RENEWABLE ENERGY ENHANCED USE LEASE OPPORTUNITY SUMMARY REPORT

Washington DC - August 2007

Booz | Allen | Hamilton

ACRONYMS

AFB	Air Force Base
AFRPA	Air Force Real Property Agency
AWEA	American Wind Energy Association
BLM	Bureau of Land Management
BMGR	Barry M. Goldwater Range
CCX	Chicago Climate Exchange
CHP	Combined heat and power
COS	Concept Opportunity Study
CSP	Concentrating solar power
DDG	Distiller's dry grain
DoD	Department of Defense
EIS	Environmental Impact Statement
EUL	Enhanced Use Lease
GIS	Geographic Information Systems
GSHP	Ground source heat pump
GW	Gigawatt
HAWT	Horizontal axis wind turbines
IGCC	Integrated gasification combined cycle
INL	Idaho National Laboratory
IOUs	Investor-owned utilities
IPP	Independent power producers
IRP	Installation Restoration Program
kWh	Kilowatt hour
LFG	Landfill gas
MAJCOM	Major Command
MGY	Million gallons per year
MMBtu/hour	Million British thermal units per hour
MSW	Municipal solid waste
MW	Megawatt
MWh	Megawatt hour
NEPA	National Environmental Policy Act
NREL	National Renewable Energy Laboratory
O&M	Operations and Maintenance
PTC	Production Tax Credit
PV	Photovoltaic
RDF	Refuse-derived fuel
RECs	Renewable Energy Credits
RFS	Renewable Fuels Standard
RGGI	Regional Greenhouse Gas Initiative
RPS	Renewable Portfolio Standard
SEPs	Supplemental energy payments
SEGS	Solar Energy Generating System
VEETC	Volumetric Ethanol Excise Tax Credit
WTE	Waste-to-Energy

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1 INTRODUCTION

A highly uncertain energy climate, regionally constrained electrical grids, and the increasing competitiveness of renewable energy sources compel the Air Force to look for ways to diversify and expand its energy portfolio. In addition, as a large landowner, the Air Force can leverage property in highly desirable energy locations to generate revenue through the Air Force Real Property Agency's (AFRPA) Enhanced Use Leasing (EUL) authority.[1]

This report considers the opportunities to lease underutilized land on U.S. Air Force bases for renewable energy development. The report provides a methodology, an evaluation of opportunities considered, and recommendations for moving forward with renewable energy EULs in the future. In addition, the report includes a full assessment of renewable energy markets and technologies and information on renewable energy project financing and development.

This report considers the following renewable energy technologies for project development: wind, solar, biomass, waste-to-energy, landfill gas and geothermal power as well as commercial-scale ethanol and biodiesel fuel plants. The assessment of opportunities is based on evaluation of the markets for renewable electricity and biofuels, the renewable energy resources at each Air Force installation, and an evaluation of the technical characteristics of the candidate underutilized parcels consistent with DoD instructions. [2]

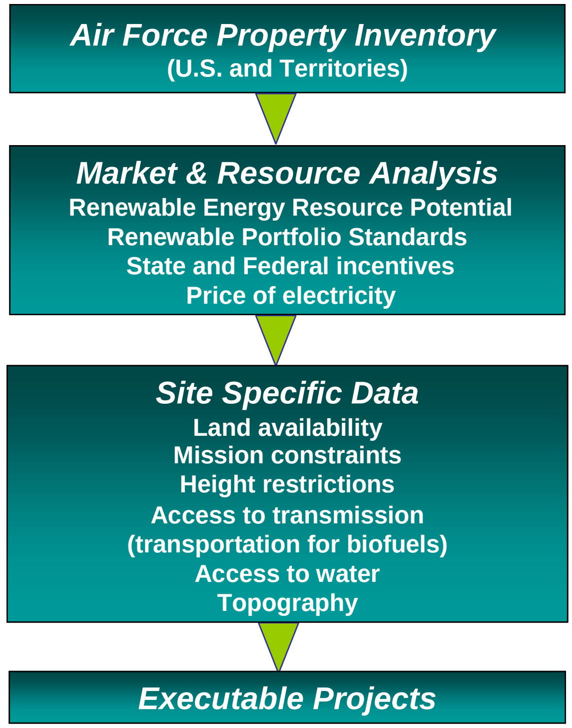
It is not within the scope of this study to identify opportunities where renewable energy could be used to primarily supply "inside the fence" or on-base electricity or fuel demand; however, the information collected could be used to facilitate such an evaluation. These distributed generation projects that primarily meet on-base demand were not considered for this study due to AFRPA's requirement that there be an off-base market for the power or fuel produced by the lessee in order to generate in-kind returns for the installation. The EUL mechanism can be used in conjunction with a power purchase agreement or a fuel purchase agreement, using the land value to reduce the price of power or fuel (or in some cases, the utility is willing and legally allowed to purchase the Renewable Energy Credit value separate from the electrical commodity, such as the recent solar photovoltaic project on Nellis AFB). However, in these cases the Air Force receives its entire in-kind benefit in the form of reduced power prices, which was not within the scope of this study.

This report is not all encompassing, and smaller-scale renewable energy EUL opportunities may exist due to local circumstances, such as a base that is located next to a large industrial customer that might purchase a portion of the power or heat from a shared combined heat and power plant. The economic feasibility of these on-base demand projects depends on the individual installations' electric and heat demand profile and energy costs, which were not available to the authors of this study. However, throughout the process, a number of possible renewable energy distributed generation opportunities were identified and are detailed in Chapter 3. It is recommended that further analysis be conducted on these possible opportunities.

[1] Title 10, United States Code § 2667
[2] DoD Instruction 4170.11- Installation Energy Management. November 22, 2005. Available online: http://www.dtic.mil/whs/directives/corres/pdf/417011p.pdf.

2 METHODOLOGY

Developing a renewable energy project is a complex process with a number of unique characteristics and variables that affect project feasibility and economic viability. The methodology used to identify these projects started with assembling an inventory of Air Force installations, including bases, guard stations, reserve centers, ranges, auxiliary fields, and research facilities. Each installation was assessed for its renewable energy potential and grouped by relevant resource area (i.e., wind, solar, biomass, geothermal, biodiesel, and ethanol). Renewable energy resource potential was determined through analysis of public and private data sources. Installations smaller than 100 acres were eliminated from consideration for wind and solar renewable energy projects because utility-scale applications of these technologies require large, contiguous land areas. Next, each base was screened against the following criteria to determine the most viable opportunities:



- Quality and availability of renewable resources (wind class, solar resources, geothermal power, and biomass—which included access to large quantities of landfill gas, biomass feedstock for power production and for large-scale biodiesel or ethanol production);
- Strength of the renewable energy market (state electricity prices, demand for renewable energy power due to Renewable Portfolio Standards, other state incentives);
- Distance to high-voltage transmission lines and power demand centers (for renewable power opportunities); and
- Access to transportation and critical infrastructure for biofuels (e.g., natural gas, barge access, and rail access).

In addition to the screening criteria, conclusions and analysis from the Department of Defense (DoD) Renewable Energy Working Group and DoD geothermal studies were considered. The initial screening process produced a list of possible opportunities from a high level view. Next, these possible opportunities were mapped with publicly available aerial imaginary and data from Booz Allen Hamilton's DoD Natural Infrastructure Geographic Information Systems (GIS) databases to determine undeveloped land areas, topographical constraints, and height restrictions.

After analyzing aerial images and land use data, a number of potential sites were removed from the opportunity list due to insufficient undeveloped land or height restrictions that limited the land areas available for project development. The sites remaining from the initial screen and mapping exercises were considered Tier I opportunities. These Tier I opportunities were further investigated through coordination with Major Commands (MAJCOMs), base engineers, base energy mangers, real estate specialists, and other base personnel to assess available, mission-compatible acreage. See Chapter 3 for detailed information on each of the Tier I opportunities.

Following this analysis and as more information was gathered about the feasibility of projects at the above mentioned installations, the list was further refined.

The following table identifies the top opportunities for AFRPA to pursue utility-scale renewable energy EULs. These opportunities were selected based on the methodology described above and are considered executable opportunities at this time. These opportunities have the necessary renewable resource assets, local market demand, suitable land acreage, access to transmission and utilities and developer interest to support the possible development of a utility-scale renewable energy project. During the project review process, the bases may wish to purchase a portion of the electricity generated directly or indirectly, but this was not the initial focus of this assessment. Each of these top opportunities was analyzed in detail including the potential financial return in a Concept Opportunity Study/Business Case Analysis.

Table 1: Top Renewable Energy EUL Opportunities

Installation	Renewable Resource
Kirtland AFB	Solar
Edwards AFB	Solar
Vandenberg AFB	Wind
Barry M. Goldwater Range	Solar

Throughout the process, a few opportunities were identified as having potential for a utility-scale renewable energy EUL, but have limitations that impact near-term implementation. Currently, these opportunities may be insufficient to attract a developer's interest, but they may be feasible in the future as renewable energy market conditions change and if available land acres with mission compatibility can be found:

Table 2: Secondary Renewable Energy EUL Opportunities

Base Name	Renewable Resource	Limitation
Nellis Air Force Base and the Nevada Test Range	Solar, Geothermal	BLM withdrawn land / DoD land authority issues; short-term market limitations, need to determine mission compatibility with geothermal.
Melrose Air Force Range	Wind	Transitioning to Special Operations Command; undetermined mission constraints until transition is complete.

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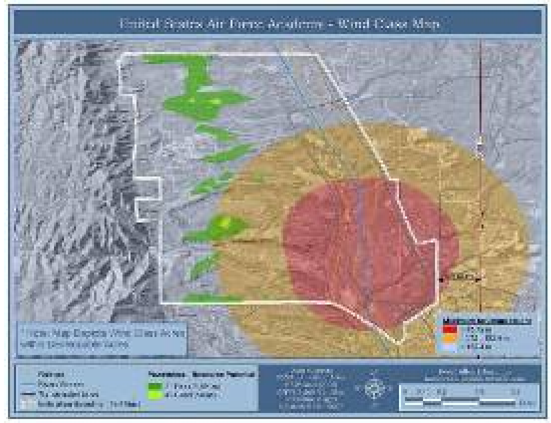
3 OPPORTUNITY EVALUATION SUMMARY

As described in the methodology section, an inventory of Air Force installations and properties was screened to determine the Tier I opportunity list. This list served as the basis for a further investigation determining project feasibility, including identification of land parcels, availability of water resources, land constraints (such as endangered species), land ownership issues, local power markets and mission compatibility. As more information was collected the list of opportunities was refined into the top and secondary opportunities presented earlier. Those Tier I opportunities that have been recommended as a Top Opportunities have been presented to AFRPA, the base, and MAJCOM in a separate Concept Opportunities Study (COS). As previously described, as bases where removed from consideration for utility-scale projects, many were noted as possible on-base energy demand projects. However, because data regarding base energy costs and demand was not available, these opportunities could not be fully evaluated. Some of these are described below and in Appendix C.

Table 3: Initial Tier I Opportunities List

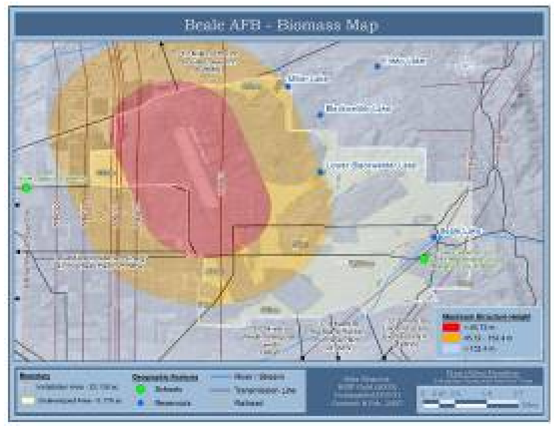
Order	Installation	Resource
1	AF Academy	Wind
2	Beale AFB	Biomass
3	Davis Monthan AFB	Solar
4	FE Warren AFB	Wind
5	Gila Bend/BMGR	Solar
6	Holloman AFB	Solar, Geothermal
7	Kirtland AFB	Solar
8	Luke AF Range	Solar
10	Melrose Air Force Range	Wind, Solar
11	Nellis AFB	Solar, Geothermal
12	Nevada Test Range	Geothermal, Solar
13	Travis AFB	Biomass
14	Vandenberg AFB	Wind
15	Westover AFB	Biomass
16	Whiteman AFB	Biofuels

1. AF Academy



The AF Academy, located in Colorado Springs, Colorado, was initially considered an opportunity for a wind EUL. Resource and height restriction analysis indicated that there was abundant class 3 and 4 wind outside of airfield buffers. However, installation staff indicated that wind turbines were not compatible with the mission of the Academy, particularly the glider training.[3]

2. Beale AFB



Beale AFB, located in Marysville, California, was initially considered a candidate for biomass development. Its potential was considered strong because Beale is located in a state with high energy costs, an RPS driving renewable projects, an active REC market, and significant biomass feedstock resources available. Additional favorable factors at Beale include its rural location, rail access ideal for feedstock delivery, and large underutilized land areas. After analysis, it was determined that the availability of feedstock in the area may be limited due to existing demand from local biomass power plants. Five existing plants within 50 miles (from 13 to 36 miles away) generate total 61.6 MW by consuming 67,830 dry tons of fuel from the area, which amounts to 26% of the existing fuel supply within 50 miles of Beale. Beale also holds potential for a direct use solar project based on California's strong solar incentives and solar resources. As mentioned in the landfill gas section of this report, there is a landfill adjacent to Beale that could produce enough gas to provide power for a power or cogeneration production to meet on-base demand.

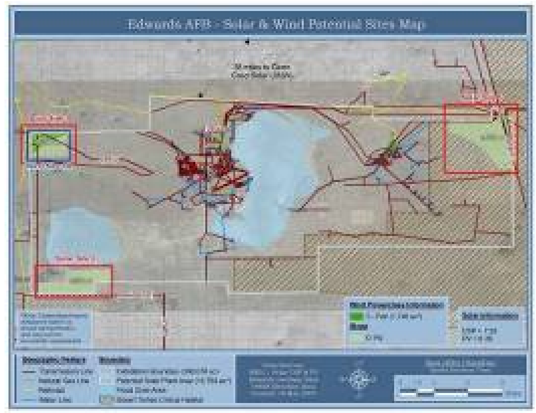
3. Davis-Monthan AFB

Davis-Monthan AFB, located in Tucson, AZ, was considered a strong solar EUL opportunity with solar resources greater than 6.6 kWh/m2/day. After investigation it was determined that there were few available land areas suitable for utility-scale solar development. The east side of the base, the old bombing range, initially appeared to be a favorable location for solar development. A site visit and discussions with the real estate

[3] Personal communication. Graziano Del Col, Public Utility Specialist, AF Academy; February 13, 2007.

office revealed that the eastern portion of the installation is owned by the City of Tucson and leased to the Air Force. This range area also currently has a number of environmental and mission constraints. Behind the base's Air Traffic Control Tower is a capped landfill that produces small amounts of methane. It was indicated that the run-off area of the landfill (about 30 acres) and the landfill surface itself could be used for solar development. There is one 30-acre parcel located next to Tucson Electric Power that might be of interest for expanding or for an alternate use. Because of the fairly limited land available, Davis-Monthan is not an ideal located for a utility-scale project. The capped landfill area and the other 30-acre parcel could be suitable for an smaller on-base project involving a PV application similar to Nellis AFB.

4. Edwards AFB



Edwards AFB, located in the Mojave Desert, California, presents a strong possible opportunity for a solar EUL and is recommended as a top opportunity. It is located in a strong renewable energy market, has access to transmission, flat underutilized land and some of the world's best solar radiation resources. The solar energy opportunity is explored further in the Renewable Energy COS, Edwards AFB, California.

