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The technical, geographical, and economic feasibility for solar energy to supply the energy needs of the US

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ABSTRACT

So far, solar energy has been viewed as only a minor contributor in the energy mixture of the US due to cost and intermittency constraints. However, recent drastic cost reductions in the production of photovoltaics (PV) pave the way for enabling this technology to become cost competitive with fossil fuel energy generation. We show that with the right incentives, cost competitiveness with grid prices in the US (e.g., 6–10 US¢/kWh) can be attained by 2020. The intermittency problem is solved by integrating PV with compressed air energy storage (CAES) and by extending the thermal storage capability in concentrated solar power (CSP). We used hourly load data for the entire US and 45-year solar irradiation data from the southwest region of the US, to simulate the CAES storage requirements, under worst weather conditions. Based on expected improvements of established, commercially available PV, CSP, and CAES technologies, we show that solar energy has the technical, geographical, and economic potential to supply 69% of the total electricity needs and 35% of the total (electricity and fuel) energy needs of the US by 2050. When we extend our scenario to 2100, solar energy supplies over 90%, and together with other renewables, 100% of the total US energy demand with a corresponding 92% reduction in energy-related carbon dioxide emissions compared to the 2005 levels.

1. Introduction

The world faces the dual challenges of fossil fuel depletion and carbon dioxide (CO_2) emissions, and the main candidates for facing these challenges are coal with carbon capture and storage (CCS), nuclear, and renewable sources of energy. However, safe and economic concepts for CCS have not been proven; nuclear suffers from high cost, radioactive waste management, fuel availability, and nuclear weapon proliferation issues, and renewables have been limited by resource limits, high cost, and intermittency problems. Biomass could be a substitute for fossil fuels, but enough land or water to meet the demand and to feed the world's growing population is not available (Perlack et al., 2005). Wind is intermittent, and the total capacity of Class 4 and higher wind resources in the US is about 1.2 Terawatt (TW) (American Wind Energy Association, 1991). Solar energy has huge potential—tens or hundreds of TWs are practical, but it suffers from intermittency. Recent drastic cost reductions in the production of photovoltaics (PV) pave the way for enabling solar technologies to become cost competitive with fossil fuel energy generation. Scaling of concentrating solar power (CSP) may also enable drastic cost reductions. In this study, we forecast future energy demand levels for the US, and then we extrapolate the deployment level of existing solar technologies, supplemented by other renewable energy sources, to prove the feasibility for solar energy to supply that energy. These technologies are (1) PV, (2) PV combined with compressed air energy storage (CAES) power plants, and (3) CSP plants with thermal storage systems. A vision for very large implementation of solar systems in desert lands of the US southwest (SW) was presented in Scientific American (Zweibel et al., 2008). The current article discusses the feasibility of this vision.

2. The technical and cost reduction feasibility

2.1. Photovoltaics (PV)

The US Department of Energy has set goals for reducing the cost of solar electricity production in the SW down to 6 US¢/kWh

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by 2020 (US-DOE, Solar America Initiative, 2008). Although there may be several PV technologies that can possibly accomplish the goal (e.g., crystalline silicon, gallium arsenide concentrators, thin film cadmium telluride, copper indium selenide, or silicon), for specificity we will demonstrate PV's path to cost competitiveness using today's lowest cost PV technology (i.e., thin film cadmium telluride (CdTe) PV (Ginley et al., 2008)). We characterize three development stages—2008, 2015, and 2020. The PV development assumptions are derived from analysis of public domain data available from First Solar, Inc. The current technology status is a PV-rated module efficiency of 10%, a current PV module manufacturing cost of $1.12/W (First Solar, 2007), a wholesale PV module price of about $2/W, and an installed PV power plant cost of $4.2/W for utility installations (Juwi International, 2007). First Solar's modules have increased in efficiency from 6% in 2005 to 10% in 2007, and the company targets 5% improvements in efficiency per year, with a module efficiency of 11.5% targeted by 2010. Based on these targets and our assessment of the technology, we determine that, with the right incentives, the following are likely. For 2015 a CdTe PV module efficiency of 12.5%, module manufacturing cost of $0.70/W, wholesale module price of $1.00/W, and installed central PV power plant cost of $2.0/W. In 2020, we project PV module efficiency of 14% and manufacturing cost of $0.50/W, wholesale module price of $0.65/W, and installed PV power plant cost of $1.20/W–$1.30/W (2007$, not accounting for inflation). A scenario for accomplishing these cost improvements is shown in Table 1. We assume that the following changes will occur for the 2020 PV projections to materialize: (1) module efficiencies will increase to 14%; (2) material flows and processes will be optimized to achieve lower manufacturing costs; and (3) the manufacturing scale of single PV manufacturing plants will increase to about 0.5–1.0 GW/yr. Each of these parameters will have a major impact on lowering module cost (Zweibel, 2005; Keshner and Arya, 2004).

Most of the module efficiency gains will result from continued technology improvement. Since existing small-area devices have already reached 16.5%, optimal scale-up of the same design should lead to module efficiencies of 14%. Module cost can be reduced in a number of ways: making thinner layers (which reduces material and processing costs); reducing glass costs by integrating glass and PV plants; making ethylene vinyl acetate (adhesive) on-site; improved make/buy decisions, economies of scale, and better designs. PV module efficiency and cost are the drivers for the total cost of PV power plants. Most improvements in the balance of system (BOS) of PV power plants will come from either higher module efficiency, which automatically lowers BOS costs through a reduction in the size and number of components needed, or through higher BOS volumes and design optimizations. The BOS components affected by efficiency are land, land preparation, mounting structures for PV modules, system wiring and wiring interconnections, power-conditioning equipment to transport the PV electricity onto transmission power lines, and labor costs. An exception is the inverters and power-conditioning equipment, where the first-order cost drivers are operating lifetime and maintenance costs.

Another important price reduction comes from reduced overhead costs. With larger volumes, companies can maintain profitable operation despite slimmer margins. Today's 40–55% differential between module price and cost can shrink by half, a major price saving.

PV electricity price estimates and underlying financial assumptions are presented in Fig. 1. PV electricity costs in the SW (i.e., insolation of 2336 kWh/m^2/yr on a south facing, latitude tilt plane) are expected to decrease from today's 16–6 ¢/kWh in 2020; these estimates are based on the installed cost of large utility systems falling from $4.2/W to $1.30/W. For distributed PV we assume capital costs that are 25% higher than central PV in all years, and US-average insolation (i.e., 1800 kWh/m^2/yr). This cost differential reflects the higher installation, overhead, and marketing costs that small systems carry. Several potential combinations of the BOS and the PV module's efficiency and manufacturing costs can give equivalently low system costs without affecting this analysis (Keshner and Arya, 2004). This cost reduction would make PV cost competitive with the grid for peak generation everywhere in the US. However, solar intermittency limits the penetration of PV in the energy market. Denholm and Margolis

Table 1
Example of PV system price reductions from $4.2/Wp AC to $1.3/Wp DC (from today's lowest installed system price to future DC PV used to feed into a CAES facility)

Aspect	Change[a]	How	Resulting system price
Eliminate inverter	$0.2/W reduction	Eliminate inverter, use DC transmission	$4/W ($2/W for module and $2/W for the rest)
Module profit margin reduction due to large volume	From 55% to 20%; module price drops from $2/W ($1.1/W cost) to $1.38/W	Volume absorption of overhead and streamlining	$3.38/W
Installation margin reduction due to high volume[b]	From 15% to 5%	Standard systems and volume sales	$3.04
Module efficiency—thin films[c]	40% increase from 10% module efficiency to 14%[b]	Output rise of 40% implies system price reduction of 29% (price/output, 1/1.4 = .71)	$2.16/W
Technological improvements of module area cost	30% reduction: optimized processes, larger volumes, larger modules, and thinner layers	$110/m2 becomes $77/m2, a saving of $33/140 W = $0.24/W; with 20% module margin and 10% integrator margin, implies a reduction of $0.32/W in system price and a module cost of $0.55/W[c]	$1.84/W (prices: module $0.69, BOS $1.15, which includes integrator margins)
Technological improvements in non-module components	20% reduction in BOS price	Save $0.23/W	$0.7 module+0.9/W BOS = $1.6/W
Make–buy decisions for components in high volumes	20% reduction in module and system component prices	20% lower cost and price (e.g., making glass instead of buying it)	$1.28/W
Larger installed systems	5% reduction in costs	Volume absorption of overhead and streamlining	$1.3/W DC feedstock electricity for CAES

[a] These changes will be done by 2020; very conservative we did not assume further technological and cost improvements beyond 2020.

