EJ/yr, assuming a capacity factor of 18%) and have exhibited significant growth this decade. Electricity generated by solar PVs and solar thermal plants (see the next section) accounted for about 0.02% of total generation, 0.23% of renewable electricity generation, and 0.04% of coal-fired generation in 2008 (Table 1). The highest use in the U.S. is in the residential sector (i.e., rooftop installations), because for states having a PV rebate, PV can provide a net monthly savings to the homeowner when the cost is folded into a 30-year mortgage. The development of single-axis tracking PV modules (e.g. ref *39*) has helped PV power enter the central electricity market as well.

Country-level assessment of PV potential by 2030 (*5*) suggests that suitable rooftop area for PV installation amounts to several billion m^2 and that the industry has the capability to produce 200 GW_p by 2030, i.e., 2 orders of magnitude higher than current capacity. Furthermore, PV deployment on rooftops, along highways, and atop shading structures in parking lots would reduce the large amount of land that would otherwise be needed to achieve this level of penetration, and it also reduces the need for extra transmission capacity and grid usage, since the electricity produced would be consumed in the immediate vicinity (*40*). One concern about both large-scale PV (and wind) power generation is that there will be times during the day when the remaining power that needs to be provided by the utility dips below that being produced by base load plants. In such cases, because base load plants cannot be economically scaled back in power output, PV/wind would have to be curtailed instead. This overlap between variable renewable power supply and steady fossil fuel base load power supply already results in curtailment of wind power in some areas such as in Texas (*41*).

Although PVs have enormous theoretical potential as a power source both nationally and globally, they are hindered because solar energy is intermittent, and electrical storage (e.g., batteries) is currently expensive. Thus, they would not likely be viable near-term substitutes for coal plants without additional storage (such as pumped hydro or compressed air energy storage). However, they could provide substantial displacement of demand for peak and intermediate load power from natural gas plants. High capital cost is also currently a significant barrier (*26*), although costs are likely to continue declining in the future. Further efficiency and technology improvements are also anticipated (*6*).

3.5. Concentrating Solar Power (CSP). CSP, aka solar thermal power, has been attracting increasing attention in recent years as a potentially large source of peak load as well as intermediate and even base load power, when combined with relatively low-cost thermal energy storage. Several different types of CSP plant designs have been deployed, distinguished by their method of concentrating solar flux (*42*). Unlike solar PVs, all CSP plants work with direct radiation only, as diffuse radiation cannot be optically concentrated to achieve the high temperatures needed to run a heat engine. CSP plants also require dedicated land area, although sparsely inhabited areas such as deserts can become viable options if appropriate transmission infrastructure is in place (see Section 4). The most common existing plant designs, employing parabolic troughs, are able to achieve solar flux to annual grid electricity conversion efficiencies of about 15%, and within the next few decades, CSP capacity factors can reach levels of 50−70% (*6*) given a sufficiently large thermal storage, possibly including up to 15% back-up with natural gas.

For many years, CSP represented the largest amount of deployed solar energy in the U.S., as a result of the 354 MW (0.7 TWh/yr or 0.003 EJ/yr, based on a no-storage capacity factor of 25%) of parabolic trough plants that were installed in the Mojave Desert during the 1980s. Construction of trough plants ceased in 1992 as a result of low natural gas prices, loss of power purchase incentives, and utility deregulation. Recently, however, there has been a strong resurgence in this technology. For instance, a 1 MW plant was built in 2006 near Tucson, Arizona, and a 64 MW plant was built outside of Las Vegas, Nevada in 2007 (*43*).

As of December 2009, an additional 8 GW of plant capacity is being planned in the U.S., with similar scale efforts planned internationally (*44*). A new 280 MW (gross) trough plant with 6 h of thermal storage that will be built outside of Phoenix for Arizona Public Service (APS) is projected to have an electricity cost roughly comparable with a new combined-cycle natural gas plant after a 30% investment tax credit (M. Mehos [NREL], personal communication) and could power up to 70,000 homes (*45*). Although CSP plants have effectively no fuel costs, their capital costs are (like PVs) currently relatively high (*26*). However, continuing cost reductions are expected as a result of R&D, economies of scale, and learning curve effects. Deployment of 4 GW of cumulative capacity by 2015 could drop the electricity cost substantially (*5, 46*). Life-cycle CO_2 emissions from CSP power are much lower than all fossil fuels (Figure 2) but depend significantly on several factors, notably the amount of molten salt storage (and whether the salt is mined or manufactured) and the amount of fossil fuels used in the operation of the plant (*47*).