5. FE Warren AFB

FE Warren, located near Cheyenne, Wyoming, was initially considered for a wind EUL. In 2005, Warren became the first AF base to build utility-scale wind turbines inside the fence line. The AF operates two 660 kW machines which generate over 4.4 million kWh of electricity annually for on-base demand.[4] Wind resource and height restriction analysis suggested that class 4 resources were available beyond buffer zones. However, upon contacting the MAJCOM and installation staff it was quickly determined that there is no underutilized land to support additional wind energy on FE Warren and height restrictions pose challenges to operations.[5]

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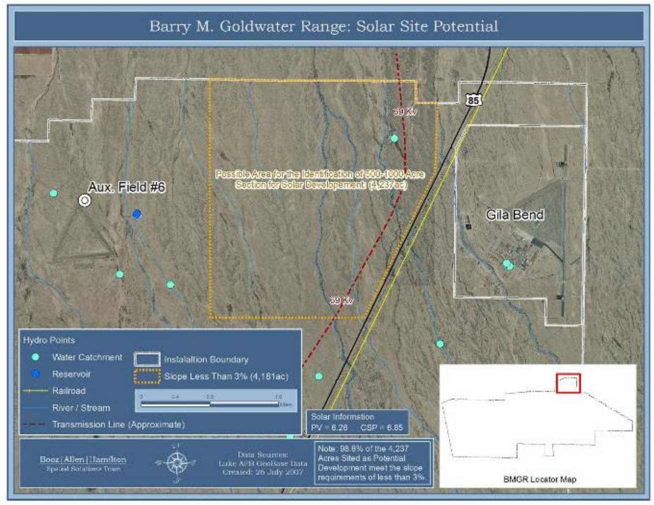
[4] Air Force Center for Environmental Excellence. *First Air Force wind farm erected at Warren AFB.* Accessed April 2007. Website: http://www.afcee.brooks.af.mil/ms/msp/center/Vol11No3/10.asp

[5] Personal communication. Lt Col J. D. Webb, 90 CES/CC; February 11, 2007.

6. *Gila Bend Auxiliary Field/ Barry M. Goldwater Range*



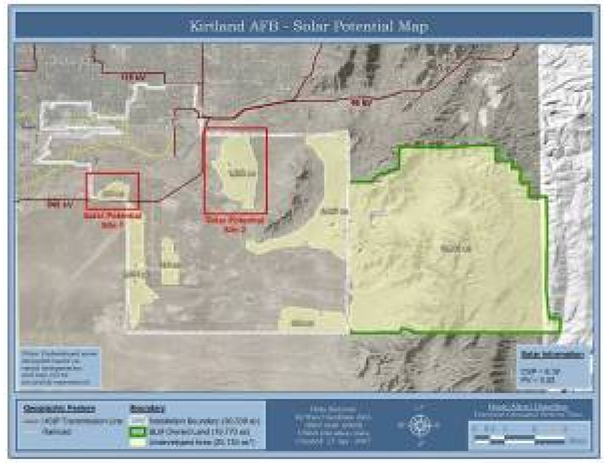
Luke AFB manages the Barry M. Goldwater Range (BMGR), formally called Luke Air Force Range, and indicated that there are areas of the range that are considered underutilized. It is located in a strong renewable energy market, has access to transmission that could wheel power to AZ or CA markets and has excellent solar radiation resources (as high as 6.8 kWh/m2/day). The BMGR is an active range with Air Force jurisdictional management of the eastern range. Western portions of the range are managed by the Marine Corps. The BMGR was established through a congressionally-approved land withdrawal of BLM lands for military use. Through discussions with the base and the MAJCOM, an area northeast of Auxiliary Field #6 has been identified as a possible location for solar development. Gila Bend Air Force Auxiliary Field (AFAF) area was initially considered a potential site for a renewable energy EUL; however, the parcels on Gila Bend are small and slightly constrained making it unlikely that a large-scale solar project would be sited there. The parcel located on the BMGR could face constraints related to access to sufficient water resources, as well as executing an EUL on military withdrawn land. The feasibility of a renewable energy EUL on military withdrawn land is currently under investigation. These renewable energy opportunities are explored further in the Renewable Energy COS, BMGR/Gila Bend AFAF, Arizona.

7. *Holloman AFB*

Holloman AFB, located near Tularosa, New Mexico, was considered for solar and geothermal potential. The solar resources at Holloman are 6.1 kWh/m2/day, and investigations done for the *Geothermal Energy Resource Assessment on Military Lands* report stated that the self-potential anomaly at White Sands could have a hydrothermal source, but that any large-scale geothermal potential was likely on the White Sands Missile Range. In addition, the base's remote, rural location does not provide access to the demand centers that would purchase renewable power, and there are ample undeveloped potential solar sites with transmission access that are closer to El Paso and Albuquerque. However, Holloman should be considered for on-base demand solar projects because of its high-quality resources.

8. Kirtland AFB

Kirtland AFB, located in Albuquerque, New Mexico, presents a strong opportunity for a solar EUL and is recommended as a top opportunity. This area has excellent solar radiation resources measured at 6.32 kWh/m$_2$/day for concentrating solar power systems and 5.92 kWh/m$_2$/day for photovoltaic systems. Kirtland AFB has suitable land (though slightly more sloped than is ideal), excellent transmission access with a large demand center close (Albuquerque), and a strong solar energy market (NM policy drivers). The solar energy opportunity is explored further in the Renewable Energy COS, Kirtland AFB, New Mexico.



9. Luke AFB

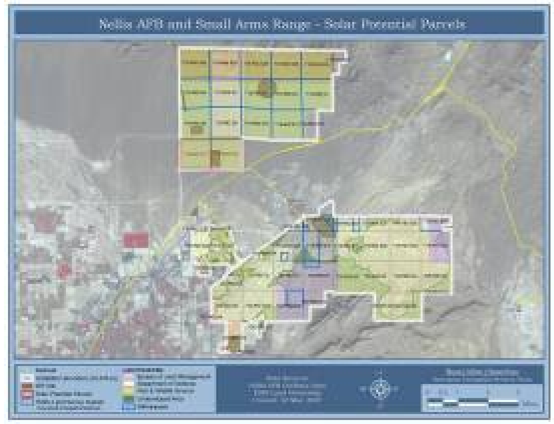
Luke AFB, located in Arizona, presented a strong solar EUL opportunity with solar resources greater than 6.0 kWh/m2/day. However, Luke AFB has very little underutilized land. Luke AFB is a good candidate for expanding a smaller-scale solar PV project.

10. Melrose Air Force Range

Melrose Air Force Range, located near Floyd, New Mexico, was initially considered for a wind and/or solar EUL. Melrose is an active range currently managed by Cannon Air Force Base. Melrose was considered because of its favorable class 3 wind resources, world-class solar resources (6.27 kWh/m2/day for PV systems and 7.0 kWh/m2/day for CSP systems), and land availability. The range is transitioning to Special Operations Command, and mission compatibility with a wind or solar project is undetermined at this time. Melrose has been recommended as a secondary opportunity for consideration when the mission transition is complete.

11. Nellis AFB

Nellis AFB and the Nevada Test Range, located north of Las Vegas, NV, is an ideal location for a solar project. Although a PV array project is currently under construction, Nellis is still considered to have potential for a utility-scale solar project that would sell power to the grid as utility-scale solar technologies become more commercialized and Nevada's utilities are driven to purchase increasing amounts of solar electricity.

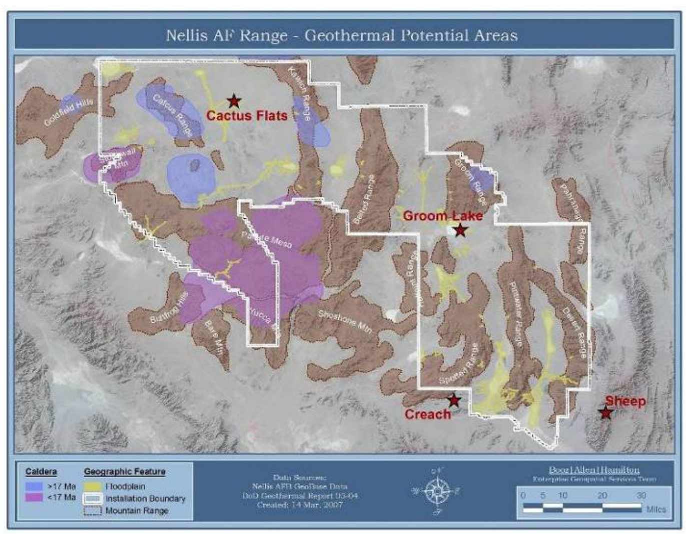


After a site visit and initial due diligence, two parcels (sections 16 and 17), on the southeast sections adjacent to the Small Arms Range, were identified for possible solar development. Currently, these parcels are designated to be returned to the Bureau of Land Management and have a number of Installation Restoration Program (IRP) sites located within. If retained as Air Force property and cleared of environmental hurdles, this location could have utility-scale solar potential. Nellis staff and personnel expressed interest in developing a solar project on these lands to provide a buffer to prevent encroachment on the Small Arms Range from the city of North Las Vegas.

Nevada has a wealth of natural resources, in particular solar, and is aggressively developing opportunities for more solar power. The local utility, Sierra Pacific Resources— the parent company of Nevada Power— commented recently

> *"We are actively developing our solar power resource, adding to our portfolio of renewable energy resources serving our customers…The Nellis solar system is our latest commitment to a set of solar power projects. In total, Nevada Power will generate more solar electricity per capita than any utility in the nation. The project accelerates Nevada Power's compliance with our solar power goals six years ahead of schedule."*[6]

12. Nevada Test and Training Range



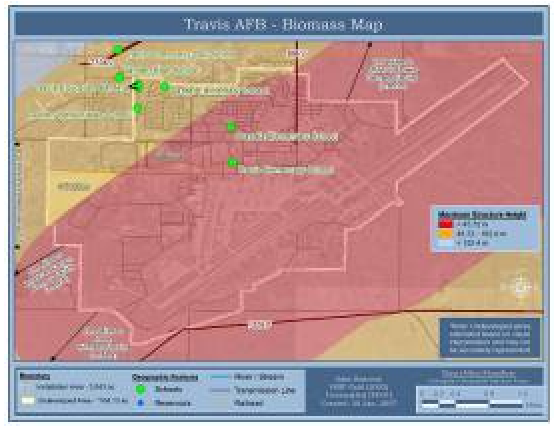
The Nellis Air Force Range, also known as the Nevada Test and Training Range, is deemed to be a top geothermal opportunity. The *Geothermal Energy Resource Assessment on Military Lands* report, prepared for the Navy in 2003, found prospective utility grade sites of high potential on the Nevada Test and Training Range. It is recommended that Nellis work with the range managers to determine if the previously identified areas could be investigated for large-scale geothermal development. As described in

[6] Renewable Energy Focus. *Air Force to Install Largest PV System in U.S.* Las Vegas, NV. Accessed May 2007. Website: http://www.re-focus.net/articles/pv/prod_news/070502_usairforce.html.

the Geothermal section of this report, China Lake Naval Weapons Station has the largest geothermal development in the country located on its range.

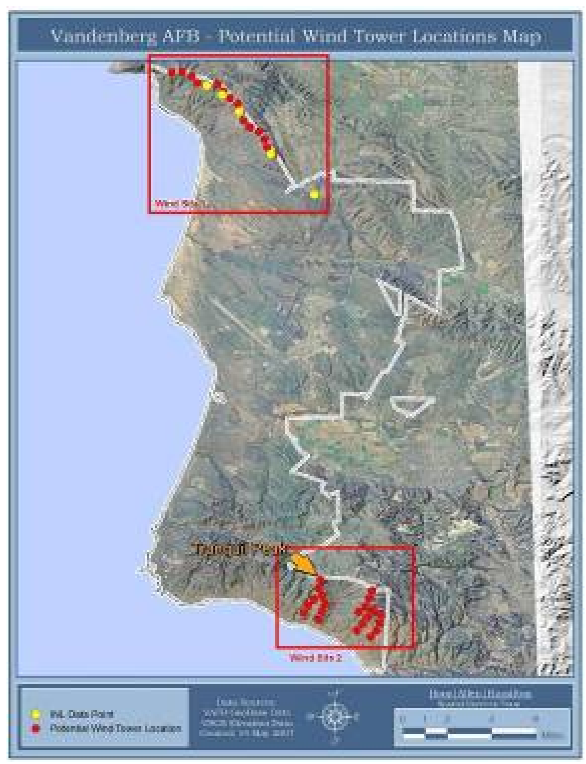
Nellis also has wind resources on the Test and Training Range, though development would conflict with mission activities and objectives. A regional transmission corridor with a high voltage line is planned to be installed on the western border of the Range. When the transmission line is built, flat areas along this corridor, such the Indian Springs area, could become attractive for utility-scale solar development.

13. Travis AFB



Travis AFB, located in Fairfield, California, was initially considered a candidate for biomass development. Its potential was considered strong because Travis is located in a state with high energy costs, an RPS driving renewable projects, an active REC market, and availability of significant biomass feedstock resources. While Travis had a few suitable parcels for biomass, base personnel indicated that siting a large-scale biomass facility on the base would be impossible due to community involvement and concerns generated from biomass combustion around the installation. In addition, air pollution restrictions in the region may make biomass power infeasible.

14. Vandenberg AFB



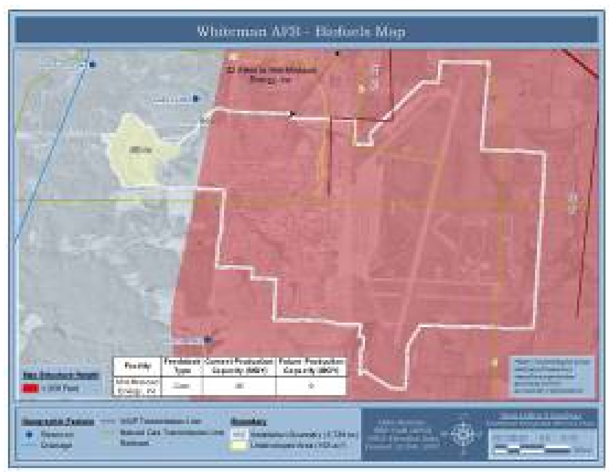
Vandenberg AFB, located near Lompoc, California, has two regions with utility-scale wind resources. In the southern portion of the base, there are several ridges oriented north to south and a long ridge oriented east to west that all have outstanding resource and exposure to prevailing winds. In the northern portion of the base, there are four ridgelines oriented roughly southwest to northeast. There are 909 acres of class 3 resource, 316 acres of class 4, 241 acres of class 5, and 31 acres of class 6 wind resource. The Idaho National Lab (INL) has collected detailed meteorological data regarding each of these ridgelines. INL data confirms that average wind speeds on the two northernmost ridges are about 15mph, slightly less on the two southernmost ridges. Wind turbines are likely to be compatible with the mission of the installation. The potential areas of the base lie outside of the FAA safety buffer. Conversations with installation staff indicate that the land is underutilized and that wind development in the region would be acceptable to range managers with close coordination on siting and proper reviews. Evidence suggests that with proper siting, adverse impacts to radar can be avoided. The Lompoc City Wind Development is presently under construction near the southeast corner of the base. Developers at the Lompoc facility have collaborated on an exhaustive line-of-sight analysis to ensure that none of the 60+ turbines would impact radar adversely. The few turbines that were found to impact radar were moved, constituting a zero-cost action that did not adversely effect the facility. Wind EUL opportunities at Vandenberg are explored in more detail in the Renewable Energy COS, Vandenberg AFB, California.

15. Westover AFB

Westover AFB, located in Chicopee, Massachusetts, was initially considered a candidate for biomass development. Its potential was considered strong because Westover is located in a state with high energy costs, an RPS driving renewable projects, an active REC market, and significant biomass feedstock resources available. Westover had a possible suitable parcel for biomass; however, base personnel indicated that siting a biomass facility on the base would be impossible due to community concerns that would be generated by local truck traffic and biomass refinery air pollution.

16. Whiteman AFB

Whiteman AFB located near Knob Noster, Missouri was selected as a Tier 1 biofuels opportunity due to its proximity to ample feed corn production. Additionally, a local animal rendering facility made Whiteman AFB an attractive candidate for biodiesel development as the tallow and yellow grease generated by the rendering facility could be used as feedstock for a biodiesel refinery. Initial assessment data indicated there was a 200 acre parcel of land owned by the base adjacent to their wastewater treatment plant that was not in conflict with runway height restrictions or other critical base mission functions. Water resources were also present at the base and not considered a limitation for site development. However, upon further investigation, it was discovered that the rail spur identified in the initial GIS base review had been abandoned due to deterioration of a trestle. Natural gas and road access to the 200 acre parcel were also limited. The existing road access is unimproved and crosses small bridges which would most likely need widening and possible strengthening to accommodate large trucks.