[b] Sample ways for efficiency increases: (1) More transparent glass (5%) and top layers that allow more light to the junction (20%). (2) Improved p-type doping of CdTe to increase voltage and reduce CdTe/contact series resistance (15%). (3) Increased useful module area by increasing the size of the modules (less edge delete) (5%).

[c] We assume an initial module price of $2/W corresponding to the quoted manufacturing cost of $1.1/W (at 10% efficiency) and 55% profit margin, e.g., like First Solar in Q4 2007 and Q1 2008.

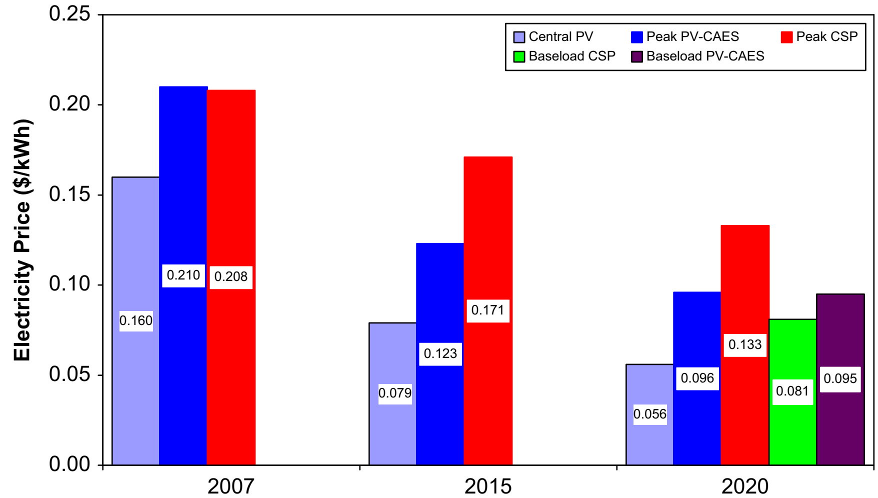

Fig. 1. Levelized cost of electricity estimates for solar electricity production in the US southwest. These estimates are calculated by the net present value cash flow method, using EPRI (2003) financial model with a 30-year capital recovery period assuming: capital structure of 45% equity and 55% debt; 10% cost of equity capital and 6.5% cost of debt capital; 30-year capital recovery period; 38.2% tax rate, modified asset cost recovery system (MACRS) depreciation; 1.9% annual inflation rate; and 5% after tax, weighted average, real discount rate. Property taxes and insurance costs are assumed to be 2% of capital. These estimates also include, power transmission losses of 10%, and HVDC transmission cost of $0.007/kWh.

(2007a) recently studied the hourly PV output and load demands for the ERCOT system in Texas and determined that the existing system has the flexibility to receive at least 10–20% of its total peak demand directly from dispersed PV systems without storage, and that with load switching and/or limited storage, such penetration could approach 50% (Denholm and Margolis, 2007b).

2.2. Compressed air energy storage (CAES) power plants

For solar energy to be converted to base-load power, excess power must be produced during sunny hours and stored for use during dark hours. Most energy storage systems are expensive, either in capital outlays or in energy losses incurred while storing and retrieving energy. For example, batteries are costly, fly wheels are suitable for short-duration storage only, pumped hydro has geographical limitations, and superconducting electricity storage is experimental. However, CAES is a proven technology that is economical for large bulk storage and can provide cycling capability, regulation, and quick start, which are sufficient for both peak and base-load applications. Electric Power Research Institute studies show that CAES today costs about half that of lead-acid batteries (EPRI, 2003). In CAES, electricity is used to compress air and pump it into vacant underground formations such as caverns, abandoned mines, aquifers, and depleted natural gas wells. The pressurized air is released on demand to turn a gas turbine that generates electricity. CAES plants have been operating reliably in Huntorf, Germany, since 1978 and in McIntosh, Alabama, since 1991 (Schainker et al., 1993; Ter-Gazarian, 1994; Cavallo, 2007). The first is a 290 MW plant designed for 2 h of generation between recharging and the second is a 110 MW plant designed for 26 h of generation. Ten new CAES plants are in the planning phases in the US, the largest would be the 2.7 GW Norton, Ohio plant (Hydrodynamics Group, 2002). Greenblatt et al. (2007) showed the economic viability of integrating wind and CAES; a CAES plant in Iowa is being built for such integration. These plants still use natural gas to heat the compressed air, but their gas consumption is 60% lower than that of single-cycle gas turbines (Haug, 2003). Eliminating the need of fuel is pursued in advanced adiabatic CAES (AA-CAES) concepts that recover and utilize the heat stored in compression; it is expected that AA-CAES would be commercialized by 2015–2020 (Bullough et al., 2005). Even if AA-CAES does not succeed in completely eliminating the need of fuel, it is certain that the operation of these plants would require even less fuel in the future and instead of natural gas, biofuels or hydrogen could be used.

We estimated that adding CAES to PV will cost an additional 4–5 ¢/kWh for peak plants and 3–4 ¢/kWh for base PV+CAES plants. These estimates are shown in Table 2; details can be found elsewhere (Mason et al., in press). Electricity from large PV farms in the SW would be sent over high-voltage DC transmission lines to compressed air storage facilities throughout the country. Turbines would be built next to the air storage facilities to generate electricity year-round.

A schematic of our model for sizing the integrated PV–CAES plants is shown in Fig. 2. We use national and state hourly electricity demand data, aggregated to daily loads, to determine the capacities of CAES needed to supply these loads. We determine the air injection–air withdrawal supply profiles required to satisfy the required daily loads. Based on the average minimum availability of solar irradiation, $I(t)$, we then determine the periods of the cycles of electricity supply from CAES and recharging from PV. This enables sizing of the storage reservoir. Then we establish the size of the PV plant, required to charge and maintain reservoir capacity with electricity generating reliability of 99.9% of planned CAES plant operation. This reliability is determined by the combination of observed winter daily loads and lowest average solar irradiation days in the 45-year solar insolation data for the entire SW. Therefore, the system is oversized for most of the year and surplus PV electricity, $E_x(t)$, is generated and fed directly into the grid. In the long run (post-2040), we model the application of excess PV electricity generation for the production of hydrogen by electrolysis of water (Mason and Zweibel, 2007, 2008).

2.3. Concentrating solar power (CSP)

CSP systems, especially parabolic trough ones, have attracted renewed interest in the US. In the 1980s and 1990s, nine parabolic trough CSP plants with a total capacity of 354 MW were built in the country (US Department of Energy (US-DOE), 2008). These

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Table 2
Cost of compressed air energy storage

Reference	Succar and Williams (2008)	EPRI-DOE (2003)	Mason et al. (in press)
Capital cost of CAES surface equipment ($/kW$_e$)	610	440	621
Cost of underground storage capacity ($/kWh)	1.95	1	2
Storage hours	88	10	100
Total capital cost ($/kW$_e$)	782	450	821
Number of cycles per year			328
Total levelized cost ($/kWh)			0.039

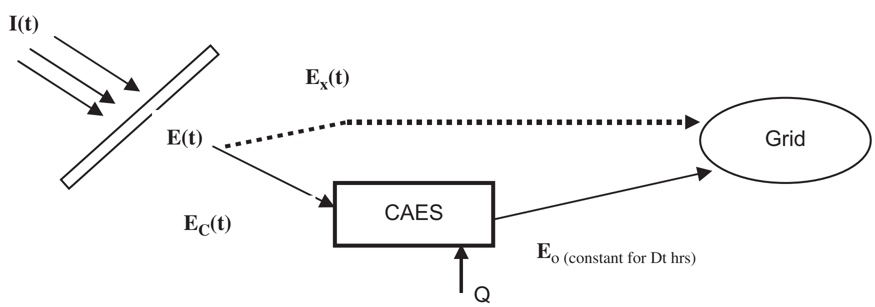

Fig. 2. The PV–CAES conceptual model.

early plants have generated electricity reliably for over 20 years. A new 64-MW CSP plant started producing electricity in Nevada this March. A 50-MW parabolic trough CSP plant with 7 h of molten salt thermal storage capacity is being constructed in Spain. Other parabolic trough CSP plants are in the planning stages around the world (Mahos, 2008). Power towers is as second CSP category that attracts interest and several plants are scheduled for installation in the Mojave desert (BrightSource Energy, 2008).

