Chapter 9 References

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Section 9.1	none	N/A	N/A
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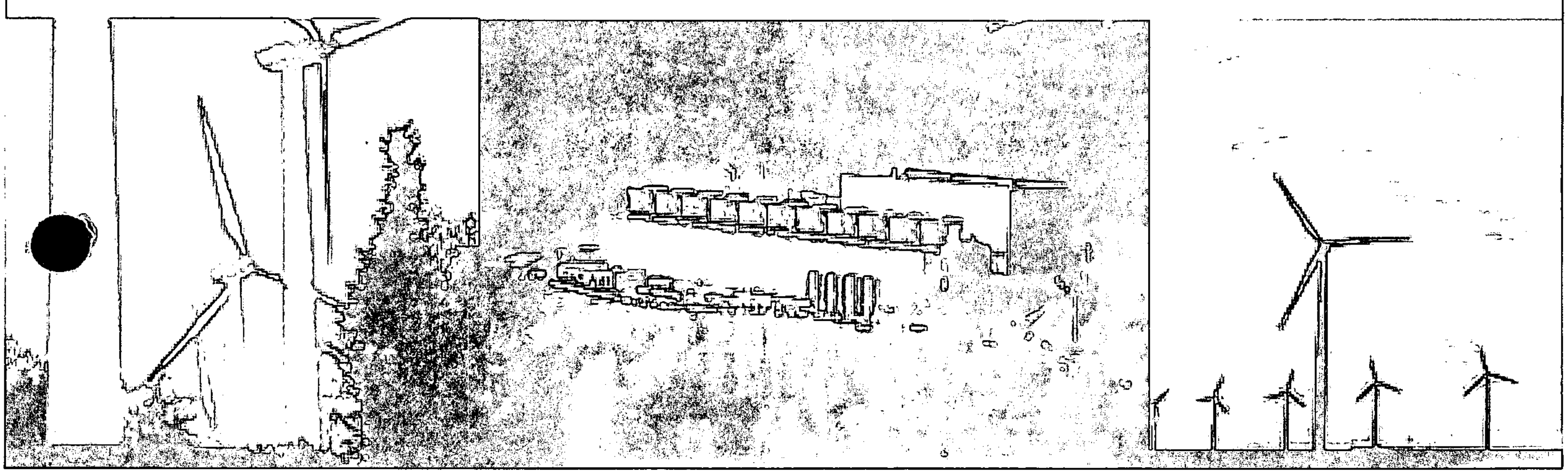
A Guidebook to Expanding the Role of Renewables in a Power Supply Portfolio

Prepared for
American Public Power Association
Demonstration of Energy-Efficient Development Program

Sponsored by
Gila Resources
Western Area Power Administration

Prepared by
Altera Energy, Inc.

September 2004



Acknowledgments

This guidebook was prepared by Brian Walshe of Altera Energy, Inc., and Larry Barrett of Barrett Consulting Associates, Inc., for the Demonstration of Energy-Efficiency Development (DEED) program of the American Public Power Association, which provided principal financing support for the project.

The guidebook was sponsored by Kenneth Mecham, President and CEO of Gila Resources and co-sponsored by the Western Area Power Administration. Additional support was provided by the U.S. Department of Energy Wind Powering America and GeoPowering the West Programs.

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Full responsibility for the report rests with Brian Walshe. Findings, opinions and views expressed do not necessarily represent the views of the sponsors and co-sponsors.

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Introduction

Momentum is building among consumers, politicians and others to increase the share of renewable resources in utility portfolios. Yet uncertainties exist about renewable resource availability, system integration, costs and rate impacts. While many parties agree there is a need to "do something," how much renewables are appropriate, and how quickly to accelerate development of renewables are more uncertain topics for utility directors, managers, planners and stakeholders. Given these uncertainties, smaller member-owned utilities especially, are often unable to commit the resources necessary to fully explore these issues.

The objective of this guidebook is to help answer a common question: What should public power utility managers be doing to expand the role of renewables in their energy supply portfolio? This guidebook describes a suggested process, analytic approach, and discusses key issues that enable a utility manager to work with key stakeholders to develop an informed answer to this question that is specifically tailored to its size, customer base, and other unique situations.

The guidebook describes key resource planning considerations and how these can be addressed in the context of a renewable energy strategy. Special attention is given to helping understand the factors driving renewable resources including environmental, financial, supply diversity, and political factors. The guidebook reviews in some detail, criteria and an evaluation framework for assessing renewable energy alternatives and quantifying results. The guidebook summarizes methods for analyzing and evaluating renewable energy alternatives including the impact to total power portfolio cost and risk from adding varying amounts of incremental, new renewable energy supply.

The importance of developing consensus among various stakeholders, including senior management, utility operating and customer service staff, energy conscious consumers, business interests and others is also discussed.

Trends are converging to increase the role of renewables

Renewable energy alternatives have been generally available to utility planners for many years. Historically, utilities have sought out opportunities to use renewable resources wherever feasible, but their options for traditional renewable resources were limited by their geographic location. The early days of the industry witnessed the development of hydro facilities in the Northeast, followed by more hydro facilities built during the New Deal era in the western United States and the Tennessee River Valley. For utilities located away from these regions however, fewer alternatives were available.

Over the past few decades, more renewable technologies became available to utilities. In many cases, they were categorized as "development" stage technologies. These early renewable alternatives tended to have higher capital costs, and suffered from the performance issues common to commercialization of new technologies. Although many utilities implemented a number of demonstration and prototype projects, they tended to be less visible to the general public than the large thermal plants with tall stacks or cooling towers. The result is that in many people's eyes, utilities have never really been inclined to implement renewable alternatives.

In recent years, a number of national and local trends are converging related to renewable resource alternatives that are causing utility managers to look hard at their alternatives and asking again: What is the proper role for renewables in today's power supply portfolio?

The most obvious and apparent trend is a sea-change increase in concerns about the environment over the past generation. This is most evident in Europe, where the Green Party has gone from a fringe political wing, to an considerable, influential force on the political scene. While the Green Party captured as much as 4 percent of some state's popular vote in the U.S. presidential election in 2000, they will likely never be as significant a political force in our two-party system as it is in Europe. However, the influence of environmental related issues on a local and national political level is growing and is gaining an increasing constituency that can be only expected to increase.

In fact, any resource planning assessment conducted today has to acknowledge that renewables are increasingly attractive against most planning criteria. When the assessment also considers uncertainties such as available hydro power, natural gas prices and existing and potential future legislation, renewables become even more attractive.

It is still true however, that although the costs of renewables alternatives are increasingly competitive; they are still generally higher than most other thermal options according to traditional resource planning criteria. However, the magnitude of any cost gap is clearly shrinking.

Recent Drivers Favor Consideration of Renewables

- ☐ **Natural Gas Price Volatility** – Natural gas volatility has driven electric price volatility to such an extent that there is a strong desire to reduce the exposure to these commodity price swings. This has resulted in greater attraction to a resource such as wind or geothermal with a more stable, predictable cost profile.
- ☐ **Renewable Portfolio Standard (RPS)** – There are 17 states with a legislated RPS. Many others are currently debating the issue.
- ☐ **Green Pricing** – Currently approximately 300 utilities are selling renewable products through Green Pricing programs. While penetration rates achieved to date are still relatively low, research indicates this is at least partly attributable to ineffective marketing programs.
- ☐ **Costs** – In just the past five years, costs have come down dramatically. Depending upon which natural gas forecast is selected, wind is now comparable on purely economic terms.
- ☐ **Technical/Experience Base** – At 2 to 3 MW turbine sizes, utility-scale wind farms can be developed in less than 6 to 9 months. Operating and maintenance services can be easily arranged. Performance has been excellent, with most newer models experiencing 98 to 99 percent availability.
- ☐ **Corporate Governance** – More and more investor-owned utilities, insurance companies and other corporations are assessing potential environmental related financial exposure, partly as a result of shareholder pressure or Sarbanes-Oxley requirements. This represents an acknowledgement that there is some amount of risk exposure, however small.
- ☐ **Costs to Integrate with Utility Grid** – Wind is an intermittent or naturally variable resource, providing energy that can offset more expensive alternatives whenever the wind is blowing. Several studies suggest that actual costs to meet wind variability are more modest than traditional planning models and assumptions would have indicated. The magnitude of the actual integration costs, and how these should be evaluated remains among the more significant debates of utility planners.

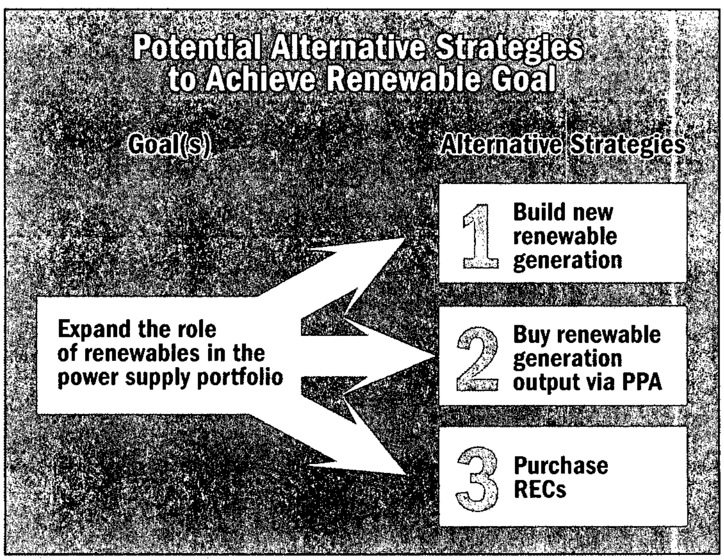
It is also true that for years, experience has shown that despite consumers indicating they will pay more when asked on a survey, the participation in actual green pricing programs runs generally in the range of one to four percent. Higher participation rates have been achieved in programs that have been more aggressively marketed by utilities, especially if this has also involved community and stakeholder organizations. Other research has indicated that customers prefer renewable energy to be paid for out of general rates. Member-owned utilities have achieved higher penetration rates than their investor-owned colleagues, yet many utilities still remain concerned with low penetration rates, and how to apply these results to determine how much renewable energy customers really want, and how much a utility manager should pursue.

Each utility will have a different unique answer for how it should best proceed to expand its use of renewable energy alternatives, depending upon its specific circumstances. For those utilities that have decided they will do "something," the question of how much and how fast is a difficult one to answer, both from an analytical, and public policy perspective. For some utilities, the answer might be a significant investment in a multi-turbine wind farm, for others it might be a single turbine installation, or a geothermal, solar, landfill or other technology application. Others might choose purchasing Renewable Energy Credits (RECs) to offset the impact of their existing generation. A variety of alternate strategies may make sense for particular utilities. Each of these strategies needs to be evaluated separately by each specific utility.

This guidebook is not intended to prescribe any particular solution or direction to any utility. Rather, it is intended to assist each utility manager to walk through the various options and alternatives in an objective, fact-driven manner, and to examine how these alternatives relate to the situation at that specific utility. The guidebook is designed to provide the raw tools and directions to help managers develop a plan that is right for them and them alone.

Evaluating Alternate Scenarios and Choosing a Strategic Path

A range of alternate strategies are available to utilities that have agreed upon a goal to increase the role of renewables in their portfolio. Which particular strategy makes the most sense for any given utility will depend upon a number of different variables, each of which needs to be analyzed. For simplicity of beginning our analysis, we identify three major strategies that a utility can pursue to support the increased use of renewables. Although some combination of strategies is also possible, every path to expand the role of renewables will start with pursuing one of the three strategies shown at right.



Requirements for a Successful Renewable Energy Strategy

Once the utility has identified alternative strategies to achieve its defined goal, then it can then quantify the impact of these strategies in today's uncertain markets by developing different scenarios to quantify the overall cost and impact to portfolio risk, depending upon which scenarios come to pass. The utility can then articulate a set of objectives and implementation plans that have a greater likelihood of acceptance and support from all stakeholders, since the costs and risks are better understood, and there is a correspondingly greater chance of success. Most importantly, the utility will have articulated a plan that makes the most sense for its specific situation.

In conjunction with certain stakeholder desires to simply increase renewable energy resources, advocates may expect management to do this as part of a cost-effective, well designed, and well managed program. Defining and articulating a plan of what the organization is doing and it is heading puts utility management in a position to say "we might be able to do a little more" which is preferable to having to say "we should probably do something."

Given the above considerations, a number of requirements to be successful are illustrated below.

Requirements for a Successful Renewable Energy Strategy

Chapter 2 **Encouraging public participation**	Chapter 3 **Clearly defined objectives**	Chapter 4 **Adequately screening alternatives**	Chapter 5 **Adequate program/project management**	Chapter 6 **Rigorous analysis of cost and risk**	Chapter 7 **Strong implementation planning**
☐ Consistent with corporate strategy, capabilities and values ☐ Support strategic requirements for power supply ☐ Addresses needs and concerns of all stakeholder groups	☐ Achieves any RPS or regulatory requirement ☐ Sets realistic and reasonable targets ☐ Coordinated with strategic plan and company goals	☐ Considers all feasible alternatives ☐ Clear decision-making criteria and process	☐ Properly considers how much, how fast ☐ Provides for flexibility if circumstances change	☐ Analytically sound ☐ Considers alternate scenarios and solutions	☐ Organized and focused project team ☐ Coordinated high level and detailed work plans ☐ Adequately staffed and budgeted to meet goals

The chapters that follow elaborate on each of these important steps to help utility managers and others understand and apply them toward successful solutions.

Chapter 2 — Ensuring Public Participation and Meaningful Governance

This chapter presents opportunities and requirements to build public support for any renewable energy initiative. It is organized into the following three sections.

- Organization governance
- Public participation
- Examples of public participation on renewable energy

Public power is often differentiated from other types of power providers and is generally considered more democratic, locally accountable, driven by purposes other than profit, centered more on customers and more focused on the long term.

Consumers need and want an opportunity to participate in the decision processes on renewable energy. Public participation brings many benefits including improving the quality of decisions, reducing risks of delay and costs for contentious decisions and maintaining credibility and legitimacy.

There is a demonstrable increase in the public's interest in renewable energy. One indicator of this interest is the growth of green pricing programs and the public participation in those programs. While studies suggest that the marketing of those programs could still be improved, they are becoming a more frequent customer offering, particularly among member-owned utilities. The chart below shows participation rates for the leading green pricing programs as found in a recent National Renewable Energy Laboratory (NREL) study. It is noteworthy that many of the leading programs are offered by member-owned utilities.

Top Ten Green Pricing Programs in Participation Rate[1]

Utility	Participation Rate	Start Date
Lenox Municipal	11.1 percent	2003
City of Palo Alto Utilities	6.6 percent	2003
Moorhead Public Service	5.5 percent	1998
Holy Cross Energy	5.1 percent	1998
Montezuma Municipal Light and Power	4.9 percent	2003
Orcas Power and Light	4.9 percent	1999
Fairbanks Municipal Utilities System	4.7 percent	2003
Sacramento Municipal Utility District	4.6 percent	1997
Central Electric Cooperative	4.1 percent	1999
Madison Gas & Electric	3.9 percent	1999

Source: National Renewable Energy Laboratory, "Top Ten Utility Green Pricing Programs," April 19, 2004.

Organization Governance

Ensuring public participation is ultimately a responsibility of the public utility board of directors. John Carver, a leading expert on governance, suggests that directors should be in frequent contact with the public's concerns, if directors represent owners-consumers.[2] Since directors represent the owners, Carver proposes that board members are morally, although not necessarily legally, responsible for the outcomes of their decisions. Thus, the challenge for the board is to determine how much to be involved in the renewable energy policy process relative to other participants, including the public, the chief executive officer and the staff.

The board must strike a balance between governance and management or between macro policy direction and organization micro-management. According to American Public Power Association briefings, the board has five functions:

☐ Set strategic direction

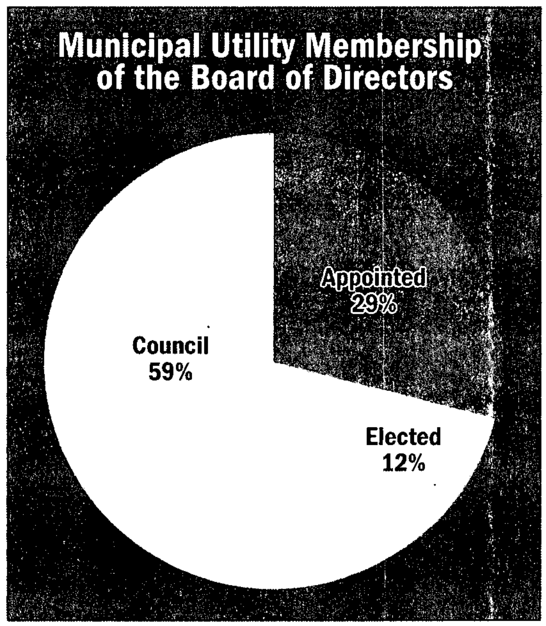
☐ Approve operating policy

☐ Monitor organizational performance

☐ Assure an effective chief executive

☐ Assure effective board performance

To some extent, how much the board becomes involved in renewable energy strategy may be affected by how its directors are selected. An APPA survey in 2001 found that 59 percent of utility boards serve dual roles as city council members. Some 29 percent are appointed and just 12 percent are elected directly as members of the board of directors for the utility. For utilities of fewer than 5,000 customers, the city council serves as the board in 71 percent of the cases.



Source: America Public Power Association "Governing in a Changing Marketplace," Scottsdale, AZ, January 2004.

In matters of policy governance, it is important to distinguish between ends and means. The "ends" are the outcomes for which the organization exists and the owner-consumers are served. It is the duty of the board of directors to approve ends in an affirmative and prescriptive way.

The "means" include the activities, practices, methods, technology, conduct and procedures employed by company management. The role of the board is a limiting or proscriptive one, providing boundaries within which management and staff are directed to achieve the "ends." This is often articulated in vision and mission statements.

Ten ends or goals of progressive public power organizations were identified by an APPA task force in a 2002 report, "Public Power in the 21st Century." Renewable energy policies can help meet at least seven of these progressive goals including:

☐ Provide superior customer service

☐ Deliver value through power supply management

☐ Keep the public in public power

☐ Optimize community infrastructure synergies

☐ Lead in environmental stewardship

☐ Build consensus in democratic leadership

☐ Invest in future technologies

The functions of the CEO can be summarized as recommending strategic direction, developing operating policies for approval and reporting on organization performance. The level of involvement by the Board must be considered for many issues such as:

☐ What should be the objectives in supplying power resources?

☐ How should renewable resources be evaluated relative to other resources?

☐ How should goals be defined for renewable resources?

☐ How should decisions be made about what resources should be acquired,

☐ How much should costs be included in general rates?

☐ Who is authorized to acquire resources and under what conditions?

☐ What is the role of the public in these and other issues?

Public Participation

Public participation refers to "any process that involves the public in problem-solving or decision-making and uses public input to make decisions."[3]

The "public" will vary from situation to situation. In one situation, it may be just a few people most directly impacted, such as landowners. In another, it may be the people living near the landowners. The public could be all the people concerned about a particular issue, such as rates or the environment. Vendors of renewable energy products and services may also be considered part of a public participation process, both for their corporate interests, as well as their interest in the welfare of the community.

In addition to individuals, groups may be interested and affected. Registered groups as well as informal or ad hoc groups could be involved in public participation, including government agencies, business associations, non-profit groups and community groups.

Decision-makers need to consider the critical components of public participation in order to be comfortable with the process. Effective public participation is based on values, oriented toward decisions and driven by objectives. Critical components include:[4]

☐ Clarify the decision and decision-making process

☐ Develop full understanding of who needs to be involved

☐ Define the appropriate level of public participation

☐ Understand and accept the core values of public participation

☐ Design a public participation process reflecting values and resources

☐ Evaluate and adapt, continuously

In planning on public participation, it is helpful to ask: "Who are the people who see themselves as affected by or interested in a decision?" Factors for utility managers to consider in public participation include the following:

☐ Proximity	Who might be directly affected due to geography?
☐ Economics	Who might bear the costs?
☐ Participation	Who perceives that they will benefit from the program or service?
☐ Impacts	Who perceives they will benefit or suffer indirectly from environmental, economic, or social impacts?
☐ Implementation	Who has legal and organizational responsibility?

Then is it helpful to determine the appropriate objective in serving those individuals and groups. At least five levels of involvement are considered when conducting a public participation process:[5]

☐ Inform: promote awareness and provide education

☐ Consult: seek broad-based input and feedback

☐ Involve: foster meaningful discussion

☐ Collaborate: facilitate consensus

☐ Empower: provide forum for public decision

Where the level is to inform, a distinction may made between building awareness and providing education. Awareness is built through such techniques as advertising, bill stuffers, brochures and fliers. Education is provided through more elaborate and involved techniques such as fact sheets, newsletters, technical reports and Web sites.

Where the level is to consult, a distinction may be made between bringing people together vs. collecting input and obtaining feedback. Techniques for bringing people together include open houses, fairs, events and study circles. Techniques for collecting input and obtaining feedback include questionnaires or opinion polls, comment forms, interviews, focus groups, and deliberative polls.

Summarized in the table on page 10 is a matrix of the public participation levels of involvement and the tools or techniques commonly used. They are grouped to also show the format purposes, such as providing information and bringing people together.

The following section in the chapter includes a couple of examples of tools used in public participation.