Market constraints were also present. Apart from the existing known plants, there are multiple planned ethanol plants and a large biodiesel plant in the initial stages of development. These plants will cause an increase in the price of feedstock in the area, making operations more costly. Additionally, there was a large demand for feed resources from local chicken farms. Production of agricultural resources does not guarantee availability, and some of the existing ethanol plants have already expanded their grain collection radius due to possible grain shortages in the local area.

Tallow from the nearby rendering facility could provide feedstock for a small scale biodiesel facility. However, tallow is a globally traded commodity, so a biodiesel plant on Whiteman would have to compete for this resource in the marketplace. Consumers of tallow include the cosmetics industry, the prepared food industry, and animal feed producers. Tallow is traded on the Chicago Mercantile Exchange and presently commands about $0.26 per pound. Prices have increased sharply to that level in recent years as grain corn has been diverted from cattle feed to ethanol production. Given the diverse incentives for biofuels production and the competing uses for tallow, prices are sustainable at that level and may continue to rise. A common alternative feedstock for a biodiesel refinery is foreign palm oil. Given Whiteman AFB's lack of port access, a biodiesel refinery at the base would be at a competitive disadvantage to its peers because it would not be able to easily import alternative feedstock.

See Appendix C for further discussion of opportunities considered and additional on-base demand distributed generation possible opportunities.

4 RENEWABLE TECHNOLOGY ASSESSMENTS

All commercially proven renewable power and fuel technologies that are feasible for an EUL were considered in this study: wind, solar, geothermal, biomass, waste-to-energy, landfill gas, ethanol and biodiesel. Wave energy was considered (at Vandenberg) but is not commercially proven at the cost and scale necessary for large-scale power production.[7] This section details the current state of the various renewable energy technologies, their economic feasibility in the U.S. market, their siting requirements and the project development process. These sections are included to provide the Air Force with data for future evaluations of proposals from renewable energy developers and to assist in evaluating the feasibility of leasing land or using renewable energy directly on its installations in the future.

4.1 Wind Power

Wind energy has been employed since antiquity to grind grain and propel ships. In the 19th century, turbine technology was exported from Europe to the New World to pump water on the western frontier. Turbines were widespread on the arid great plains until the advent of electric pumps in the early 20th century brought an end to wind power's first era. The first grid-connected, utility-scale wind turbine was built in Vermont in 1941, but the industry did not gain traction until the late 1970s, when the oil shocks of that decade ignited widespread interest in utility-scale wind energy generation. Installed capacity grew rapidly in the early 1980s, nowhere more so than in California where the Altamont Pass and Tehachapi Pass wind farms employed thousands of turbines to create hundreds of megawatts (MW) of electricity. In the mid-1980s, oil supply constraints eased, tax advantages for wind were rescinded, and the industry declined sharply. The industry entered a phase of rapid growth in the late 1990s, primarily due to sustained energy demand, and U.S. wind energy installations now exceed 10,000 MW of generating capacity. The American Wind Energy Association (AWEA) expects the U.S. to exceed 15,000 MW of installed capacity by the end of 2007. Although capital costs for turbines and components have increased in this decade, the cost of wind power has fallen by more than 80% over the past 20 years due to progressive policy and technological advances.[8]

Technology

Many types of turbines have been designed to capture wind and generate electricity. Three-blade horizontal axis wind turbines (HAWT) dominate today's market. Blades in these modern turbines are composed of lightweight fiberglass composite materials. Modern rotor and blade assemblies feature the ability to intentionally stall in storm-force winds. Nacelles are capable of rotating the blade and rotor assembly atop the support tower to capture the maximum energy of the wind even as its direction varies. Wind velocity increases dramatically with height, so many modern utility-scale wind turbines exceed 400 feet to capture high-altitude wind. The rotor diameter of utility-scale wind turbines now typically exceeds 150 feet. Blade and rotor failures due to fatigue are the most common problems associated with turbines, but many state-of-the-art assemblies achieve greater than 95% availability. Although marginal increases in efficiency are

[7] The US Navy/Marine Corps have an R&D pilot project off Kaneohe Bay, HI. It was funded through the SBIR Phase I and II programs in late 1990's then transitioned to congressionally funded SBIR Phase III in 2001. For more information contact Brian Cable, NFESC Ocean Facilities Department.
[8] AWEA Wind Power Cost FAQ. Accessed March 3, 2007. Website: http://www.awea.org/faq/cost.html.

still being realized through research and development, wind is regarded as a mature and proven technology.[9]

Average turbine size is growing and wind energy facilities are proliferating. Many of these facilities have begun to pose encroachment concerns for the Air Force. Adverse impacts to radar are foremost among these concerns. The DoD recently catalogued many of these concerns in a study of the interaction between air defense and missile warning radars and wind turbines. The results indicate that the large radar cross section of a wind turbine can impact the ability of radar to discriminate the wind turbine from an aircraft. Tests also demonstrated that wind farms have the potential to degrade target tracking capabilities as a result of shadowing and clutter effects. The DoD report advocated more study of this complex issue and stated that proposed wind farms should be evaluated on a case-by-case basis to ensure acceptable military readiness is maintained.[10] Anecdotal evidence indicates that wind turbines can degrade air-to-air and air-to-ground radar as well. For example, air-to-air radar testing and evaluation operations were impacted at Edwards Air Force base by the Tehachapi Pass wind development, a sprawling 5,000-turbine wind farm 30 miles from the fence line.[11]

Wind is compatible with Air Force mission at certain locations

Although wind may be inappropriate at some sites due to radar impacts, it has proven to be compatible with AF missions at certain sites.

FE Warren AFB – This installation hosts two 600kW wind turbines behind the fence line which generate 4.4 MM kWh of energy annually. FE Warren is presently exploring opportunities to expand this program. *(http://www.afcee.brooks.af.mil)*

Ascension Island - AF has operated a 1MW wind facility at this remote location for more than a decade. More than 1.4 million gallons of fuel were saved between 1995 and 2001. *(www.inl.gov/wind/photogallery/index.shtml)*

Vandenberg AFB – A large wind farm was proposed in 2006 near the southeast corner of VAFB. Installation staff performed a radar line-of-sight analysis and determined that only four of the 60 proposed turbines would adversely impact radar operations. Plans for these four turbines were changed by the developer. *(Personal communication, Bradley King, VAFB Base Energy Manager, April 2006)*

Economics

Although wind energy is a mature, commercialized technology, the wind industry is still relatively small and immature. Turbine production volumes are rapidly increasing and economies of scale are a major factor driving prices down, along with technological advancement and progressive policies.

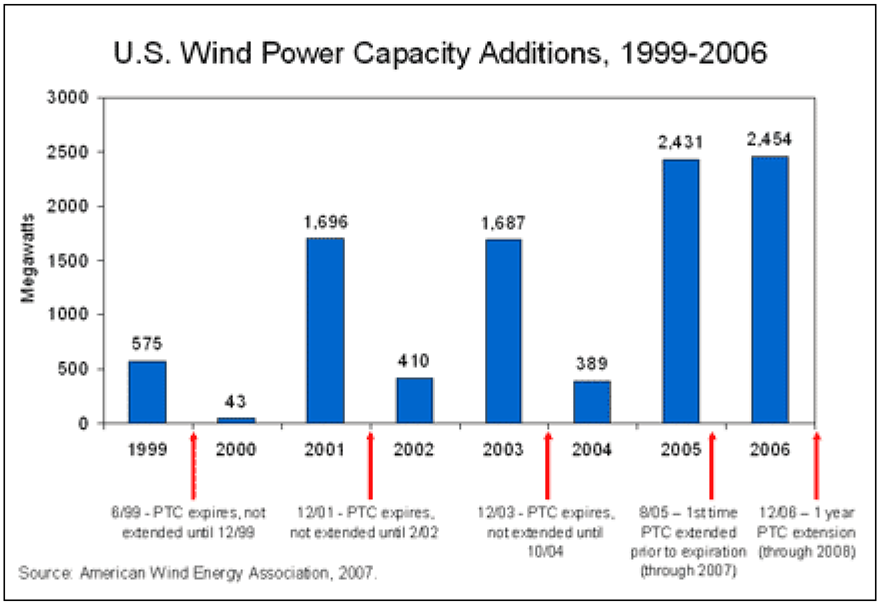
Despite the industry's growth, wind development is still regarded as a higher risk venture than conventional energy. For this reason, lenders will typically demand more security (such as a signed long-term Power Purchase Agreement) and a higher return on investment. In February 2005, AWEA examined the economics of a notional 50 MW facility with a capital cost of $65 million, and financed with a 60/40 debt/equity ratio and incurred annual expenses including debt service, distribution, O&M, lease payments, and insurance. Assuming a power purchase price of $0.04/kWh, AWEA found the expected return to be $6 million annually. In addition, tax credits associated with accelerated depreciation[12] and the PTC were found to be significant contributors

[9] Tester J. (2005). *Sustainable Energy: Choosing Among Options*. MIT Press: Cambridge, MA, p. 617.
[10] DoD, Office of the Director of Defense Research and Engineering, (2006) *The Effect of Windmill Farms On Military Readiness*.
[11] Personal communication. Dwight Deakin, Edwards Air Force Base, AFFTC/XPX; March 2007.
[12] Wind energy facilities enjoy a 5-year double declining balance depreciation schedule.

to the bottom line.[13] Since 2005, power prices have increased in many parts of the country. The PTC has also increased from $0.015/kWh to $0.019/kWh. However, the demand for turbines and rising energy costs has increased overall capital costs of turbines and their components.

The recent increase in wind turbine capital costs may be ascribed in part to the inconsistency of the PTC. This invaluable tax credit must be periodically renewed by Congress. As the date of renewal approaches, developers have shown a tendency to build frenetically. If the credit is not renewed for a period of time, development essentially ceases for that time (see Figure below). These boom and bust cycles lead to inefficiencies throughout the supply chain. They also discourage the creation of a U.S. domestic turbine industry, thereby increasing domestic developers' reliance on overseas suppliers. These conditions are detrimental to an industry with thin profit margins due to the dollar's recent weakness. Other factors driving up wind's capital costs include rising energy and material costs and global turbine and component shortages.

Figure 1: U.S. Wind Power's Dependence on the Federal Production Tax Credit



Siting Requirements

Wind is generated by uneven heating of the earth's surface. This uneven heating generates temperature, and therefore pressure differentials between air masses. High-value wind resources are found wherever these pressure differentials are large and unperturbed by surface features or other turbulence-inducing forces. Open water sites offer the highest quality wind resource in the world. Offshore sites in the North Sea achieve some of the highest capacity factors[14] of any wind farms. Ridgelines also offer attractive wind resource. Air masses are accelerated over ridgelines like the air over an airplane wing, so developments in these locations also have high capacity factors.

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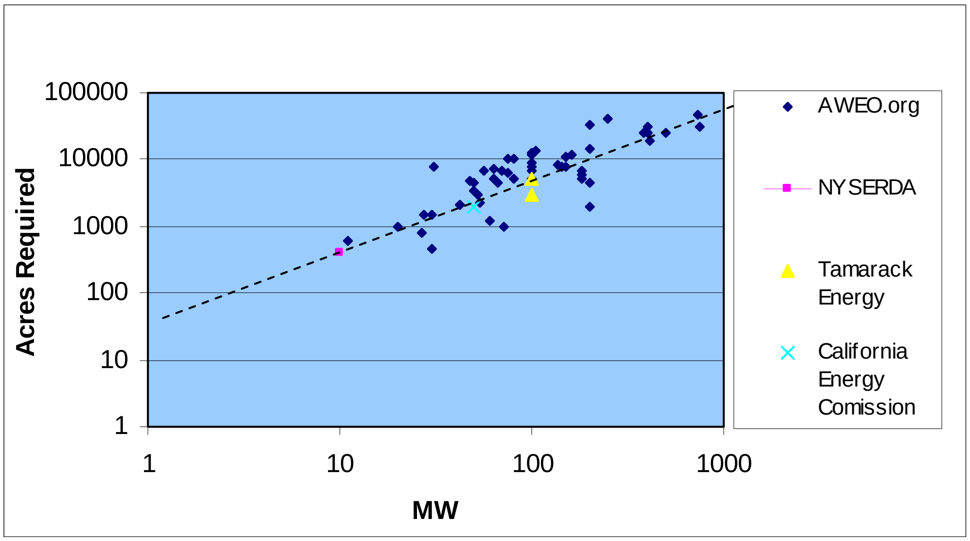
[13] AWEA. (2005). *The Economics of Wind Energy*. Accessed March 2007. Website: http://www.awea.org/pubs/factsheets/EconomicsOfWind-Feb2005.pdf.

[14] Capacity factors show the percent of total possible output, if the wind turbines were turning at maximum speed for the entire year, non-stop. Capacity factors in the 30-40% range are average for on-shore wind turbines in the US.

A buffer zone is required around each turbine in a wind farm to ensure that they don't interfere with each other aerodynamically. The size of the buffer zone around each turbine is highly dependent on the direction of the wind, geographic features and the locations of the turbines. In general, as turbine size increases, the turbulence generated by that turbine increases, so the buffer zone required around it increases as well. A review of existing wind energy facilities suggested that each turbine in a facility may require a circular buffer zone of 90 acres or more per 1.5 MW turbine (Figure 2).[15] Due to advances in technology, smaller buffer zones may be appropriate on high-quality sites.[16]

Figure 2: Acres Per MW for Wind Development



Transmission access is another important siting requirement. High-voltage transmission may cost $1 million per mile, so nearby transmission is critical for economical wind development. The absence of external factors such as endangered species or critical habitat also increases the value of a wind energy site.

Project Development Process

After site identification, the first phase of project development involves wind resource characterization. A developer typically secures the right to develop the site for a defined period of time from the landowner; leases may include cash payments, revenue sharing agreements, or both. The developer then proceeds to gather at least one year of detailed data regarding wind speed and direction in order to analyze the seasonal variability of wind at the proposed site. The developer must also begin the permitting process and generally sign a Power Purchase Agreement with the utility(s). Wind power is desirable for utilities operating in states with an RPS because it is generally cheaper than other renewable sources. In many regions, utilities also offer wind power directly to consumers for a premium. The permitting process can me more onerous, and at the very least, the state public utilities commission must approve plans. The permitting phase is unpredictable for developers since those opposed to the wind plans can use

[15] The data in Figure 2 regarding acres required per turbine for several facilities was compiled from AWEA, the New York State Research and Development Authority, Tamarack Energy, and the California Energy Commission

[16] Personal communication. Robert Trotta, Airtricity, LLC; January 2006.

the environmental impact statement (EIS) and other permitting documents as leverage in trying to stop a development. Developments with a federal nexus fall under the National Environmental Policy Act (NEPA), which may require the preparation of an EIS.[17] Many projects remain in the EIS phase for years; and some never emerge. If no hurdles arise in the permitting phase, then the turbine construction and grid connection occur rapidly. For example, the Maple Ridge wind farm in upstate New York, composed of 120 1.65 MW turbines, was completed in about a year.[18]

[17] BLM has developed a Programmatic EIS that addresses anticipated issues and concerns associated with an individual wind energy project, the BLM will by policy tier off of the analysis in the Programmatic EIS and limit the scope of additional project-specific NEPA analyses. Instruction Memorandum No. 2005-069, dated February 1, 2005.

[18] Personal communication. Bill Moore, PPM Energy; February 2007.

4.2 Solar Power

The sun's heat and light provide an ubiquitous and abundant source of energy. There are a variety of technologies that have been developed to take advantage of solar energy, including, but not limited to, photovoltaic (PV) systems, concentrating solar power (CSP) systems, passive solar heating and daylighting, and solar hot water. Solar power can be used in large-scale applications to provide electricity to a utility grid, or in smaller systems suited for providing electricity to homes or businesses.[19]

Today, PV and CSP are the two most commercially viable technologies. Solar technologies are well suited for warm climates where peak solar resources are directly related to increased energy demand (i.e., air conditioner use). CSP is more economically viable than PV for utility-scale applications (generating electricity to sell wholesale to the energy grid) due to its lower costs. PV systems are ideal for meeting on-site energy demands due to their flexible sizes and siting requirements (though in most states small-scale technologies can sell excess power to the grid – referred to as net metering). Other small-scale solar technologies, such as solar heating, lighting, and ponds, are ideal for off-setting or supplementing on-site energy needs.