Ongoing research at the National Renewable Energy Laboratory demonstrates that the electricity production profile of CSP power plants can be transformed from a non-dispatchable to a dispatchable power source during the summer by applying 6 h of molten salt thermal storage capacity and by geographically dispersing the CSP plants (Blair et al., 2006). A CSP plant with 16 h of thermal storage capacity can be designed to generate electricity at full capacity for 24 h a day in the spring, summer, and fall months, and at 70% capacity for 16 h a day during average SW winter conditions. Thermal storage confers flexibility in tailoring electricity output to meet variations in load demands. The ability to use thermal storage to shift time-of-day electricity generation is illustrated in Fig. 3. CSP steam power plants can be equipped with auxiliary boilers using fossil or synthetic fuels, to provide electricity during cloudy days.

The key to the commercial development of CSP is establishing a consistent annual deployment schedule leading to lower costs. In a US-DOE sponsored study, Sargent and Lundy (2003) estimated that such cost reductions could be realized through economies of scale by building large plants, through learning-curve experience with manufacturing components in volume, and through technical improvements from continuing research (Shinnar and Citro, 2006). The Solar Energy Task Force of the Western Governors' Association (WGA) concluded that CSP electricity prices of $0.10/kWh or lower are possible with construction of 4 GW by 2015 (San Diego Regional, 2005; WGA, 2006). To help meet the CSP deployment goal, the US-DOE's Energy Efficiency and Renewable Energy Office and the WGA agreed to promote the installation of 1 GW of new parabolic trough CSP plants by 2010. In our modeling, we assume that drastic cost reductions will occur post-2015 with advances in thermocline thermal storage.

Water allocation is an issue for siting CSP plants, as any type of thermoelectric plants. Different options may exist (e.g., air cooling, on-site rain-runoff collection and storage systems or transfer of water from ocean desalination plants), and these need further study.

2.4. Other renewable technologies for electricity generation

The American Council on Renewable Energy (ACORE) (2007) estimates that the prospects of building renewable power plants in the US by 2025 include 248 GW of wind, 164 GW of solar, 23 GW of hydro (in addition to the current 75 GW), 100 GW of geothermal energy and power, and 100 GW of biomass. It is noted that ACORE's estimates for PV do not include storage, and this is the major reason for our PV estimates being higher. For all other renewables, we use the ACORE projections to 2025, and we extend the forecast to 2100 (Table 1).

Geothermal heat pumps are especially attractive in our plan. They have been supplying homes and small businesses with heat, space cooling, and hot water for buildings and pools for more than 20 years. Due to projected increases in heating oil and natural gas prices, we project that geothermal heat pump capacity will start growing significantly in the 2030s, that it would become the dominant source of residential and commercial space heating and cooling by 2050, and would become universal by 2100. The universal adoption of geothermal heat pumps, with 30% greater efficiency than conventional space heating and cooling systems, will result in a 23 quadrillion Btu (Q-Btu) (24.3 EJ) energy use reduction in space heating and cooling energy consumption by 2100.

2.5. Energy technologies for enabling solar energy use in transportation

Plug-in hybrid electric vehicles (PHEVs) can be powered with electricity produced with solar and other renewable, non-polluting, electricity sources. Although there are still formidable challenges related to the development of light and inexpensive batteries, current technologies (e.g., lithium ion) have the

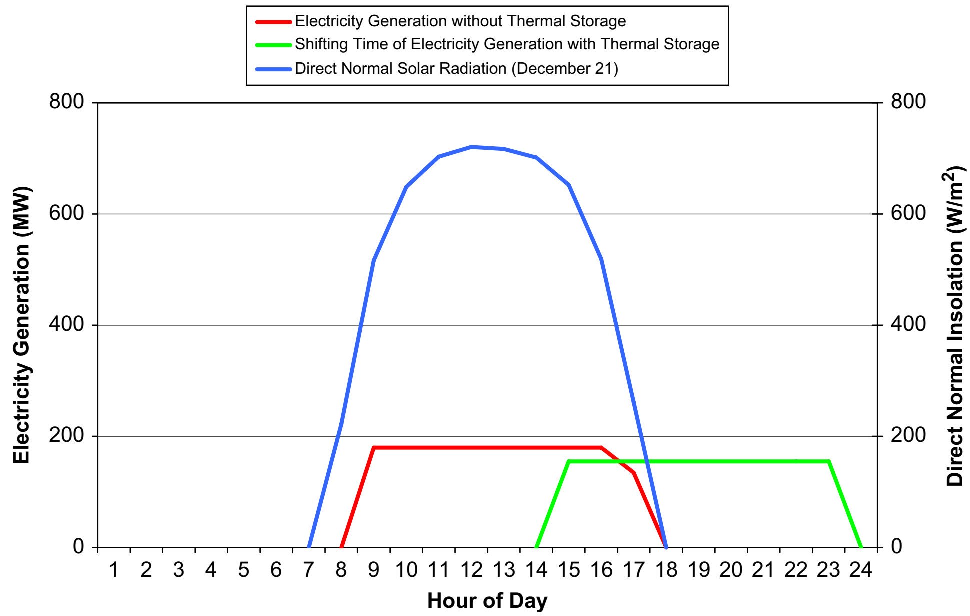

Fig. 3. Winter electricity generation: a CSP power plant with thermal storage shifting time-of-day electricity generation to supply electricity through a winter evening's peak demand, 5–10 pm.

potential to make these cars driving full-range (e.g., 40 miles) between charges (US Department of Energy (US-DOE), 2007). Several auto manufacturers have built plug-in hybrid prototypes, and at least one company has a target for introducing a PHEV in the market in 2010 (Lutz, 2008). Biofuel produced from cellulosic biomass can be used for plug-in hybrid vehicles. In the US, the cellulosic biomass resource is estimated at 1.2 billion dry tones per year (Perlack et al., 2005). From this quantity, fuel can be produced to supply 14 Q-Btu of energy for transportation and electricity generation in the US without encroaching on food crop production, at fuel prices lower than the current price of gasoline.

In the long term, there are questions regarding the extent to which the land and water resource base can support biomass production. However, if needed, hydrogen can be used to power both plug-in hybrid vehicles and fuel cell vehicles. Hydrogen can simply be burned as fuel in plug-in hybrids, much as natural gas is today. The bottom line is that PV electricity can be used to power all types of vehicles, whether they are plug-in hybrid vehicles or fuel cell vehicles.

PV electricity can be used to produce hydrogen by splitting water through the process of electrolysis. Then, hydrogen can be employed to power vehicles or gas turbine electricity-generating plants. Mason and Zweibel (2007) estimate a $6/kg price of hydrogen produced by electrolysis plants using PV electricity at a PV electricity price of $0.06/kWh. This high hydrogen price precludes its near-term use for electricity generation. However, this price is economically viable if hydrogen is used in transportation by advanced fuel economy vehicles such as plug-in hybrid or fuel cell electric vehicles. In the future, hydrogen produced by PV electrolysis might become economical for use by heavy trucks, planes, trains, and ships.

3. The geographical feasibility

3.1. Solar and land availability in the southwest of the US

The US, and especially the SW, is endowed with a vast solar resource. There is at least 640,000 km^2 (250,000 square miles) of land suitable for constructing solar power plants in the SW alone (Fig. 4). A large faction of this land, e.g., 85% in Arizona, is not privately owned. Note in Fig. 4 that environmentally sensitive lands and lands with a slope greater than 3% are excluded from consideration.

The available land area receives over 4500 Q-Btu of usable solar radiation per year (6.4 kWh/m^2 day). If just 2.5% of this solar radiation is converted into electricity, the 110 Q-Btu of energy is more than the current level of annual energy consumption in the US. The land required for installing a 500 MWp PV power plant with 14% efficient modules is 10.6 km^2. In this land area estimate, we included the land for adding PV to maintain a constant annual level of electricity production to compensate for an estimated 0.5% annual PV output degradation rate. This land is less than the land needed for an equal GWh output from coal power when factoring in the land for coal mining (Fthenakis and Kim, in press), land that often is permanently altered. As module efficiencies increase, even less land will be required. Furthermore, throughout the rest of the country, the sunlight received can be used by distributed PV systems.