Public Participation Framework

Format	Techniques	Levels of Involvement[6] Inform	Consult	Involve	Collaborate	Empower
Awareness	Advertising	✓				
	Bill stuffers	✓				
	Brochures	✓				
	Displays	✓				
	Fliers	✓				
	Kiosks	✓				
Education	Fact sheets	✓				
	Information centers	✓				
	Newsletters	✓				
	Public access TV	✓				
	Technical reports	✓				
	Web sites	✓				
Bring people together	Tours	✓				
	Symposia/panels	✓				
	Open houses		✓			
	Fairs		✓			
	Events		✓			
	Briefings		✓			
	Workshops		✓	✓		
	Town meetings		✓	✓		
	Advisory committees		✓		✓	
	Task forces		✓		✓	
	Deliberative polls		✓		✓	
Collect input and feedback	Focus groups		✓			
	Questionnaires		✓			
	Citizen juries					✓
	Voting					✓

Source: International Association for Public Participation. Techniques for Effective Public Participation Student Workbook ©2002. Used with permission.

Public Participation and Renewable Energy

Opinion Polling. Numerous customer opinion surveys have been conducted on renewable energy. Whether focused on individual utilities or covering the nation, these surveys provide similar results about customer interest in and willingness to pay for renewable energy. These survey results may be summarized as follows:[7]

- ☐ There is a long standing preference among adults and electricity consumers in the United States for renewable energy over other energy sources.
- ☐ Consumers may not be knowledgeable about renewable energy, unless they participate in a specific program.
- ☐ In more than 50 percent of the responses, consumers profess a willingness to pay additional amounts for renewable energy, if price is not mentioned.
- ☐ When price is mentioned, 75 percent say they are willing to pay at least $5 per month for electricity from renewable sources.

- When asked to pay more individually for a green energy program or spread the costs among all ratepayers, most respondents preferred modifying general rates to spread the costs among all ratepayers.

Deliberative Polls Because consumer opinion polls are relatively spontaneous where respondents have little time to ponder the questions, another type of polling has been practiced. Deliberative polls have been characterized as "informed" surveys and have been employed to assess consumer attitudes on renewable energy, in a three part process.

- First, a random sample of customers is surveyed by telephone with a set of questions on renewable energy and its costs, relative to other resource choices.
- Second, an all-day education and discussion town meeting is facilitated for a subset of participants among those surveyed who are willing become more informed.
- Third, the same poll is offered again to meeting participants with the expectation that the results will be more representative.

Nebraska Public Power District conducted a deliberative poll on alternative energy resources in 2003.[8] The telephone survey reached 1,351 customers. Then 109 of the survey participants attended an all-day session with a professional facilitator. Meeting participants received an information package prior to attending.

At the meeting, the central question asked of the participants was whether to pursue 200 MW of wind energy, equivalent to 5 percent of capacity by 2010. In the process, other information was gained and exchanged about values and choices. Results included:

- 96 percent agreed with the plan to pursue wind energy, even at a bill increase of $1 to $2 per month.
- 81 percent agreed to obtaining 5 MW through methane from animal waste.
- 94 percent, believed new resources should be paid for by all customers.

The meetings also offered an opportunity to compare values and choices before and after the event. Values deal with such matters as the importance of cost, reliability, availability and environment. Choices relate to priorities such as lowest cost, highest reliability and more renewable energy resources relative to fossil resources. Values changed less than choices in the deliberative polling process.

Regarding values, participants increased the importance of availability, reliability, economic development and environment, after the workshop. Regarding choices, support increased for energy efficiency, wind, coal and natural gas resources. Respondents' support for solar and methane from animal waste declined after the workshop.

These findings are consistent with a series of deliberative polls conducted in Texas in 1996 to 1998.[9]

While questions may be raised about deliberative polling, participants consider the process valuable, fair and balanced. There are, of course, costs to consider with any of these techniques. Rather than use one tool, some utilities have found it cost-effective to deploy a combination of tools such as focus groups, survey questionnaires and evening meetings to meet public participation objectives.

This chapter addresses some considerations involved in defining renewable energy objectives. It reviews companies that have recently reassessed their perspective on renewable energy and discusses how renewable energy objectives can be established using a common strategic planning framework. It is organized into the following two sections:

- ☐ Reassessing renewable alternatives
- ☐ Alternate approaches to developing a strategic vision

Reassessing Renewable Alternatives

Many energy companies around the world and in the United States have recently made strategic announcements indicating a fundamental shift in how they regard renewable energy alternatives. These companies include some of the leading global energy companies as well as investor-owned and public power utilities. While they have each reached these conclusions for different reasons and applying different decision criteria, the inescapable fact remains that they are all independently reaching the same conclusion; namely, that renewable energy alternatives are increasingly attractive from a cost perspective, and that this will result in a growing use of renewables on the part of electricity consumers.

Global Energy Companies

Many of the companies announcing a revised strategic perspective on renewable energy are among the most highly regarded companies in the world for their strategic planning capability. Their planning processes' are regarded as comprehensive, fact-driven and analytically robust. They often developed this new perspective on renewables quietly, as part of an ongoing strategic planning process, and announced it to the world by way of a major capital investment. These actions have caused other companies and investors to challenge and reassess how they themselves viewed the future of renewable energy. Examples[1] of these companies include:

- ☐ General Electric's building a $1.3 billion renewables business group following its acquisition of EnronWind Corp for $358 million in 2002. This was further increased by its acquisition of AstroPower Inc., a leading manufacturer of solar products in March 2004
- ☐ Royal Dutch/Shell's acquisition of Siemen's solar business in 2002, which was accompanied by the development of Shell WindEnergy into one of the world's largest wind developers
- ☐ BP Amoco's investment in the BP Solar business group which operates in 160 countries and has an estimated 17 percent share of the world's solar market
- ☐ FPL Energy growing to become the U.S.'s largest producer of wind energy with 2,700 MW operating in 15 states

Member-Owned Utilities

Member-owned utilities operate in a significantly different environment than energy companies and investor-owned utilities. Probably the biggest difference is that member-owned utilities "enjoy" a much more open planning process that involves consideration of a much wider range of stakeholder discussions and concerns.

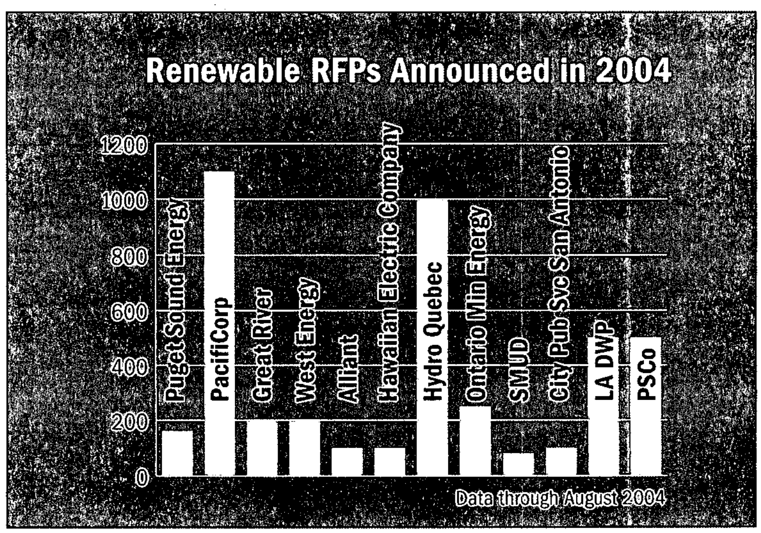
Member-owned utilities are run by elected or appointed officials who tend to listen much more closely to what their stakeholders, (or voters) want. Traditionally, cost of service is among the most important considerations for these stakeholders. However, other considerations such as economic development, growing environmental concerns, or the influence of vocal political constituencies, have resulted in many member-owned utilities announcing new goals and strategies related to renewable energy. While these utilities all had some degree of planning and analysis supporting their announced strategies, they were also motivated to respond to a growing voice from their consumer owners to become more proactive regarding renewable energy, and to "do something," rather than waiting for every single uncertainty to be analyzed. Some of these member-owned utilities are:

- ☐ City of Austin Utilities
- ☐ Sacramento Municipal Utility District
- ☐ Fort Collins Utilities
- ☐ City Public Service of San Antonio
- ☐ Waverly Light and Power
- ☐ Richmond (Ind.) Power & Light

Investor-Owned Utilities

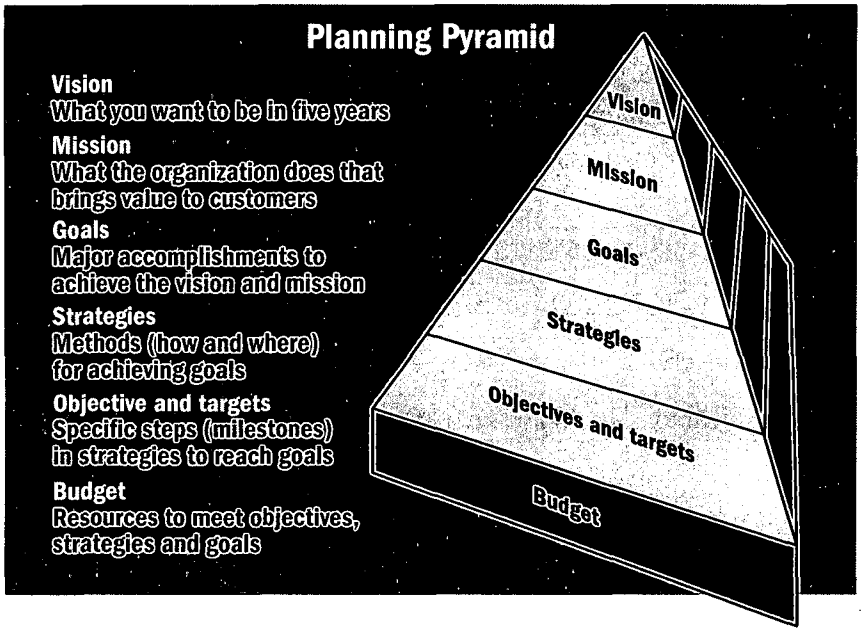
Several large investor-owned utilities have also revaluated renewable energy alternatives. Particularly in states where deregulation had stalled, utilities had often deferred their generation plans and now were contemplating large scale supply-side additions to their portfolios. In some of these cases, utilities as part of their Integrated Resource Planning or Least Cost Planning process, formally evaluated all supply-side alternatives. When they conducted IRP/LCP evaluations, renewable alternatives emerged as a significant component of their announced long term strategy, primarily for economic reasons. The chart below shows announced renewables-only solicitations for energy issued through June 2004.

These examples describe three vastly different kinds of organizations that have independently determined that current circumstances and trends make a compelling case for renewable energy options in today's energy markets. Whether it is a Fortune 500 company renowned for strategic planning expertise, IOUs looking for the most economically favorable resource alternative, or public power organizations responding to social and environmental concerns of their stakeholders, they have reached the same conclusion. This creates a moment in time when every utility manager should be asking if there is some reason not to be doing the same.



Alternate Approaches to Developing a Strategic Vision

A wide range of different approaches and techniques are available to develop a strategic vision and supporting goals and strategies. These different approaches are well-researched and a great deal of information is available on them outside of this guidebook. Each of these alternate approaches has its own merits, advantages and disadvantages that utility managers need to assess. Most approaches however, have similar components. APPA defined six components of a strategic planning process in its January 2004 Policy Maker's Workshop. These components are sometimes presented as a pyramid, since each layer builds upon the others to define a framework for planning and budgeting purposes that help achieve the defined vision. An illustrative pyramid is shown at right:



In almost every case where an organization achieves significant progress against any strategic goal, it has reinforced its commitment with clear goals and targets. This is not to say that an organization cannot achieve its goals without explicitly defined targets, but the likelihood of success is increased when the organization, its employees, customers and other stakeholders all recognize the depth of its commitment. When all of these groups understand, and have alignment on the goals and direction that the organization has committed to pursuing, then significant progress is generally achieved.

This guidebook presents an approach to developing a renewable energy strategy. The guidebook has adopted the APPA Planning Pyramid as a reference for terminology and structure and uses it to help build a renewable energy strategy. While the approach described is focused exclusively on renewable energy issues, it could easily be integrated into the other components of a utility's overall strategic planning process.

For the purpose of this guidebook, it will be helpful to define a renewable energy goal to build upon in later chapters. This goal could also be incorporated into a vision statement. The decision of how prominently to elevate the statement of renewable goals is one that needs to be made by each utility during its planning process.

Each utility will need to assess its situation, and after analyzing the data and potential scenarios, it might change the text or targets we have suggested, but defining the goals, strategies, and objectives should be a helpful learning tool. For the purpose of providing illustration and direction in future chapters of this guidebook, the following two goals are assumed for a utility seeking to expand the role of renewables in its portfolio.

Chapter 4 - Screening Renewable Energy Alternatives

This chapter reviews the many opportunities available in renewable energy technologies. A robust planning process starts with identifying all feasible options to reduce the risks of overlooking real possibilities. Reviewing the universe of renewable energy opportunities also increases the confidence of stakeholders that all reasonable opportunities have been considered. This chapter is organized in three sections:

- Utility scale renewable energy technologies
- Customer scale renewable energy technologies
- Options screening

Renewable energy resources are defined as energy resources that are constantly replenished and will never run out. Non-renewable energy resources, in contrast, are resources that will eventually dwindle.

Renewable technologies may be categorized by type of energy source. These include:

- Wind
- Geothermal
- Bioenergy
- Solar
- Hydro
- Oceans
- Hydrogen

This listing reflects the relatively increase in renewable energy resources in the years ahead and is the basis for organizing the remainder of the chapter. Wind is forecast to be the largest source of renewable energy followed by geothermal and then bioenergy including biomass and landfill gas.

On a national basis, the U.S. Department of Energy forecasts the addition of more than 18,000 MW of renewable energy resources from 2001 to 2025. It is noteworthy that more than half of the planned resource is driven by legal and regulatory mandates, including renewable portfolio standards (RPS).

U.S. Renewable Energy Generation in MW

Energy Source	2002	2025	Increase
Wind	4,830	15,990	11,160
Geothermal	2,890	6,840	3,950
Biomass	1,830	3,740	1,910
Landfill gas	3,490	3,950	460
Hydro	78,290	78,680	390
Solar PV	20	410	390
Solar thermal	330	520	190
Total	91,680	110,130	18,450

Source: U.S. Department of Energy, EnergyInformation Agency, Annual Energy Outlook 2004.

Utility Scale Renewable Energy Technologies

Utility scale renewable technologies refer to resources targeted for acquisition and use by electricity suppliers. These are typically larger systems providing more energy than needed by individual homes and businesses.

Wind Energy

Wind is created by the uneven heating of the atmosphere by the sun. Wind currents turn two or three blades connected to a rotor that drives a generator, either directly or through a step-up gear box. There are two general types of wind turbines:

Vertical axis. Vertical axis wind turbines have advantages such as being able to place the generator and gearbox on the ground. A principal disadvantage is that they are shorter and capture wind closer to the ground where speeds are lower and turbulence is higher.

Horizontal axis. Horizontal axis wind turbines place their generator and gear box behind the blades that are elevated to catch higher wind speeds. They are the most common wind energy machines. They may be categorized by size.

Large turbines [500 kW to 6 megawatts (MW)]: used as central-station wind farms, distributed power and offshore wind generating stations.

Intermediate turbines [10 kW to 500 kW]: used for village power, hybrid systems and distributed power.

Small turbines [less than 10 kW]: used for on-site or remote applications such as battery charging, water pumping and telecommunication sites.

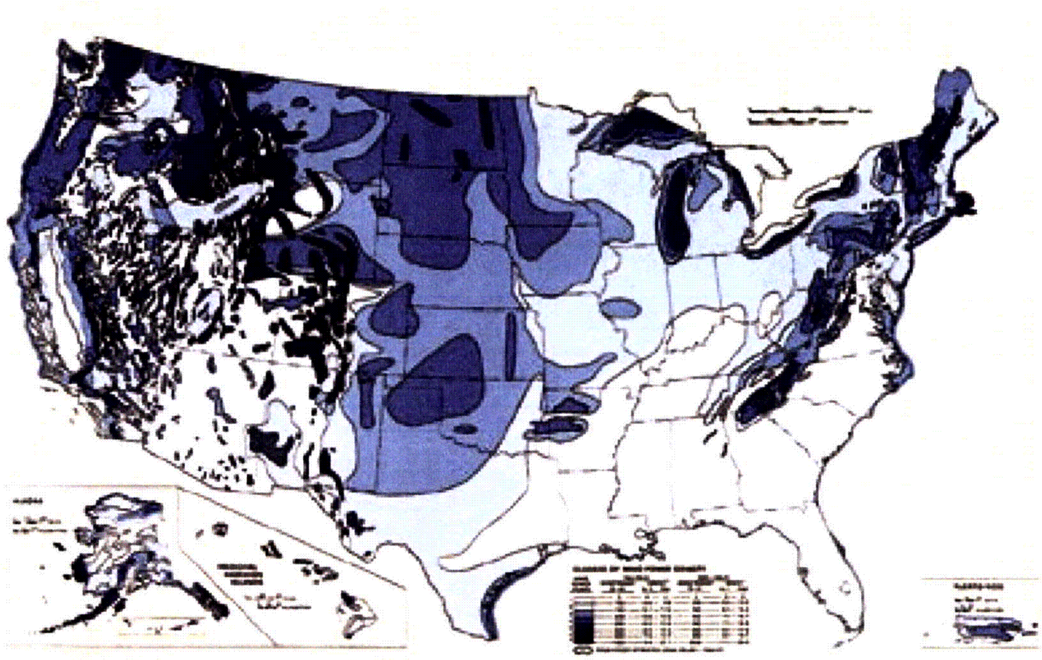
Good wind areas, which cover 6 percent of the contiguous U.S. land area, have the potential to supply more than one and a half times the current electricity consumption of the United States.

Estimates of the wind resource are expressed in wind power classes ranging from class 1 to class 7, with each class representing a range of mean wind power density or equivalent mean speed at specified heights above the ground. Areas designated class 4 or greater are suitable for the advanced wind turbine technology under development today. Class 3 areas may be suitable for future technology. Class 2 areas are marginal and class 1 areas are unsuitable for wind energy development.

Because techniques for wind resource assessment have improved greatly in recent years, work began in 2000 to update the U.S. wind atlas. The work will produce regional-scale maps of the wind resource with resolution down to one square kilometer. The new atlas will take advantage of modern mapping techniques. It will also incorporate new meteorological, geographical and terrain data. Advanced mapping of the wind resource is another important element necessary for expanding wind-generating capacity in the United States.

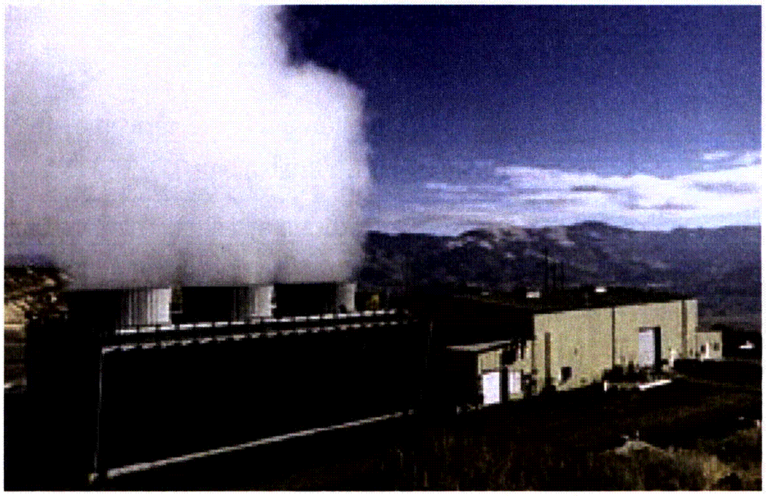
The figure below shows the relative distribution of wind resources across the United States. More detailed maps for individual states are also available at WindPowering America's web site at **http://www.eere.energy.gov/windpoweringamerica/**. WindPowering America maintains an active catalog of wind resource maps with a number of interactive features that allow zooming in to more detailed geographical areas that might be of further interest.

United States Annual Average Wind Power



Source: U.S. Department of Energy, Wind Energy Resource Atlas of the United States.

Geothermal Energy



Geothermal energy is heat from beneath the earth's surface, usually a couple of miles or more underground. There are three types of geothermal power plants: dry steam, flash steam and binary cycle.

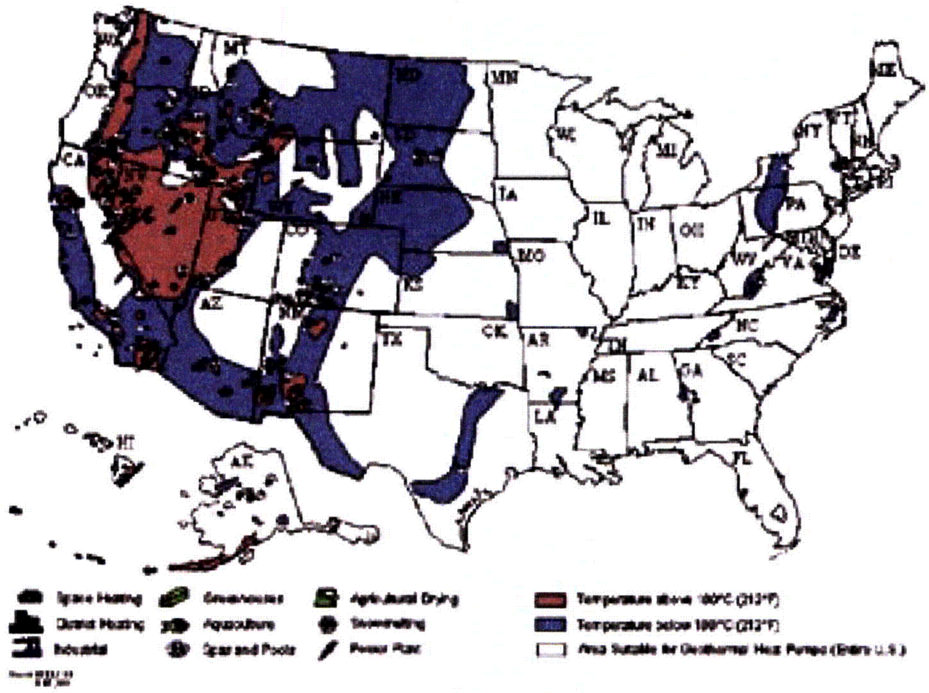
Dry steam: Steam is piped directly from underground wells to the power plant, where it is directed into a turbine generator unit. No boilers or fuel are needed. The Geysers in California is the only domestic commercial operation.