Technology

PV systems, or solar cells, use semiconductor materials that directly convert sunlight into electricity. Flat-plate PV arrays, the most common PV application, can be mounted on rooftops, as standing arrays at a fixed angle, or can be mounted on a tracking device that follows the sun, allowing more sunlight capture over the course of a day. PV systems are popular for distributed generation and well-suited for meeting either residential or commercial on-site energy needs.[20] About 10 to 20 PV arrays can provide enough power for a household and, for large electric utility or industrial applications, hundreds of arrays can be interconnected to form a single PV farm. Typical PV systems have an efficiency of 15%, as about one-sixth of the sunlight striking the cell generates electricity; however, recent efficiencies have been reported exceeding 40%.[21]

CSP systems focus or concentrate the thermal energy of the sun to drive a generator. They produce electric power by using various mirror configurations to concentrate the sun's energy. Apart from dish systems, most CSP systems use significant amounts of cooling water for condensing the stream used for power production. There are three main CSP technologies for large-scale power generation:[22]

- *Parabolic-trough systems* concentrate the sun's energy through long rectangular, curved (U-shaped) mirrors. The mirrors are tilted toward the sun, focusing sunlight on a pipe that runs down the center of the trough, heating the oil flowing through the pipe. The hot oil then is used to boil water in a conventional steam generator to produce electricity. There are a number trough systems in operation in the U.S. today.

[19] National Renewable Energy Laboratory. *Solar Basics.* Accessed January 2007. Website: http://www.nrel.gov/learning/re_solar.html.
[20] Personal Communication. Greg Rosen, Powerlight; January 2007.
[21] National Renewable Energy Laboratory. *Photovoltaics.* Accessed January 2007. Website: http://www.nrel.gov/learning/re_photovoltaics.html.
[22] Solar Energy Industries Association. *Solar Energy Types.* Accessed January 2007. Website: http://www.seia.org/solartypes.php#swh.

- *Power tower systems* use a large field of mirrors to concentrate sunlight onto the top of a tower, where a receiver sits. Molten salt flowing through the receiver is heated and used to generate electricity through a conventional steam generator. Molten salt retains heat efficiently, so electricity can be produced on cloudy days or hours after sunset.[23] Test power tower systems have operated in the U.S., but none have been built for commercial use. The first European commercial power tower came online in Spain in March 2007.

- *Stirling energy dish systems* use a mirrored dish to collect the radiant solar energy to heat hydrogen gas in a closed loop. The heated gas expands, driving the Stirling engine-generator to produce electricity. Stirling technology has a net solar-to-electric conversion efficiency reaching 30 percent.[24] Currently they are no commercially operating Stirling plants but there are several proposed in the U.S.

Figure 3: Solar Power Plant Technologies

[23] National Renewable Energy Laboratory. *Solar Basics.* Accessed January 2007. Website: http://www.nrel.gov/learning/re_csp.html.
[24] Sandia National Laboratories, News Center. *Sandia, Stirling to build solar dish engine power plant.* Accessed February 2007. Website: http://www.sandia.gov/news/resources/releases/2004/renew-energy-batt/Stirling.html.

Economics

The primary barrier for large-scale solar development and deployment is cost, but advances in solar technologies have been significant over the last twenty years, and today the use of solar power has become increasingly competitive in energy markets with adequate incentives. PV and CSP have different cost structures, which dictate how the technologies can best be deployed as economically viable sources of power. Presently, CSP technology is considered more cost competitive for large-scale utility development than PV technology. Significantly reducing costs of PV systems is a goal the PV industry hopes to achieve by 2012.[25]

The cost of PV-generated electricity is still high and not an economical technology choice for utility-scale grid-tied systems. With subsidies and incentives, PV-generated electricity costs at best have reached $.12 per kilowatt-hour in niche markets; however, today, the price of electricity from PV systems is generally in the range of $.18 to $.30 per kWh.[26,27] Today in the U.S., PV is best suited for on-site generation and offsetting retail energy as opposed to competing with the wholesale energy market. Although there have been major investments in large-scale PV plants throughout Europe, especially in Germany and Spain, they are dependent on subsidies as high as $.45/kwh for wholesale energy to make them feasible.[28]

CSP technologies currently offer the lowest-cost solar electricity for large-scale power generation (50 MW-electric and above). According to the Arizona Corporation Commission, CSP facilities that generate about 250 MW experience the greatest cost efficiencies. Trough and tower plants can take advantage of economies of scale for cost reduction, as the fixed costs per kW decline with increased size.[29] Current technologies cost $2–$3 per watt, resulting in a cost of solar power of $.09–.22 per kWh. New innovative hybrid systems that combine large concentrating solar power plants with conventional natural gas combined cycle or coal plants can produce power at costs as low as $1.50 per watt or $.08 per kWh.[30]

CSP plants can make use of thermal storage or

Large-Scale PV and Solar Thermal Plants in the U.S.

PV Systems

Springerville Generating Station through Tucson Electric Power Company is located near Springerville, Arizona and has a current capacity of 4.6MW.

Rancho Seco Solar Generating System through Sacramento Municipal Utility District produces approximately 3MW, enough electricity to power about 2,200 single-family homes.

Nellis Air Force Base Solar System will be 15 MW plant and would be the largest solar PV installation in the world. This project is in conjunction with Powerlight Corp. and would provide base-demand energy.

The U.S. has a large number of solar PV projects with capacities fewer than 2MW, such as the 1.3MW plant at Twenty-nine Palms Marine Corps Air Ground Combat center.

CSP Systems

Solar Energy Generating System (SEGS) I through IX, is the largest group of solar parabolic trough plants in the world. The nine plants are located in the Mohave Desert in southern California, and five plants are located directly outside Edwards Air Force Base. The SEGS plants were built between 1985 and 1991 and have a total capacity of 354 MW.

Nevada Solar One, a 64MW parabolic trough system, is scheduled to come online by spring 2007, and will be the largest solar electric power plant to be built globally in the past 14 years. Nevada Solar One is located in El Dorado Valley, Nevada. Solargenix has signed two long-term purchase power agreements with Nevada Power and Sierra Pacific Power.

Saguaro Power Plant, a 1MW parabolic trough system, is located in Red Rock, Arizona about 30 miles north of Tucson. Arizona Public Service contracted with Solargenix for Arizona's first commercial trough solar plant.

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[25] Personal Communication. Greg Rosen, Powerlight; January 2007.
[26] Ibid.
[27] Solarbuzz. *Photovoltaic Industry Statistics: Costs*. Accessed January 2007. Website: http://www.solarbuzz.com/StatsCosts.htm.
[28] Personal Communication. Greg Rosen, Powerlight; January 2007.
[29] Black and Veatch, subcontract to NREL (2006). *Economic, Energy, and Environmental Benefits of Concentrating Solar Power in California*. Available online: http://www.nrel.gov/csp/news/2006/510.html.
[30] DOE Sunlab. *CSP Technologies Overview*. Accessed January 2007. Website: http://www.energylan.sandia.gov/sunlab/overview.htm#cost.

hybrid fossil systems to achieve greater operating flexibility and distribution. Storage capabilities allow the system to produce electricity when needed by the utility system, rather than only when sufficient solar resources are present, for example, during short cloudy periods or shortly after sunset when demand may still be high.[31]

Siting Requirements

Siting requirements for PV and CSP technologies differ. The key siting requirements for solar technologies include solar resource availability, land area, access to transmission lines, flat topography (less than 1 % slope) (CSP only), water resources (CSP parabolic trough and power tower only), and natural gas (CSP parabolic trough and power tower only).

The siting requirements for PV technology are more flexible due to siting on rooftops and other surfaces; however, for utility-scale development, it is unlikely a rooftop area would provide enough space to support the large capacity needed. The majority of large-scale PV plants are sited as free-standing solar arrays. The land area requirement for PV farms is approximately 8 acres per MW. CSP technology requires approximately 5 to 8 acres per MW, but also ideally needs a land area with a topographical slope less than 1%.[32] Areas with slopes as great as 3% may be feasible for trough systems and slopes as great as 5% may be feasible for some CSP dish applications.[33]

PV systems do not use steam to produce electricity so the water requirements for PV are relatively low, requiring only some water for periodic washing of the panels. Similarly, since CSP Stirling technology does not use steam generation to produce electricity, it too has a low water requirement. CSP parabolic trough and power towers, however, require significant amounts of water, comparable to that of a coal-fired power plant.[34] Data collected from Solargenix indicates roughly 2 million gallons per year (MGY) is needed per MW. For example, a 500 MW plant would require approximately a billon gallons per year or approximately 2.7 million gallons per day. This siting requirement is generally a concern for project development because the prime locations to site large-scale power plants are in areas with limited or strained water resources.[35] If solar storage was added, the water requirements would be higher.[36]

Project Development Process

The development of large-scale solar projects is a complex process generally involving three main players: the independent power producer, the utility (power purchaser), and the land owner. The majority of large-scale projects have utilized this scheme because regulated utilities have been unwilling or unable to obtain approval given the large, high risk investment needed for large-scale solar plant development. Unlike other renewable energy technologies, such as wind and geothermal, large-scale solar projects benefit from the relative ease of determining the resource availability. Solar resource availability and strength are easily identified and require

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[31] Black and Veatch, subcontract to NREL (2006). *Economic, Energy, and Environmental Benefits of Concentrating Solar Power in California*. Available online: http://www.nrel.gov/csp/news/2006/510.html.
[32] Personal Communication. Oded Rhone, Edison Mission Group; January 2007.
[33] Email Correspondence. Robert Liden, Striling Energy Systems; February 14, 2007.
[34] Solargenix, PowerPoint presentation (2004). *An Overview of the Concentrating Solar Power Industry*. Accessed February 2007. Website: http://www.solargenix.com/ae_files/case_study/files/PowerGen.pdf.
[35] Leitner, Arnold, subcontract to NREL (2002). *Fuel from the Sky: Solar Power's Potential for Western Energy Supply*, pg. 43. Available online: http://www.nrel.gov/csp/pdfs/32160.pdf.
[36] Email Correspondence. Bob Misback, Solargenix; June 7, 2007.

little collection of resource data before project implementation. Areas of the southwestern U.S. are considered ideal for solar projects.

For CSP power plant development, in particular for parabolic trough technology, developers would require a land area that meets certain criteria. As described previously, a land area suited for parabolic trough development would need to be flat, have access to water, have access to transmission lines with excess capacity, and ideally have proximity to natural gas. In addition, state incentives would have to be present to make the electricity cost competitive for the consumers.

Solar Markets Overview

The market for solar energy, similar to any renewable energy technology, is driven by federal and state subsidies and incentives, including RPS, coupled with abundant resources. In the U.S. today there is rapidly expanding use of solar PV technologies on a small scale; however, there are virtually no PV projects that sell power wholesale and only a handful of utility-scale solar thermal projects in operation. The market is poised for rapid growth with many gigawatts in various stages of approval and planning.

4.3 Geothermal

Geothermal energy is produced by harnessing the energy from geologic heat sources. Geothermal can be used in both utility-scale and ground source heat pump (GSHP) applications. Both systems use the heat stored in the earth, but they have vastly different scales and purposes. GSHPs provide heating, cooling, and hot water for homes and commercial buildings. Large-scale geothermal power plants are the focus of this assessment and can be used to supply large amounts of energy.

Over the course of the past several years, significant technological advances have made it possible to produce electricity from lower geothermal temperatures. Twenty years ago, geothermal temperatures greater than 400 degrees Fahrenheit (°F) were needed for a commercial application. Today, resource temperatures can be as low as 200°F, depending on the location of the site. For example, a generator in Alaska started producing power at the lowest ever utilized water temperature in a geothermal plant, 74 degrees Celsius (or 165°F).[37] Even with the most advanced technology, most generators in the warm areas of the Southwest U.S. must have underground heat sources of 250°F or more. Along with the technological advances, interest in reducing carbon dioxide emissions from power generation and the recent inclusion of geothermal energy in the Production Tax Credit have spurred a resurgence in geothermal power.

Technology

Geothermal power technologies have very high (95%) capacity factors because they are not dependent on the weather and are available 24 hours a day, unlike other renewable energy technologies, such as wind and solar. There are three main types of geothermal power technologies:

- *Dry Steam Power Plant* technology is the oldest type of geothermal plant, first produced in Italy in 1904, it uses hydrothermal fluids (primarily steam) to power a turbine. The steam goes directly into the turbine, which drives the generator to produces electricity, without the need to burn fossil fuels to run the turbine. These plants emit excess steam and minor amounts of gases. The Geysers Plants in northern California, which together are the world's largest single source of geothermal power, use this technology.

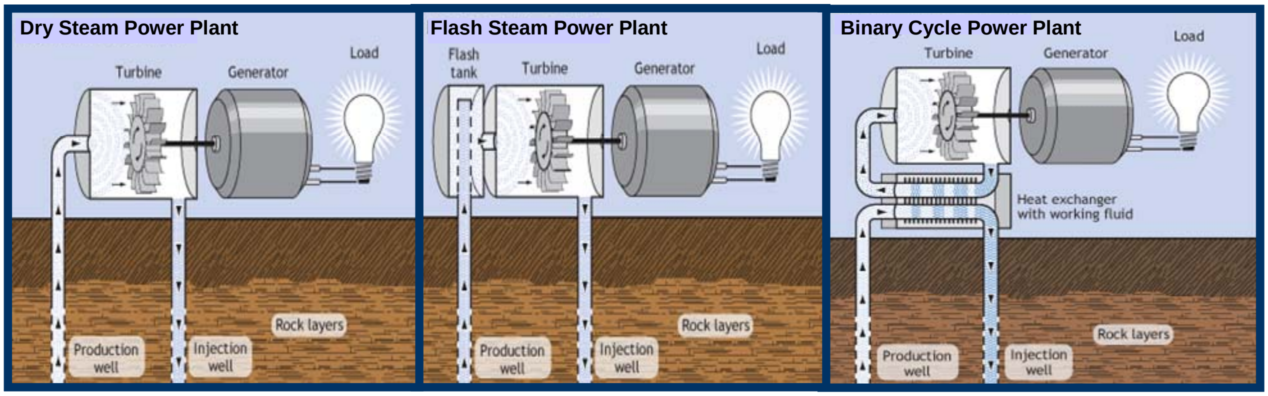
- *Flash Steam Power Plant* or "flashing" takes place when fluid rapidly vaporizes upon being transferred into an area of much lower pressure. Hydrothermal fluids above 360°F (182°C) are sprayed into a tank held at much lower pressure, causing them to "flash," and the vapor drives the turbine, which drives the generator. Any liquid remaining in the tank is flashed again in a second tank to extract additional energy.

- *Binary-Cycle Power Plant* technology, the most common technology for new large-scale applications today, uses moderate-temperature water (below 400°F) and a heat exchanger to power the generator. In this system, energy is extracted from the hot geothermal fluid to heat secondary – "binary" – fluid when passed through the heat exchanger. Heat from the geothermal fluid causes the secondary fluid to flash to vapor, which then drives the

[37] Evans, Gavin and Mathew Carr (2007). *Geothermal Steams Ahead in Germany, U.S. on Clean-Energy Push.*

turbines. Because this is a closed-loop system, virtually nothing is emitted to the atmosphere.

Figure 4: Geothermal Power Plant Technologies [38]



Future plants using "hot dry rock" technology would inject water into underground areas that lack it to produce steam. Hot dry rock technology is still precommercial.