The historical transience of sunlight in the SW is illustrated in Fig. 5. This figure shows daily average and minimum values of 45-year (1960–2005) solar radiation records for six locations—El Paso, Albuquerque, Tucson, Phoenix, Las Vegas, and Daggett (NSRDB, 2007). As shown elsewhere (Fthenakis et al., in preparation), the geographic locations of these six sites afford an accurate assessment of average solar radiation in the SW. Furthermore, these records enabled the construction of a regression model that forecasted extreme events in the period 1991–2005. This systematic analysis of the historical sunlight record for the SW shows that there is a great confidence in predicting the daily average and minimum sunlight in the US-SW.

3.2. Transmission of electricity from the southwest

The distribution to the whole nation of solar electricity produced in the SW and wind electricity produced in the central

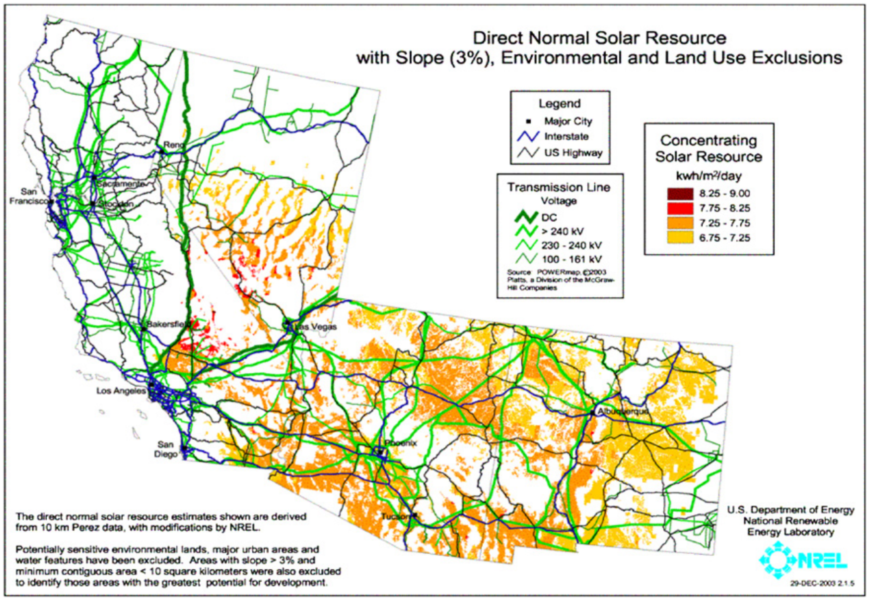

Fig. 4. Land availability map for the southwest US (*source*: National Renewable Energy Laboratory).

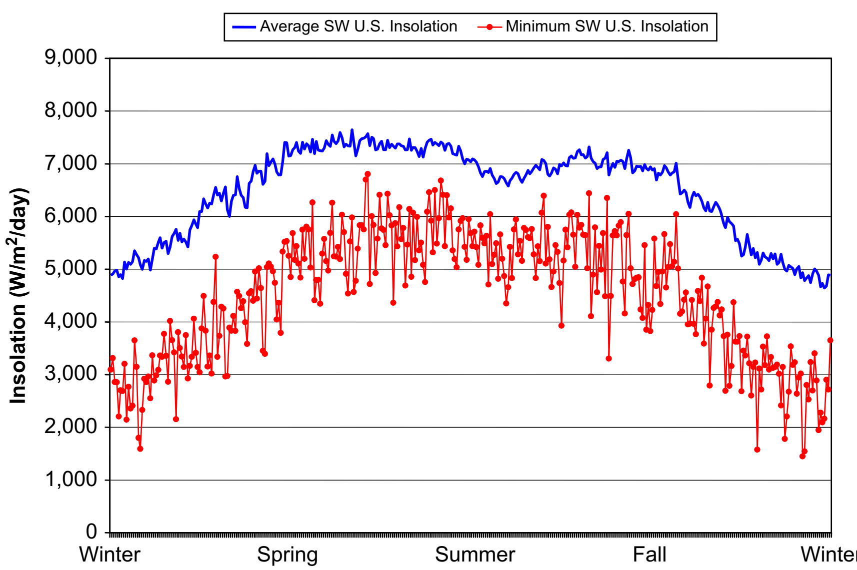

Fig. 5. Daily average and daily minimum global insolation levels on a flat surface tilted at an angle equaling the site's latitude (average of 45-year insolation records for six locations in Southwest US: El Paso, Albuquerque, Tucson, Phoenix, Las Vegas, and Daggett).

region of the US will require the construction of a national transmission network. The long distances involved will necessitate high-voltage direct current (HVDC) lines. The transmission of electricity over 2000 miles of HVDC lines entails a 10% electromagnetic loss versus a 22% or higher loss via high-voltage AC power lines of the same distance (DLR, 2006). Also construction of high-voltage DC power lines requires 37% less land area than constructing high-voltage AC ones. The technology is well established but there are cost and siting challenges that need to be addressed.

Currently, HVDC transmission lines with a capacity of 5 GW are being built in China utilizing 800 kV technology, and in the future a doubling of this capacity is expected (McCoy and Vaninetti, 2008). The array converters will be boosting array voltages of around 1 kV DC to a "gathering" voltage of around 50 kV DC. A second DC to DC converter will be used to boost the "gathering" voltage to the transmission voltage of 800 kV DC. These converters are already in common use throughout the electric utility industry in power-conditioning devices and high-voltage DC power lines in Europe and the US.

McCoy and Vaninetti (2008) estimate the cost of constructing a network of HVDC lines with current technology to be $0.02/kWh. However, the same authors foresee a dramatic improvement in technology and in unit cost with a plan for large deployment and domestic production of the large quantities of heavy cables required. The TransMed study for connecting North Africa with

Europe shows a capital cost of 750 million/1000 miles transmission lines and \$475 million per converter station (DLR, 2006). From these capital costs we estimate a levelized cost of \$0.024/kWh, for an average distance of 1500 miles and one converter per line and capacity utilization factor of 27%. The cost will decrease with technological improvements and scales of deployment (McCoy and Vaninetti, 2008). As it is happening today, this cost will be included in the royalties that grid developers receive.

Siting of the transmission lines has to be carefully studied. To address ecological, land use, and security concerns, many lines would have to be placed underground. HVDC has the attractive feature of being "underground-able" for long distances, unlike high-voltage AC lines (McCoy and Vaninetti, 2008).

3.3. Underground compressed air storage availability in the US

Mapping by the natural gas industry and EPRI indicates that geological formations suitable for CAES exist in 75% of the country (Mehta, 1992).

The selection of PV–CAES air storage sites can build upon the 80-year history of storing pressurized natural gas in underground reservoirs. The natural gas industry currently uses an underground storage working gas capacity of 113 billion m^3 (Bm^3) in approximately 400 underground reservoirs distributed throughout the US and a much higher capacity exists. Our plan would require 1.1 Tm^3 of working air storage capacity for 880 GW of peak PV–CAES plants, 307 GW of base-load PV–CAES plants, and 297 GW of base-load wind–CAES plants by 2050. A peak PV–CAES plant is designed to supply 127 h of storage between charging cycles, a base-load plant would supply 312 h and a PV–wind plant will supply 250 h between charges (Mason et al., in press). The working capacity of CAES plants proposed by 2050 is a factor of 10 greater than the current working gas storage capacity in the US underground natural gas industry. There are indications that much larger volumes of underground storage exist. Mapping by EPRI shows that geological formations suitable for CAES exist in 75% of the country (Swensen and Potashnik, 1994). The National Energy Technology Laboratory determined that deep saline aquifers in North America can store 496 Tm^3 of carbon dioxide (NETL, 2007). Saline aquifers can also be used for CAES; such a system is under development in Iowa (Haug, 2003). Detailed studies on the suitability of individual sites will have to be performed, but it appears that siting is not a critical path activity for CAES development (Katz and Lady, 1990; Mehta, 1992). Nevertheless, underground storage development in the large scales we describe may be the biggest challenge for accomplishing our grand solar plan.