Flash steam: Hot water at a temperature of more than 360° F flows up through wells in the ground under its own pressure. As the hot water rises, its pressure decreases and some of the hot water boils into steam. The steam is separated from the water and used to power a turbine generator. Leftover water and condensed steam are injected back into the reservoir, making this a sustainable resource.

Binary cycle: Operates on water at temperatures of 225° to 360° F. Heat from the hot water is used to boil a working fluid, usually an organic compound with a low boiling point. The working fluid is vaporized in a heat exchanger and used to turn a turbine. There are little or no air emissions as the water and working fluid are kept separate.

The Idaho National Engineering and Environmental Laboratory maintains geothermal resource maps for individual states and the country. A map showing the distribution of geothermal resources across the entire United States is shown below.

U.S. Geothermal Projects and Resource Areas



Source: Idaho National Engineering and Environmental Laboratory, GeoHeat Center, April 2004.

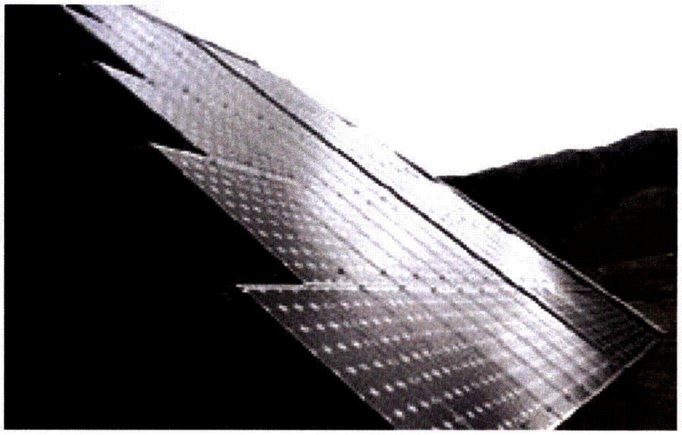
Solar Energy

Solar energy is characterized by two general types of systems: photovoltaic solar cells and solar thermal arrays.

Photovoltaic systems. These systems convert sunlight or "photons" into electricity or "voltage" for a "photovoltaic" effect. The conversion takes place in solar cells of semi-conducting materials similar to those used in computer chips. The solar energy knocks electrons loose from their atoms, thereby allowing electrons to flow through the material to produce electricity. Solar cells can be arranged into several types of systems.

Flat plate collectors: silicon wafers or solar cells that are 150 to 300 microns thick are combined into modules and about 10 modules are mounted onto flat arrays. The arrays can be mounted at fixed angles to the sun or on a tracking device that follows the sun. Both direct and diffuse sunlight are converted into electricity at an efficiency of about 13 percent with current technology and greater than 16 percent in the future. Electric storage may be added to the array, such as with batteries. Small arrays can serve individual structures, while large arrays can be interconnected with the electric grid.

Photovoltaics concentrator: lenses, such as Fresnel lenses, with mirrored dishes focus sunlight on solar cells especially designed for concentrated sunlight. A principal advantage of this technology is reduction in the amount of expensive conducting material. However, only direct sunlight can be used. It is important then to design tracking systems to focus the sunlight.



Solar thermal power systems. Just as conventional power plants boil water to create steam to run through a turbine and generate electricity, solar energy can also be harnessed with similar effect. Three types of solar power systems use reflector principles to concentrate solar energy.

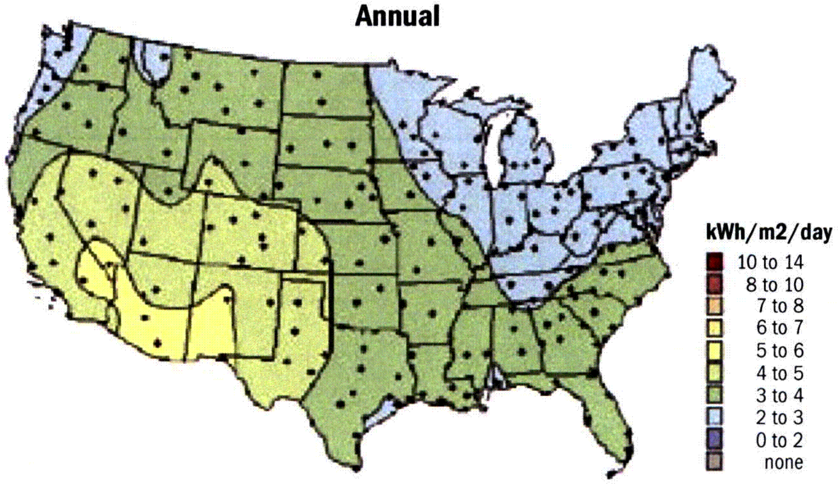
Solar power towers: Sunlight is reflected from mirrors to a thermal receiver on a tower. A working fluid, such as molten nitrate salts in the receiver, absorbs the heat energy and is sent to a turbine generator. The fluid may also be sent to a storage tank and then onto a heat engine to meet peak electric loads or continuous operation of the solar system, including after sunset.

Solar thermal parabolic troughs: Sunlight is reflected from mirrors onto specially coated metal pipes inside vacuum insulated glass tubes, all suspended above the mirrors. The pipes contain a heat transfer fluid, such as synthetic petroleum, that is heated, and is then passed through a heat exchanger to generate superheated steam to power a conventional steam turbine electric generator.

Solar thermal parabolic dishes: Sunlight is reflected from a parabolic mirror array to a focal point for each dish. The energy may be converted directly, such as in a Stirling cycle heat engine, or to heat a working fluid piped to a central engine.

A map showing the distribution of solar resources across the United State is shown below.

Average Daily Solar Radiation Per Month
Annual



Source: National Renewable Energy Laboratory, National Solar Radiation Database. Dots on the map correspond to 239 NSRDB sites.

Hydropower

Hydropower resources convert energy contained in falling or flowing water into electrical energy through the use of a turbine and generator. Several types of hydropower may be distinguished.

Impoundment: A dam on a river stores water in a reservoir that is released through a turbine to produce electricity. Water releases may be managed to meet changing electricity needs or for agricultural, recreational or other needs.

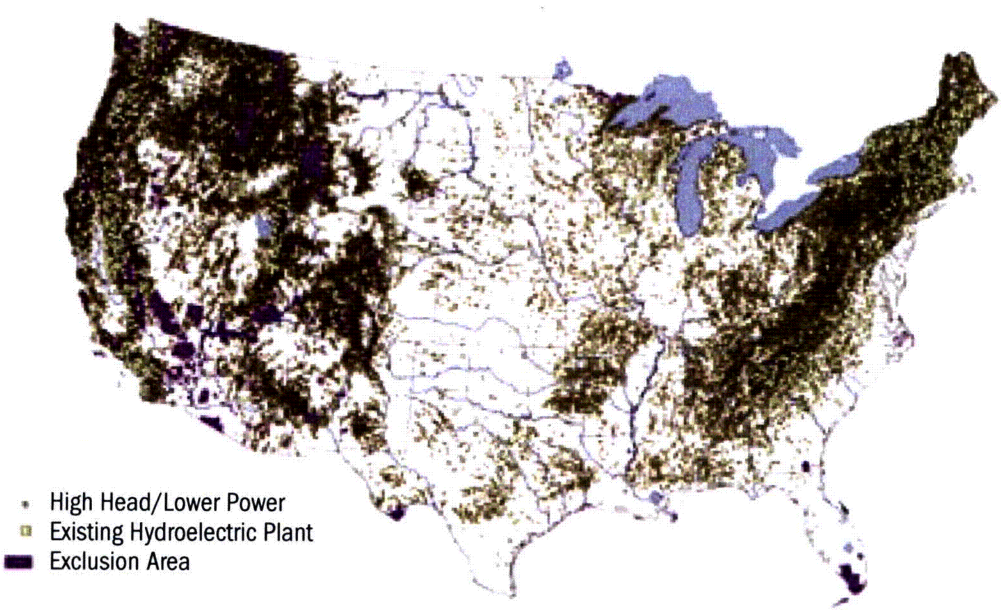
Diversion or run-of-river: A portion of a river is diverted through a canal or penstock and run through a turbine. The turbine spins a shaft which may be used to run a generator or to operate mechanical equipment such as a water pump.

Water pressure relief: Excess pressure within conveyance systems is released with the use of a microturbine and generator.

Pumped storage: When demand for power is low, water is pumped from a lower to a higher reservoir by having generators reverse the turbines; when demand for power is high it is released from the upper to the lower reservoir thereby spinning the turbines to activate the generators.

Hydropower may be further distinguished by size. Large hydropower is defined by the U.S. Department of Energy as capable of providing 30 MW of power. Small hydropower is from 30 MW down to 100 kW. Micro hydropower is below 100 kW. Since many municipal power agencies are also in the water business, they may have unique opportunities to capture renewable energy benefits from hydro resources.

The geographic locations of low head/low power potential sites in the conterminous United States are shown below. In this figure, different color symbols are used to designate sites of power potential corresponding to each of the three classes of low head/low power technologies. Areas in which hydropower development is excluded because of federal statutes and policies are also shown. The map is intended to show the relative density of power potential. The symbols are larger than the actual extent of the stream reach containing the potential they designate, so that the density of symbols gives a distorted image of the actual density of the stream reaches.



Source: U.S. Department of Energy, Water Energy Resources of the United States with Emphasis on Low Head/Low Power Resources, April 2004.

Bioenergy

Bioenergy comes from renewable biomass resources used to produce a variety of energy related products. These products include: solid, liquid and gaseous fuels; heat; chemicals; and electricity. Biomass resources include: dedicated energy crops and trees, agricultural food and feed crops, agricultural wastes and residues, forest and wood wastes and residues, aquatic plants, and animal wastes. One of the most common bioenergy resources is municipal solid waste with its potential for landfill gas production. Another opportunity for municipalities is to capture and use methane generated in the sludge disposal process in waste water treatment plants.

Biopower technologies take biomass resources and convert them to power generation. Multiple energy conversion processes are available.

Direct combustion: Biomass is burned with excess air to turn water into steam to drive turbine generators to produce electricity.

Co-firing: Biomass resources are mixed in the boiler with conventional fuels to produce electricity from steam turbine generators.

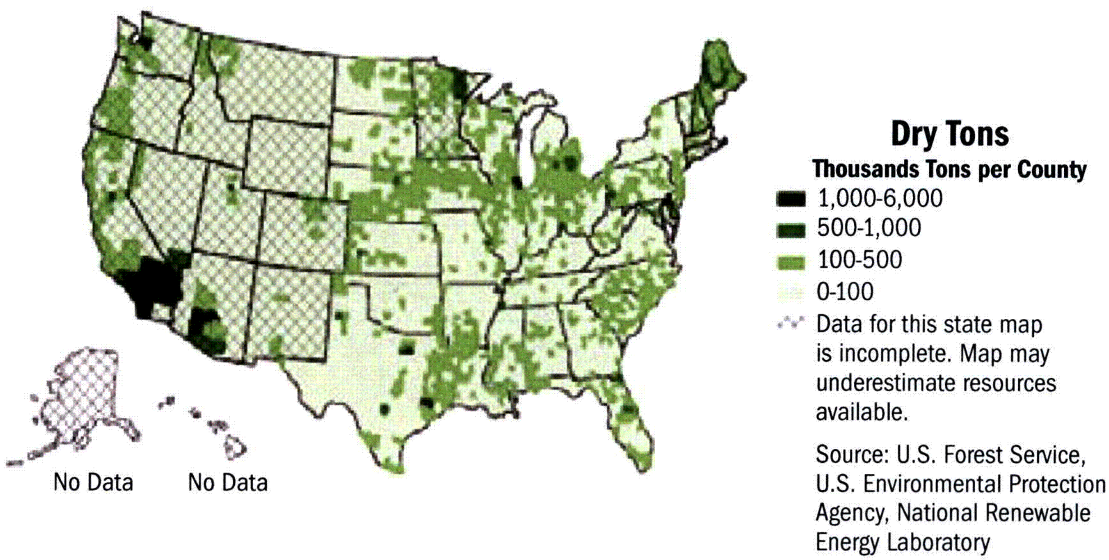
Anaerobic digestion: Organic matter is decomposed by bacteria in the absence of air producing methane and other fuel products available that can be used for energy production.

Cogeneration: The combustion of biomass resources is used to generate electricity and to provide process steam or hot water.

Gasification: Biomass is heated in an oxygen-starved environment to produce a medium or low calorific gas. This biogas can be used as a fuel in a combined cycle power plant that includes a topping and a steam turbine bottoming cycle.

Pyrolysis: Biomass is heated in the absence of air to decompose biomass. The end products of pyrolysis is a mixture of solids (char), liquids (oxygenated oils) and gases (methane, carbon monoxide and carbon dioxide).

A variety of other biofuels can be made from biomass resources. These include: ethanol, methanol, biodiesel, hydrogen and methane. While most of these fuels are finding use in transportation applications, opportunities also are being found in direct energy production, such as biodiesel in diesel generators. A map showing the distribution of biomass resources across the United States is shown below.



Please note that biomass availability can very significantly from one locality to the next. These map is intended to provide a general indication of a region's biomass availability. Only municipal waste, mill and forest residues and select crop residues are considered in this map. Some areas not shown on the map that are near urban or manufacturing centers, or areas with agricultural residues that have not been considered, may have excellent biomass resource availability.

Oceans

Ocean energy draws on the energy in ocean waves, tides and the thermal energy stored in the ocean. Two principal technologies convert ocean energy into electric power.

Tidal energy: A dam is placed across an opening of a tidal basin and water is directed flow through a sluice into the basin. The sluice can be closed while the tide drops and then the water releases through conventional hydropower technologies to produce power.

Ocean thermal. Advantage is taken of the temperature differences at different levels of the ocean. Closed-cycle systems circulate a working fluid in a closed system, heating it with warm seawater, flashing it to vapor, routing the vapor through a turbine, and then condensing it with cold seawater. Open-cycle systems flash warm seawater to steam and route the steam to a turbine. Hybrid plants flash warm water to steam and use the steam to vaporize a working fluid in a closed system. Various versions of ocean thermal systems are land-based by mounting on the ocean shelf or offshore as floating plants.

Hydrogen

Hydrogen is found in many organic compounds, as well as in water. It is the most abundant element on the Earth, but it does not occur naturally as a gas. It is always combined with other elements, such as oxygen to make water. Once separated from another element, hydrogen can be burned as a fuel or converted into electricity.

Hydrogen can be produced from numerous hydrocarbons including gasoline, natural gas, methanol, propane and even coal. Hydrogen may also be produced from water by electrolysis. Hydrogen has the highest energy content of any fuel and produces almost no pollution.

In the future, hydrogen could join electricity as an important energy carrier. The energy for producing hydrogen can be produced from renewable resources including wind and solar. It can then be stored and moved to provide energy to consumers.

Customer-Scale Renewable Energy Technologies

Renewable energy technologies are also available for buildings such as for businesses and homes. A utility should be aware of these options and may encourage their adoption.

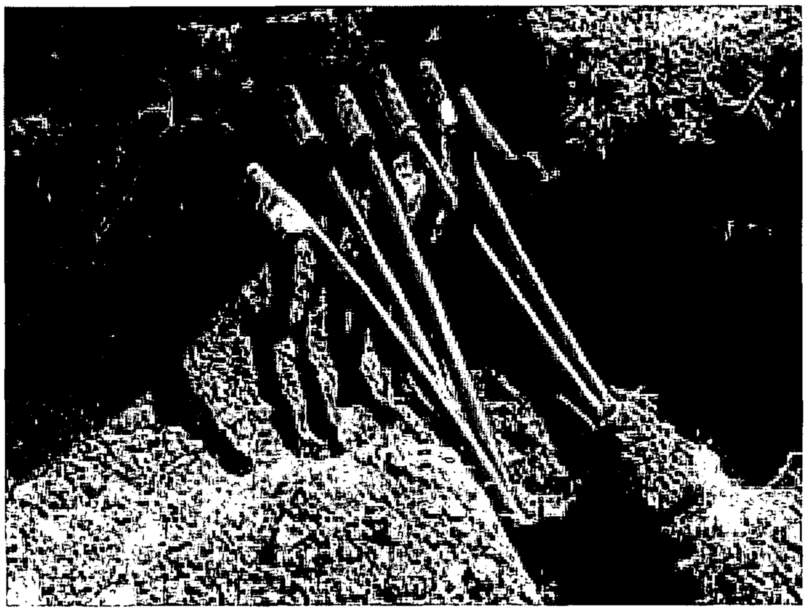
Solar water heating — active: Sunlight heats water or other heat transfer fluid in collectors which is then pumped to storage tanks. The system involves controls, sensors and pumps. Drainback systems send the water back from the collector to the storage tank when pumping stops. Draindown systems send water into storage whenever freezing conditions occur.

Solar water heating — passive: Sunlight heats water or a heat transfer fluid that send the water by convection to storage tank located above the collector until needed. Called thermosyphon systems, there are no moving parts and they may have electric heaters for freeze protection.

Passive solar design: Buildings are designed to maximize useable solar heat. Techniques include south-facing windows, moveable insulation, walls and floors to absorb heat, white roofs to reflect heat, sunspaces, greenhouses, overhangs, shades, landscaping and vents.

Transpired collectors: Air is preheated for ventilation. A transpired collector consists of a black metal panel mounted on a south-facing wall to absorb the sun's heat. A space behind the perforated wall allows the air streams from the tiny holes to mix together. The heated air is then sucked from the top of the wall space into the ventilation system for the building, such as for warehouses and airplane hangers.

Geothermal direct use: Heat is provided directly from geothermal reservoirs of hot water. In addition to time-honored uses for bathing and cooking, modern uses include heating buildings, heating whole towns or groups of buildings, raising plants in greenhouses, drying crops, serving fish farms, and some industrial processes, such as pasteurizing milk.



Geoexchange heat pumps: Heating, cooling and water heating can be provided by a system including a heat pump, ground loops, and a distribution system, such as ductwork, in the building. Earth-coupled geoexchange heat pumps treat the ground as a heat source or sink with a liquid circulating to provide heat transfer. The fluid may be water or a mixture of water and antifreeze. Typical applications include homes and commercial buildings of various types, but usually those with sufficient land area. Water-source geoexchange heat pumps operate with water from a well, stream or pond.

Photovoltaic systems: Photovoltaic systems convert sunlight to electricity. Smaller applications for buildings are typically flat plate or thin film photovoltaic designs. Thin film solar cells are semiconductor material of only 1 to 10 microns thick and are attached to inexpensive backing materials. Numerous applications include metal or glass, allowing them to double as rooftop shingles, roof tiles, building facades, and even skylights. Efficiencies range from 5 percent to 11 percent, although, layering thin-film materials on top of each other may allow conversions of more than 15 percent of sunlight into electricity. Systems can be scaled up to meet internal building use during peak hours as well as send excess electricity into the utility grid.

Small wind turbines: These are typically horizontal axis wind systems of less than 10 kilowatts designed to meet electrical use through on-site generation. However, systems could also be grid connected.

Fuel cells: Fuel is converted to electricity through chemical processes without combustion. Fuel cells are not renewable energy technologies as such. However, fuel cells are considered renewable technologies, when a renewable fuel such as methanol from biomass or hydrogen is employed.

Option Screening

Choices must be made in selecting among numerous renewable energy options due to limitations of time and money to perform the analyses. Several criteria may be considered in screening options down to those most applicable to a particular utility, including:

- **Resource availability:** Is the resource available in the utility service territory or in relative proximity? For example, geothermal resources are not readily available in many parts of the country. However, landfill gas resources are commonly available.
- **Resource size:** Is the available resource of sufficient size to be considered? When it comes to renewable resources, even small size projects can be considered, including wind and solar.

- ☐ **Technology maturity:** Is the renewable technology commercially available? Some technologies are still being refined through research and demonstrations.
- ☐ **Capacity factor:** What is the energy output relative to the potential output? Intermittent renewable energy resources have lower capacity factors than dispatchable units.
- ☐ **Economically competitive:** How do the costs compare to conventional resources? Even if some renewable technologies cost more, customers may be willing to pay a premium. Cost comparisons need to recognize that capital costs may be higher for renewables but operating costs may be lower.
- ☐ **Resource diversity:** How much does the resource add to supply diversity? Renewable resources can add diversity and reduce price risk associated with traditional energy supplies.
- ☐ **Environmental impact:** What are the environmental advantages and disadvantages? While many environmental technologies have air quality benefits, there can be disadvantages in terms of land use, visibility and other impacts.
- ☐ **Public preferences:** How strong are the public perceptions and attitudes? There can be significant public education benefits from renewables and some stakeholders may have strong preferences in their favor.
- ☐ **Transmission interconnection:** How easy will it be to bring the renewable energy that is generated and deliver it to the utility's load?

Important criteria are economics and capacity factor. The U.S. Department of Energy estimates contained in the 2004 annual outlook are shown below. Note, that while the table reports point estimates, each situation will be different depending on local resources, costs, system integration and other factors.