Economics

The cost of developing a utility-scale geothermal plant can be high, but once developed, geothermal power plants have very low operating costs (i.e., no fuel costs) and are very reliable. Plant development, similar to wind development, requires up-front costs associated with resource characterization and assessment. Determining the resource potential through geological studies and test bore wells can be very expensive; costs for utility-scale geothermal projects can be $3 million to $10 million prior to confirmed feasibility.[39]

Overall capital costs for plant construction range from $3,000 to $5,500 per kilowatt. A 10 MW or larger plant requires at least 12 operators. Geothermal developers usually consider 20 MW or more the minimum economic size for developing a utility-scale plant. Because of the significant high exploratory and capital costs, electricity sold from these projects is generally about $.05[40] to $.08 per kWh.[41]

Siting Requirements

Geothermal sources that are close enough to the earth's surface to be economically captured for power production are not widespread; therefore, there is little flexibility in their location (though as noted previously, as technological advancements reduce the required temperatures more resources are viable). Extensive geological studies are carried out in known high-potential areas before investment is made in drilling test holes. The world's most significant geothermal resource areas are located around the "ring of fire" along the Pacific Ocean and in the Great Basin area of the U.S. (Western Utah, Nevada, and parts of Eastern California). Recent studies

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[38] DOE Energy Efficiency and Renewable Energy (EERE). *Geothermal Technologies Program*. Accessed January 3, 2007. Website: http://www1.eere.energy.gov/geothermal/powerplants.html.
[39] Personal Communication. Dan Schochet, Ormat Technologies, Inc.; January 2007.
[40] DOE EERE. *Geothermal Technologies Program.* Accessed January 2007. Website: http://www1.eere.energy.gov/geothermal/faqs.html.
[41] Western Governors Association (2006). *Geothermal Task Force Report.* Available online: http://www.westgov.org/wga/initiatives/cdeac/Geothermal-full.pdf.

by the Great Basin Center for Geothermal Energy at the University of Nevada, Reno found over 400 different hot springs in the Great Basin, most of them able to power 10 to 20 MW power plants. A 2006 study by the Western Governors Association predicts that there are several hundred high-potential sites that could produce 6000 MW at $.08 /kWh by 2020. California and Nevada lead the way with near-term geothermal power capacity potential (2,400 MW at 25 sites for CA and 1,500 MW at 63 sites for Nevada).

Geothermal resource areas are often located in undeveloped natural areas, which can cause public controversy over perceived invasive drilling, construction, and operations of a plant. However, the actual surface footprint of the plant is very limited and causes minimal wildlife impacts. A concern for nearby residents is odor, as plants typically emit traces of hydrogen sulfide gas (recognizable by its rotten egg odor). Additionally, arsenic, nickel, and silicate deposits collect in the pipes and turbines, requiring some waste disposal, even though the water is typically reinjected. The last major concern for nearby residents is the small but sometimes frequent earthquakes that can be caused by reinjecting the water back underground to maintain power levels.

Project Development Process

Developers first assess all available documentation, including maps created by National Renewable Energy Laboratory (NREL) in the 1970s and 1980s, to determine whether there is real geothermal potential. Once there is some indication of potential, developers seek to get an agreement that gives them full access to land, without which they will be reluctant to spend more of their own resources for costly explorations. With such an agreement in place, developers undertake further explorations to determine the exact heat flow amounts and locations. The initial above-ground testing and study usually costs about $200,000, followed by drilling shallow temperature gradient wells and other studies costing about $300,000. After that, deep drilling of "slim holes" is conducted. The overall purpose of these explorations is to develop a feasibility report that documents 30% of the total reservoir. Developers assess the results after each of these intermediary steps and make decisions about whether to continue project development

Concurrently with land explorations, developers engage with utilities to determine whether it will be possible to get power onto the grid. After the heat resources show to be significant and a power agreement is in place, the developer can start development. Because of the significant up-front exploratory and capital costs, developers generally require full control over the selling of the plant's power for at minimum a 20- to 30-year period.

Geothermal Market Overview

Today, geothermal electricity is generated in 24 countries. According to the International Geothermal Association, worldwide geothermal capacity will raise 10% a year from now to 2010, a rate three times that of the last ten years. However, geothermal plants still account for only around 10,000 MW (of 4,100 GW total) of electricity produced worldwide.[42]

Current U.S. geothermal electric power generation totals about 2,200 MW. Development of geothermal today in the U.S. benefits from the PTC (which was recently modified to include geothermal investments), RPS, and Department of Energy support for cost-shared drilling and

[42] California Geothermal Energy Collaborative.

technology advances. In addition, U.S. developers have been assisted by extensive geothermal mapping done by the DOE during a previous period of concern about domestic energy sources from 1973-1983.

The market for geothermal energy production is particularly good in states with strong legislative incentives such as California and Nevada, as well as the other twenty states with mandates for minimum requirements of renewable energy purchases. California accounts more geothermal-powered electricity than the rest of the nation combines, producing 1,900 MW accounting for 86% of the U.S. geothermal powered electricity production. Within the state, geothermal powered electricity production accounts for 7% of total state electricity production and 22% of state renewable energy production (a figure second only to hydropower)[43] This large geothermal market benefits from regulations that require 20% of electricity be derived from renewables by 2010.[44,45] The potential for future development is great. Using existing technology and known fields, the state could increase geothermal power supply by 2,400 MW to 4,800 MW. [46, 47]

The Nevada geothermal market has also attracted significant developer attention recently. As in California, the market has been largely driven by a combination of large natural resource potential and the state's RPS requirements and the PTC incentives. In addition, with so much land in Nevada owned by the federal government, BLM's recent efforts to reduce its leasing backlog have helped speed up the development process for these plants, thereby encouraging interest from developers. Nevada also benefits from exploration work being done by the Great Basin Center for Geothermal Energy at the University of Nevada, Reno, with funding from DOE, U.S. Geological Survey and other government agencies.

While current capacity from Nevada 15 geothermal power plants only amounts to 276.4 MW, the Geothermal Energy Association predicts that Nevada is on pace to quadruple production over the next three to five years to over 1000 MW. Production at this level would meet about 25% of the state's total power needs. Much of this development has already begun. The 29 geothermal power projects now under development should produce about 850 MW. With the target of more than 1000 MW of capacity, Nevada alone would be generating more power than all other countries in the world besides the U.S. as a whole and the Philippines, and would be generating more power than all other U.S. states, with the exception of California.[48]

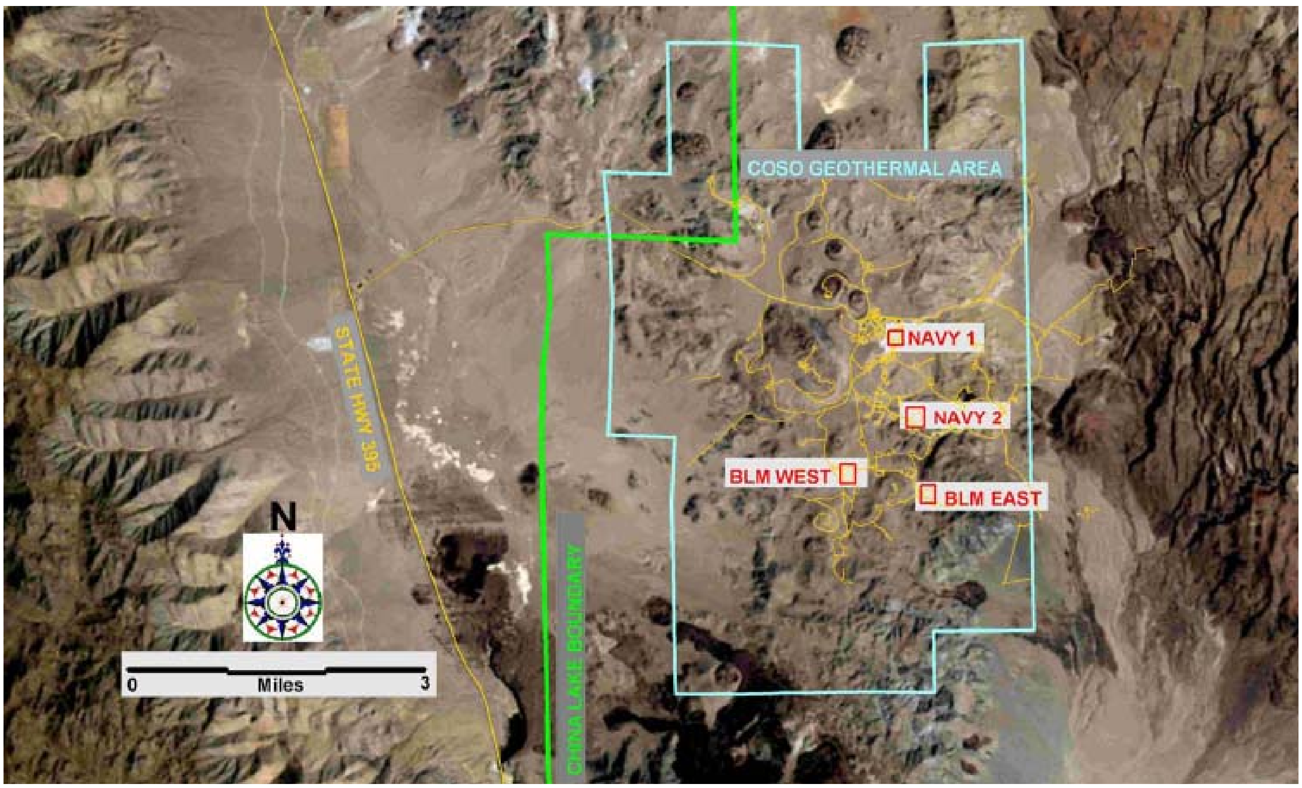
Operating Geothermal Plants on US Military Installations

Naval Air Weapons Station China Lake, California – In 1989, China Lake geothermal plant began operating through a joint venture between the Navy and Caithness Corp., called the Coso Operating Company, LLC. The project was developed through a public-private partnership contract. Caithness pays royalties on electric power sales to the Navy under a contract that started at a lower percentage and gradually escalated. After the 15th year of operation the Navy was to receive 20% of revenues under the original contract but the contract has been

[43] Ibid.
[44] The biggest retailer of renewable energy in the country, Southern California Edison Co., got over half of its renewable energy from geothermal sources in 2005 (892 MW). Southern California Edison likes geothermal because of its consistency and reliability.
[45] Evans, Gavin and Mathew Carr (2007). *Geothermal Steams Ahead in Germany, U.S. on Clean-Energy Push.*.
[46] Western Governors Association (2006). *Geothermal Task Force Report*. Available online: http://www.westgov.org/wga/initiatives/cdeac/Geothermal-full.pdf.
[47] California Geothermal Energy Collaborative.
[48] Geothermal Energy Association. Accessed February 2007. Website: http://www.geo-energy.org/.

renegotiated. Instead, the Navy continues to receive 15% of revenues up to an agreed upon revenue baseline, but if the project produces above this baseline the Navy receives a 50% revenue share. To date, the U.S. government has received approximately $300 million.[49] Photos of the project are included below; the total project consists of four power plants – two Navy and two BLM, with nine turbine generator sets with a 270 MW capacity. The footprint of each power plant is only a few acres; there were two transmission lines installed, 166 wells dug and 200,000 lineal feet of pipe for the total development.[50] The project is located in an active Navy training range, but has never been damaged or caused mission impacts. If there were any damage from military operations, it would be the sole responsibility of the private corporation to repair.

Figure 5: China Lake Geothermal Power Plant Photos[51]



[49] Personal Communication. Frank Monastero, Naval Air Weapons Station Geothermal Program Office; Feb 2007.
[50] Bill Tayler, Director, Department of Navy Shore Energy Office Naval Facilities, ADC Conference presentation, June 2007.
[51] Ibid.

Fallon Naval Air Station – In Fallon, Nevada, the Navy conducted their own thorough geothermal assessments, allowing Ormat, a geothermal developer, to come in for plant development. The plant is planned to come online in 2008 at a capacity of 30 MW and will sell power commercially to the local utility. An agreement between Ormat and the Navy has been negotiated allowing for the Navy to use the power during a national emergency. The Navy gets a revenue share (i.e., 5% for first 20 years and 15% thereafter) and BLM receives a royalty.

The U.S. Navy has a team of geothermal experts that are available to assist other DoD services with geothermal resource evaluation and development.[52]

[52] For more information contact Frank Monastero, frank.monastero@navy.mil, Naval Air Weapons Station Geothermal Program Office

4.4 Biomass Power

Biomass refers to any plant-derived organic matter available on a renewable basis, including dedicated energy crops and trees, agricultural food and feed crops, agricultural crop and wood wastes and residues, animal wastes, and municipal wastes.[53] Biomass is used in the U.S. for generation of baseload electric power and industrial process heat and steam, and is the largest non-hydro renewable electricity resource, providing 47% of the nation's renewable energy and 13% of renewable electricity generation, with about 11 GW of installed capacity. Forest product and agricultural residues account for about 7.5 GW, MSW accounts for about 3 GW, and the last 0.5 GW of this production capacity is produced from landfill gas and other biomass resources such as switchgrass. Burning biomass for power is generally accepted to result in a net reduction in greenhouse gas emissions. The overall balance calculations are complex but as biomass grows it absorbs carbon from the atmosphere and fixates some of that carbon in the soil. In addition, biomass that is disposed of in a landfill produces methane emissions that, over the long term, result in higher global warming potential than the emissions from a biomass power plant, even if the methane is captured and flared or used for power.

Most of today's biomass-derived generation is provided by combined heat and power (CHP) facilities at pulp and paper mills and paperboard manufacturer's industry sites.[54] Non-captive biomass resources considered for this study include forest thinnings (small diameter trees and logging residues); primary and secondary mill residues (wood trimmings, bark, sawdust and pulp screenings); agricultural residues (corn stover, wheat straw, other); urban wood residues from MSW (wood chips and pallets, utility and private company tree trimmings); wood residues from construction and demolition debris (stumps, wood residues from lot clearing, used wood from building construction and demolition); and switchgrass.

Technology

Biomass power today is largely based on direct combustion (boiler/steam turbine) technology, though gasification of biomass is a growing method. The average size of a utility-scale biomass power plant is 20 MW (the largest facilities approach 75 MW) with an average electrical generating efficiency of 20%. Future technologies, such as high efficiency integrated gasification combined cycle (IGCC) and improved direct combustion technologies including fluidized bed boilers, will increase efficiency while lowering emissions produced from biomass power production. The efficiency of IGCC biomass power can reach 60%. There are three main biomass technologies:

- *Traditional traveling grate boilers* can accommodate air-dried (20% moisture) woody biomass. These boilers have an average internal power consumption of 9%, meaning 9% of the combustion energy produced in the boiler is used to burn the fuel. If the feedstock resources are not dried (50% moisture) – such as with freshly-harvested wood biomass, paper mill sludge, or agricultural residues (which contain a high ash content that causes slagging in traditional boilers) – a fluidized bed boiler is required to efficiently and reliably accommodate this biomass.

[53] DOE EERE. *Biomass Program.* Accessed February 2007. Website: http://www.eere.energy.gov/RE/biomass.html.
[54] Ibid.

- *Fluidized bed boilers* allow fuel flexibility by accommodating many types of biomass resources, and their combustion characteristics reduce emissions when compared to traditional boilers. However, the internal power consumption of a fluidized bed boiler is 15% to 18%, which lowers overall plant efficiency by 6% to 9% over a traditional boiler design. Additionally, a fluidized boiler will raise the capital equipment cost by about $500 per installed kilowatt.

- *Closed loop biomass* is defined as dedicated energy crops (e.g., switchgrass and fast-growing willow and poplar trees) grown specifically for the production of renewable energy, while open loop biomass is defined as all other forms of biomass (e.g., crop residues, mill residues, forest thinnings, wood waste). Establishing the infrastructure for closed loop biomass (growth, collection and transport) requires significant investment and time (five years for woody crops) compared to open loop biomass which is already available and simply needs to be collected for use. There are no closed loop biomass plants in the U.S. because to date, the costs for planting, growing, and harvesting have exceeded the value of the power output from burning the feedstock and/or other higher value uses for the crops exist.

Economics

Electricity production costs for biomass power range from $0.07 to $0.08 per kWh. Smaller plants have higher operating costs and lower efficiencies which makes them more sensitive to spikes in feedstock cost, resulting in electricity production costs of $0.07 to $0.12 per kWh. Fuel – or feedstock – costs are very dependent on the interplay between available fuel, demand from competing plants, and any monopoly or oligopoly dynamics that allow suppliers to keep prices artificially high (such as waste/refuse collectors). In general, if a developer can secure reliable, consistent feedstock at $40 per bone dry ton, the plant has favorable economics. For fluidized bed technology 0.95 bone dry tons per MW of fuel is needed. For non-fluidized bed technologies, which are less efficient, 1-1.1 bone dry ton per MW is needed. Overall, collection, processing and transport of wood biomass costs are approximately $0.04 per kWh. Because plant operating costs are largely dictated by the cost of feedstock, any fluctuations in feedstock price can easily impact the overall economic viability of the plant.[55]

The capital cost for a 40 MW direct combustion biomass power plant ranges from $1,750 to $2,200 per installed kilowatt with wet cooling. Dry cooling adds an additional $200 to $300 per installed kilowatt and lowers the overall plant efficiency by 4% to 5%.