A 2005 study for the Western Governors' Association (*46*) concluded that the ultimate CSP capacity potential in the Southwestern states is several thousand GW i.e., several times the total current U.S. electric capacity (*8*). Although this power would serve Southwest cities in the near term, construction of long-distance, high-voltage DC transmission lines could allow it to be transported across the country (Figure 6).

After also factoring in distance to available transmission lines, an ASES study (*5*) using a National Renewable Energy Laboratory (NREL) market deployment model (*48*) identified 200 GW of optimal sites, distributed as shown in Figure 6. The same analysis suggests that, assuming a carbon price of at least 35\$/tCO_2, 80 GW could be competitively deployed by 2030. These plants would have 6 h of thermal energy storage, resulting in an average capacity factor of 43%. They would generate about 300 TWh/yr, which is about 75% of the EIA's projected increase in U.S. coal demand between 2007 and 2030 (*11*). The U.S. DOE aims to make CSP an intermediate-load, economically viable power source by 2015, and a viable source of base load power by 2020 (*49*). On a global scale there are ambitious plans to further develop over 3400 GW of CSP capacity (including in developing countries), and CSP-supplied electricity could account for 5% of world electricity demand by 2040 (*6*).

Several key research and technology needs must be addressed in order to upscale CSP. Specifically, for it to become a viable base load substitute for coal, greater cost-effective thermal storage is needed. For instance, to achieve

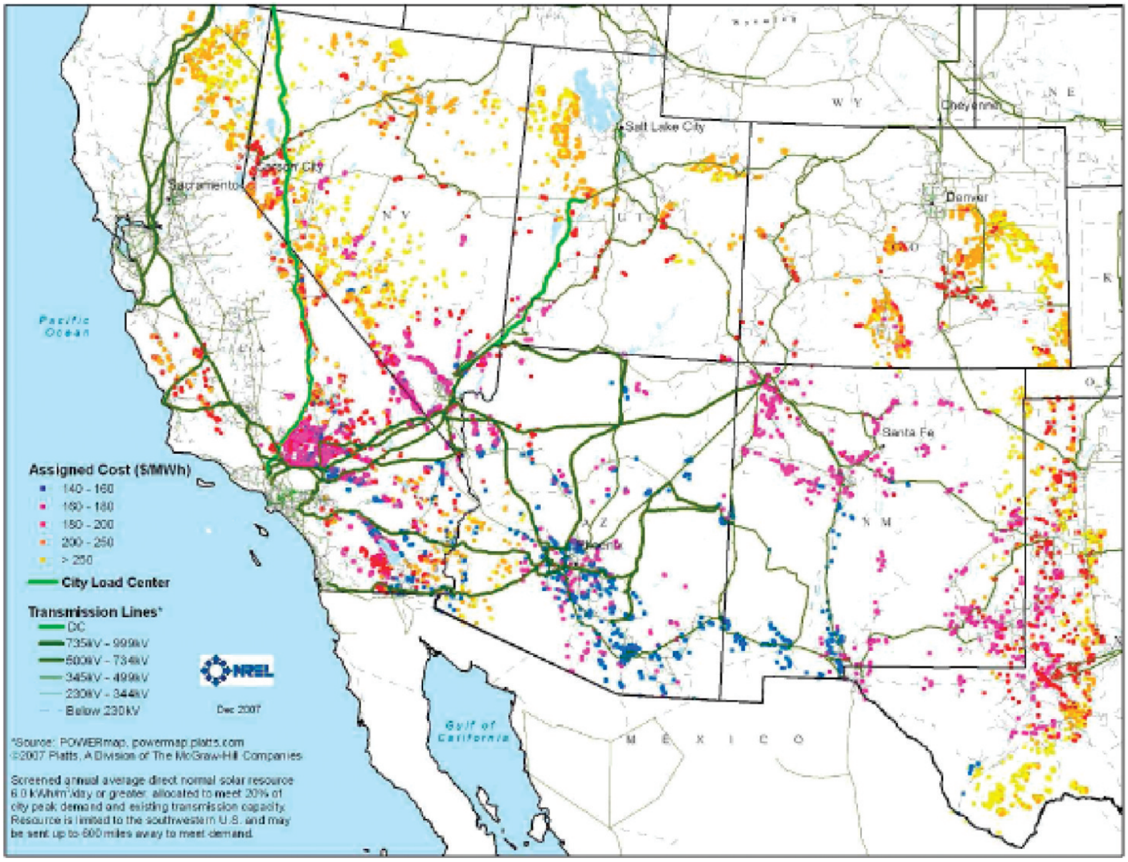

FIGURE 6. Geographic distribution of resources for concentrating solar power (from ref *98*; reproduced with permission).