4. The economic feasibility of large-scale implementation

The solar energy power plant is composed of central PV power plants, CAES power plants supplied with PV electricity, CSP plants with 6 and 16 h of thermal storage capacity and auxiliary, fuel-burning, boiler units, and distributed PV power plants. All central PV and CSP power plants are built in the SW on a gigawatt (GW) scale. Distributed PV systems play an important role by reducing daytime electricity load. CAES power plants are located throughout the US and utilize multi-hundred-megawatt (MW)-scale gas turbine/generator units. The electricity to power CAES plant compressors for compressed air storage is supplied by central PV power plants located in the SW. The electricity produced in the SW is distributed to national markets via HVDC power transmission lines.

4.1. Present to 2020—policy options

There are three distinct stages in realizing the development of the SW solar power plant. The first stage, possibly from 2011 to 2020, is a proposed 10-year solar deployment and incentive program. The proposed deployment schedule is presented in Table 3.

Although several technologies have the potential for low-cost production, none has reached the scales necessary for optimizing manufacturing and achieving lowest cost. We propose the implementation of a US solar deployment and incentive program designed to bring those solar technologies with potential of being low-cost electricity producers to optimized manufacturing scale over a 10-year deployment period. The goal of the 10-year program is to establish a competitive, non-subsidized solar market. This will open the door to explosive growth in central solar plant deployment post-2020 as needed.

We propose a mix of incentives that includes government-guaranteed loans, a mandatory solar portfolio standard for electric utilities, and a solar price support program for a feed-in tariff (FIT). In the first 5-year round of solar deployment, the FIT subsidy levels are \$0.11/kWh for CSP, \$0.11/kWh for PV–CAES, and \$0.2/kWh for distributed PV. The FIT subsidy levels are reduced in the second 5-year round of solar deployment to \$0.07/kWh for CSP, \$0.03/kWh for PV–CAES, and \$0.1/kWh for distributed PV. The FIT subsidies are paid over the entire 30-year capital recovery period and the total cost is \$300 billion. With sustained growth in the solar industries, subsidies will not be needed for solar plants built after 2020, since the scale of manufacturing will suffice to foster competitive market dynamics for all plant components, resulting in competitive electricity prices. This should set the stage for self-sustained, explosive growth in the CSP and PV markets post-2020.

Analysis of the European incentive programs has found FIT to be an effective means to increase the deployment rate of renewable energy technologies (Mitchell et al., 2006). The idea of a FIT is to subsidize the differential between the cost of electricity production for an emerging renewable energy technology and the wholesale electricity market price. FIT is flexible, subsidy levels can be tailored to meet the needs of different technologies, and they can be reduced over time as technologies mature.

A drawback to FIT subsidies is that they can be economically inefficient since the subsidies can enable poorly performing companies or technologies to survive. To improve the efficiency of FIT programs, Lesser and Su (2008) have proposed a two-part model that involves both a capacity payment and a market-based energy payment. In the first part, a capacity payment is determined through bids in a Forward Capacity Market (FCM) auction similar to the one recently implemented in New England (Coutu, 2007). In the second part, the winning bid companies receive the market price for wholesale electricity just like any other electricity production company. The FCM auction is a descending clock auction, whereby the first price offered will be set high enough to attract sufficient number of bids to meet the solar capacity target for that round. The offered price is then systemically reduced until just enough bids are entered to meet the capacity target. Only those companies confident of earning required returns will enter the reduced bids that will determine the final clearing price, which helps weed out inefficient companies. The Lessor and Su model should be relatively easy to implement since it builds upon a capacity addition model already adopted in US electricity markets. Since government budgets are affected by the cost of incentive programs, there must be consideration of a revenue source to offset the subsidy cost. Two revenue-generating programs presently being considered in the

Table 3
Proposed cumulative deployment schedule for renewable energy technologies

	2015	2020	2030	2050	2100
1. Concentrating solar plants (GW)[b]					
a. Peak CSP plants (GW)	9	28	90	1130	2790
b. Base-load CSP plants (GW)	0	0	28	374	1320
2. PV compressed air energy storage plants (GW)[c]					
a. Peak CAES plants (GW)	9	28	90	880	3484
*PV for peak CAES plants (GW)[d]	(12)	(40)	(130)	(1280)	(5067)
b. Base-load CAES plants (GW)	0	0	28	307	1234
*PV for base-load CAES plants (GW)[d]	(0)	(0)	(110)	(1266)	(5090)
3. Distributed PV capacity (GW)	3	6	11	258	1258
4. Wind Compressed air energy storage plants (GW)[e]	12	29	84	279	400
*Wind capacity for CAES plants (GW)[f]	(29)	(72)	(210)	(698)	(1000)
5. Central geothermal power plants (GW)	6	17	55	200	200
6. PV dedicated to electrolytic hydrogen production					5000
Total renewable power plant capacity (GW)[a]	39	108	386	3428	10,686
Above total normalized for 90% capacity factor (GW)	24	67	252	1852	5392
7. EIA/DOE total projected capacity additions (GW)	65	111	249		

[a] The capacity factors for the power plants listed above are 90% for base-load CSP plants; 30% for peak CSP plants; 90% for base-load PV–CAES plants; 30% for peak PV–CAES plants; 35% for wind plants; and 90% for geothermal plants. Power line losses are assumed to be 10% for all technologies.

[b] Base-load CSP power plants have 16 h of thermal storage capacity, and peak CSP plants have 6 h of thermal storage. All CSP plants have auxiliary boiler units heated with natural gas for use to meet electricity production when thermal storage is depleted.

[c] Base-load PV–CAES plants have 300 h of compressed air storage and peak PV–CAES plants have 100 h of compressed air storage.

[d] PV for CAES is not included in the row for "Total renewable power plant capacity", since it provides intermediate energy used in CAES plants.

[e] Wind CAES power plants are modeled as base-load plants with a wind to turbine power ratio of 2.5, with a CAES gas turbine plant annual capacity factor of 90%, and with 200 h of compressed air storage.

[f] Wind capacity for wind–CAES is not included in the sum of "Total renewable power plant capacity" since it provides intermittent energy used by CAES plants. Wind growth estimates are based on ACORE (2007) projections to 2035, for the development of Class 4–Class 7 wind resource regions.

US are carbon cap and trade and a carbon dioxide (CO_2) emissions tax. A climate-change bill that is headed for vote in the US Senate would create an estimated $150 billion of new assets in the first year it takes effect, for a total of $3 trillion from now to 2050 (Gunther, 2008). Advocates of this bill see proceeds used for a variety of causes including investments in renewable energy.

Another important issue to be taken into account is national energy security. Post-2020 there is a high probability that global natural gas supply will tighten in a similar vein to the present tightening in global oil supply (Mason, 2007). And adding to the problem is the possibility that global coal supply will begin to tighten by mid-century. This means that energy supply shortages and prices will escalate in waves of increasing intensity over coming decades. Revenues for the solar FIT program can be generated with the implementation of a national energy and environmental security levy imposed on all electricity produced by fossil fuel power plants. Revenues to cover the $300 billion cost of the FIT subsidy program can be generated by a levy of only $0.005/kWh on all electricity produced by fossil fuel power plants in the US. A levy of this magnitude will not have adverse economic impact and is a small price to pay to prepare the US for possible increasing price volatility in natural gas and coal markets post-2020.

4.2. 2020–2050

The second stage of solar power plant development, post-2020, involves a commitment to an annual deployment schedule of new plant construction at a level able to sustain growth in the manufacturing market for plant components and the adoption of prototype innovations. Post-2020, solar power will be positioned to begin reducing the use of natural gas and coal for electricity generation and to provide electricity for the plug-in electric vehicle market.

To illustrate the electricity production potential of the US solar power plant, we modeled a hypothetical, 2011–2050 deployment schedule for PV–CAES and CSP power plants, as well as wind–CAES and central geothermal power plants. The cumulative deployment schedule is presented in Table 3. Our projections are well below the EIA projections of cumulative electric power sector additions for the period 2010–2030. The later specify that an additional 250 GW of electricity generation will be needed to satisfy demand growth and replace 51 GW of retired plants (EIA, 2007). Since there are no published estimates for needed additions beyond 2030, we simply extrapolated the 2030 capacities based on 1% growth in demand.

The corresponding annual growth in electricity production is shown in Fig. 6. The increase in renewable energy production stabilizes by 2040, as all fossil fuel power generation has been replaced. Biofuel is used instead of natural gas in the CAES and CSP plants. By 2050, 3800 TWh of electricity is produced above what is needed to replace fossil fuels, and it can be used to produce electrolytic hydrogen.