Resource Comparisons in Capital Costs and Capacity Factor

Resource	Capital Cost ($/kW)	Capacity Factor (percent)
Biomass	$1,715	83 percent
Geothermal	$1,882	86 percent
Landfill gas	$1,470	90 percent
Solar photovoltaic	$3,889	24 percent
Solar thermal	$2,577	15 percent
Wind	$1,010	39 percent

Source: U.S. DOE, Energy Information Administration, Assumptions to the Annual Energy Outlook 2004, February 2004, p. 128, 129.

Summary

This chapter outlines the wide variety of renewable energy resources available to utilities and their customers. Both utility-scale and customer-scale resources are identified. Starting with a complete inventory of options helps stimulate consideration of the criteria for narrowing down the options. Such criteria as resource availability, technological maturity and comparative economics can then be applied with greater confidence. Forecasts at the beginning of the chapter estimated potential resource development and at the end of the chapter summarized relative costs.

Chapter 5 - Designing Projects and Programs

Once the technologies have been screened to those of primary interest to a utility, it is desirable to outline the key aspects for more detailed consideration. Somewhat like developing a business or product plan with pro forma financial statements, it helps to design or describe in some detail the potential or hypothetical projects or programs. The outputs of this process are a set of energy production estimates and associated load impacts, along with estimated costs and risks. The costs then feed into a more detailed and robust financial and risk analysis discussed in the next chapter.

This chapter suggests the key considerations in producing sufficiently detailed project or program designs. The chapter is organized into the following sections:

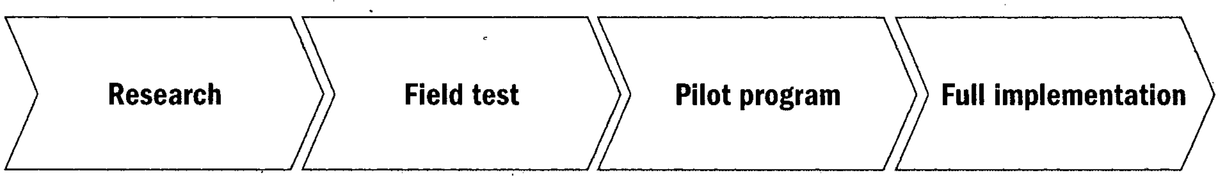
- ☐ Stages of development and implementation
- ☐ Framework for program design

Development and Implementation Stages

It is important to recognize the stage of development and readiness when implementing a project or program. It is also useful to distinguish between the term project or program. Supply-side opportunities are typically thought of in project terms, since they can involve a long planning and implementation cycle supporting one single installation or resource. For example, a plan to develop a new wind facility to be integrated with other supply-side resources is usually thought of as project planning. A plan to offer customers an option to purchase blocks of wind power is usually thought of as a green power program.

Demand side opportunities are typically thought of in program terms, since they typically involve applying a similar set of programs or features to a set of customers that grows over time. In the case of a customer focused-program, a utility may want to conduct a pilot program before launching a full-scale program.

Thus, the stages of development and implementation as shown below may be more appropriate for customer scale programs, while utility scale programs proceed directly to full scale design.



This figure suggests that the program for the prospective renewable energy technology may need to proceed through several stages of development before reaching full scale implementation. In the research stage, more detailed analysis may be required to identify the technical, economic, environmental and other issues of concern. In the second stage, a field test may be appropriate to confirm how important the issues are and whether they are adequately resolved. This may involve putting a renewable energy system on a customer or employee home for testing.

Assuming the field test is satisfactory, a pilot program may warranted. In a pilot program, a segment of the customer population may be offered the program to test market acceptance and help predict participation rates. Finally, full scale implementation may follow with roll-out to all customers.

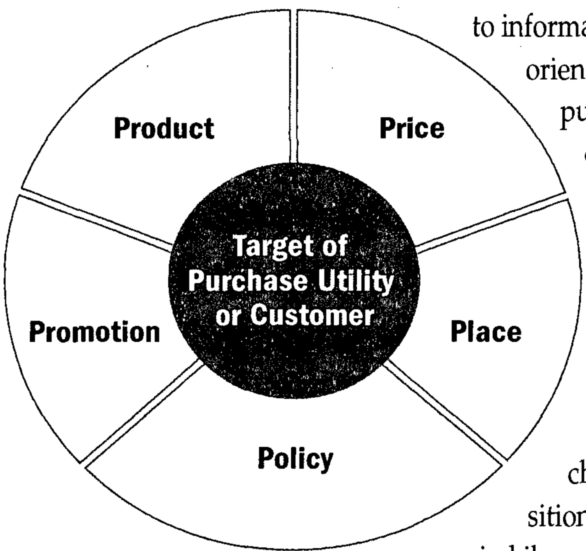
Supply-side projects are less likely to follow this path of development and implementation. For one thing, the projects are more discreet. For another, they do not lend themselves to partial or phased-in implementation.

A Framework for Program Design

The first topic to consider is: Who is purchasing or acquiring the resource? Is the utility purchasing the resource to integrate into its supply mix for all customers? Is the utility purchasing the resource on an aggregation basis for participating customers? Is the customer purchasing the resource directly, such as a photovoltaic system? In other words, who is the target user for the renewable resource.

A second set of considerations may be summarized as the five Ps of program design: Product, Price, Place, Promotion and Policy. Product refers naturally to the resource being acquired. Price refers to its cost either to the consumer or to the utility. Place refers to delivery and how the product reaches the user, whether the user is the utility or the end-use consumer. Promotion, of course, refers to information, education and sales, which is more involved for consumer-oriented programs, but even utility purchases can have a significant public education component. Policy refers to the realities of building codes, environmental rules, transmission access and the numerous other regulatory considerations. These aspects for program design are explored below.

Five Ps of Program Design and Development



Product Considerations. Products need to be defined by technology and the features associated with that technology. Product considerations include such matters as resource size, energy produced and metering. If it is a service, such as consumer purchases of green power, product considerations may include composition of the green energy in the product bundle and size of the bundle in kilowatthours per some period of time. Product considerations include maintenance responsibilities, repair services, warranty coverage, safety protections, and appearance or packaging. For long-term programs, the product may be defined by length of term and termination provisions.

In the case of a project where the utility is acquiring resources, then the utility will go through a purchasing process. The purchasing process could be a sole source arrangement without competitive bidding. Sole source arrangements are likely where a renewable energy resource is uniquely situated with no other potential buyers except the utility. Another approach is by competitive bidding through a request for proposal from existing or prospective developers of renewable resources. The product becomes defined by the project size, terms, capacity available, energy produced and other aspects.

These product considerations need to be described or specified to create cost estimates for purpose of analyzing the program or project.

Pricing. A second key consideration in program design is pricing. If the utility is building a renewable energy resource, then pricing is really about costs or what the utility will pay for. If the utility is not building, but instead buying, the renewable resource, multiple pricing choices may be considered, including:

- ☐ capacity purchases
- ☐ energy purchases
- ☐ combinations of capacity and energy
- ☐ quantity discounts
- ☐ timing premiums or discounts
- ☐ front-loaded purchase agreements where some capital costs are covered
- ☐ back-loaded purchase agreements where prices rise over time
- ☐ lease purchase arrangements
- ☐ application of tax incentives

For customer programs, pricing strategies adopted by the utility are equally varied. The first question is to determine whether renewable energy resources cost the utility more or less than conventional resources. If the renewable resources cost less, then the utility may choose to include the resource costs in general rates and keep average rates from rising. If the renewable resources cost more, then the question is whether to charge full cost for renewable resources or absorb some of the costs in average rates.

One example of the pricing considerations may be seen with a green pricing program where wind energy costs more than conventional resources. If a premium is charged for wind power, the following pricing policies may be considered:

- ☐ participating customer pays full cost for wind generation
- ☐ participating customer pays for the incremental cost above conventional types of energy
- ☐ participating customer pays some share of the incremental cost with remaining costs recovered through average rates

One pricing strategy is to offer a fixed rate for renewable energy. Since most of the renewable energy cost is fixed, variable costs are a minor portion of the total costs and utilities can guarantee a rate over a number of years. This can be attractive to customers as a way to avoid volatile energy costs for conventional resources.

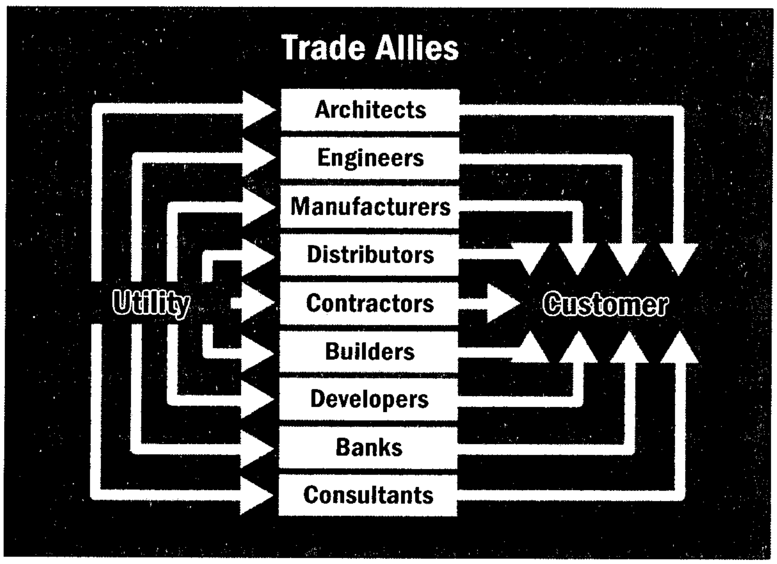
Listed below are various types of financial incentives that may be offered by the utility for renewable energy products for end-use customers:

Renewable Resource Pricing Strategies

Pricing Strategies	Description
Rates	Special rates such as premium, discount, guarantees and time-of-use
Credits	Bill credits for power sent into the grid based on net metering using marginal rates; using average rates
Connection charges	Surcharges, discounts, waivers such as to builders
Rebates	Single payment for purchase and installation of product
Coupons	Certificates with cash value to reduce product purchase price
Loans	Financing at favorable rates including zero interest
Shared savings	Investing in customer facilities with payments made from savings
Leasing	Making regular payments instead of upfront financing with option to purchase

Place or Delivery. Delivering or getting the product to the user's place of business or home is a third key program design consideration. Where the utility is the purchaser, such as for wind energy, delivery can be a crucial part, considering the transmission system and integration requirements.

Where the customer is the user and renewable energy technology or capability is being built onto a facility, two typical options are found. One option is for the utility to arrange installation of the renewable energy product either with its own employees or with contractors. A second option is for the customer to arrange delivery with a third party, often called a trade ally.



A trade ally is any organization that can influence the transaction between a utility and its customers. Trade allies perform valuable services to the customer directly and the utility indirectly. Trade allies are important in:

- ☐ educating customers
- ☐ training
- ☐ marketing and sales
- ☐ testing
- ☐ financing
- ☐ certification
- ☐ developing standards and procedures
- ☐ installation, maintenance and repair

Utilities can work effectively with trade allies by providing them with standards, training, education materials, sales materials and quality inspection services. Utilities may choose to develop a list of recommended trade allies for specific skill areas such as in engineering, installation and service. Also, customers may be encouraged to secure funds from recommended financial institutions.

Promotion. A fourth design consideration is promotion, a term encompassing education, publicity and sales. Where the utility is the user or buyer of renewable resources, promotion is focused on education and publicity, and the sales process is between the utility and the vendor of renewable resource products. For example, in the case of a wind farm development, the utility purchasing electrical output may wish to promote its activities with customers and others.

There are multiple strategies for marketing where the utility may take the lead, a third party may be encouraged to market its service, or some combination, such as cooperative advertising.

Marketing and promotion are important for new technologies and new programs. There are various possible value propositions just as there are multiple renewable energy program options. For renewable energy programs to succeed, the many potential market participants may need to be educated and indeed sold on the values that can be achieved.

Success in marketing is not only related to education and awareness of participants, but also program stability. If program designs change radically from year to year or even within a year, it is more difficult to attract and retain end-use customers as well as others in the value chain.

Various marketing methods may be adopted. The general categories of marketing include:

- ☐ customer education
- ☐ direct customer contact
- ☐ advertising and publicity

For each of these strategies, various tools are available. Customer education options include:

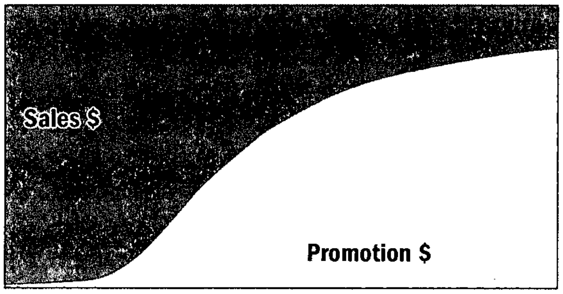
- ☐ brochures
- ☐ Web sites
- ☐ bill inserts
- ☐ speakers bureaus
- ☐ direct mailings
- ☐ customer seminars

For direct customer contact, consider:

- ☐ on-site technical analyses
- ☐ workshops
- ☐ telemarketing
- ☐ seminars
- ☐ on-site visits
- ☐ inspections
- ☐ mall storefronts
- ☐ fairs and home shows

For advertising and promotion, consider:

- ☐ **mass media:** print, radio, TV and print media
- ☐ **personal media:** direct mail, brochures, CDs and Web pages
- ☐ **other advertising:** posters, symbols, logos, pencils, key chains and hundreds of other items
- ☐ **other promotion:** contests, games, demonstrations, fairs, shows, conferences and meetings



The tools used will depend on such considerations as objectives and costs. Objectives might include maximizing participation in renewable resource programs or maximizing the amount of renewable resources acquired. Cost considerations might include maximizing gross revenues or maximizing net revenues of the organization.

It is also useful to consider market segments in such terms as demographics, facility types, appliance saturations and energy use patterns. These should be considered to optimize budget expenditures for promotion. There is probably some minimum amount that should be spent on promotion, but do not expect a direct relationship between sales and promotion.

It is generally acknowledged that in marketing and advertising, there are diminishing returns. Initial spending on these promotional activities may generate great customer acceptance, participation and sales for the early amounts spent. But higher levels of spending should not be expected to increase sales proportionately. In fact the opposite will occur, so that additional promotional dollars result in smaller increments of participation.

Policy. Government rules and regulations play a larger role in most products than is generally recognized. Whether producing consumer goods or services, from apples to zinc, market success can be depend heavily on compliance with government policies such as health, safety, environment, anti-trust, insurance, and energy regulation. Since this guidebook includes material on public participation, it is important to note that stakeholders need to include regulatory officials in energy, environmental and other agencies.

Government laws and regulations may encourage or discourage certain types of renewable energy products. Government rules may add to costs or may be modified to reduce costs.

For example, building codes may inhibit roof-mounted solar panels or restrict building heights that shade solar arrays for homes and businesses. For situations where the utility is the purchaser of renewable resources, it may need to comply with land use covenants, zoning regulations, environmental restrictions, transmission policies and other public policies.

A complex web of government rules and regulations may need to be negotiated in implementing arrangements by the utility to build or purchase renewable resources. While many municipal utilities may have the power through their boards of directors to modify local policies, extra attention may be needed for county, state and national rules and regulations.

Public policy options to foster and potentially reduces costs for renewable resources include:

- ☐ adopting favorable building codes
- ☐ encouraging tax incentives
- ☐ authorizing green tag programs
- ☐ supporting renewable portfolio standards
- ☐ harmonizing net metering rules
- ☐ standardizing service interconnection requirements

Summary

Once decisions have been made to analyze renewable resource projects or programs in depth, many program or project design considerations must also be featured in. An early consideration is whether to proceed to a full scale program or adopt a more incremental approach such as a pilot program, particularly for customer-focused programs. Another early consideration is to confirm if all utility customers or just participating utility customers are the users of the products being offered under the renewable energy program.

For customer-scale programs, and in some cases for utility-scale projects, five sets of design topics should be reviewed. This systematic review will help ensure that costs and risks are being addressed. This should add confidence to the detailed analysis recommended in the next chapter. This design process should also set the stage for more efficient implementation as discussed in the last chapter of the guidebook. The design topics are summarized in the diagram below to highlight some of the key issues for consideration.

Key Issues in Program and Project Design

Design Topics	Utility Project User	Customer Program User
Product	Quantity, Quality, Timing	Features, Services, Terms
Price	Costs, Bidding	Premiums, Discounts, Financing
Place	Location, Integration	Utility delivery, Trade allies
Promotion	Education, publicity	Marketing, Advertising
Policy	Environment, Safety	Zoning, Safety

This chapter addresses the consideration and methods to measure, analyze and compare renewable energy alternatives. It is organized into four sections:

- ☐ An appropriate level of modeling and analysis
- ☐ A suggested approach
- ☐ Monte Carlo analysis
- ☐ Applying a portfolio perspective to evaluate costs and benefits

An Appropriate Level of Modeling and Analysis

One early step in developing a renewable energy strategy is determining what level of modeling and analysis is appropriate. Many larger municipal utilities undergo a rigorous resource planning effort, while for many smaller member-owned utilities, this level of analysis is neither required nor warranted due to their limited resources. However, even smaller utilities undergo some form of resource planning that should be used as the basis to evaluate the impact of adding additional renewables resources into their portfolios. For example, Western Area Power Administration's IRP Regulations (10 CFR Part 905) require firm-power customers to submit IRP type plans.

Larger production cost models provide attractive features useful to a resource planner. They can analyze detailed interactions of dozens or even hundreds of different input variables and related decision factors and provide detailed, hourly dispatch and cost estimates for a service territory or a region. However, these models are heavily dependent upon input assumptions and require a high degree of training and sophistication to properly interpret their output. These models also require significant license fees that can put them out of reach of most smaller, member-owned utilities.

Statistical packages can also be useful. These can be stand-alone statistical packages, or what is referred to as "add-ins" to Microsoft Excel. These "add-ins" can be used with Excel to develop spreadsheet models to analyze data-intensive forecasts to a much greater degree than was possible even a few years ago. These spreadsheet models can simulate scenarios allowing different input variables to fluctuate and then estimate the resulting power prices over a long-term horizon. Much more importantly, they provide these results in only a few minutes or hours, depending upon the complexity of the spreadsheet. This speed and ease of use is better suited for evaluations where alternate scenarios need to be run quickly and is of great value to a team evaluating alternate scenarios such as the impact difference of adding 2 percent or 10 percent renewables to a power portfolio.

The choice of whether its more appropriate to use a production cost model, an Excel spreadsheet-based approach, or some combination of the two, will depend on the specific utility's needs and internal capabilities. Most smaller utilities tend to have forecasts built upon a spreadsheet and do not require the complexity of a production cost model. However, the box at left outlines a representative sample of the types of analytical capabilities be provided by the larger production cost models.

This guidebook presents a spreadsheet-based approach suitable for smaller utilities to apply. This results in a simplified model, but still requires some degree of spreadsheet expertise and detailed knowledge of the utility's loads and resource projections to be most useful.

Analytic Capabilities Provided by Production Coat Models

Risk Modeling (stochastic)	Fuel supply
Resource addition logic	DSM
Upgrades for RTO/LMP modeling	Shortage pricing
Evaluation period (hourly vs. daily)	Method of unit outage modeling
Emissions modeling	System flexibility
Modeling support	Loss of load probability
Geographic scope	Report function
Reserves calculation	Data extraction
Demand elasticity	

A Suggested Approach

Our suggested approach builds upon the various demand and supply side studies and models that a utility typically has completed as inputs to our analysis. Our approach is broken out in two phases:

- ☐ Phase I develops the base case estimate for a utility's power supply forecast and budget. This could be as simple as applying the current methodology used by the utility to develop its power forecast.
- ☐ Phase II builds upon this base case forecast to develop a number of alternate potential scenarios. It then assigns probability distributions to key variables and runs simulations against these alternatives to better understand the cost and risk impacts to the total portfolio.

It is important to reiterate that a more simplified methodology for Phase I could be appropriate for smaller utilities, depending upon the detail available from their planning studies. The important factor is that at the end of Phase I, the utility needs a forecast of a 5- to 10-year time horizon, which represents expected power supply requirements and expenditures. One potential methodology for Phase I is described in the figure that follows.

Phase I
Develop Base Case Forecast

1 Develop Preliminary Utility Load Forecast ■ Typical day/typical month ■ Annual load growth	Review and update the utility's load forecasting methodologies and develop a preliminary forecast. For our analysis, we will simplify this step by using a typical daily load profile, and a typical monthly load profile, as well as an assumed constant load growth estimate for the 10-year horizon of our analysis period.
2 Complete Utility–Specific Load Forecast ☐ Conservation program ☐ Other utility-specific assumptions	The preliminary load forecast can be adjusted to reflect utility-specific considerations or other forecasting adjustments. These could include the utility's conservation or peak load management program assumptions or other contract parameters. In our simplified discussion, we make no adjustments for utility-specific considerations.
3 Develop Method of Existing Power Portfolio ■ Existing contracts ■ Self-generation assets ■ Spot-market purchases	Here, we collect the relevant dispatch attributes of the existing power supply portfolio and generation fleet, including factors such as heat rate/disptch basis, expected availability, capital and O&M estimates. We also compile cost and other data related to contractual supply resources, as well as spot-market purchases as appropriate.
4 Develop Capacity Expansion Plan ☐ Fuel forecast ☐ Contract alternatives ☐ New resource alternatives ☐ Specific new projects	This plan describes how we will meet further load growth and other obligations. For utilities without significant load growth, this paln could also consider replacing existing resources with renewables. We compile dispatch attributes of "generic" new resources, which will be incorporated into the evaluation of alternatives to project forward how future load growth will be met and at what expected market prices.
5 Develop Power Supply Forecast and Budget ■ "Expected case" ■ Longer-term (5-10 year) perspective	We conclude with the "expected case" of the power supply forecast and budget. This will reflect the longer term (e.g. 5-10 year) forecast for power supply load requirements and financial projections. This will be used as the base case in later steps, to determine the impact of alternate scenarios to add renewables to the portfolio.