Siting Requirements

A utility-scale biomass plant requires land that is free of height restrictions, has access to water, and facilitates the delivery of significant supplies of feedstock. Assuming annual biomass feedstock is delivered year round, 20 to 30 acres are required – depending on power level of the plant – for biomass receiving, storage and conveyance. The land must be fairly flat, with transmission and road or rail access (for bringing in fuel supplies). There must be no height restrictions that would prohibit the construction of 105 to 165 foot stack. Both wet and dry

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[55] Information in this section taken from "Testimony Before the Subcommittee on Select Revenue Measures of the House on Ways and Means," William Carlson, Chairman, Carlson Small Power Consultants, May 24, 2005, subsequent phone interview with Carlson on 2/8/07, and conversation with Phil Reese of Colmac Energy biomass plant, 2/12/2007.

cooling technologies require 75 MGY for boiler water. Wet cooling technology – which is not allowed in California but possible in other states – adds an additional water demand of 176 to 202 MGY, bringing total water demand for wet cooling to 251 to 277 MGY.

Air quality concerns are also an issue for biomass plant siting. Biomass power plants are subject to the federal Clean Air Act requirements, as well as additional state air emissions and water discharge permitting requirements. Existing pollution control technology allows biomass power facilities to meet air permitting and water discharge requirements. In addition, a biomass facility requires continual delivery of feedstock by either truck or rail, which can further impact local air quality issues. As a result, non-urban settings are preferable for plant siting.

Project Development Process

The development of a biomass plant is significantly influenced by the local current and future availability of feedstock suppliers. Long-term availability and reliability of the feedstock is a critical factor for biomass plant development, and suppliers typically only agree to one-year contracts. Close proximity to another biomass plant can increase prices as it could cause the plants to compete for feedstock resources with suppliers controlling the prices. A developer must consider these long-term market dynamics in addition to short-term factors such as permitting issues. Most developers consider 20 MW to be the minimum viable size for utility-scale and prefer power levels closer to 40 or 50 MW.

In addition to feedstock, a developer must determine the method of sale into the local power (and possibly heat from cogeneration) market, local air permitting requirements, the value of renewable energy credits, the best fuel source boiler start-up (natural gas or liquid fuel based on local resources), and the optimal boiler design based on likely feedstock resources.

Biomass Market Overview

Most biomass plant development is currently taking place in the Northeast. The reasons for this include, significant biomass feedstock supplies, high electricity prices, high renewable energy credit prices, and a lack of other competing renewable energy technologies. The abundant biomass power feedstock comes from urban waste biomass and forest resources in the Northeast.

For utility-scale power generation, California has the largest and most diverse existing biomass industry in the U.S., with development that peaked in the early 1990s at 4.5 billion kWh per year while disposing over 10 million tons of the state's solid waste annually. California has diverse agriculture and forestry industries which provided an ample supply of biomass to support these biomass power facilities. However, over 25% of the biomass power facilities in California terminated operations following a downturn caused by the termination of California's Standard Offer contracts that guaranteed a relatively high price per kWh and the opening and deregulation of California's electricity market.

Under California's RPS, the utilities' hold auctions where proposed renewable energy projects compete based on offered power price to supply the grid. Biomass power projects face stiff competition in these renewable energy auctions because of: (1) their reliance on unpredictable resources that could have a wide price fluctuation over the lifespan of the project; and (2) their relatively poor emissions profile compared to other renewable technologies. In addition, waste biomass residues from national forest harvesting do not count as renewable resources unless they are harvested in state and under California timber harvest plan requirements. Recently, the state's energy agencies set a rough goal for biomass sources to generate 4% of the state's power by 2010; this goal may spur further development.

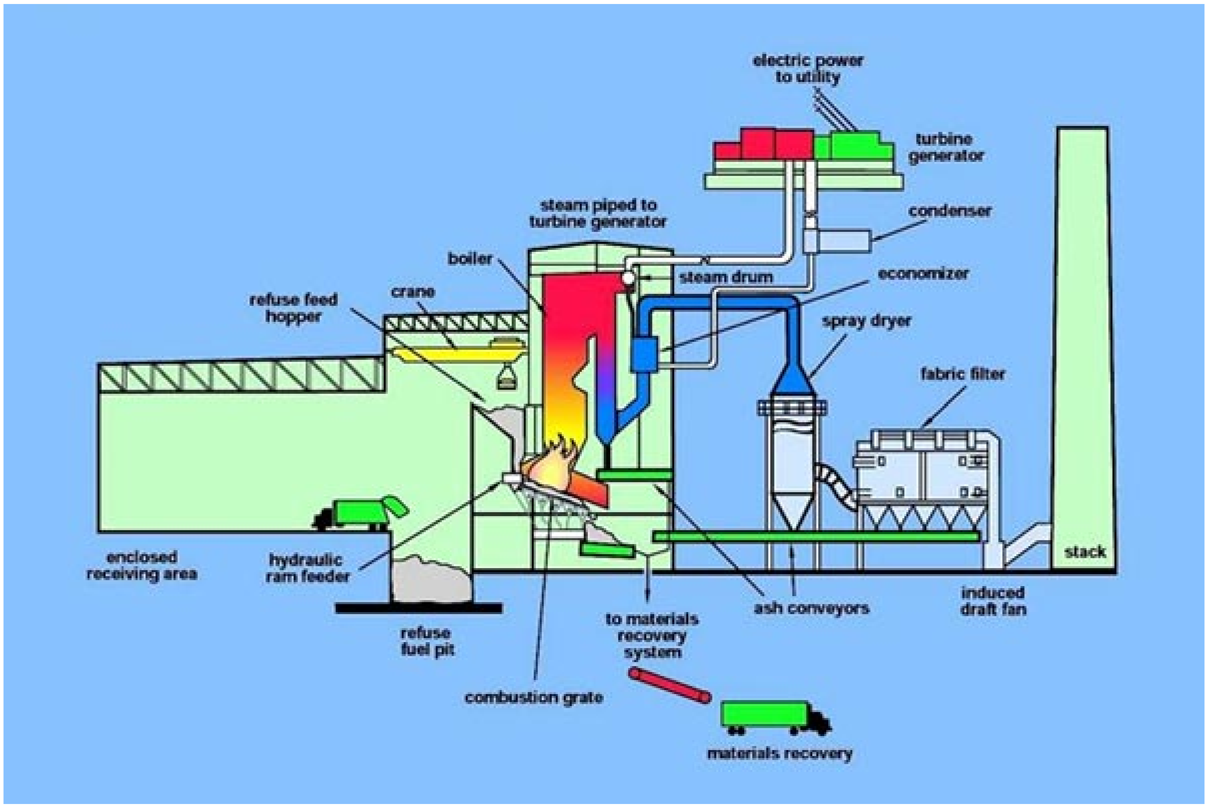
4.5 Waste-to-Energy

Waste-to-energy (WTE) comprises a range of processes usually associated with municipal waste (but also industrial waste) where the waste is burned, gasified or digested at a high temperature. Heat energy is recovered from these processes and is often reclaimed to produce steam and/or recovered to generate further electricity.

Technology

WTE plants work very much like coal-fired power plants, except that they use garbage – not coal – to fire an industrial boiler. As shown in Figure 5, electricity production follows closely that of coal plants: the fuel is burned, releasing heat; the heat turns water into steam; the high-pressure steam turns the blades of a turbine generator to produce electricity; and the utility company sends the electricity to the grid.

Figure 6: Waste-to-Energy Power Plant Technology[56]



The high-temperature incinerator burns most of the waste, leaving ash, of which 300 to 600 pounds is usually left for every 2,000 pounds of garbage. With typical garbage, about 80 pounds of every 100 pounds can be burned as fuel to generate electricity. Appropriate fuels include municipal and industrial waste. On average, every ton of municipal waste generates about 525 kWh of electricity,[57] much less than what a similar amount of coal – which has a higher heating

[56] Integrated Waste Services Association. Accessed March 2007. Website: http://www.wte.org.
[57] U.S. Energy Information Agency. *Waste-to-Energy*. Accessed March 2007. Website: http://www.eia.doe.gov/kids/energyfacts/saving/recycling/solidwaste/wastetoenergy.html.

content – could produce. It takes nearly 2,000 pounds of municipal waste to equal the heat energy in 500 pounds of coal, though some industrial waste such as rubber and plastics have higher BTU values.

The technology most predominantly used is mass burning, though there are several plants in the U.S. using the Refuse-Derived Fuel (RDF) process that pre-shreds waste into small pieces and separates some of the non-combustible materials (metals and glass).[58]

Economics

The economics of WTE plants are driven by the costs of waste disposal and the power price. Waste disposal in a landfill is generally much cheaper than burning the waste for energy, so areas with ample land and low waste disposal tipping fees are less economical for WTE. The capital costs can range from $110,000 to $140,000 per daily ton of capacity, so a plant that processes 1,000 tons of MSW per day would cost $110 to $140 million. Additionally, a 1,000-ton per day plant requires approximately 60 personnel and has other operating costs such as ash disposal and transportation for obtaining the waste feedstock. A typical MSW plant will generate a net of 500-600 kWh per ton. Larger plants result in lower costs per ton of MSW processed.[59] WTE is a baseload power that can operate with 95% plus capacity factors. With revenues of $.04 per kWh, a 1,000-ton per day plant would have revenues of $20 to $30 per ton of MSW. The plant will also receive revenues from tipping fees (fees paid by the communities to dispose of garbage), and recycled material value (primarily for the ferrous and non-ferrous scrap collected). WTE is more economical when WTE is included in the state RPS so that it can capture an added REC value in addition to the power value, but many states do not include WTE in their RPS (15 at time of this report). Many studies indicate that burning waste decreases the net greenhouse gas emissions from waste disposal (factoring in the methane production from decaying waste in a landfill), so it is possible that in the future, carbon offset credits could be obtained by WTE facilities, which would further enhance economics.

Siting Requirements

In the U.S., most WTE facilities range from 500 to 3,000 tons per day and are located at MSW landfills, minimizing transport costs. A WTE facility requires a site that is properly zoned, near major roads or highways, accessible to high-voltage transmission for large-scale power production, and has appropriate industrial infrastructure, such as water and sewage. A minimum of twenty-five acres is preferable, but facilities can be located on as little as 5 acres if trucks can line up off site. [60]

Project Development Process

The project development process can be prolonged due to permitting issues. The developer must obtain waste supply commitments and the heat content, moisture, and other criteria of the waste composition must be characterized. A developer must obtain control of the site either through lease or ownership, ensure proper zoning and/or land use conformance, and seek the appropriate environmental permits. A developer must also ensure it can obtain a profitable Power Purchase

[58] Waste to Energy Research and Technology Council. Accessed March 2007. Website: http://www.seas.columbia.edu/earth/wtert/.
[59] Ibid.
[60] Ibid.

Agreement and pursue an interconnection agreement with the local utility. The construction period takes approximately 24 to 30 months.[61]

WTE Market Overview

Today in the United States, there are 90 WTE plants, as well as a number of older-style solid waste incinerators that simply burn trash instead of generating heat energy to make steam. The U.S. burns 14% of its solid waste total. Worldwide, there are more than 600 WTE plants in 35 different countries, which cumulatively use the waste of 40 million people. WTE has become more popular in European and Asian countries that have little open space (high tipping fees) and few fossil fuels.

[61] Ibid.

4.6 Landfill Gas

Technology

MSW naturally produces landfill gas (LFG) through anaerobic digestion and many landfills generate revenues through capture and combustion of this gas for the production of electricity, process heat or both (CHP). The gas is not pipeline quality and must normally be cleaned before combustion, but can be burned in traditional natural gas internal combustion engines or gas turbines. The economics of landfill gas capture are dependent on the amount of gas produced, the expected longevity of the gas resources (declines over time after closure), the capital costs of the system, the revenues from the power and/or heat sales, and any additional environmental payments from compliance RECs (where the state RPS includes landfill gas) or voluntary RECs. Assuming future carbon regulations, landfills will be able to obtain significant payments for carbon reductions created by capturing their methane emissions, as methane has a greenhouse effect 21 times greater than carbon dioxide.

Economics

Rough estimates for total U.S. power production from LFG are 432,000 cubic feet per day and 0.8 MW of electricity per million tons of MSW.[62] Currently there are 600 candidate landfills in the U.S. with a total LFG generation potential of 725 million scf/day (about 15,000 MMBtu/hour).[63]

Project Development Process

Landfill gas energy technology was initially considered for utility-scale development on Air Force bases as an EUL opportunity. Using data from the EPA's Landfill Methane Outreach program, which collects data on operational LFG projects and candidate MSW landfills having LFG energy potential, candidate landfills over 12 million tons were mapped for proximity to Air Force bases. Twelve million tons was considered the minimal amount feasible for a 10 MW+ plant. Based on the EPA data, no landfills meeting this criterion were located within a 15-mile radius of any Air Force base.[64]

Although no large-scale potential was identified, there are smaller opportunities to meet on-base demand with landfill gas energy. For example, Hill Air Force Base currently generates 1.2 MW of power (supplying on-base demand) from gas that is piped from a landfill located less than two miles from the base. Beale Air Force Base has the Ostrom Road Landfill in Wheatland just outside the fence line. This relatively new landfill (opened in 1995) is expected to be active for at least 50 years and is sized to accept up to 3,000 tons of waste per day.[65] In addition, due to landfill expansion, technology maturity and expected new regulations requiring or rewarding methane capture, there may be other landfill gas opportunities at Air Force bases that were not identified in this limited analysis.

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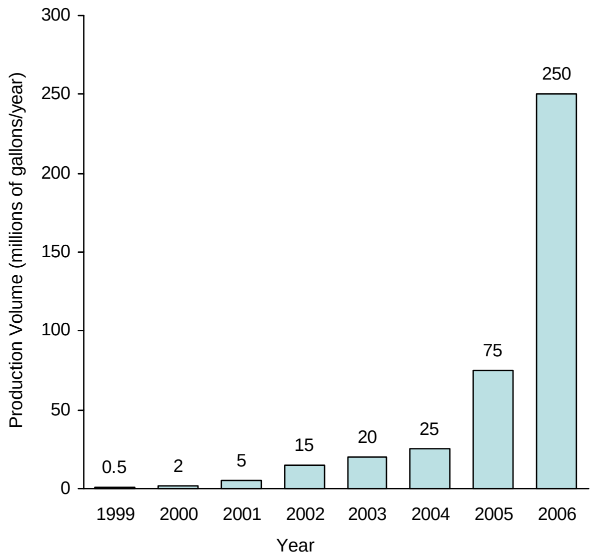
[62] U.S. EPA, Landfill Methane Outreach Program. *An Overview of Landfill Gas Energy in the U.S.*, April 2006 PowerPoint. Available online: http://www.epa.gov/lmop/docs/overview.pdf
[63] ibid.
[64] 15 miles was conservatively assumed to be the farthest distance LFG might be piped.
[65] Norcal Waste Systems Ostrom Road Landfill, Inc. Accessed May 2007. Website: http://www.ostromroadlandfill.com/.

4.7 Biofuels

Biofuels are fuels produced from renewable resources. Traditional biofuels include ethanol, made from either sugars or starches converted into sugars, and biodiesel, made from vegetable oils (virgin or recycled) and rendered animal fats. Next generation biofuels, including synthetic fuels and cellulosic ethanol, are those produced from biomass[66] through either biochemical[67] or thermochemical[68] technologies. Biofuels are currently used primarily as blending components in gasoline (ethanol) and diesel fuel (biodiesel). Currently, only ethanol and biodiesel conversion technologies are produced on a commercial scale. Plants have been typically sited close to their feedstocks (raw resource inputs), although some are beginning to be sited close to their customers (demand for fuel or byproducts such as DDG) or in shipping ports with access to low cost transportation. Ethanol plants are predominately in the Midwest (corn belt), while biodiesel plants are primarily located east of the Rocky Mountains where soybean production is prevalent. U.S. biofuels production has increased significantly since 1999 and is projected to double between 2007 and 2009.