By 2050, we demonstrate that the following new capacities are feasible, contingent on a national commitment to a renewable-energy-based electricity production and distribution system: 258 GW of distributed PV, 1.187 TW of CAES–PV peak and base-load power plants (with 2.546 TW of supporting PV power plants), 1.504 TW of CSP steam power plants, 279 GW of CAES–wind power plants (with 698 GW of supporting wind power plants), and 200 GW of central station geothermal power plants. The capacity factors assumed for each of these plants are shown in the footnote of Table 3. The current electricity generation estimates are the same with those listed elsewhere (Zweibel et al., 2008), noting that the projections in the previous study were normalized for average US grid of 90% plant capacity factor, whereas the current article shows the details of the capacities in each technology.

Fig. 7 shows the major contributions to fuel reduction resulted from the introduction of renewable electricity and biofuel. We assume that replacement of internal combustion automobiles with plug-in hybrid electric vehicles PHEVs will start on or about 2015; then our model estimates that by 2037 the whole fleet of light cars and trucks, amounting to 344 million vehicles, would

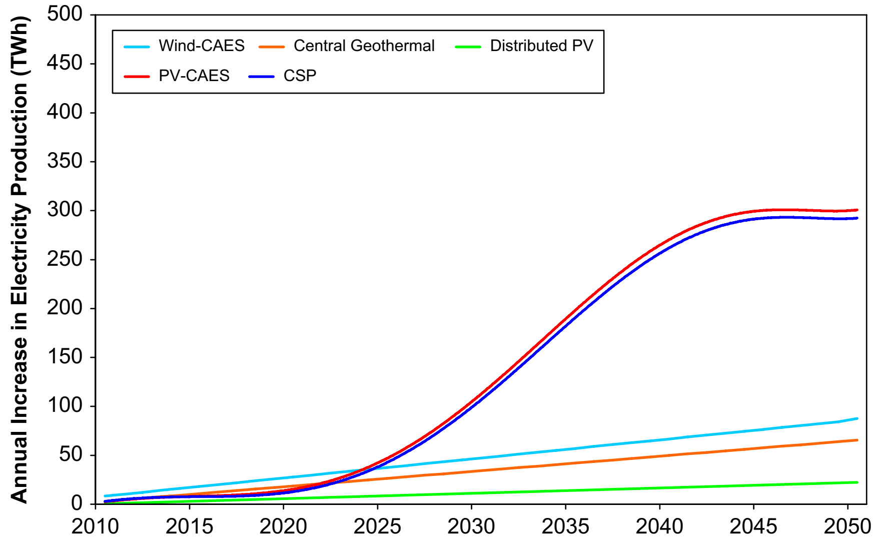

Fig. 6. Annual added electricity production from renewable energy.

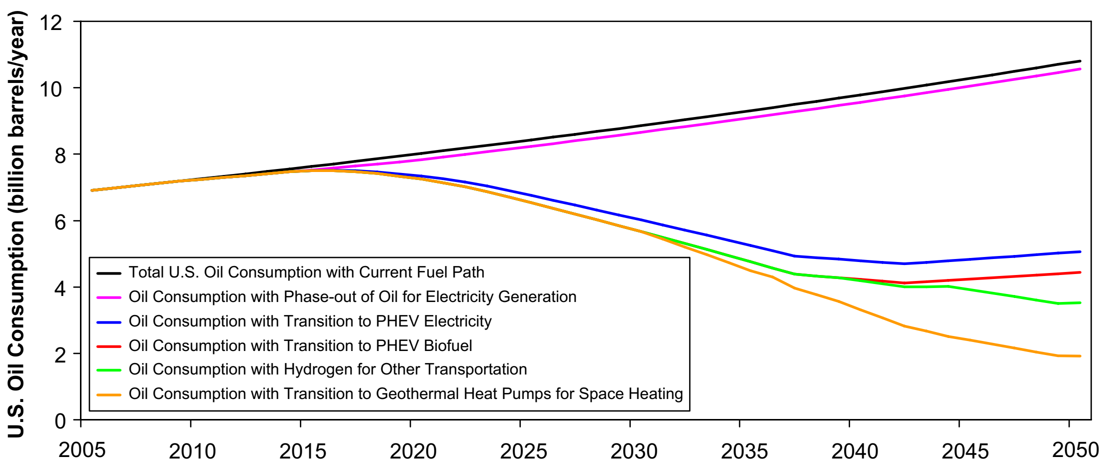

Fig. 7. US annual oil consumption with the current energy path and reductions corresponding to each of the technologies of the renewable energy path. (Each curve shows additional oil reduction; the bottom curve shows the total oil consumption in the renewable energy path.)

have been replaced by PHEVs. Transportation is 68% of total US oil consumption, and cars and trucks comprise 55% of the transportation oil consumption. Although by 2037, gasoline consumption for car/trucks is eliminated, consumption of oil in other modes of transportation and industry sectors continue to grow at a 1% annual rate.

The seasonal contributions of the renewable energy power plants and the corresponding load (i.e., demand) curves are shown in Figs. 8A–D. During the spring and fall, the total electricity generated by renewables almost satisfies the demand, whereas in the winter the effects of short days on the solar electricity production level and of high electricity demand are evident. In 2050, the solar power plants produce 69% of total US electricity generation and 35% of total US energy consumption. This quantity is adequate to supply all US peak period electricity and all electricity consumed by PHEVs. Most importantly, the combined renewable energy sources reduce carbon dioxide emissions in 2050 by 62% below the 2005 level.

In 2050, biofuel produced from the projected 1.2 billion tonne of the annual cellulosic biomass resource base in the US will be sufficient to replace 95% of the fuel consumed by PHEV, by the PV and wind–CAES power plants, and by the auxiliary boilers in the CSP power plants. The first market for biofuel will be PHEVs. The fuel needed for the CAES and CSP plants will initially be natural gas, but as natural gas prices increase over coming decades, CAES and CSP plants will increasingly turn to biofuel. The total fuel consumption by PV–CAES, wind–CAES plants, and CSP plants is 10.9 Q-Btu in 2050.

Deployment of solar power plants entails higher capital costs, but much lower operating costs, than deployment of fossil fuel power plants. Avoided fuel costs and lower annual O&M expenses offset the annual cash flow effects of capital costs. Importantly, electricity generation by peak solar power plants becomes cost competitive by 2020. Base-load solar plants are projected to become cost competitive with advanced base-load coal and combined-cycle natural gas plants outfitted with carbon capture and storage (CCS) systems when the natural gas price is \$9.6/GJ and the coal price is \$3.4/GJ (Mason et al., in press).

At present, annual US energy production exceeds 100 Q-Btu (105 EJ). In the proposed renewable energy system, US energy production in 2050 has *fallen* to 93 Q-Btu, although consumption has been increasing by 1% per year during 2010–2100. This unusual result reflects the large efficiency gains of a renewable energy system. Our model shows 52.4 Q-Btu in energy savings by the elimination of fossil fuels in the electricity generation system, 17.8 Q-Btu in transportation fuel savings by adopting PHEVs, and 4.7 Q-Btu in space heating savings by implementing geothermal heat pumps. EIA projects a 1.4% annual growth rate till 2030;