the above DOE goals would likely require between 6 to 16 h of energy storage, thereby raising costs significantly, absent any major technology improvements, subsidies, etc. In addition to the critical storage-related R&D needs, the cooling water need for CSP plants is also an important consideration, especially since CSP plants are best suited for arid regions (*50, 51*). Air cooling increases the cost of electricity slightly compared to water cooling, and parallel wet−dry cooling systems show potential for greatly reducing water consumption, with better economics than an air-cooled plant (*50*).

4. Electricity Transmission and Grid Integration of Renewables

Electrification, enabled by the current U.S. power grid, has been deemed by the National Academy of Engineering to be the most important engineering achievement of the 20th century (*52*). However, the current grid has a number of fundamental limitations - most notably, grid efficiency, reliability, and security, and environmental and economic concerns. The U.S. DOE recently commissioned a report that provides a useful introduction to the "Smart Grid" notion (*53*). Among other things, the report asserts that increasing the efficiency of existing (centralized) grid structure by just 5% would provide GHG emissions reductions equivalent to removal of over 50 million cars. Public and private utilities in a number of U.S. states are already implementing smart grid demonstration projects, which will provide valuable insights into the feasibility of various aspects of a smart grid.

Improvements in power transmission and distribution methods hold great potential to enable much larger-scale deployment of renewable power. Major factors affecting implementation of grid improvements include economic costs as well as energy policies. Current grid integration costs for upward of 20−25% capacity penetration for wind power are fairly minor (*54, 55*) and are projected to decrease with improvements in forecasting (*56*). Thus, despite its variable nature, wind power (and by extension, solar power) does not necessarily have to be accompanied by costly, large-scale energy storage, even at relatively high grid penetration. In a recent study on the deployment of 20% wind by 2030 (*37*), new transmission was estimated to cost about 10% of the wind capital cost, but estimates of transmission costs vary widely by region. "Smart" redistributing of wind power would also require substantial new transmission capacity (Figure 5), as wind source regions are often far-removed from power demand regions.

In addition to economic and policy measures, Earth science research can also play an important role in enabling large-scale renewable grid integration, via improved forecasting of solar and wind fluxes. NREL and the National Oceanic and Atmospheric Administration are currently engaged in such a collaborative effort.

5. Nuclear Power

5.1. Current-Generation Reactors. Virtually all of the world's existing nuclear power plants use second-generation reactors and employ once-through fuel cycles, i.e., they do not recycle/reprocess the spent fuel products. There are several nuclear reactor designs in use around the world, but all of the 104 U.S. reactors are light water-based. Of these, 69 are pressurized water reactors (PWRs) and 35 are boiling water reactors (BWRs) (*57*).

A major advantage of nuclear power over most alternative (low-carbon) energy sources is its ability to supply reliable base load power. France, for instance, depends on nuclear power for about 80% of its electricity production (*58*). As with renewable energy sources, life cycle GHG emissions from nuclear power plants are generally very low compared to fossil fuels (Figure 2) and might be even lower for future plants employing fuel recycling (*59*).

Nationally, nuclear power presently has a capacity of about 100 GW and operates at a capacity factor of over 90% (*8*). In 2008 it provided about 800 TWh/yr (3 EJ/yr) or about 20% of total U.S. electricity generation and 40% as much as coal-fired power (Table 1). There are 18 pending license applications for new nuclear reactors under review by the U.S. Nuclear Regulatory Commission (NRC), located mostly in the Atlantic states and based on third-generation once-through fuel cycle designs (*60*). Spent nuclear fuel rods are currently stored on site in specially designed water pools at the power plants, although if maximum storage capacity is reached, the NRC allows plants to store the waste in above-ground dry containers. As spent fuel waste exceeds on-site storage capacity at a growing number of plants, the long-standing debate over future long-term storage of this waste will intensify.