Integration Issues and Costs

The topic of integrating wind power into an electric system has received considerable attention and generated much discussion among those responsible for managing the utility transmission and distribution systems. A great deal of research has been completed over the last few years that indicates while there may be some additional costs associated with integrating wind, these costs are modest, especially at low penetration levels.

The Utility Wind Interest Group has sponsored or conducted a number of recent studies that have identified and quantified recent case study examples that review how utilities have addressed integration issues and provide a more recent and accurate indication of the associated costs. This information is specifically identified in the references section at the end of this guidebook, or is avialable at the UWIG Web site at www.uwig.org.

Phase II of our suggested approach focuses upon developing an analytic capability to understand the cost and risk trade-offs involved with adding different levels of new renewable resources. This phase involves developing the renewables integration module, developing alternate scenarios for adding incremental generation to the portfolio and evaluating the impact to portfolio cost and risk. The steps are discussed in greater detail in the appendix to this guidebook. An overview of our suggested approach for Phase II is described in the following figure.

Phase II
Evaluate Additional Renewables

6 Develop Renewable Energy Integration Module ■ Reliability and cost parameters ■ Integration and forecasting assumptions	The integration module can be developed from a site-specific project under construction, or estimated as a generic plant from industry sources. The module should contain specific data and assumptions for local resource capabilities, costs and projected output data.
7 Assign Probability Distributions to Inputs ☐ Load forecast ☐ Electric price forecast ☐ Fuel (gas) forecast	We now take the key input variables developed in Phase I and assign a probability distribution to them. This step can have an extremely significant impact on the eventual results and care must be taken to assign the proper distribution shape, and to ensure the interaction of different input variables with themselves and with other variables.
8 Define Scenarios ■ 2% versus 10% ■ Others as appropriate	Scenarios will quantify the cost and risk impact on the total portfolio. For each scenario, we allow the input variables to fluctuate according to the probability distributions we assigned in step 7. We will simplify our scenarios to include only two: 2% and 10% of total portfolio comprised of renewables.
9 Run Simulations ☐ 2% versus 10% ☐ Relative contribution of key input parameters to total cost and risk	We next examine the impact of the input variables for the two scenarios on the total impact to portfolio cost, but this could also be expanded to examine other measures. With simulations, we get a distribution of values for the expected portfolio cost. The shape of these distributions provide insight to total portfolio risk.
10 Interactive Review of Assumptions ■ As appropriate	The level of effort involved in this last step depends on the priority and ability to meet and work with different stakeholder groups to develop a consensus opinion on the final recommended strategy.

The steps described in Phase II might at first glance, appear to be overly complex, and too labor-intensive to interest many smaller utilities. However, the general concept is actually fairly straightforward. We are taking our existing forecast from Phase I and using Microsoft Excel to perform a large number of simulations, using different values for our input variables, to estimate the power portfolio costs as these variables change. By looking at a large number of simulated results, we develop better insight to the cost and risk impacts of different scenarios such as adding increasing increments of renewables to the power portfolio.

Monte Carlo Analysis

The power of a Monte Carlo simulation analysis is to test a wide range of uncertain conditions, and to evaluate their overall impact on the end result. A number of different scenarios could also be evaluated instead of just portfolio costs that are considered here. These other scenarios could include different reserve margins requirements, different natural gas price forecasts or legislative events such as imposition of a national carbon tax, if desired. To help simplify the discussion, two scenarios are defined. One scenario assumes 2 percent of the total portfolio is comprised of renewable resources and the other scenario assumes 10 percent.

Once Phase II analysis is completed, a series of workshops or meetings can then be held with various stakeholder groups to walk through the analysis and to educate these groups on the impact that the different input assumptions have on portfolio cost and risk. By running a large number of iterative simulations and examining the results, stakeholders can see that there are a smaller number of input variables that drive the results than they might have thought beforehand. For example, O&M costs and the degree of fluctuation in wind output can have a much smaller impact on total cost and risk than the natural gas forecast used for the analysis.

At these workshops, participants can propose alternative parameters or scenarios to be evaluated, and see for themselves the impact on the end result. This can be a powerful learning tool, as well as allowing each stakeholder's voice to be heard, resulting in greater alignment among stakeholders with the eventual recommended strategy. When stakeholders feel they can have all of their opinions examined in a fair and open manner, the discussion can avoid some of the digressions that can typically occur, and the group can move toward a more fact-based analysis and conclusion.

By using the PC-based application to run hundreds of simulations, the utility will also be in a much better position to estimate the expected impact to portfolio costs of incrementally increasing its power portfolio exposure to specific fuel types (e.g. gas vs. wind) and at what point the attractiveness of incremental addition of a given fuel type begins to decline. This information is critical to determine the overall goals for renewable energy commitments and targets that make the most sense for the utility's stakeholders.

Applying a Portfolio Perspective to Evaluate Costs and Benefits

Modern portfolio theory can provide planners with valuable insight regarding the risk factors affecting individual assets and groups of assets in a power supply portfolio. Risk factors can include load growth assumptions, fuel price forecasts and the costs for spot market replacement power purchases. Applying portfolio principles can quantify how each of these risk factors affect individual assets and the portfolio as a whole.

A portfolio-based perspective of power supply assets also provides a better understanding of how individual assets interact to different planning scenarios and risk factors. In addition, an understanding of the interaction of the assets to each other provides insight to their true strategic value and cost to the enterprise as a whole. The ultimate objective of this analysis is to develop an understanding of how the utility's power portfolio is affected by different percentage compositions of renewable resources and to use this insight to help develop a target renewable portfolio composition.

To evaluate the portfolio impact from adding incremental amounts of wind generation, it is first necessary to define a dependent function, such as the total portfolio cost, and to examine all the independent variables that affect the costs of the assets individually and the portfolio in aggregate. We then allow the primary input variables to vary, according to some probability distribution that is appropriate for that variable. For example, let us assume that we define the total portfolio cost of a power supply portfolio as follows.

Statistical Covariance Between Variables

Certain risk factors will affect different assets differently, and sometimes in opposite directions. For example, rising natural gas prices will increase the production cost of gas fired plants while having little impact on the cost of base load coal and wind plants. In addition, the spot market price for wholesale electricity will increase as rising gas prices are passed on through to the market. Understanding how these risk factors affect each of the individual assets independently, as well how they affect the entire portfolio, is the next evolution of corporate risk management.

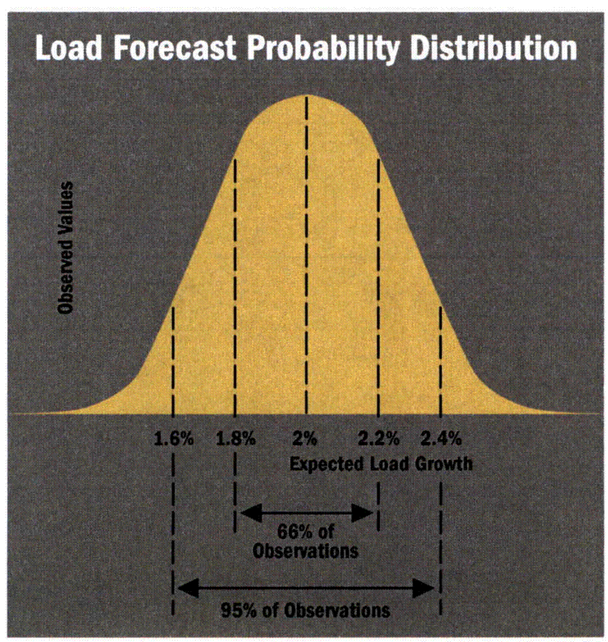
The statistical measure of how different components of an overall react to different risk factors is measured by the covariance between independent variables (in this case, wholesale power prices and wind production costs). Understanding the covariance of wind production costs and how this interacts with the other portfolio cost drivers is the key to understanding the impact of adding incremental amounts of renewables to a portfolio and to quantifying what is an appropriate target percentage for renewables in a portfolio.

$$\text{Total portfolio cost} = \left\{\begin{matrix}\text{Load}\\\text{required}\\\text{to serve}\end{matrix}\right\} \times \left\{ \overbrace{\left[\left(\text{Owned units}\right)\left(\text{Var + fuel cost}\right)\right]}^{\text{Self-generation cost}} + \overbrace{\left[\left(\text{Energy contracts}\right)\left(\text{Energy cost}\right)\right]}^{\text{PPAs}} + \overbrace{\left[\left(\text{Renewable energy facilities}\right)\left(\text{Renewable energy costs}\right)\right]}^{\text{Renewable purchases}} + \overbrace{\left[\left(\text{Spot energy purchases}\right)\left(\text{Spot energy costs}\right)\right]}^{\text{Spot purchases}} \right\}$$

When the dependent function has been defined, it is possible to use a PC-based spreadsheet model to calculate total portfolio costs under a range of varying values for the input variables. A statistical package such as @Risk or Crystal Ball can be used as a business simulation tool to examine the economics and underlying risk potential of assets such as wind turbines in a manner not available previously.

In a simplified example, we could calculate the portfolio production cost for a number of different load growth forecasts. For a given utility, it might be reasonable to forecast a load growth of 2 percent annually for the next 10 years. We might further specify that our projected load growth has a probability distribution that is normally distributed, with a mean of 2 percent and a standard deviation of 0.2 percent. This is shown in the probability distribution chart to the left.

Applying the statistical measures to our assumed forecast, the chart at right shows us that we expect a load growth rate of 2 percent, it is also normally distributed, so it has the same chance of being too high as too low. We also know that approximately 66 percent



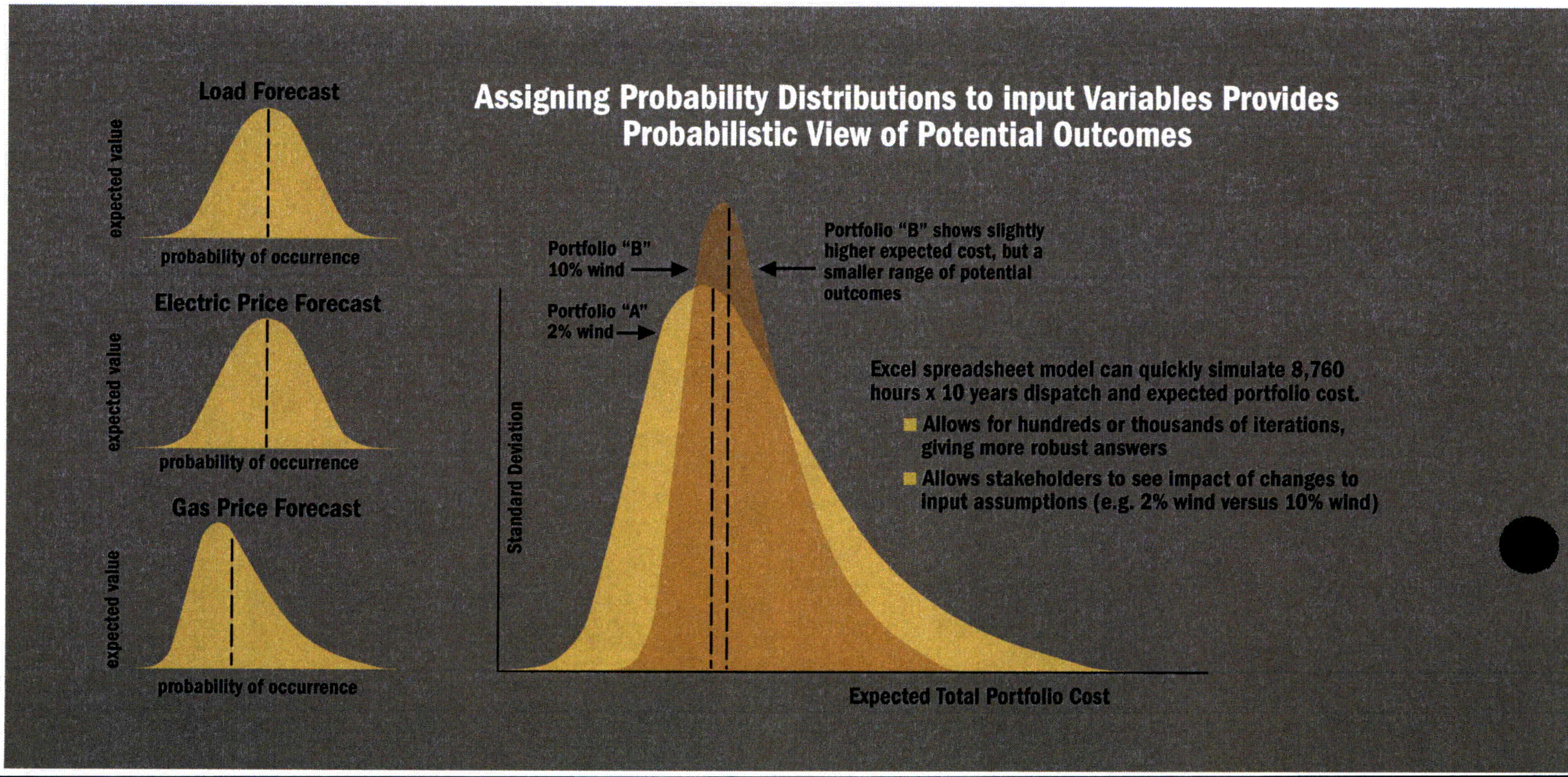
of the time, the actual forecast will be between 1.8 percent and 2.2 percent; (one standard deviation) and that 95 percent of the time, the actual load growth rate will be between 1.6 percent and 2.4 percent (two standard deviations).

For each of these different load growth rates, each asset in the power supply portfolio will react differently, as it will have to produce a varying amount of future generation, depending upon what the actual load growth turns out to be. We can then simulate our expected future by calculating hundreds or even thousands of iterations for a range of potential load growth rates. We estimate a different load growth for each iteration, and then calculate the total portfolio cost for each assumed load growth for each iteration. This gives an expected portfolio cost, which is the mean value from all the iterations, as well as a probability distribution telling us the distribution of calculated portfolio costs for each of the different iterations.

We can apply this same concept to the other primary independent variables that will largely determine the total portfolio costs. In our simplified case, we have identified the three most important variables to consider as the load forecast, the projected electric price forecast and the projected gas price forecast.

When we have estimated the expected value and probability distributions for the input variables, we then calculate total portfolio cost by running a specified number of iterations on the spreadsheet program. The time required to perform these iterations will depend upon how complex the portfolio and its dispatch assumptions are, and what type of computer resources are available. However, even an older PC should be able to run through the 1,000 iterations for a small portfolio with a 10-year planning horizon in a matter of seconds. Even to perform 10,000 iterations would only require a few minutes on most computers.

In our example discussed earlier, we ran through the iterations for two different scenarios. The first scenario assumed 2 percent of energy costs would be met by wind resources and the second scenario assumed 10 percent of future energy costs would be met by wind resources. The results are described in the figure below.

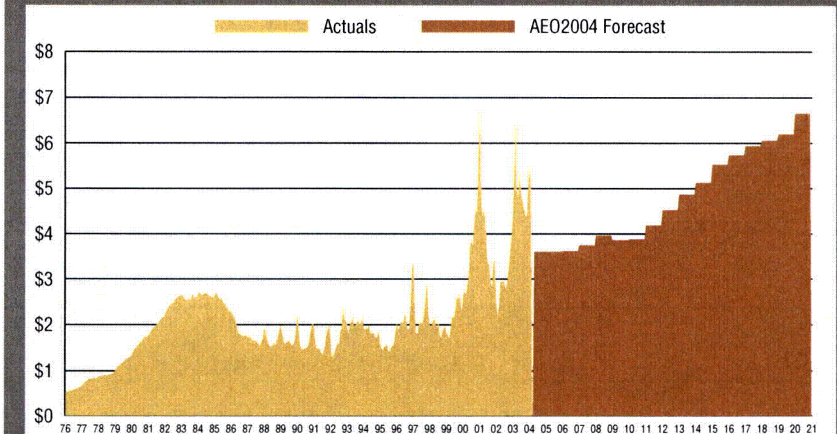


What our previous example illustrates, and what can be seen in the previous figure, is the trade-off between choosing the least cost or the least risk strategy. In our example, our second scenario consisted of 10 percent wind. Current cost and production data indicate that at today's prices, wind is generally still going to have higher construction cost per MW than a traditional gas-fired CCCT option. While wind will have lower fuel and operating expenses than the gas plant, which helps its relative economics, it is still a more expensive economic option on a life-cycle basis. Although it should be pointed out that there are numerous project-specific opportunities where prevailing wind conditions, and electric or gas transmission access and availability could make wind more attractive than a CCCT even strictly on an economic basis.

However, the primary advantage that wind provides a total portfolio is a result of its significantly less volatile fuel costs compared to an alternative such as natural gas. Wind has zero fuel costs and small O&M costs, while natural gas prices have demonstrated extreme price volatility in recent years. When the projected price and assumed volatility for natural gas are incorporated into the simulation, the range of potential gas prices must include some probability that the price for natural gas will spike upward at times. The result of this volatility is that, while the total expected cost of the power supply portfolio is less for the natural gas- based alternative, there is a probability of occurrence that can be measured where a future price of natural gas will make the production cost for the resource greater for gas than for wind.

The trade-off that must be considered and communicated to stakeholders comparing portfolio cost is that renewables might have a slightly higher cost than traditional alternatives under today's assumptions, but the reduced risk exposure to natural gas prices must also be considered. This perspective is especially important for utilities that might be obligated by statute to procure power supply requirements in a "least cost" manner. The figure at right shows actual historic natural gas prices and the Energy Information Agency's latest forecast. What is immediately evident from this figure is that gas price volatility has increased dramatically, and the current forecast for future prices to trend lower and more stable is not a clear certainty by any means. Especially in light of the extreme magnitude of recent gas price volatilities, least cost may not always be preferable to least risk.

U.S. Natural Gas Wellhead Price Actuals through 2004 and Forecast through 2020
(Monthly $/Mcf nominal)



Source: Energy Information Agency, Annual Energy Outlook, 2004 Forecast

Conducting an assessment using a business simulation tool improves the ability to weigh these trade-offs between costs and risks, and allows stakeholders to better understand how pricing and risk assumptions affect the eventual recommended strategy.

This chapter discusses the challenges and requirements to successfully implement renewable energy goals, strategies and objectives. It is divided into two sections:

□ Organizing the implementation team

□ Implementation planning work steps

Organizing the Implementation Team

Once the renewable energy goals, strategies, and objectives are approved, the utility should develop a plan to implement these decisions in an organized, well-structured manner. We assume for our implementation planning discussion in this chapter that the CEO has designated the renewable energy project manager and considered and approved specific:

□ Goals, strategies and objectives

□ Milestone schedules and planning targets

□ Budgets and authorization levels

A large number of tasks should be considered and incorporated into the initial implementation team organization and planning. To be successful, the planning effort needs to consider the wide array of functions within the utility that will need to become involved as well.

One of the first steps for the implementation project manager is to create the project organization and ensure the roles are filled with the appropriate people from throughout the utility. As this team is selected, it is useful to consider the following common hazards that many project managers face when assigned a new task, and to take steps early on in the process to ensure these are avoided if at all possible.

□ Not providing dedicated resources to perform required tasks, but instead simply "adding it on" to existing job requirements

□ Not recognizing the total budget requirement, or allowing for future budgetary authorization review at key milestones

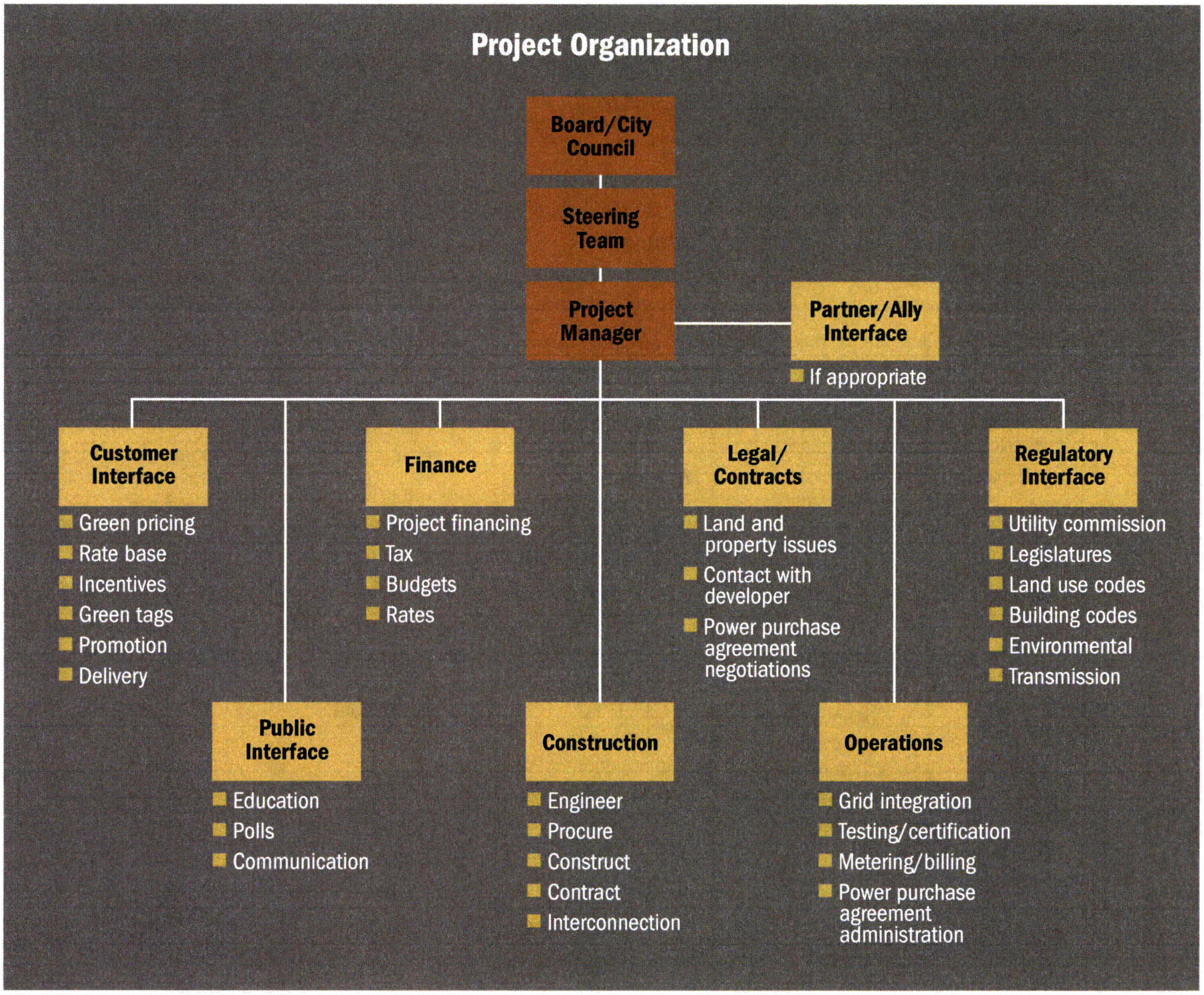
□ Not building in schedule contingencies to "check and adjust" as the project develops or as circumstances might change

□ Assigning loose responsibility among various project participants without designating lines of authority and accountability

□ Informal approach to project management, decision making and progress reporting

□ Not being clear about the need for, and use of, outside resources from equipment vendors, contractors and consultants

A representative project organization chart in the figure below provides perspective on how many functions will be involved with the various tasks to be completed. It is recognized that for smaller utilities, one individual may be responsible for two or more of the functions listed, but each function is shown to represent a wide range of internal organizations.