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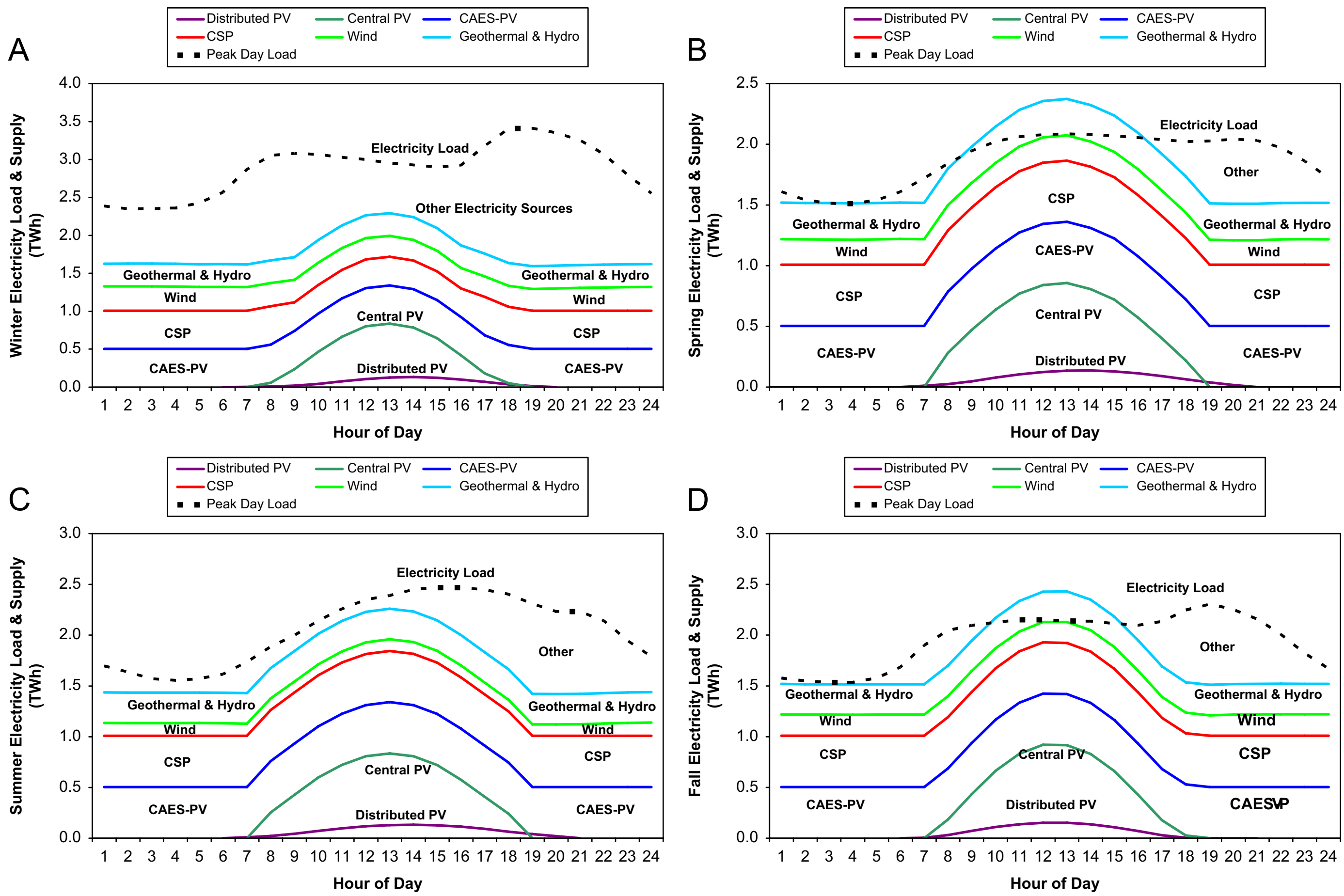

Fig. 8. (A) Winter 2050 electricity load and supply scenario. Based on seasonal daily average insolation shown in Fig. 5. (B) Spring 2050 electricity load and supply scenario. (C) Summer 2050 electricity load and supply scenario. (D) Fall 2050 electricity load and supply scenario.

when accounting for the above described efficiency increases, this is equivalent to the 1% average annual growth rate to 2100 that we use in this study.

The land needed for the cumulative PV and CSP installations by 2050 is 99,840 km^2, which is just 16% of the total land area suitable for solar plants area in the SW. This estimate includes additions of PV to counter a 0.5%/yr degradation in PV performance. In addition, there are many areas with excellent sunlight and open space in the rest of the country, and a large potential for rooftop installations. Only 10% of the PV plants we modeled is distributed PV systems, but with inexpensive PV and developments in roofing technologies, distributed PV might become ubiquitous throughout the US and can play a much larger role than indicated here.

4.3. 2050–2100

Our model shows that there is potential in the proposed solar energy plan to satisfy 90% of the total energy needs of the US by 2100, even if we assume, extremely conservatively, no improvements in the efficiencies of renewable power generation, transmission, and storage in the post-2050 period. If, for example, third-generation PV technologies and better storage technologies become available, accordingly the outlook and associated costs would be better than what we project.

For renewable energy to totally meet its full potential in the US, we have to carefully assess the solar resource under worst conditions. A review of the 45-year data of the National Solar Radiation Database (NSRDB, 2007) shows that the lowest, on record, solar irradiation day in the SW occurred on 16 January 1979, and the insolation level was 70% below the historical average for that date. In such conditions, electricity production by CSP power plants is zero, and electricity production by central PV power plants is only 30% of the average winter day PV electricity production level (Fig. 9A). However, having added storage capacity in the form of CAES and thermal storage ensures that solar electricity production on the lowest radiation day, combined with the electricity production from the other renewable energy power plants, is sufficient to meet winter peak day load in 2100 (Fig. 9B). To meet this hypothetical peak load the solar power plant capacity is increased to the following: 4.72 TW of CAES–PV plants connected to 10.16 TW of supporting PV plants, 4.11 TW of CSP, and 1.26 TW of distributed PV. The corresponding cumulative underground storage air working capacity for PV and wind increases to 2.3 Tm^3.

In 2100, the renewable power plant will supply 100% of winter, spring, summer, and fall electricity demand. Actually, the system will produce surplus electricity for 75% of the year (see Fig. 10 for surplus in a typical spring day). The annual surplus of electricity is capable of producing by electrolysis 261 billion kg of hydrogen, and the addition of 5.23 TW of PV dedicated to hydrogen production is capable of producing another 175 million kg. The modeling of hydrogen production by PV electrolysis plants is based on prior studies (Mason, 2007; Mason and Zweibel, 2007, 2008). We project that 566 million plug-in hybrid vehicles, all heavy trucks, ships, and planes would be fueled by hydrogen, from electrolysis of water and biomass gasification.

Estimates of carbon dioxide emissions for "business as usual" and for our renewable energy plan are presented in Fig. 11. With our proposed path, in 2050 energy-related carbon dioxide emissions are 60% below the 2005 emissions level, and by 2100, such emissions are 92% below the 2005 level. Industrial coal and coke are the only sources of energy not replaced by the renewable energy power plant in our scenario.

5. Conclusion

It is clearly feasible to replace the present fossil fuel energy infrastructure in the US with solar power and other renewables, and reduce CO_2 emissions to a level commensurate with the most aggressive climate-change goals. We proposed a plan based on well-documented status and progress expectations in PV and CSP technologies, integrated with CAES for PV and thermal storage for CSP. Energy storage transforms solar energy from an intermittent to a 24-h/day, 365 days/yr, base-load technology. Wind, biomass, and geothermal also play significant parts in our plan. We foresee an evolution to plug-in hybrids for transportation, wherein a large fraction of the liquid fuel needed for transportation is replaced with renewable electricity for battery charging.

We locate about 90% of the solar production in the US-SW, transmitting DC electricity to the rest of the US By itself, the US-SW has extremely favorable reliability as a solar resource. We must oversize the solar plants by about 45% for peak PV–CAES plants and by about 300% for base-load PV–CAES plants to meet diurnal needs; however, this oversized PV electricity output will allow making hydrogen from solar electricity during spring, summer, and fall months. Hydrogen has great value during the