The future potential of current-generation nuclear power could be limited by these and other factors, e.g., safety concerns, risk of increased nuclear weapons proliferation, timeliness of plant construction, and capital costs (*61*). Current cost estimates show a very wide range but are comparable to most other power sources on the lower end (*26*). In the EIA reference case (*11*), nuclear power capacity and generation in the U.S. both grow by about 12% by 2030, while proportional contribution to total electricity generation decreases by almost 2%, a result similar to other near-term projections. However, such analyses do not fully incorporate policies enacting major constraints on GHG emissions. Thus with respect to climate change mitigation, they can be regarded as conservative projections. By contrast, more optimistic scenarios (e.g. ref *61*) yield several-fold increases in U.S. as well as global nuclear power capacity by midcentury, assuming cost mitigation measures and other policies designed to make nuclear and other alternative power sources more economically competitive with fossil fuels.

5.2. Next-Generation Reactors. There are various possible designs for fourth-generation reactors that employ closed fuel cycles and/or create (breed) new fuel during their operation. Breeder reactors in particular potentially have numerous major advantages over current-generation reactors (*62*). If designed properly they would generate little or no long-lived waste, nothing suitable for weapons, and would require neither mining nor enrichment of uranium, thereby potentially reducing life-cycle GHG emissions much more than even conventional nuclear power. Various breeder reactor designs have been successfully demonstrated and used around the world (e.g. ref *63*), albeit mostly at relatively small scales (for details see ref *62* and references therein). Below we briefly discuss two such designs, which were subjects of prior research efforts in the U.S.: thorium-based reactors (specifically liquid fluoride thorium reactors or LFTRs) and integral fast reactors (IFRs).

A key disadvantage of these and other advanced (closed) fuel cycle technologies is that they have not yet been demonstrated at commercially viable (∼GW) scales on a widespread basis. It is possible that their large-scale deployment could take longer to achieve than current-generation reactors. Among other reasons, because uranium supplies appear adequate in the near term and reprocessing is expensive, one study (*61*) concluded that near-term expansion of the nuclear industry should use the conventional once-through fuel cycle. However, this study has been challenged in detail (*64*), and several fourth-generation reactor designs with closed fuel cycles might have near-term deployment potential (*62*).

Ultimately, the potential nuclear energy resource could increase by about a factor of 30 if fuel recycling is utilized (*6*), and it is often asserted that the widespread deployment of breeder reactors could offer effectively unlimited energy (e.g. ref *62*). We believe it is therefore vital to pursue commercial-scale feasibility assessment of fourth-generation reactors. This could be easily accomplished with appropriate government policies. Indeed, some major energy-consuming countries have plans to deploy advanced fuel cycles including LFTRs.

5.2.1. Thorium-Based Nuclear Fuel Cycles. Use of thorium, which exists in nature almost entirely as weakly radioactive ^{232}Th, as a fertile fuel for nuclear power has been demonstrated since the mid-1960s in five different reactor designs in numerous countries, with reactor power output ranging from 2 to 300 MW (see ref *65* and references therein). Numerous benefits are afforded by Th-based fuel cycles, including some advantages over fertile ^{238}U-based cycles (*65*−*68*). For instance, thorium is 3 times more abundant than uranium in the Earth's crust and is present in high concentrations in populous, major energy-consuming countries such as India where relatively little uranium is available. Thorium-based fuel cycles are inherently proliferation-resistant due to the production of strongly radioactive ^{232}U (half-life ∼74 yr) and its relatively short-lived daughter products. In addition, waste and other byproducts could be relatively easy to manage. Thorium-based fuel cycles also possess several disadvantages relative to U-based cycles, a key practical one being the relatively limited experience and empirical data on which to base future larger-scale investment (see ref *65* for further details).

The USGS estimates that domestic reserves of thorium amount to about 300,000 tonnes or 20% of the world's supply (*69*). In the context of LFTRs in the U.S., Oak Ridge National Laboratory (ORNL) successfully conducted the Molten Salt Reactor Experiment in the 1960s, which provided a modest amount of power (∼7 MW) and operated for 4 years (*70*). A subsequent ORNL experiment, the Molten Salt Breeder Reactor, demonstrated that breeding is also feasible with thorium-fueled reactors (*71*). These experiments and others demonstrated that molten salt reactors can be designed to be passively safe and can make highly efficient use of fuel (*66*−*68*) - e.g., to generate the same amount of energy in a given year in a current-generation reactor, several thousand times more uranium ore would have to be mined. Additionally, far fewer problems arise with the spent nuclear fuel. Large-scale feasibility assessment projects are currently being planned by some thorium-rich energy-intensive countries (e.g., India), and other countries also have substantial R&D programs (e.g., France, Russia, Norway, and Canada) (*65, 66*).