Figure 7: Biodiesel Production 1999-2006

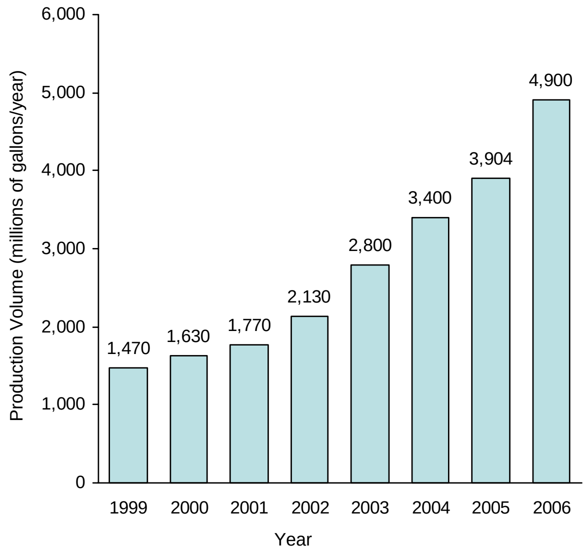


Biodiesel Source: National Biodiesel Board (www.biodiesel.org)

Biodiesel Plant Statistics:
- 105 existing plants with an annual production capacity of 864 million gallons
- 77 plants under construction and 8 under expansion raise production capacity to 1.7 billion gallons per year by 2008

[66] Plant derived organic matter including agricultural and forest residues such as corn stover and wheat straw and dedicated energy crops such as switchgrass and fast growing poplar and willow trees.
[67] Conversion of plant matter to sugars followed by fermentation to ethanol.
[68] Gasification and catalytic conversion of syngas to synthetic gasoline, diesel, or mixed alcohols.

Figure 8: Ethanol Production 1999-2006



Ethanol Source: Renewable Fuels Association (www.ethanolrfa.org)

Ethanol Plant Statistics:

- 114 existing plants with an annual production capacity of 5.6 billion gallons
- 80 plants under construction and 7 under expansion raise production capacity to 12 billion gallons per year by 2009

Technology

Due to their lower cost of construction and lower energy requirements, over 80% of new ethanol plants are "dry mills." Dry mill technology involves milling the corn into a meal that is mixed with water. Enzymes added to this solution breaks down the starch contained in the corn meal into sugars. These sugars can be sold as sweetener or fermented to ethanol, which can then be distilled into fuel grade ethanol. The by-product is distiller's dry grain (DDG), which is sold as cattle feed. Ethanol facilities using "wet mill" technology separate the germ (oil), fiber, and protein from the corn starch prior to enzymatic starch conversion to sugar and fermentation to ethanol. Though more capital-intensive to construct and more power-intensive to operate, a wet mill plant is still more economical due to the high value of co-products that produced and sold, including sugars, ethanol, starches, germ (corn oil), dextrins, and bran. Most grain ethanol plants are powered by natural gas.

Cellulosic ethanol can be produced through either biochemical or thermochemical technology. Biochemical technology converts lignocellulosic biomass, the non-edible crop residue and woody portion of biomass, into fermentable sugars. These sugars are subsequently fermented and distilled – C5 sugars require highly specialized enzymes, while C6 sugars are more easily fermented. The by-product, lignin, can be dried and used as boiler fuel to power the process. Thermochemical conversion involves gasification of biomass (heating to the point of combustion in an oxygen-deprived environment) to produce a syngas (mainly hydrogen and carbon monoxide), which is then converted by means of a metal catalyst to mixed alcohols including ethanol and methanol. Some of the raw syngas is diverted to provide the fuel necessary to run the process.

Currently, there are no commercial plants producing cellulosic ethanol in the U.S., although a recent DOE announcement of the partial funding of 6 projects over the next 4 years (at a total cost of $385M) ensures that construction will soon begin on commercial scale cellulosic ethanol biorefineries.

Biodiesel is produced through transesterification, where organic oil is mixed with alcohol in the presence of a catalyst under moderately elevated temperature (150°F) and pressure (20 psi) to produce alcohol esters that closely resemble diesel fuel. The by-product of transesterification is glycerin, used to make pharmaceutical products and soap. Most biodiesel is made from oils purchased from an oilseed processor (e.g., soy, canola, sunflower, cotton, mustard) or from a rendering facility (tallow, yellow grease, grease trap waste). Agricultural oil is released from seeds through either mechanical means (seed crushing) or solvents. The by-product of soybean oil extraction is crushed soybean "cake," sold as a high value animal feed. When oil is extracted from mustard seeds the mustard shells can be used as a natural pesticide. Most U.S. biodiesel is currently produced from soybean oil.

Currently, there are no commercial plants producing synthetic fuels from biomass in the U.S.

Synthetic fuels can be produced through gasification, pyrolysis and hydrothermal liquefaction. With gasification, the syngas is catalyzed into paraffin molecules, which is then upgraded to synthetic diesel and jet fuel with traditional petroleum refining technology. Biomass can be converted to pyrolysis oil (bio-oil). Pyrolysis involves the conversion of biomass to gas, liquid, and char through rapid heating and quenching in the absence of oxygen. Direct Hydrothermal Liquefaction can also produce bio-oil. Biomass is converted into an oily liquid by immersion of biomass into water at elevated temperature and pressure for 30 minutes. The end-product is an oily liquid similar in properties and composition to bio-oil. Bio-oil can also upgraded to synthetic diesel and jet fuel with traditional petroleum refining technology.

Economics

High oil prices and government subsidies are encouraging continued private sector investment in grain ethanol and biodiesel, which are established commercial technologies. Recent price increases in steel, stainless steel, copper, and concrete and the demand for the expertise to build biofuels plants has driven up construction costs. The cost of construction for a 60 million gallon per year (MGY) ethanol plant has increased to $2.25 per gallon of name plate[69] production capacity. The cost of less complex biodiesel plants are lower but are estimated to be $1.47 per gallon for a 30 MGY biodiesel plant.

The cost of biofuels production is largely dependent on the price of the feedstock. For ethanol, feedstock makes up on average 66% of the cost of goods sold, while for biodiesel, feedstock is over 80% of the cost. However, the sale price of biofuels is largely based on the price of a barrel of oil and the subsequent price of a gallon of gasoline (ethanol) or diesel fuel (biodiesel). Biofuels plants calculate the maximum feedstock price they can afford to pay and remain profitable relative to their netback price (wholesale biofuels price + tax and producer credits – all other costs). A 60 MGY ethanol plant with a netback price of $1.89 per gallon must pay less than $4.28 per bushel of corn. A 30 MGY biodiesel plant with a netback price of $2.93 per gallon must pay less than $0.331 per gallon of soybean oil.[70] As oil prices decrease the netback price is reduced along with the price that the plant can afford to pay for feedstock and remain profitable.

[69] Plants often can exceed nameplate production capacity.
[70] Eidman, Vernon (2007). *The Evolving Biofuels Industry: Implications for U.S. Agriculture*. Department of Applied Economics, University of Minnesota, Presentation at USDA.

Primary U.S. ethanol production feedstock (raw resource input) is feed corn that has traditionally been used as animal feed and for the production of corn meal and high fructose corn syrup. The recent addition of significant ethanol production capacity has doubled the price of feed corn from $2 to $4 per bushel (56 pounds) over the past two years, causing a strain on the economics of livestock production (cows, pigs, chickens) and ethanol production. Due to these price increases, corn planting acreage for 2007 is predicted to increase 15% over 2006 at the expense of soybean acres (down 11% from 2006) and cotton acres (down 20%). However, this additional corn acreage may not have a significant impact on reducing the cost of feed corn, since ethanol plant demand for corn continues to rise with the introduction of new ethanol production capacity. As soybeans are the primary feedstock for biodiesel, this acreage shift will also directly affect the cost of producing biodiesel. The high demand placed on agricultural commodities to support biofuels production and the subsequent increase in the price of these feedstocks puts a strain on the economics of biofuels plants that is exacerbated by the rapid increase in biofuels production capacity.

Tax credits for fuel blenders have helped to offset the higher costs of biofuels production and encourage their use as transportation fuel additives. Among the Energy Policy Act of 2005 biofuels production incentives designed to encourage the expansion of biofuel production in the U.S. is the Volumetric Ethanol Excise Tax Credit (VEETC). This credit provides a $0.51 tax credit per gallon of ethanol blended into gasoline, recently extended through the end of 2010. There is also a similar credit for biodiesel blenders, good through the end of calendar year 2008. It provides a $1.00 per gallon blenders tax credit for each gallon of agri-biodiesel (biodiesel made from virgin agricultural products) added to petroleum diesel to form a biodiesel blend, and a $0.50 per gallon blenders tax credit for each gallon of biodiesel (made from other feedstocks including used cooking oil, tallow, and grease trap waste) added to petroleum diesel to form a biodiesel blend. Additionally, the Small Ethanol and Biodiesel Producer Credits provide a $0.10 per gallon production tax credit (taken on the first 15 million gallons of production) for plants with a production capacity of up to 60 MGY. This credit is capped at $1.5 million per year per producer and good through the end of calendar year 2008.

Siting Requirements

An average-sized ethanol plant (60 MGY nameplate production capacity) requires approximately 150 acres to accommodate the plant, grain silage, ethanol and denaturant (gasoline) storage, roadway access for grain delivery (and possibly ethanol shipment via truck), and a rail spur capable of facilitating the loading of a unit train (100 rail tank cars). Most ethanol plants use natural gas as process fuel for generating steam used in the distillation column and for heating the fermentation tanks. All ethanol plants require electricity to operate the pumps and electronic control equipment used throughout the plant. The average grain ethanol plant requires 3 gallons of water for every gallon of ethanol produced. The plants are approximately 150 feet tall including the distillation column, grain silage and fuel storage, and other stacks.

An average sized biodiesel plant (30 MGY production) can be much smaller, requiring approximately 20 acres to accommodate the plant, storage tanks for oil, glycerin and biodiesel, and road access for transport of the feedstock and finished fuel. New facilities prefer a rail spur and/or port to facilitate access to a more diverse feedstock supply and for shipment of finished fuel. Most biodiesel plants use natural gas as process fuel for generating steam used in the distillation column (if so equipped) and for heating the conversion tanks. All biodiesel plants require electricity to operate the pumps and electronic control equipment used throughout the plant. The average biodiesel plant requires 1 gallon of water for every gallon of biodiesel produced. Plants are approximately 60 feet tall including the distillation column, tank storage and other stacks.

Traditional grain ethanol and biodiesel plants are considered minor emitters and as such are not subject to large environmental constraints due to air pollution concerns. Increased concerns are likely with the introduction of solid fuel boilers and gasifiers for the production of cellulosic ethanol and synthetic fuels. New biofuels facilities are designed as zero discharge, where no process water is released from the plant. Only blowdown (non-evaporated cooling water) from the wet cooling towers used for distillation and other evaporative cooling requires release, and can be disposed of through evaporation from a holding pond if zero water discharge is required. Feedstock transport and processing can lead to vehicle emissions and particulate matter releases that can affect local air quality, and environmental impact studies may be required as part of the permitting process to determine the levels of all associated emissions.

Given the mercurial marketplace for biofuel feedstock, vertically integrated producers that own many parts of the supply chain, such as Archer Daniels Midland and the Andersons, enjoy a competitive advantage. Producers able to lock in long term feedstock supply contracts also enjoy an advantage, as is the case with ethanol and biodiesel plant cooperatives, where farmer owners are contracted to deliver a specified volume of feedstock to the plant annually. Ethanol producers beholden to the spot market are likely to become progressively more disadvantaged, as competition increases between new and existing biofuels plants for feedstock supplied from overlapping geographic regions. The Chicago Board of Trade futures market for corn forecasts continued price increases through 2011.

Biodiesel producers without long-term feedstock supply security are also in a perilous position. Soy plantings have decreased as demand for corn — and the acreage required to satisfy that demand — has increased (Figures 9 and 10). Several oil seed crushing facilities contacted by Booz Allen Hamilton have expressed unwillingness to enter into long-term feedstock supply contracts. Therefore, in order to decrease exposure to price fluctuations, non-integrated refiners must have a diversity of feedstock options. For example, biodiesel refiners must be able to import palm oil from Asia or Latin America as that feedstock is expected to become more cost-competitive. Refiners without access to overseas feedstock markets are at a competitive disadvantage; therefore, port access is becoming a key siting requirement for biodiesel facilities.

Figure 9: U.S. Corn Planted Acreage

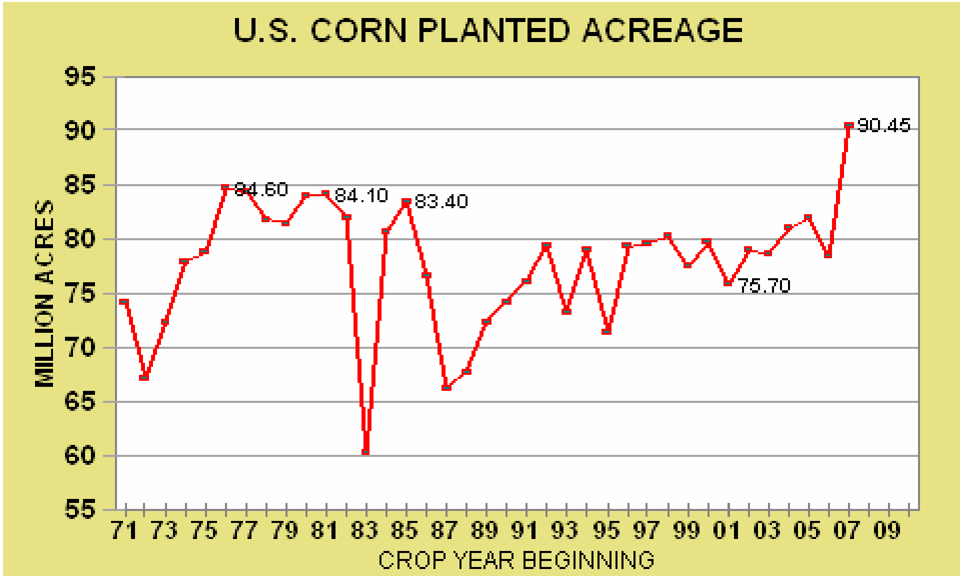


Figure 9 shows that the acreage of corn has increased dramatically as demand for ethanol has increased.
Source: Chicago Board of Trade

Figure 10: U.S. Soybean Planted Acreage

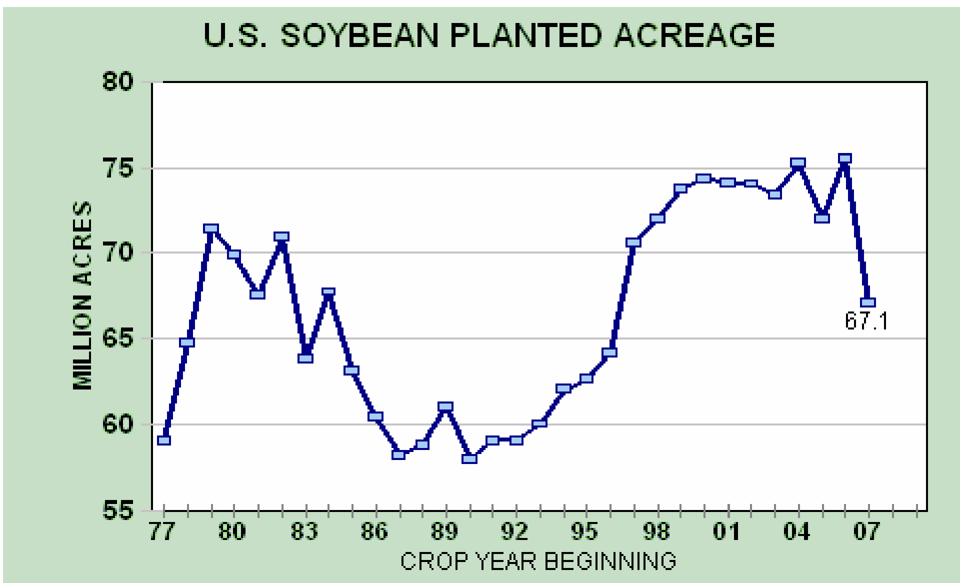


Figure 10 shows that corn plantings have increased at the expense of soy plantings in recent years.
Source: Chicago Board of Trade

Project Development Process

The development of a biofuels plant is significantly influenced by feedstock and water availability. Competition between ethanol plants for feedstock can have a significant impact on price, as can having only a single source for soybean oil at a biodiesel plant. Siting a biofuels plant requires evaluating a location for feedstock availability, water resource, energy source (natural gas and electricity) and road and rail transport access. A 50-mile collection radius is economical for feedstock collection, and usually the determining factor for site selection by a biofuels project developer. For this reason, the vast majority of biofuels plants are located in close proximity to feedstock resources.