In team-oriented organizations, there may be a steering team and a project team. The steering team provides overall direction and consists of the organization's top management. The project team consists of staff members with functional expertise and responsibility and is led by the project leader. The project team may meet weekly and the steering committee may meet monthly, as one example of how they may interface.

The project organization chart provides an indication of the coordination effort that is required to successfully implement the goals and strategies associated with a large programmatic effort such as a renewable energy strategy. In addition, the time frame for implementation is likely to extend over many months, so the time invested up-front to develop an organized approach and methodology can be expected to pay dividends in the longer term, during implementation.

Implementation Planning Work-Steps

We have defined five suggested steps to be performed during implementation planning before the implementation team is even ready to begin work. These steps are designed to ensure that the team has a well-focused, well-organized approach defined before proceeding. The five steps are illustrated below and described in the following paragraphs.

Implementation Planning Work Steps

Step 1 **Ensure clarity of objectives, roles and responsibilities**	Step 2 **Designate team and project organization**	Step 3 **Develop detailed cost and schedule information**	Step 4 **Develop individual work plans for team leaders**	Step 5 **Initiate work report progress**
1. Compile relevant documents on renewable energy goals, strategies and objectives ▪ Project analysis ▪ Approval authority ▪ Budget authority ▪ Explicit goals, strategies and objectives 2. Compile relevant documents on goals, strategies and objectives ▪ Internal ▪ External ▪ Feedback loop 3. Identify steering team and project manager and define roles and responsibilities	4. Define roles and responsibilities and reporting requirements for team leaders ▪ Marketing/ Customer ▪ Finance ▪ Legal/Contracts ▪ Regulatory ▪ Public ▪ Construction ▪ Operations 5. Communicate organization structure and responsibilities via communication plan	6. Translate approved budget into cost and schedule task and areas of responsibility 7. Define project management tools and approach ▪ Project reporting ▪ Performance measures ▪ Progress reviews ▪ Contigency planning 8. Review available information from APPA, NREL, DOE and other public sources	9. Separate plan for each team leader ▪ Marketing/ Customer ▪ Finance ▪ Legal/Contracts ▪ Regulatory ▪ Public ▪ Construction ▪ Operations ▪ Partner/Ally Interface (if appropriate)	10. Initiate discussions/ negotiations with developer(s) 11. Coordinate with vendors and trade allies 12. Document progress ▪ Project team ▪ Steering team ▪ Public information

Step 1 – Ensure clarity of objectives, roles and responsibilities.

To the greatest extent possible, it is important to be explicit regarding program goals and objectives. As discussed earlier in the guidebook, most organizations that successfully implement significant change, or redirect their strategic priorities, also set explicit targets and executive commitments and provide the necessary support to achieve those targets. There will be times when a new initiative such as a new renewable energy strategy might proceed without such specificity, but the implementation manager is well-advised to obtain this level of clarification wherever possible.

Step 2 – Designate team and project organization.

The implementation team might not be as numerous as indicated in the project organization chart shown on page 45. However, each of these functional areas will need to be addressed at some point during implementation. Responsibility for these functions needs to be identified and communicated as part of the communication plan.

Step 3 – Develop detailed cost & schedule information.

It is important to include sufficient administration and project support funding in this early stage of the effort to allow for adequate project management and controls. While the project construction and integration costs of potential new renewable resources can only be estimated at this point in time, detailed cost and schedules can be defined with allowances for contingency as needed. In addition, the project management tools and approach should be defined and understood by all project participants.

Step 4 – Develop individual work plans for team leaders.

Separate work plans should be prepared by each functional team leader and communicated with the rest of the implementation team. These should define expected tasks, schedule milestones and key points of interface with other members of the implementation team.

Step 5 – Initiate work and report progress.

After the detailed planning steps are completed, then the utility is ready to initiate work in a structured, organized manner. This may include a process of identifying, selecting and negotiating with one or more developers. It may include working with vendors, particularly if the resource is being acquired on a long-term basis. Also, contractors and trade allies may be involved in customer-oriented programs that result in the installation of renewable energy equipment on homes and businesses. As the work progresses, it is useful to document and report on progress. Not only does this help the project team better manager the process, it makes efficient use of the steering committee resources. Finally, it may be desirable to report to the public on progress at opportune times.

Summary

As we have stressed throughout this guidebook, each utility is different and will need to address the issues we have discussed in the manner that makes the most sense for their specific needs. The real world rarely unfolds as anticipated, and the utility manager seeking to expand the role of renewables in their portfolio will likely be faced with insufficient funding, unrealistic time schedules and vocal, and sometimes conflicting, opinions from various stakeholder groups.

This guidebook has attempted to identify the major issues and to address how these issues might affect a utility manager's thought process in looking at renewable energy alternatives.

We have also attempted provide a framework for evaluation and decision-making that results in a more thorough evaluation of alternatives, involving all interested stakeholders in a process that is pursued together, so that all participants feel that their viewpoints have been adequately considered to ensure greater support for the strategies chosen.

It has been said the three functions of management are to plan, organize and implement. And of these, implementation, it can be argued, is the most important, since without action, nothing happens. This chapter offers an outline of the functions of likely importance in organizing a renewable energy project or program. It recognizes that for small utilities, one person may be responsible for multiple functions. The chapter concludes with implementation steps. By following the five steps, there is greater assurance of a successful project brought in on-time, within budget and supported by the customers.

Chapter 2

[1] National Renewable Energy Laboratory, "Top Ten Utility Green Pricing Programs," April 19, 2004, **http://www.eere.energy.gov/greenpower/topten.shtml.**

[2] John Carver, "A Theory of Corporate Governance: Finding a New Balance for Boards and Their CEOs," Corporate Board Member magazine, January 2001, **www.boardmember.com.**

[3] International Association for Public Participation, "IAP2's Public Participation for Executives and Decision Makers," p. 22 **www.iap2.org.**

[4] International Association for Public Participation, "IAP2's Public Participation for Executives and Decision Makers," p. 27, **www.iap2.org.**

[5] International Association for Public Participation, "IAP2's Techniques for Effective Participation," p. 17, **www.iap2.org.**

[6] International Association for Public Participation, "IAP2's Techniques for Effective Participation," p. 17, **www.iap2.org.**

[7] Barbara Farhar, Willingness to Pay for Electricity from Renewable Resources: A Review of Utility Market Research, National Renewable Energy Laboratory, NREL/TP.550-26148, July 1999.

[8] Will Guild and Dennis Thomas, "Nebraska Public Power District Customer Meeting on Energy Alternatives: Summary of Results," Western Area Power Administration, August 19, 2003, **http://www.repartners.org/members/doc/finalNPPDpoll.doc.**

[9] Lehr, R.L. and W. Guild, D. Thomas, B. Swezey, 2003. Listening to Customers: How Deliberative Polling Helped Build 1,000 MW of New Renewable Energy Projects in Texas, NREL/TP-620-33177. Golden, CO: National Renewable Energy Laboratory, NREL/TP-620-33177, June 2003, **http://www.eere.energy.gov/greenpower/resources/pdfs/33177.pdf.**

Chapter 3

[1] Public Renewables Partnership, "Thinking about doing market research," **www.repartners.org**

Western Area Power Administration, Southwestern Power Administration, and Southeastern Power Administration, Resource Planning Guide Volume III: Intermediate Workbook. Stone and Webster Management Consultants, December 1993.

American Public Power Association, **www.appanet.org**

Public Renewables Partnership, **www.repartners.org**

Chapter 4

American Wind Energy Association, **www.awea.org**

National Renewable Energy Laboratory, **www.nrel.gov**

Public Renewables Partnership, **www.repartners.org**

Refocus, International Renewable Energy Magazine, **www.re-focus.net**

U.S. Department of Energy, **www.eere.energy.gov**

U.S. Department of Energy, Energy Information Administration, *Assumptions to the Annual Energy Outlook 2004*, February 2004, p. 137, www.eia.doe.gov.

Western Area Power Administration and U.S. Department of Energy, *DSM Pocket Guidebook – Volume 5: Renewable and Related Technologies for Utilities and Buildings*," National Renewable Energy Laboratory, undated.

Chapter 5

Jim Patterson, "The Energy Grows Greener," *Public Power*, July-August 2003, p. 13.

American Public Power Association, **www.appanet.org**

American Public Power Association Governing in a Changing Marketplace, January 15-17, 2004 Scottsdale Arizona

Chapter 6

Examples or recent operational practices can be found on the Utility Wind Interest Group (UWIG) web site from the Fall 2003 Technical workshop: **http://www.uwig.org/TechnicalWorkshop03-wa.html**

UWIG also helped sponsor an operating impact study of the Xcel system in Minnesota which is available at **http://www.uwig.org/operatingimpacts.html.**

Studies that are available thru UWIG should inform analyses of wind in utility systems. In addition, there are two recent papers that summarize recent integration studies that have been done in the U.S. that provide additional information on integration impacts available at the Utility Wind Interest Group web site **www.uwig.org**

Wind Power Impacts on Electric-Power-System Operating Costs: Summary and Perspective on Work to Date, March 2004. J. Charles Smith, NexGen, Ed DeMeo, Renewable Energy Consulting Services, Brian Parsons and Michael Milligan, National Renewable Energy Laboratory. Presented at the Global Windpower Conference, Chicago, IL. March 2004

Grid Impacts of Wind Power: A Summary of Recent Studies in the United States. Brian Parsons and Michael Milligan, National Renewable Energy Laboratory; Bob Zavadil and Daniel Brooks, Electrotek Concepts; Brendan Kirby, Oak Ridge National Laboratory; Ken Dragoon, PacifiCorp; Jim Caldwell, American Wind Energy Association. Presented at the *European Wind Energy Conference*, Madrid, Spain. June 2003.

Appendix 1 Resources

This appendix lists additional sources of information on renewable energy alternatives. It should be pointed out that most of the tools and other information presented in this section is extracted from the Public Renewables Partnership Web site at **www.repartners.org**.

General Information Resources

Topic / Website	Resource Description
Wind	
http://www.awea.org/utilityscale.html	Utility scale wind
http://www.eere.energy.gov/windpoweringamerica/wpa/small_wind.asp	Small scale wind
http://www.repartners.org/members/pdcstechno.htm	Wind technology case studies
http://www.eere.energy.gov/windandhydro/wind_potential.html	Wind resource maps
http://www.repartners.org/members/toolsident.htm	Tools for identifying and screening wind energy projects
http://analysis.nrel.gov/retfinance/login.asp	Renewable energy finance model
http://www.repartners.org/keycontact.htm	Key wind industry contacts
http://www.greentie.org/index.php	Wind supplier information
Solar Power	
http://www.eere.energy.gov/solar/	DOE solar energy technologies program
http://www.repartners.org/members/pdcstechno.htm	Solar technology case studies
http://rredc.nrel.gov/solar/old_data/nsrdb/	National solar radiation data base
http://www.eere.energy.gov/state_energy/states.cfm?state	State renewable energy potential
http://www.repartners.org/members/toolsident.htm	Tools for identifying and screening solar energy projects
http://analysis.nrel.gov/retfinance/login.asp	Renewable energy finance model
http://www.repartners.org/keycontact.htm	Key solar industry contacts
http://www.greentie.org/index.php	Solar supplier information
Geothermal Power	
http://www.eere.energy.gov/geothermal/powerplants.html **http://geothermal.id.doe.gov/what-is.shtml**	Overview of Geothermal power technologies
http://www.eere.energy.gov/geothermal/directuse.html	Direct use applications
http://www.eere.energy.gov/geothermal/heatpumps.html	Ground source heat pumps
http://www.geothermal-biz.com/utilities.htm	Why utilities choose geothermal energy
http://geoheat.oit.edu/dusys.htm **http://geothermal.inel.gov/maps-software.shtml**	Geothermal Resource Map of US
http://geoheat.oit.edu/colres.htm	More detail about where direct use applications can be found
http://www.repartners.org/members/toolsident.htm **http://geothermal.inel.gov/geot-s2.shtml**	Tools for identifying and screening geothermal energy projects
http://analysis.nrel.gov/retfinance/login.asp	Renewable energy finance model
http://www.repartners.org/keycontact.htm	Geothermal industry contacts:
http://www.greentie.org/index.php	Geothermal supplier information
Hydropower	
http://www.eere.energy.gov/windandhydro/hydro_plant_types.html	More information on hydropower plants
http://hydropower.inel.gov/hydrofacts/default.shtml	General information on hydropower
http://hydropower.inel.gov/resourceassessment/states.shtml	DOE report on low-impact hydro sites
http://www.eere.energy.gov/state_energy/states.cfm?state=	State renewable energy potential
http://hydropower.inel.gov/resourceassessment/software/	Hydropower evaluation software
http://analysis.nrel.gov/retfinance/login.asp	Renewable energy finance model
http://www.repartners.org/keycontact.htm	Key hydro industry contacts
http://www.greentie.org/index.php	Hydro supplier information

Bioenergy	
http://www.eere.energy.gov/biomass/biomass_basics.html .	More information on biomass
http://www.eere.energy.gov/state_energy/tech_biomass.cfm?state=AK. I	National biomass resource map
http://www.eere.energy.gov/biomass/biomass_feedstocks.html#avail	Information on resource availability
http://www.eere.energy.gov/state_energy/states.cfm?state=	State renewable energy potential
http://analysis.nrel.gov/retfinance/login.asp	Renewable energy finance model
http://www.repartners.org/keycontact.htm	Key biomass contacts
http://www.greentie.org/index.php	Bioenergy Supplier information

Hydrogen	
http://www.eere.energy.gov/hydrogenandfuelcells/	Comprehensive DOE hydrogen page

Ocean Energy	
http://www.eere.energy.gov/RE/ocean.html	More information on ocean energy

Customer Scale Renewable Technologies	
http://finder.rmi.org/	Community energy finder
http://www.focusonenergy.com/page.jsp?pageId=538	PV watts calculator
http://www.consumerenergycenter.com/pv4newbuildings/	PV new construction tool kit
http://www.greenbiz.com/toolbox/tools_third.cfm?LinkAdvID=43007	Sustainable design tools
http://www.consumerenergycenter.com/renewable/estimator/	Clean power estimator
http://www.deforum.org/debasic.asp	Distributed energy calculator
http://analysis.nrel.gov/windfinance/login.asp	Wind project finance calculator
http://www.eere.energy.gov/femp/information/download_fresa.cfm	Federal renewable energy screening assistant
http://www.eere.energy.gov/buildings/tools_directory/	Building energy software tools
http://hydropower.inel.gov/resourceassessment/software/	Hydropower evaluation software
http://analysis.nrel.gov/retfinance/login.asp	Renewable energy finance model:
http://geothermal.inel.gov/geot-s2.shtml	Software for analyzing geothermal direct use system economics
http://rredc.nrel.gov/solar/calculators/PVWATTS/	PV watts performance calculator
http://www.thegreenpowergroup.org/gpat/	Green power analysis tool
http://www.greentie.org/index.php	Renewable energy supplier information:
http://www.repartners.org/members/geocase/GeoHeatPumps_Introduction.htm	Geothermal heat pump case studies
http://www.appanet.org/publications/index.cfm?category=2&id=1013U01	APPA power supply RFP guide
http://www.appanet.org/publications/index.cfm?category=2&id=779	APPA Introduction to Financing Public Power Guide

Renewable Energy Assessment Tools

Wind

Wind Engineering Mini Codes. Collection of mini codes related to Wind Power Engineering
http://www.ceere.org/rerl/projects/software/mini-code-overview.html

WndScreen3. wind/diesel systems screening model
http://www.ceere.org/rerl/projects/software/wind-screen3-overview.html

The Utility Wind Resource Assessment Program database was prepared by the Utility Wind Interest Group to technically and financially support utilities conducting wind resource assessments
http://www.uwig.org/uwrapprotocols.htm

The Union of Concerned Scientists has produced Assessing Wind Resources: A Guide for Landowners, Project Developers, and Power Suppliers intended to guide developers through the process of site assessment. It provides practical information on how to develop reliable estimates of the wind resource and electricity production at a given site. This includes information on how to measure wind speeds and direction; how to qualify your land's potential for wind projects; how certain variables affect wind production costs and return on investment; what information is typically needed by banks and investors to finance a project; and where to look for additional information.
http://www.uscusa.org/clean_energy'renewable_energy/page.cfm?pageID=1013

Wind Power Map.org's Northwestern United States Wind Mapping Project's new high-resolution, state-of-the-art maps of wind energy potential are now available for the Northwest. Resource estimates are easily accessible to the public through an interactive Geographic Information System Web site. Maps are provided at state, county and utility scale.
http://www.windpowermaps.org/default.asp

TrueWind Solutions TrueWind Solutions provides state wind resource maps
http://www.truewind.com/htm/reports_pubs.htm

For more information on wind resource assessment, see Wind Resource Page.
http://www.wapa.gov/es/prp/wind/wpblows.htm

Solar Photovoltaic

PV New Construction Toolkit
http://www.consumerenergycenter.com/pv4newbuildings/

PVWATTS calculates electrical energy produced by a grid-connected photovoltaic system. Currently, PVWATTS can be used for locations within the United States and its territories.
http://rredc.nrel.gov/solar/calculators/PVWATTS/

Sustainable By Design provides a suite of shareware tools to aid with solar design and building-energy analysis.
http://www.greenbiz.com/toolbox/tools_third.cfm?LinkAdvID=43007

For more information on solar resource assessment, see Solar Resource Page
http://www.repartners.org/solar/pvresources.htm

Geothermal

For information on geothermal resource assessment, see Geothermal Resource Page.
http://www.repartners.org/geothermal/georesources.htm

Biomass

For information on biomass resource assessment, see Biomass Resource Page.
http://www.repartners.org/biomass/biosources.htm

Green power

Green Power Analysis Tools permit corporate managers to analyze the economic and environmental attributes of one or more green power projects.
http://www.thegreenpowergroup.org/gpat/

Hydropower

Hydropower potential of the United States
http://hydropower.inel.gov/resourceassessment/

Project Economics Tools

All Renewables

Clean Power Estimator is an economic evaluation software program the California Energy Commission is licensing for use from Clean Power Research. The program provides California residential and commercial electric customers a personalized estimate of the costs and benefits of investing in a photovoltaic solar or small wind electric generation system.
http://www.consumerenergycenter.com/renewable/estimator
http://www.clean-power.com/

"The Community Energy Opportunity Finder is an interactive tool that will help you determine your community's best bets for energy solutions that benefit the local economy, the community, and the environment."
http://finder.rmi.org/

RETFinance is used to calculate cost of energy of biomass, geothermal, solar, and wind based on modifiable project assumptions; the program also allows users to store and change multiple projects.
http://analysis.nrel.gov/retfinance/login.asp

RETScreen International is used to analyze the technical and financial viability of renewable energy projects. These tools make it easier for stakeholders to consider the financial feasibility of renewable energy projects at the critically important initial planning stage while significantly reducing the costs of assessing potential projects. Some of the enabling tools include renewable energy project analysis software models and manuals; international product and weather databases; project case studies; and university textbooks. RETScreen assesses both large and small scale, on-grid and off-grid wind, photovoltaic, small hydro, solar thermal, passive solar, biomass heating and ground source heat pumps.
http://retscreen.gc.ca

Wind

Distributed Energy Calculator
http://www.deforum.org/debasic.asp

The National Renewable Energy Laboratory's Wind Project Finance Calculator allows users to create new (or modify an existing) project by entering values for numerous assumptions step-by-step, until enough information has been entered to calculate the project's cost of electricity.
http://analysis.nrel.gov/windfinance/login.asp

Windustry's Wind Project Calculator was developed to assist farm owners and operators in evaluating the economics of installing a wind turbine on their farms to provide electricity for the farm and home. Windustry also provides a directory of national wind maps resources.
http://www.windustry.org/calculator/default.htm
http://www.windustry.org/resources/windmaps.htm