5.2.2. U-Based Integral Fast Reactors (IFRs, aka Liquid Metal Fast Reactors). As mentioned above, although fast breeder reactors have been used in various countries in the past (*62*), the world's first, and to date only, IFR prototype was conceived and developed at Argonne National Laboratory (ANL) from 1984 to 1994. A detailed overview of the IFR technology is provided by Till et al. (*72*). Almost all of the elements of the IFR were demonstrated successfully, although the program was canceled by Congress at the behest of the Clinton Administration.

In brief, the IFR program was developed largely out of proliferation concerns as well as recognition that continued deployment of conventional nuclear power was growing politically untenable. The IFR design possesses four key features that distinguish it from conventional (once-through fuel cycle) reactors (*72*). First, it can make safe, highly efficient use of its input fuels, possibly generating about 100 times more energy from uranium than conventional thermal reactors, and can consume virtually all of the uranium or plutonium used to operate it. Second, the IFR design incorporates inherent passive safety features (see refs *73* and *74* for technical safety details). Third, through its fuel recycling processes, an IFR can avoid production of virtually all of the most problematic waste of conventional reactors, and it can ensure that plutonium is never separated during the fuel cycle (*75, 76*). However, the IFR fuel cycle would still produce some waste (fission products) that would be highly radioactive for decades. Unfortunately, demonstration of a complete commercial-scale IFR fuel cycle would have required until at least 1998 (*77*). Fourth and last, IFR technology could be inherently free from the risk of proliferation (see ref *78* for details).

6. Carbon Capture and Storage (CCS) at Coal-Fired Power Plants

CCS involves the prevention of power plant CO_2 emissions from reaching the atmosphere (capture) and the subsequent permanent burial (storage or sequestration) of the captured CO_2. Of all the technologies discussed herein, CCS is the only one that would be specifically undertaken for mitigation of anthropogenic global warming. The current status of CCS reveals that although it is an urgently needed technology given the world's ever-increasing use of coal, it is far from being accomplished on a sufficient scale, although there are plans for large-scale demonstrations by the G8 countries, China, and others. In broad terms, the two greatest challenges for deploying widespread CCS will be reduction of capital costs (which are largely related to capture) and reduction of uncertainties related to long-term, large-scale storage. Detailed technical assessments of the numerous issues involved in CCS are provided by others (*79, 80*).

In general, there are three key steps in any CCS approach: capture of the emissions; transport of the captured effluent (usually in supercritical form); and injection of the effluent into a geological reservoir - typically beneath land (*79, 80*), although subseafloor burial has also been proposed (*81*). All of these components have been demonstrated successfully in other contexts - usually for enhanced oil recovery (EOR) projects. The Swedish company Vattenfall had planned to conduct a demonstration at a 30-MW pilot coal plant in eastern Germany (*82*) but ceased the project due to strong public resistance (*83*). More recently, a U.S. pilot plant became the first in the world to fully employ CCS, although its CO_2 emissions are reduced by only about 1% (*84*). Capture of CO_2, which is typically about 90% effective (*79*), can be done in three ways: postcombustion, precombustion, and oxyfuel combustion. Each of these methods will inevitably raise overall plant costs and thus electricity costs and exert an energy penalty in the range of 10 to 40%, reducing plant power output (*79*). Geological storage (e.g., in saline aquifers) has been successfully conducted for commercial EOR projects on a limited basis on a scale of 1 Mt CO_2/yr, which is of similar magnitude as the annual emissions of a 500 MW coal plant (typically 3 Mt CO_2/yr) (*80*).

Several major barriers exist for large-scale CCS deployment in the near term. The biggest by far is the lack of a substantive national and global emissions reduction framework and the resulting lack of a price on carbon emissions. Combined with the decreased plant efficiency due to the energy penalty discussed above, much higher capital costs can raise the ultimate cost of electricity substantially (*80, 85*). Lack of experience with long-term, large-scale (several Mt CO_2/yr) CCS projects is also problematic. Furthermore, unresolved legal and regulatory issues exist regarding licensing for large-scale geological storage projects, subsurface property rights, and monitoring standards for sequestration sites, among other things.