Many biofuels plants are owned by farmer cooperatives. In the cooperative business model, shareholders of the plant are contracted to supply a certain volume of feedstock on an annual basis, the plant is assured a minimum volume of feedstock delivery per day. As a farmer in a cooperative, lower grain prices mean less payment for feedstock but higher dividend checks from the biofuels plant, while higher feedstock payments mean more revenues from farm products but less return on their biofuels plant investment. A cooperative is a win-win proposition for a farmer, while at the same time ensuring delivery of a minimum volume of feedstock necessary to keep the facility operational.

Biofuels Market Overview

The Energy Policy Act of 2005 contains a Renewable Fuels Standard (RFS) mandating a doubling of the transportation renewable fuel volume nationally from 4 billion gallons in 2006 to 7.5 billion gallons in 2012, thus increasing the market size and making investments more attractive. However, U.S. biofuels production and use well exceeds minimum mandated biofuels use, and the 2012 requirement of 7.5 billion gallons per year will likely be exceeded 4 years ahead of schedule. Federal production and blending credits are available throughout the U.S. Some states have additional biofuels production incentives, as well as mandated blend percentages based on the volume of biofuels produced within the state. However, the driving factor after oil prices is availability of and access to economically priced feedstock.

Biofuels EUL Potential

The EUL biofuels analysis first evaluated the bases based on the biofuels feedstock resources relative to a 50-mile collection radius for each base. As most large biodiesel plants obtain their feedstock from seed crushing facilities, the initial analysis of biodiesel opportunities considered the location of seed crushing facilities as well. For bases that were identified with sufficient grain or soy bean feedstock resources, the next screen was the available underutilized land on the base with access to rail, water, and natural gas. Height restrictions, rail access and sufficient underutilized land were limiting factors for potential ethanol plant candidate sites. In addition, cooperative plants are generally sited on farmland with immediate rail access and an ethanol producer on an Air Force base would most be beholden to the spot market for feedstock.

Biodiesel was less limited by height and land constraints; however, due likely future feedstock constraints in the U.S., most large new biodiesel plants developers are seeking port access (either inland or coastal) to accommodate imports of inexpensive agricultural oils from overseas producers and to provide for low-cost shipping of finished products. Apart from Patrick AFB in Florida, Air Force bases do not have deepwater ports.

Based on this high-level analysis it was determined that there were no Air Force bases meeting the requirements for an ideal biofuels plant and it was therefore unlikely that there was an opportunity to attract a developer to site a commercial scale plant at this time.

Opportunities to site smaller-scale plants are more likely, particularly if the Air Force wished to enter into a fuel purchase agreement for a large portion of the output. Another model could be smaller-scale production from waste grease from base operations, combined with other feedstock sources and refined to provide a measure of energy security and compliance with Executive Order 13423 C (g). Tallow and yellow grease could also be sourced from local rendering facilities and used as feedstock. Yellow grease is usually half the cost of virgin agricultural oil and tallow currently commands about $0.26 per pound.

Appendix A
Renewable Energy Markets

Against a backdrop of escalating oil and natural gas prices, heightened concern about the security of energy supplies, and increasing evidence of global climate change, investment in alternative energy technologies is growing dramatically. As the negative impacts of our dependence on fossil fuels becomes more apparent, worldwide government support is creating and expanding markets for alternative power and fuel technologies.

Alternative energy sources are becoming increasingly important for power generation, but currently, renewable energy represents only 9% of the nation's electricity production; and roughly 75% of this production comes from conventional hydropower.[71] However, due to a variety of economic and environmental barriers, development of large-scale hydroelectric production facilities has nearly stopped. As a consequence, solar and wind are currently the fastest growing renewable energy segments. The growth in solar and wind is aided by technological improvements, which – along with regulatory incentives, such as Renewable Portfolio Standards (RPS), and federal tax credits – have significantly reduced costs. Utility-scale renewable energy power plants that produce electricity for the wholesale markets have been predominantly powered by wind and developed by utilities or independent power producers. However, the expectation of long-term carbon dioxide limitations and targeted policy support are beginning to spur the diversification of renewable resources and significant growth in other technologies.

Federal Renewable Energy Policies

The Energy Policy Act of 2005 (H.R. 6) established a number of federal incentives to continue support for the development of renewable energy projects. One of the most significant aspects of the Energy Policy Act, driving much of today's renewable energy development, is the Production Tax Credit (PTC). The PTC provides a 1.9 cent per kilowatt-hour (kWh) benefit for electricity generated by wind, geothermal, and closed-loop biomass for the first 10 years of a renewable energy facility's operation, and provides a 1.0 cent/kWh incentive for open-loop biomass, small irrigation hydroelectric, landfill gas, municipal solid waste (MSW) resources, and hydropower.[72] The PTC was initially set to expire on December 31, 2007, but has since been extended through 2008.

The Energy Policy Act of 2005 also expanded the Investment Tax Credit for solar and geothermal energy property to include fuel cells and microturbines installed in 2006 and 2007, and hybrid solar lighting systems. These provisions of the tax credit were later extended through December 31, 2008, by Section 207 of the Tax Relief and Health Care Act of 2006 (H.R. 6111). The credit applies to 30% of expenditures for solar technologies and related energy property equipment that uses solar energy to generate electricity, to heat or cool a structure, or to provide

[71] Energy Information Administration. *2006 Energy Power Annual*; figures are for 2005 production.
[72] Database of State Incentives for Renewables and Efficiency (DSIRE). Accessed April 2007. Website: http://www.dsireusa.org/library/includes/incentive2.cfm?Incentive_Code=US13F&State=Federal&currentpageid=1&ee=0&re=1.

solar process heat.[73] This incentive has played a major role in the development of solar thermal and photovoltaic systems across the county.

State Renewable Energy Policies

A Renewable Portfolio Standard (RPS) is a state policy that requires electricity providers to obtain a minimum percentage of their power from renewable energy sources. This requirement can be satisfied either by owning renewable electricity generation or by buying credits or electricity from a renewable generator within an allowed area, determined by each RPS. As of November 2006, 20 states plus the District of Columbia have RPS policies in place; two states have voluntary renewable programs that are non binding.[74] RPS are currently in place in over 20 states, although their aggressiveness and penalties for non-compliance vary substantially.

Most RPS regulations are recent and have gradually increased over time, by approximately 1% per year. If current conditions remain, REC prices will rise as states with RPS increase their standards, the low hanging fruit, such as wind with transmission access, becomes limited and additional states implement RPS. Throughout the U.S., rural electric cooperatives are generally exempt from RPS requirements and in some states, such as Pennsylvania, RPS rules differ for each investor-owned utility (IOU).

RPS systems are “market-friendly” because they impose fewer regulatory burdens on the market and better reward the lowest cost producers of qualified renewable energy than other regulatory mandates. However, because they are market-friendly, they do not necessarily encourage unproven, new or more expensive technology commercialization. To counter this aspect, some states have created additional multipliers for preferred sources of energy, such as solar. For example, state policies in Nevada, California, Arizona, and New Mexico have created strong incentives for solar technologies and projects. Below is a table of state RPS and targets for renewable energy.

Summary of State Renewable Portfolio Standards[75]

State	Amount	Year	Organization Administering RPS
Arizona	15%	2025	Arizona Corporation Commission
California	20%	2017	California Energy Commission
Colorado	10%	2015	Colorado Public Utilities Commission
Connecticut	10%	2010	Department of Public Utility Control
District of Columbia	11%	2022	DC Public Service Commission
Delaware	10%	2019	Delaware Energy Office
Hawaii	20%	2020	Hawaii Strategic Industries Division
Iowa	105 MW		Iowa Utilities Board
Illinois (voluntary)	25%	2017	Illinois Department of Commerce
Massachusetts	4%	2009	Massachusetts Division of Energy Resources
Maryland	7.5%	2019	Maryland Public Service Commission
Maine	10%	2017	Maine Public Utilities Commission
Minnesota	25%	2025	Minnesota Department of Commerce

[73] Database of State Incentives for Renewables and Efficiency (DSIRE). Accessed April 2007. Website: http://www.dsireusa.org/library/includes/incentive2.cfm?Incentive_Code=US02F&State=federal&currentpageid=1&ee=1&re=1.
[74] DOE EERE. *States with Renewable Portfolio Standards*. Accessed April 2007. Website: http://www.eere.energy.gov/states/maps/renewable_portfolio_states.cfm.
[75] ibid.

Summary of State Renewable Portfolio Standards (continued)

State	Amount	Year	Organization Administering RPS
Montana	15%	2015	Montana Public Service Commission
New Jersey	6.5%	2008	New Jersey Board of Public Utilities
New Mexico	20%	2020	New Mexico Public Regulation Commission
Nevada	20%	2015	Public Utilities Commission of Nevada
New York	24%	2013	New York Public Service Commission
Pennsylvania	18%	2020	Pennsylvania Public Utility Commission
Rhode Island	15%	2020	Rhode Island Public Utilities Commission
Texas	5,880 MW	2015	Public Utility Commission of Texas
Vermont (voluntary)	10%	2013	Vermont Department of Public Service
Washington	15%	2020	Washington Secretary of State
Wisconsin	2.2%	2011	Public Service Commission of Wisconsin

Across the country, prices for the RECs created by need to comply with RPS have varied substantially – on the order of $2 per Megawatt hour (MWh) in some regions, up to $53/MWh in Massachusetts. These REC values provide a premium for renewable energy over bulk power prices and have driven the markets in some parts of the country. In the Northeast, for example, the active REC market is partly responsible for the recent utility-scale biomass activity. (Other factors contributing to the recent utility-scale biomass activity include the lack of other significant large-scale renewable resources, the availability of significant biomass feedstock and high electricity costs.) California provides supplemental energy payments (SEPs) to eligible renewable generators for the above-market costs of renewable energy procurement for its three largest IOUs: Pacific Gas & Electric, San Diego Gas & Electric and Southern California Edison. However, California also has abundant wind and solar resources, so biomass activity has been limited to date.

Voluntary Markets

Besides state-mandated RECs, voluntary RECs, or ‘green tags,’ from private Green Power marketers are another source of revenue for renewable energy power plants. There are many private sector organizations and utilities that voluntarily purchase RECs from renewable energy producers on behalf of their customers as a means to support renewable energy. The prices in these voluntary markets tend to be far lower than in any of the RPS compliance markets.

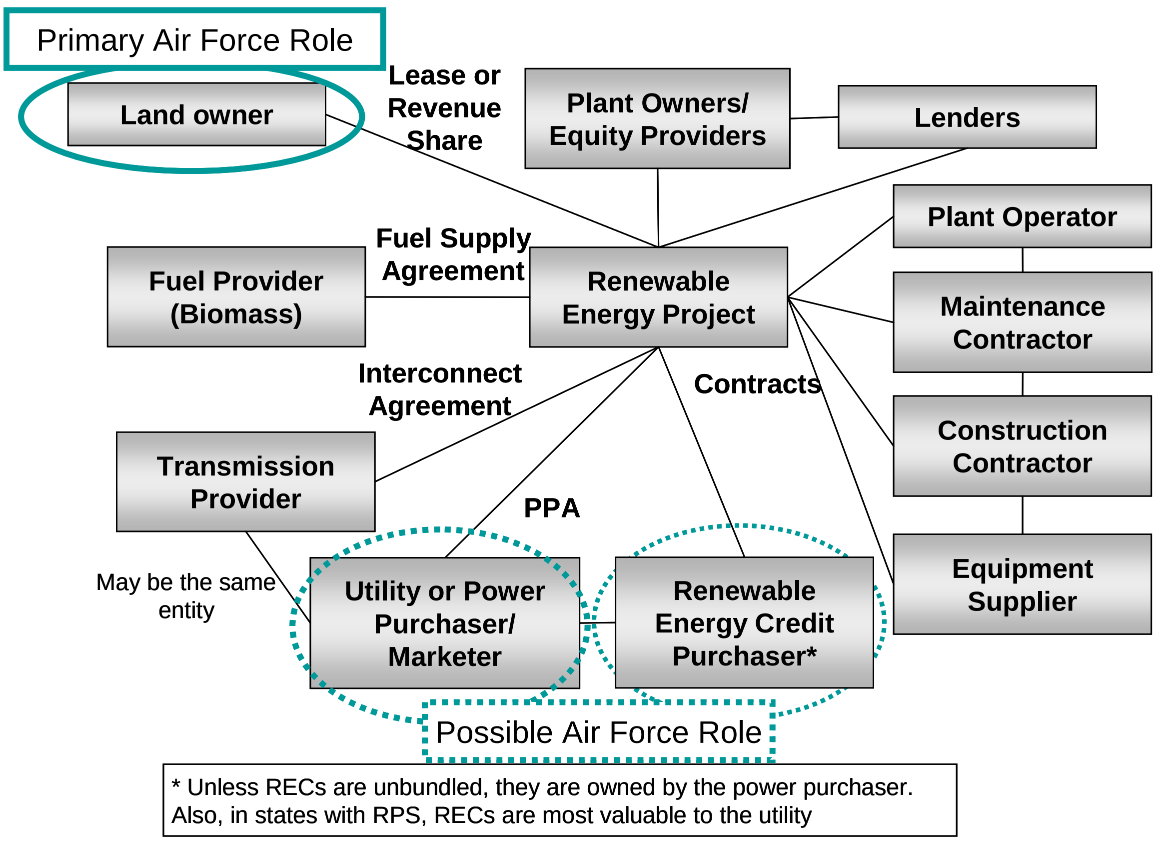
Possible Future Policies

An emerging source of revenue could be carbon emission reduction credits that result from nascent carbon cap and trade systems. Some U.S. farmers are currently receiving payments of up to $5 per ton for carbon offsets purchased on the Chicago Climate Exchange (CCX). While CCX is a voluntary prototype exchange, the value and amount of carbon offset funding available for alternative energy or carbon capture projects is anticipated to grow. The Northeastern U.S. – under the Regional Greenhouse Gas Initiative (RGGI) – and California are in the process of instituting carbon emissions regulations, and most power industry executives expect that the U.S. will have carbon limits or taxation schemes established within a few years.

Appendix B
Financing and Developing Large-scale Projects

When the Air Force enters into an EUL agreement to lease land for the development of a utility-scale renewable energy power plant, it will be one participant among many in the project. Power project development is complex and involves numerous entities as shown below. The Air Force may choose to purchase a portion of the power from the project or a portion of the RECs produced; although, as shown below, the power purchaser will normally own the RECs and in states with a RPS where the purchase of renewable energy is driven by the REC requirements, the utility will be unlikely to sign a Power Purchase Agreement without the RECs.

Entities Involved in Utility-scale Renewable Energy Independent Power Production and the Air Force Role in the EUL Process



Development of a power plant includes:

- Economic feasibility studies;
- Transmission studies;
- Engineering and project design;
- Air quality and site permitting;
- Equipment procurement;
- Construction and project management; and
- Project commissioning.

During the construction phase, while the construction contractor usually "wraps" the construction risk – a arrangement that reduces project risk to the contractor by spreading it among various parties – the project developer takes the risk of project completion. The project developer therefore needs to provide evidence of insurance and credit security for any shortfall or failure to deliver. The Air Force should ensure that it is legally insulated from these risks. At least one wind project is known to have had a developer fail to complete the project and declare bankruptcy, resulting in the construction contractor putting a lien on the landowner's property.[76]

Power plants receive revenues from a variety of sources: capacity payments – although these are normally low for wind plants because of the inability to guarantee generation and thus add capacity to the grid, electricity payments, and environmental benefits payments, such as RECs. The optimal financial structure for a renewable power plant depends heavily on tax regulations and available subsidies. Renewable energy power plants typically face significant financial hurdles beyond traditional power plants including technology and market risk premiums. Many technologies are relatively unproven, such as biomass gasification and cellulosic ethanol, or the lifecycle costs of the technologies are uncertain, such as with new advanced wind turbines. Market risk premiums are higher due to uncertainties in resource availability and continued policy support. Renewables face tax disadvantages due to their relatively higher capital and lower operating costs when compared to fossil fuel plants. The policy and tax incentives that renewables currently receive more than offset these disadvantages, but they must be renewed by Congress, creating regulatory risk over the life of the project.

76 Sieve Wind Farm, Lincoln County, Minnesota, Wind Energy Easement and Lease Agreements, WINDUSTRY.