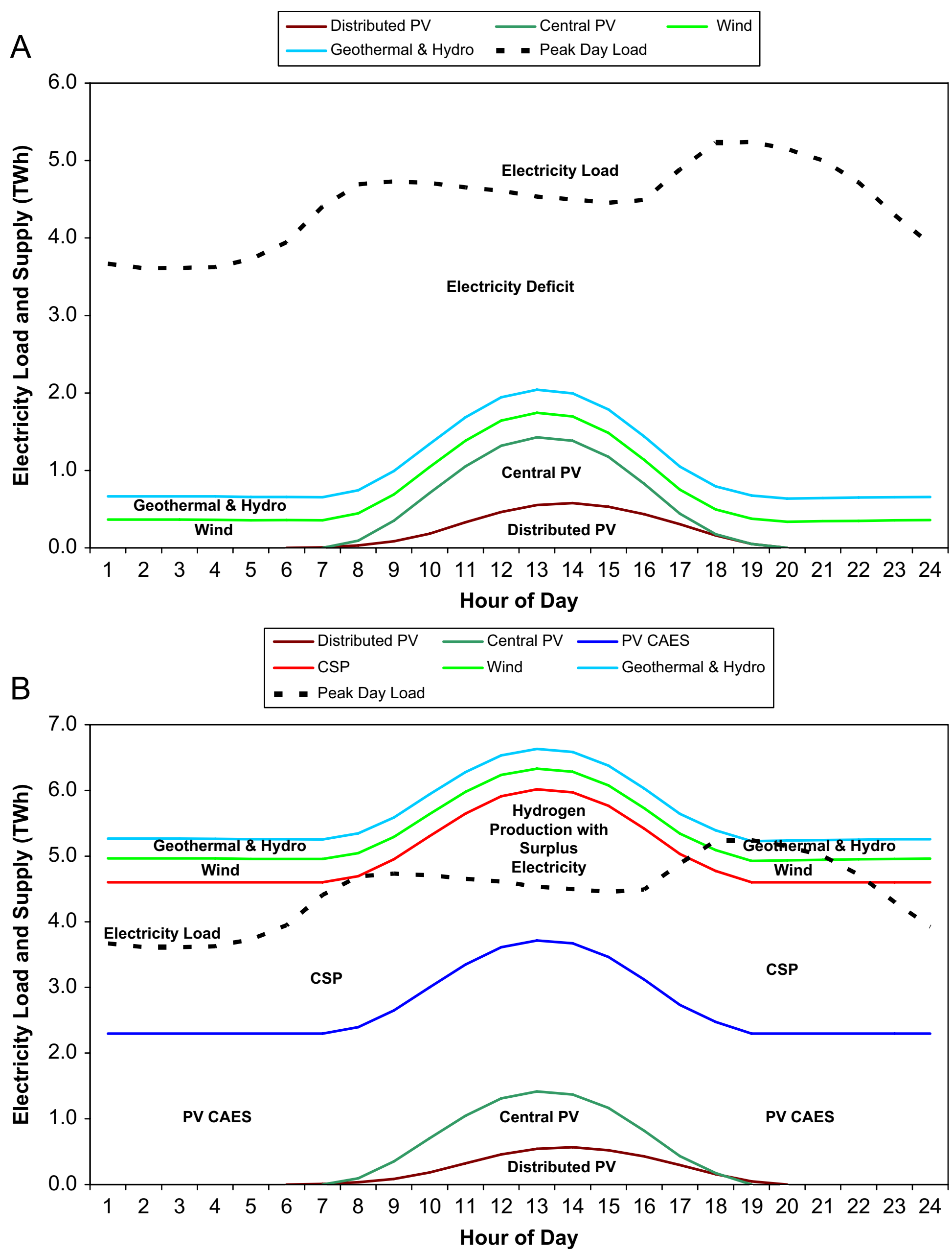

Fig. 9. (A) 2100 worst case scenario solution. This case represents a combination of days when solar radiation levels in the southwest are at the lowest recorded levels. CSP power plants are without auxiliary heater/boiler units, and there is no storage capability for PV. Observe the large electricity deficit. (B) 2100 worst case scenario solution. It employs CSP plants with auxiliary boiler units and PV–CAES plants with 100 h of storage for peak capacity and 300 h of storage for base-load capacity. Biofuel or hydrogen from renewable sources is used in the CSP and CAES.

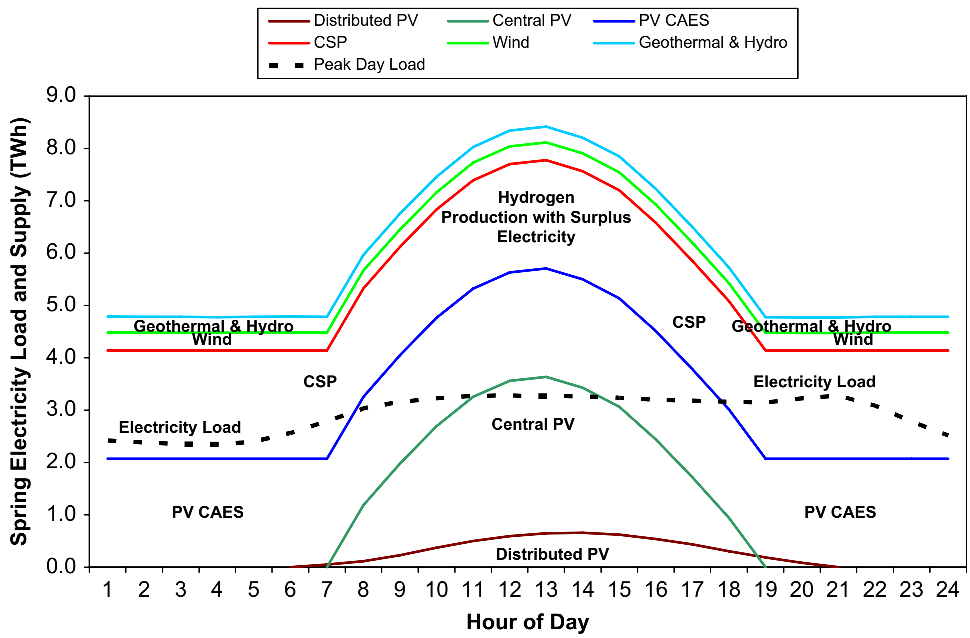

Fig. 10. 2100 spring electricity load and supply scenario.

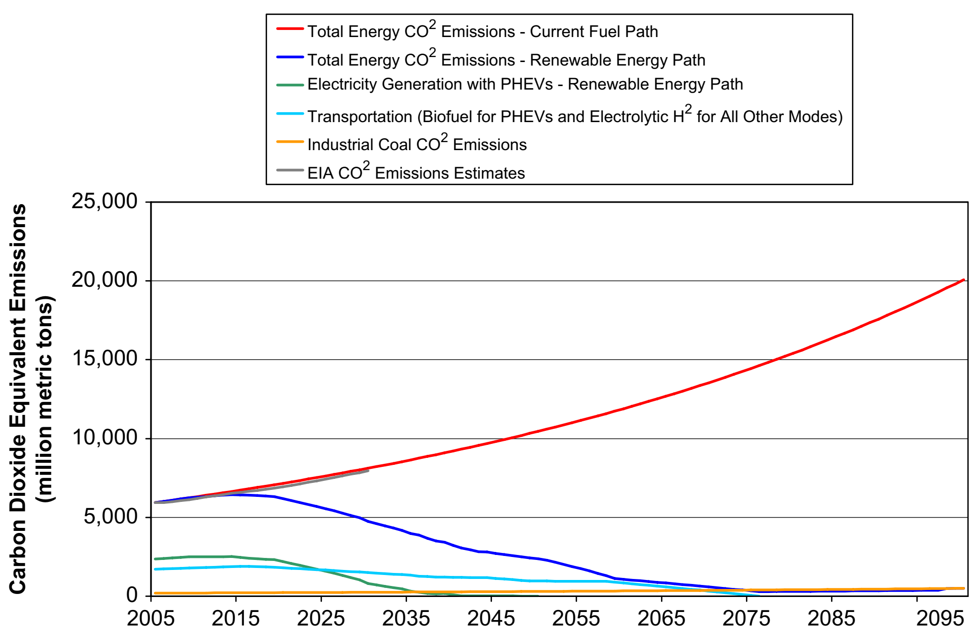

Fig. 11. US energy-related carbon dioxide emissions, 2005–2100 from the current energy technology fuel path and the renewable energy technology and fuel path.

latter half of the 21st century as a transportation fuel to supplement biofuels.

The key challenges for the vision to materialize are

Near term

1. Political foresight to create the appropriate incentives to advance the development of solar technologies from their present levels to cost competitiveness.
2. Reducing the price of PV systems by 63% (to \$0.06/kWh for US-SW insolation).
3. Reducing the price of CSP by 55% (to \$0.09/kWh for US-SW insolation).
4. Developing underground compressed air storage caverns.
5. Constructing long-distance transmission from the US-SW.
6. Developing 16-h economical and reliable thermocline heat storage for CSP.

Intermediate term

7. Perfecting batteries for plug-in hybrid electric cars.
8. Integrating compressor heat recovery and re-use for CAES systems to replace the use of natural gas combustion (or replacing it with syngas from biomass or solar hydrogen).

The biggest challenge, in our opinion, is the political foresight. Technical challenges are only minor challenges in comparison to those already overcome.

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thermal storage; and Hank Price, National Renewable Energy Lab (NREL), for data and reviews of the CSP materials.

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