Nonetheless, there is widespread agreement on the clear need for large-scale CCS demonstration projects in a variety of economic and environmental settings (*86*). Although the scientific feasibility of the essential components of CCS seems reasonably certain, large-scale demonstration projects could help resolve the problematic socioeconomic issues. A particularly important issue is the magnitude of the required carbon price signal. Model estimates suggest a signal of 50−70 \$/tCO_2 will be needed relative to a supercritical pulverized coal plant without CCS, with different ranges for different types of reference plants (*79, 85*).

Assuming large-scale demonstration projects of CCS power plants can eventually succeed, the required time frame for widespread CCS implementation means that it is not likely to greatly reduce near-term GHG emissions. Some assessments suggest that CCS could play a somewhat significant role in reducing U.S. electricity emissions by 2030 (Figure S4) (*87*), whereas others offer the more sobering view that the majority of global CCS deployment is unlikely until after ~2050 (*79*).

7. Conclusions

Tax policy, energy efficiency regulations, and utility profit motives must be altered to achieve rapid phaseout of coal emissions. Large-scale efficiency improvements and conservation measures are deployable the soonest. The building sector - by far the dominant user of coal - could be carbon neutral by 2030, with appropriate policies and existing technologies. We believe a rising fee for carbon emissions is needed, along with rigorous, enforceable building design standards, increased government investment in efficiency measures, and restructuring of utility profit motives. A rising carbon fee would likely have greater success at reducing emissions than the "cap-and-trade" approach, as concluded by the Congressional Budget Office (*88*) and others (e.g. refs *3*, *89*, and *90*). We emphasize that such a fee does not imply increased cost for those consumers who minimize their carbon footprint - indeed, their costs may decline.

Geothermal and biomass energy could displace much of the base load electric power now provided by coal in the near term. Federal and private-sector investment in research, development, and demonstration of enhanced geothermal systems should be given high priority. Biomass power, properly designed to account for full life-cycle impacts, has special attraction because, combined with CCS, it has the potential to draw down atmospheric CO_2. Biomass power should employ inedible or waste-derived feedstocks.

Wind and solar energy could be deployed to a much larger degree via addition of new transmission lines and improvements to the national electric grid. CSP generated in the arid Southwest combined with at least 12 h of thermal storage (typically using molten salt storage tanks) could become a large, commercially viable source of base load power. Solar PVs are well suited for rooftop deployment in which transmission issues are avoided and they compete against the retail cost of electricity. PV power does not lend itself to low-cost storage and typically displaces electricity from natural gas plants that provide power in the peak and intermediate load markets. Wind power also tends to displace natural gas and not coal. However, both solar and wind power can be enabled to a much greater extent by the use of batteries in PHEVs or EVs as well as by a smart grid. They could then displace some base load coal plants and substantial gasoline use.

Energy efficiency, renewable energy technologies, and a smart grid deserve first priority, but it would be unwise to simply assume that these alone will meet all near-term electric power demand. Third-generation nuclear power can substantially contribute to base load power in the near-term. High-priority development and demonstration of fourth-generation nuclear technology (including breeder reactors) is needed to provide a solution to nuclear waste disposal and eliminate the need to mine more uranium for many centuries. The time required for these advanced nuclear technologies to be proven is debatable, but they warrant rapid development given the need to dispose of existing nuclear waste, and growing national and global electricity demand.

CCS technology development also warrants investment for large-scale demonstration. It can then be one of the elements in the competition among different energy technologies, and it can be deployed at both biomass plants and remaining coal plants. However this investment should not be an excuse to simply continue building new coal plants (including "capture-ready" ones), given that near-term potential of widespread CCS deployment seems questionable, and as others (*80*) have pointed out, retrofits at coal plants will probably be impractical.

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Supporting Information Available

Contains additional text, tables, and figures related to liquid biofuels vs bioelectricity; building sector energy efficiency improvement options; global fossil fuel supply estimates and CO_2 mitigation scenarios; recent growth in U.S. renewable electric capacity; potential wind electric capacity enhancement by PHEVs; and electric power sector CO_2 emissions reductions pathways. This material is available free of charge via the Internet at http://pubs.acs.org.

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