The National Wind Coordinating Committee has produced a report Guidelines for Assessing the Economic Development Impacts of Wind Power designed to guide the assessment of the economic impacts of wind power development. The purpose of the guidelines is to identify the most important factors that should be considered in economic impact analyses of wind power development as well as to provide a consistent basis for comparing the impacts across studies.
http://www.nationalwind.org/pubs/economic/guidelines.pdf

Geothermal

Financing Geothermal Development from Geothermal-biz.com takes a look at types of geothermal projects, direct use costs, electricity generation costs, financing challenges, sources of financing, state and federal incentives.
http://www.geothermal-biz.com/Battocletti_Portland_620_2.pdf
http://www.geothermal-biz.com/

Geothermal resource maps have been developed by the U.S. Department of Energy to assist states, utilities and others, interested in identifying geothermal resource potential for use in power generation and direct use applications.
http://geothermal.id.doe.gov/maps-software/

Green House Gas

Greenhouse Gas Equivalency Calculator
http://www.usctcgateway.net/tool

Science Applications International Corporation, under a grant from the U.S. DOE, has developed a new project screening software tool for distributed generation applications. The Distributed Generation Analysis Tool provides assessments of DG applications in the form of a 20-year life cycle cost analysis and environmental impact assessment and predicts successful projects.
http://www.eere.energy.gov/distributedpower/news/134.html

Project Implementation and Integration Tools

General Renewables

The GREENTIE Project Broker Facility is a tool to help you source appropriate supplier organizations for your clean energy project from the GREENTIE Directory. The Directory contains information on more than 5,000 suppliers around the world whose clean energy technologies help to reduce greenhouse gas emissions. The Broker takes you through a step-by-step process, designed to gather information about your project and requirements, and then matching them to the most appropriate organizations that may be able to help you out. The Broker then allows you to send information to those suppliers it finds to match your project profile.
http://www.greentie.org/project_broker/

The Federal Renewable Energy Screening Assistant Version 2.5 allows energy auditors in the DOE SAVEnergy Program to quickly evaluate renewable energy opportunities and energy systems options for possible inclusion in a facility's energy program. The program is a supplement to the energy and water conservation audits that will be completed for all Federal buildings and will flag renewable energy opportunities by facilitating the evaluation and ranking process.
http://www.eere.energy.gov/femp/techassist/softwaretools/softwaretools.html#fresa

The DOE Office of Building Technology, State and Community Program has descriptions of 265 energy-related software tools for buildings, with an emphasis on using renewable energy and achieving energy efficiency and sustainability in buildings.
http://www.eere.energy.gov/buildings/tools_directory/

Wind

The Iowa Department of Natural Resources wind programs Web site provides a number of reports on wind power including, "Wind Analysis Guidelines," "Analysis of Delivering Wind Energy to High Load Centers in the Midwest," and "Wind Hybrid Study."
http://www.state.ia.us/dnr/energy/MAIN/publications&Reports.html#RenewableEnergyPublications

Recognizing the emerging popularity of wind as a distributed generation application, the Utility Wind Interest Group has organized this effort to assess the impacts of small-scale wind generation on utility distribution networks. The primary goal of the Distributed Wind Impacts Project is the development of a set of tools to aid utility distribution and planning engineers in analyzing wind generation at the distribution system level. The tools consist of technical information resources and a set of engineering software application tools.
http://www.uwig.org/uwigdistwind/

The Utility Wind Interest Group has released a summary report, Wind Power Impacts on Electric-Power-System Operating Costs, which includes results from studies conducted on the power systems of Xcel Energy, Bonneville Power Administration, PJM, We energies and others. The study results, which are linked to the penetration of wind on a given system, show a range of $1.47/MWh for 7 percent penetration in BPA's system to a high of $5.50/MWh for much higher penetration of 20 percent in PacifiCorp's system. The report also addresses integration issues that still warrant investigation.
http://www.uwig.org/operatingimpacts.html

AWEA's small wind toolbox is a resource for individuals seeking to install a small wind energy system and for individuals, policy makers or others interested in improving opportunities for small wind energy use.
http://www.awea.org/smallwind/toolbox/default.asp

For more information on integrating wind, see the Wind Power Integration Page.
http://www.wapa.gov/es/prp/wind/wpintegration.htm

Solar

The purpose of A Guide to Photovoltaic System Design and Installation is to provide tools and guidelines for the installer to help ensure that residential photovoltaic power systems are properly specified and installed, resulting in a system that operates to its design potential. This document sets out key criteria that describe a quality system and key design and installation considerations that should be met to achieve this goal. This document deals with systems located on residences that are connected to utility power and does not address the special issues of homes that are remote from utility power.
http://www.energy.ca.gov/reports/2001-09-04_500-01-020.PDF

For more information on connecting solar to the grid, see the Grid-Connected PV page.
http://www.repartners.org/solar/pvgrid.htm

Appendix 2 Powerpoint Presentation of Monte Carlo Analysis

Evaluating Incremental Additions of Renewable Energy to a Power Supply Portfolio

A Spreadsheet Model Case Study

Prepared to Accompany DEED Project Guidebook
Expanding the Role of Renewables in an Energy Supply Portfolio
September 2004

Acknowledgement

This case study utilized loads and resource information for Gila Resources in Safford Arizona. The analysis was used to present an approach to screening and modeling portfolio impacts to a power portfolio. While the analysis was based upon Gila resources' portfolio data and transmission situation, the results are intended to be illustrative only and do not present an entirely complete description of the evaluation. They were simplified to describe the concept and approach.

Considerable support and insight was provided by K. R. Saline & Associates, PLC of Mesa Arizona who provide resource evaluation and analytic support to Gila Resources, and without whom, this case study would not have been possible.

Purpose of this case study

This case study was developed to illustrate an analytic approach and methodology to evaluating renewable energy alternatives

The case study describes steps to screen alternatives to identify feasible alternatives for further considerations

- How to use resource maps and other decision tools to identify and assess alternatives
- Provide a framework for analysis that can then be built upon and refined
- Provide the analytical elements to begin evaluating the cost vs. risk tradeoffs and their impact to the total power portfolio

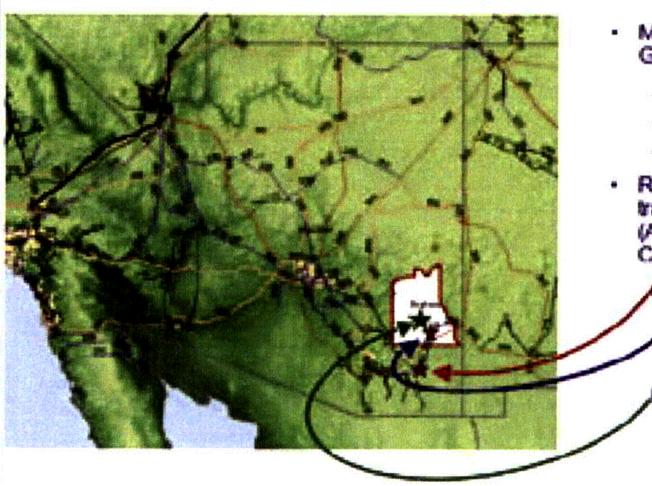
The case study describes the steps to begin an analysis, it does not provide the final answer

- Critical to develop project-specific information as that becomes known
- We have simplified some detailed information on transmission and contractual details to focus discussion on conceptual approach

This case study does not present a detailed solution for Gila Resources, but it does tee-up important questions

- What is the cost break-even point that renewables are more attractive on an economic basis?
- What transmission or other obstacles need to be solved to make renewables make sense
- What level of cost and risk is Gila comfortable pursuing?

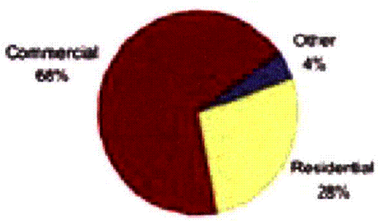
Overview of Gila Resources



- Municipal utility serving the City of Safford, in Graham County Arizona
  - 3,711 customers
  - 10 employees
  - $5.265 million retail revenue*
- Receives federal preference power that is transported by Arizona Electric Cooperative (AEPCO) and Graham County Electric Cooperative (GCEC)
  - a. from Western's Federal Transmission lines, thru AEPCo's lines to it's Apache substation and thennto it's Dos Condados substation
  - b. then delivered to Gila's 5th Ave. substation

* 2001 data as reported in APPA Annual Directory & Statistical Report (2003)

Overview of Gila Resources' Customer Base



Customer	Annual Electric Revenues ($)	% Total Gila Resource's Revenue
Mt. Graham Hospital	346,124	7%
Safford Unified Schools	247,974	5%
City of Safford	205,064	4%
Thriftee Supermarket	155,089	3%
Graham County Government	124,021	2%
Impressive labels	100,136	2%
K Mart Corp	93,230	2%
McDonalds	49,706	1%
QWEST	42,673	1%
Omega Healthcare	42,157	1%
Total	1,406,174	27%

* 2001 data as reported in Gila Resources' first 5 Year IRP Update (2002)

Analyzing the potential increase of wind power to Gila Resource's portfolio

Resource Assumption

- Wind is the resource analyzed for this case study. Other resources that could be considered include geothermal, solar, or landfill gas
- Two scenarios considered for evaluation
  - Add 350 kW of renewables (2%) in 2005
  - Add 1,800 kW of renewables (10%) in 2005

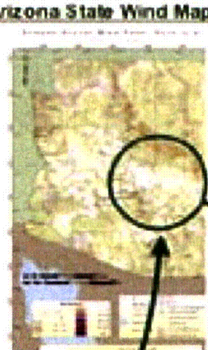
Integration Assumption

- the renewable energy displaces the energy currently provided by short-term market resources
- The output is sold to the City of Safford, Graham County, and to the Unified Schools
- the renewable energy is produced inside the city of Safford or accessible to their 69kV network

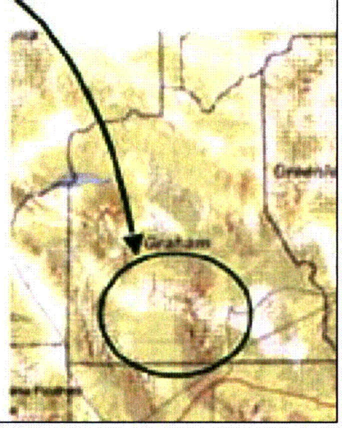
Location Assumption

- Without a detailed site assessment, there is no way to know if a viable wind resource can be located in the city of Safford or an area accessible to the 69kV network. However resource maps indicate there are a small number of Class 3-4 areas in the general vicinity.

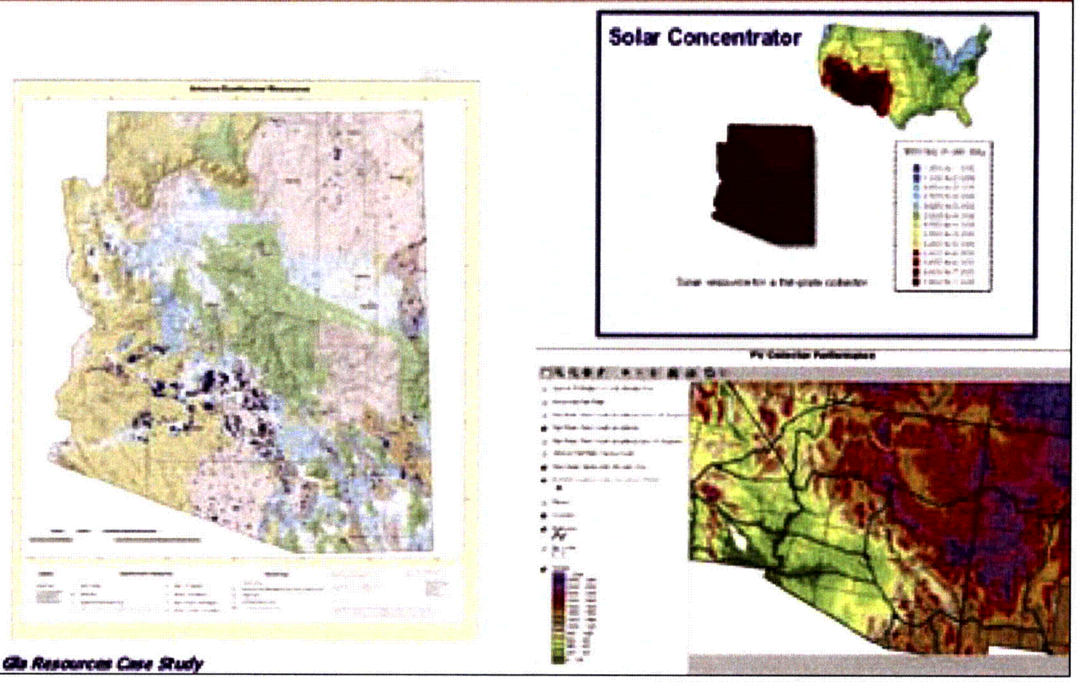
Arizona State Wind Map



Focus on Graham County Area



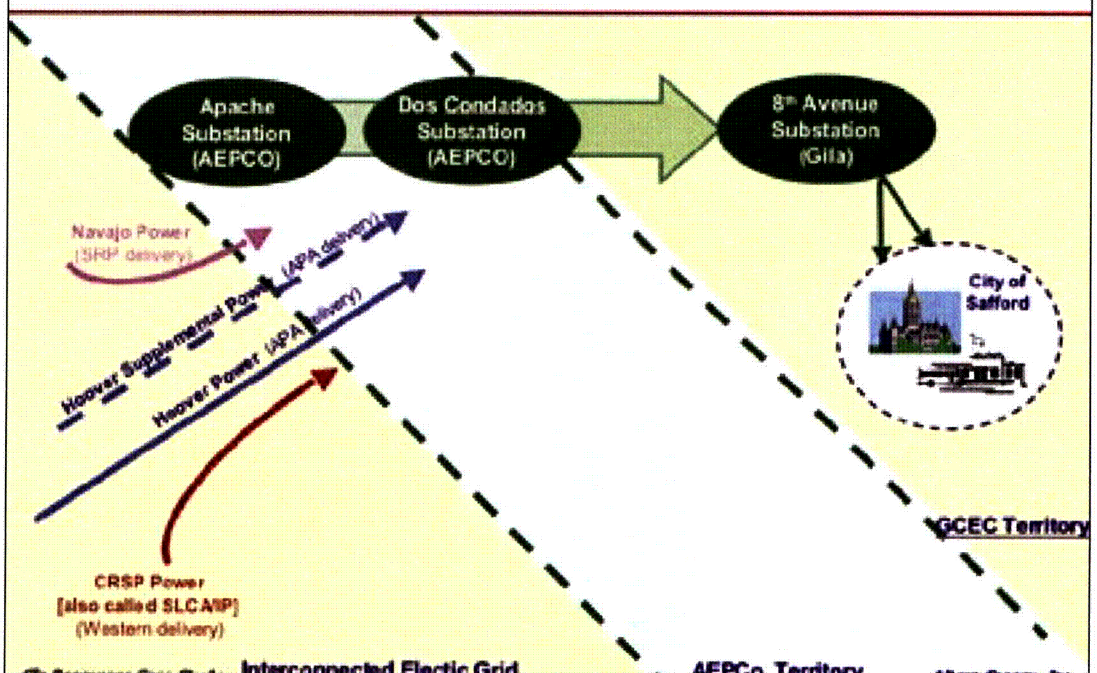
While this case study looks at wind, other potential sources of renewable energy could also be considered. A useful starting point is a renewable resource map of the state



Gila Resources Case Study

Gila Territory

There are currently three primary power supply sources (solid line arrows) and two alternate sources for supplemental supply (dotted line arrows)



Gila Resources Case Study

This case study follows the 10-step approach described in the Guidebook

Phase I - Develop Base Case Forecast

1. **Develop Preliminary Load Forecast**
   - Typical day/ typical month
   - Annual load growth
2. **Complete Utility-Specific Load Forecast**
   - Conservation program
   - Other utility-specific assumptions
3. **Develop Model of Power Portfolio**
   - Existing contracts
   - Self-generation assets
   - Spot market purchases
4. **Develop Capacity Expansion Plan**
   - Fuel forecast
   - Contract alternatives
   - New resource alternatives or new projects
5. **Develop Power Supply Forecast & Budget**
   - "Expected case"
   - Longer-term (5-10 year) perspective

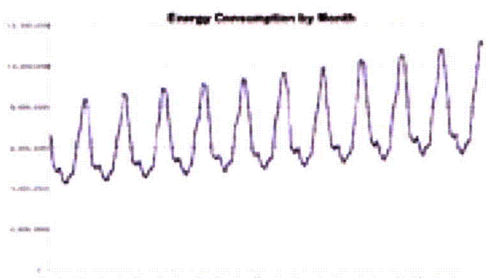
Phase II - Evaluate Additional Renewables

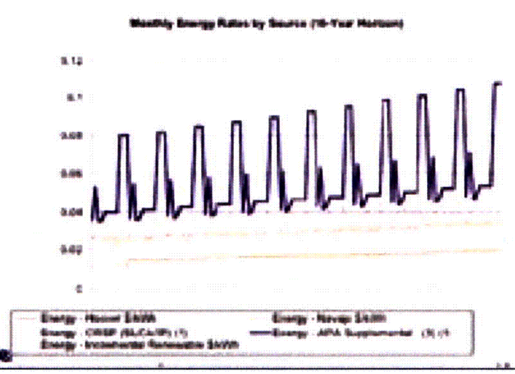
6. **Develop Wind Integration Module**
   - Reliability & cost parameters
   - Integration and forecasting assumptions
7. **Assign Probability Distributions to Inputs**
   - Load forecast
   - Electric price or fuel (gas) forecast
   - Resource variability
8. **Define Scenarios**
   - 2% versus 10%
   - Others, as appropriate
9. **Run Simulations**
   - 2% versus 5%
   - Relative contribution of key input parameters to total cost and risk
10. **Interactive Review of Assumptions**
    - As appropriate

Gila Resources Case Study

1 Develop Preliminary Utility Load Forecast
- Typical day/ typical month
- Annual load growth

Review and update the utilities' load forecasting methodologies and develop a preliminary forecast. For our analysis, we will simplify this step by using a typical daily load profile, and a typical monthly load profile, as well as an assumed constant load growth estimate for the 10 year horizon of our analysis period.





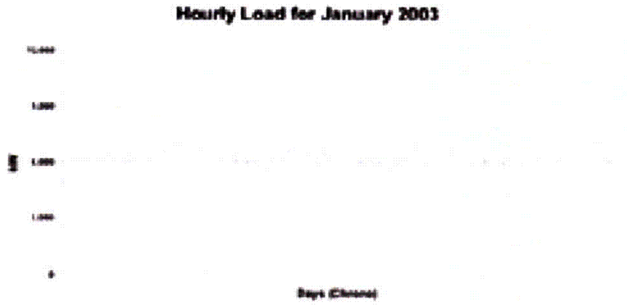
- **Actual consumption by month for the year 2003 is projected forward for 10 years with a 3% annual growth in energy and demand**
- **Monthly Energy rate chart indicates relatively higher cost power from APA Supplemental during summer months (which will be displaced by renewable energy)**

Altera Energy, Inc.

1 Develop Preliminary Utility Load Forecast

- Typical day/ typical month
- Annual load growth

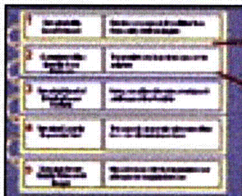
Review and update the utilities' load forecasting methodologies and develop a preliminary forecast. For our analysis, we will simplify this step by using a typical daily load profile, and a typical monthly load profile, as well as an assumed constant load growth estimate for the 10 year horizon of our analysis period.



- **Hourly data can also be used if readily available and if a greater degree of precision is required**
  - Illustrates the variability between days and within the 24-hour period
  - Could be important if demand charges are significant

- **Detailed econometric, or end-use forecasts can be done on this data or it also can be projected forward with an assumed annual growth rate (over the same hour in the previous year)**

Gila Resources Case Study 11 *Altera Energy, Inc.*



2 Complete Utility-Specific Load Forecast

- Conservation program
- Other utility-specific assumptions

The preliminary load forecast can be adjusted to reflect utility-specific considerations or other forecasting adjustments. These could include the utility's conservation or peak load management program assumptions or other contract parameters. In our simplified discussion, we make no adjustments for utility-specific considerations.

- **In our example any reduced consumption from conservation or other peak-demand programs are already reflected in our forecast, so no adjustment is appropriate**
- **If new programs were introduced by utility, it would be appropriate to reduce load forecast accordingly**

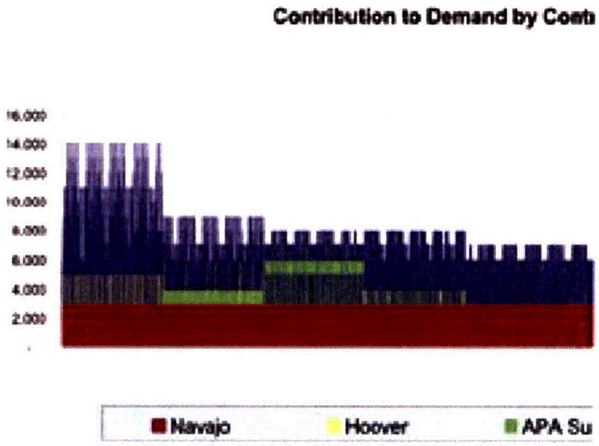
Gila Resources Case Study 12 *Altera Energy, Inc.*

3

Develop Model of Existing Power Portfolio

- Existing contracts
- Self-generation assets
- Spot market purchases

Here, we collect the relevant dispatch attributes of the existing Power Supply Portfolio and generation fleet, including factors such as heat rate/dispatch basis, expected availability, capital and O&M estimates. We will also compile cost and other data related to contractual supply resources, as well as spot market purchases as appropriate.

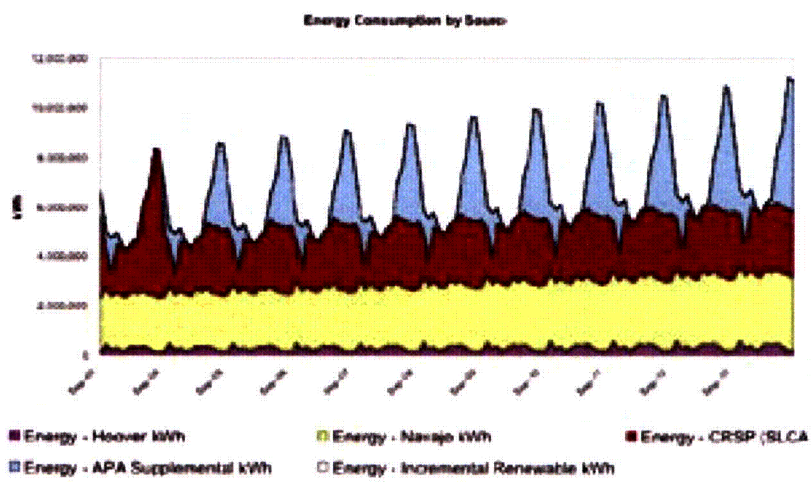


4

Develop Capacity Expansion Plan

- Fuel forecast
- Contract alternatives
- New resource alternatives
- Specific new projects

The capacity expansion plan describes how we will meet future load growth and other supply-side obligations. We compile dispatch attributes of "generic" new resources, including cost, availability and heat rate performance. These resources will be incorporated into the evaluation of alternatives to project forward how future load growth will be met and at what expected market prices.

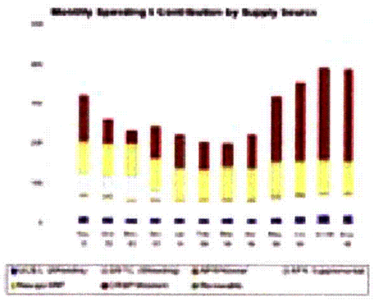


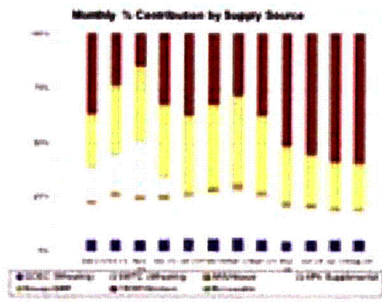
Assumes for modeling purposes that existing Navajo contract is extended after 2011

5 Develop Power Supply Forecast & Budget

- "Expected case"
- Longer-term (5-10 year) perspective

We conclude with the "expected case" of the power supply forecast and budget. This will reflect the longer term (e.g. 5-10 year) forecast for power supply load requirements and financial projections. This will be used as the "base case" in later steps, to determine the impact of alternate scenarios to add renewables to the portfolio.



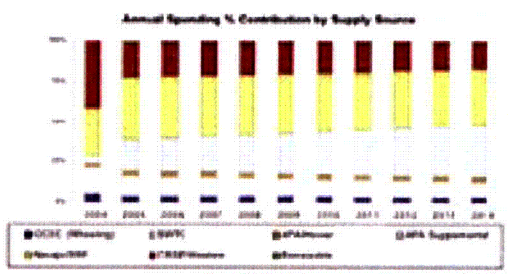


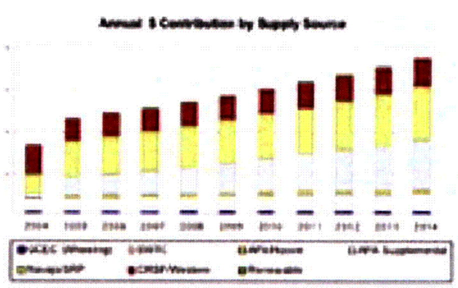
- Step 5 concludes with a monthly (or hourly if applicable) projection of power supply costs by supply source
- Many utilities will already have this level of detail and this will be their actually starting point in the analysis

5 Develop Power Supply Forecast & Budget

- "Expected case"
- Longer-term (5-10 year) perspective

We conclude with the "expected case" of the power supply forecast and budget. This will reflect the longer term (e.g. 5-10 year) forecast for power supply load requirements and financial projections. This will be used as the "base case" in later steps, to determine the impact of alternate scenarios to add renewables to the portfolio.



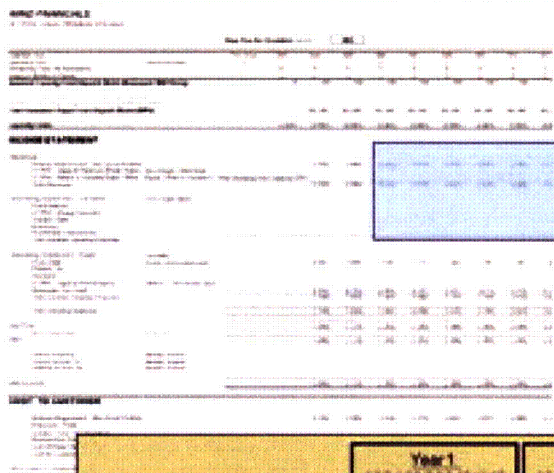


- Using the results of step 5 and projecting forward gives a 10-year horizon more useful for planning purposes
  - Our example has used expected price increases where known, and assumed annual growth rates for other portfolio components
- A 10 year horizon also highlights which portfolio component will be assumed to be displaced by the incremental renewable additions

6 Develop Wind Integration Module

- Reliability & cost parameters
- Integration and forecasting assumptions

The wind integration module can be developed from a site-specific project under consideration, or estimated as a generic wind plant from industry sources. The module should contain specific data and assumptions for local wind resource capabilities, costs, and projected output data.



- This model shown here as illustrative example only
- Integration Module can be for any type of renewable, and can be of various levels of detail. It could even include price quotes from a developer. It only has to provide the following data:

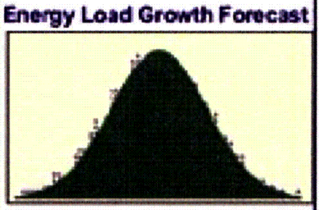
	Year 1 1 2 3 4 5 6 7 8 9 10 11 12	Year 2 1 2 3 4 5 6 7 8 9 10 11 12	Year 10 1 2 3 4 5 6 7 8 9 10 11 12
kWh produced			
$/kWh (PPA or Production Cost)			
$/kW (Capacity cost, or value)			
Transmission & Ancillary Services			
Total Delivered Cost			

7 Assign Probability Distributions to Inputs

- Load forecast
- Electric price forecast
- Fuel (gas) forecast

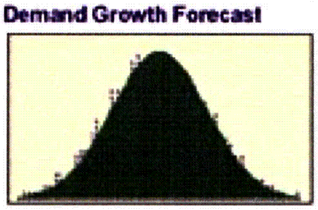
We now take the key input variables developed in Phase I and assign a probability distribution to them. This step can have an extremely significant impact on the eventual results and care must be taken to assign the proper distribution shape, and to ensure the interaction of different input variables with themselves and with other variables.

Energy Load Growth Forecast



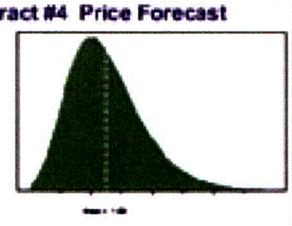
- Energy needs estimated to increase by 3% annually, with a standard deviation of 1%.
- When we perform Monte Carlo simulations, we expect to see:
  - 66% of observations will be between 2% and 4%
  - 95% of observations will be between 1% and 5%

Demand Growth Forecast



- Demand estimated to increase by 3% annually, with a standard deviation of 0.5%
- When we perform Monte Carlo simulations, we expect to see:
  - 66% of observations will be between 2.5% and 3.5%
  - 95% of observations will be between 2% and 4%

Contract #4 Price Forecast



- We assume that short-term supply contract (to be displaced by renewables) is subject to considerable price variability
- We have assumed that energy prices increase by 3% annually, with a standard deviation of 2%. It has a lognormal distribution (more likely to increase than to decrease)

8 Define Scenarios

- 2% versus 10%
- Others, as appropriate

Scenarios will quantify the cost and risk impact on the total portfolio. For each scenario, we will allow the input variables to fluctuate according to the probability distributions we assigned in step 7. We will simplify our scenarios to include only two: 2% and 10% of total portfolio comprised of renewables.

Base Case

Continue receiving power from existing four contract sources

1. Increase contracted delivery from some sources as utility grows into the need.
2. Use APA Supplemental contract to fill short-term needs

Scenario 1

Obtain 2% of portfolio needs from renewables

Install 350 kW project in 2005

1. Use output to provide energy to City, to School District and to County Government customers
2. Assume renewable energy displaces what would have been procured from APA Supplemental supply
3. Assume no contract penalties from existing supply and positive cooperation from SWTC

Scenario 2

Obtain 10% of portfolio needs from renewables

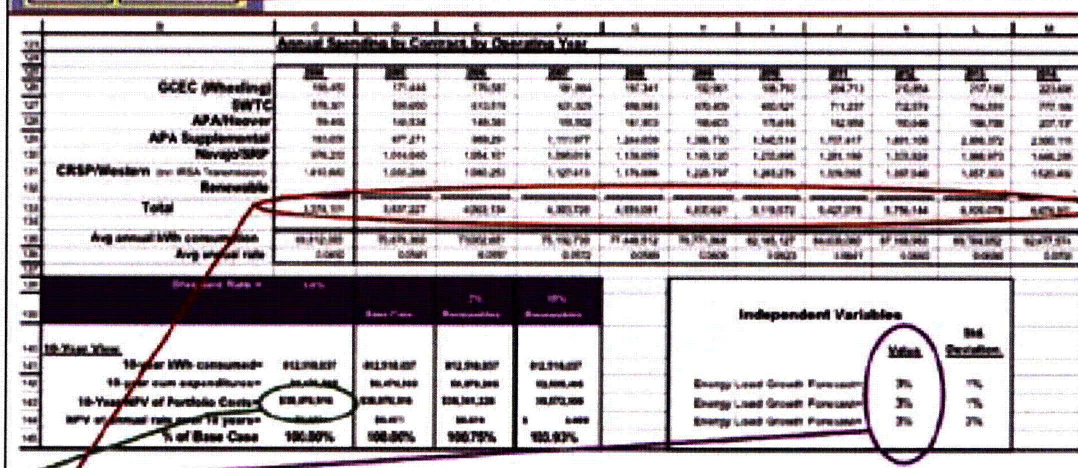
Install 1,800 kW project in 2005

1. Use output to provide energy to City, to School District and to County Government customers
2. Assume renewable energy displaces what would have been procured from APA Supplemental supply
3. Assume no contract penalties from existing supply and positive cooperation from SWTC

10 Interactive Review of Assumptions

- As appropriate

The level of effort involved in this last step will depend on the priority and ability to meet and work with the different stakeholder groups to develop a consensus opinion on the final recommended strategy.



10,000 iterations run for base case and each of the two scenarios

- Annual expenditures for each supply contract calculated over the 10 year horizon
- On each iteration, the value for the independent variables (energy growth, demand growth, and power price) is randomly assigned from the expected range of potential outcomes, and annual costs for each contract, and for each year is calculated
- The frequency which the dependent variable (10 year NPV of portfolio costs) occurs over the 10,000 iterations provides a measure of the portfolio risk

9 Run Simulations

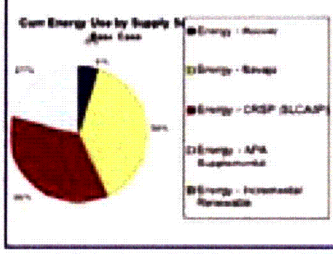
- 2% versus 5%
- Relative contribution of key input parameters to total cost and risk

We next examine the impact of the input variables for the two scenarios on the total impact to portfolio cost, but this could also be expanded to examine other measures. With simulations, we get a distribution of values for the expected portfolio cost. The shape of these distributions provide insight to total portfolio risk.

Base Case

10-Year View

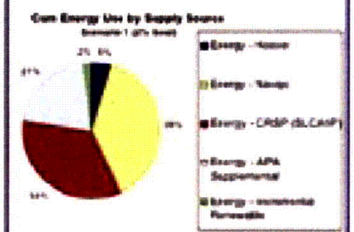
Total kWh consumed:	812,518,037
Cum expenditures:	$50,476,565
NPV Portfolio Costs:	$38,076,916
Avg rate (nominal):	$.0471



Scenario 1

10-Year View

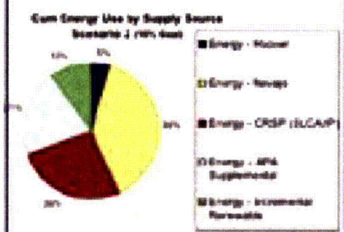
Total kWh consumed:	812,518,037
Cum expenditures:	$50,878,268
NPV Portfolio Costs:	$38,361,226
Avg. rate (nominal):	$.0474
NPV increase from base:	**0.75%**



Scenario 2

10-Year View

Total kWh consumed:	812,518,037
Cum expenditures:	$52,595,405
NPV Portfolio Costs:	$39,572,900
Avg. rate (nominal):	$.0489
NPV increase from base:	**3.93%**



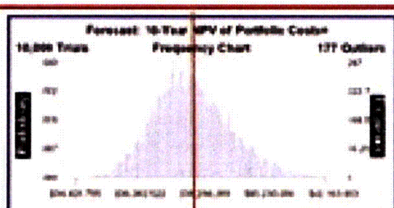
NOTE: *The above results are for a single spreadsheet calculation of expected value. The mean and median values for NPV of Portfolio Cost shown on other output will differ from the expected value due to the distribution of simulated results.*

10 Interactive Review of Assumptions

- As appropriate

The level of effort involved in this last step will depend on the priority and ability to meet and work with the different stakeholder groups to develop a consensus opinion on the final recommended strategy.

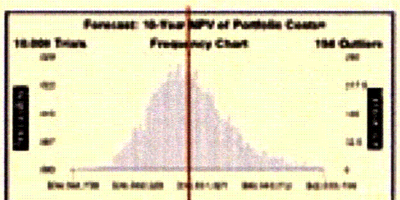
Base Case



Statistic	**Value**
Trials	10,000
Mean	$38,200,426
Median	$38,005,753
Standard Deviation	$1,600,045

Scenario #1

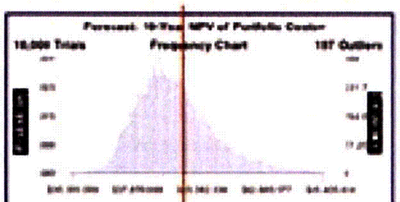
2% renewable added in 2005



Statistic	**Value**
Trials	10,000
Mean	$38,460,468
Median	$38,243,222
Standard Deviation	$1,537,711

Scenario #2

10% renewable added in 2005



Statistic	**Value**
Trials	10,000
Mean	$39,761,990
Median	$39,389,134
Standard Deviation	$2,159,044

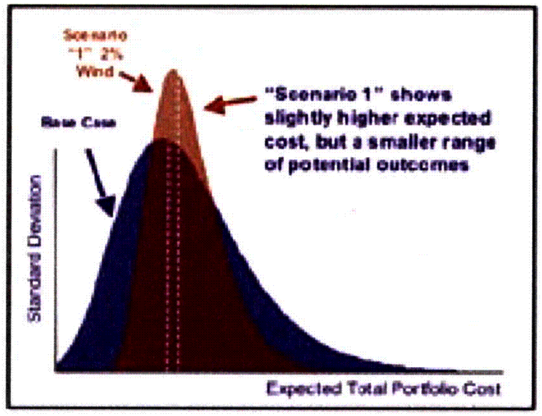
10 Interactive Review of Assumptions

- As appropriate

The level of effort involved in this last step will depend on the priority and ability to meet and work with the different stakeholder groups to develop a consensus opinion on the final recommended strategy.

Another simplified illustration of the statistical results are shown at left:

- Scenario 1 incurs slightly higher expected costs (0.75% higher than base case)
- The distribution of simulated results for Scenario 1 also incur dramatically tighter range of potential outcomes (less risk)



Summary and Conclusion

This type of simulation of the expected portfolio cost and risk helps answer many questions from a modeling perspective.

What Monte Carlo Simulation Can Provide

1. The relative impact of different incremental additions of renewable energy to a portfolio
2. A quantified approach to trading off least cost versus least risk alternatives
3. A screening approach and methodology to focus in on preferred alternatives
4. A method to calculate a threshold cost that a utility might be willing to pay for a specified amount of renewable energy (to meet a portfolio cost target)
5. A flexible model that can be used in planning workshops, or even public forums, to allow participants to pose hypothetical analysis, and quickly see the portfolio impact

What Monte Carlo Simulation Cannot Provide

1. An absolute, quantifiable answer. The results are always going to be dependent upon input assumptions.
2. A final answer. The results of this type of screening analysis must then investigate more detailed transmission interconnection issues to better understand the true impact

Richmond Power & Light Case Study:

Focus on Communication to Encourage Public Participation to Purchase Renewables

Richmond Power and Light is implementing a public participation plan that includes customer surveys, education and Web site signup for a green energy program. Richmond Power and Light is a municipal utility in eastern Indiana with annual revenues of $15 million.

The utility committed to investing in a 1.5 MW landfill gas recovery and generation system for operation in early 2005. To help pay for this renewable energy resource, a goal was established to sell 900 blocks of green energy at 1.5 cents per kilowatthour per month per block.

However, awareness of renewable energy among the 18,000 residential and 4,000 commercial/industrial customers was low, based on survey results. The utility designed a seven-month public education program on renewable energy culminating in a call to action to subscribe to the program. A series of bill inserts over the period progressively educated customers on renewable energy in general, then different types of renewables, and finally on landfill methane as a renewable energy source.

Text and graphics emphasized many benefits for this 100-MW, coal-burning utility. Themes included using local resources, displacing car loads of coal, improving the environment and husbanding energy for the future.

Segmenting customer markets results in several tactics to recruit participants. Early adopters and environmental sympathizers are being targeted at a local college. Corporate citizenship is being appealed to at companies with sustainability policies. For the high-tech segments of the population, a utility Web site echoes the bill insert education materials, shows photos of progress on landfill construction and allows on-line registration for the program. All customers are receiving bill inserts for each of seven months reinforcing the message of supporting renewables programs.

Plans also include contingencies. One is if the program is oversubscribed. In this case, it will be expanded to add wind and perhaps solar resources to the energy supply mix.

Richmond Power and Light is proceeding with this well planned program through the Demonstration of Energy-Efficient Development program of the American Public Power Association.

Fort Collins Utilities:

Screens and Selects a Wide Range of Renewable Alternatives

Ambitious goals and objectives develop over time with careful study and deliberate implementation, as demonstrated by City of Fort Collins Utilities, a Colorado municipal utility providing electric, water, wastewater and storm water services. In 1998, it was one of the first United States utilities to adopt a green pricing program for customers to purchase wind energy. By 2003, 0.8 percent of the utility's energy was purchased from wind farms in cooperation with Platte River Power Authority (PRPA), a joint action agency providing wholesale power to Fort Collins and other Front Range cities.

Fort Collins' City Council adopted the Electric Energy Supply Policy in March 2003, which set an ambitious objective of increasing the city's percentage of renewable energy to 2 percent by the end of 2004 and to 15 percents by 2017. These objectives grew out of a deliberative process that began in December 2001 and culminated in March 2003.

Fort Collins Utilities has a long history of leadership in environmental and renewable energy planning and implementation. The Fort Collins City Council, sitting as the Utility board of directors, charged the utility's citizen advisory board (CAB) to recommend long-term supply policies. The CAB recommended several objectives as part of a broader strategy to encourage renewable energy. They included increasing public awareness of renewable energy, working with PRPA to diversify resources and supporting sustainable practices in energy use and management. The CAB recommended a goal of 10 percent renewable energy by 2017. City Council supported the goal to 15 percent by a one-vote margin in March 2003.

Now, in the summer of 2004, Fort Collins Utilities is effectively moving forward. In addition to the 10,000 megawatthours the utility has been buying under its green pricing program. It will also purchase another 20,000 MWh of wind energy from PRPA based on renewable energy credits for a total of 2.3percent of electricity sales in 2004.

Fort Collins Utilities has reduced the green pricing program premium from 2.5 cents/kWh hour to 1 cent/kWh, reflecting the blended costs of the various sources of wind energy. Starting in January 2004, electric rates were increased by 1 percent to all customers to help underwrite the renewable energy program. Fort Collins Utilities will continue to evaluate opportunities to increase the use of renewable energy to reach its goal of 15 percent by 2017.

The utility participates in other renewable energy programs as well. Net metering started in April 2004 at retail rates for up to 10 kilowatts per customer for the first 25 customers. Geothermal heat pumps are encouraged with expert technical assistance. At its wastewater treatment facility, the utility captures methane gas to provide heat to the digester process. Other renewable resource options that have been explored over the years include solar domestic water heating, small head hydro and fuel cells. The utility is working on a joint project with the city's transportation department to build a hydrogen fueling station to supply fleet transportation applications for the City of Fort Collins.

Sacramento Municipal Utility District:

Sets Clear Goals and Implements Aggressively

Sacramento Municipal Utility District continues to build on its strategy for resource diversity with objectives to increase the renewable energy in its system portfolio from 7 percent in 2002 to 10 percent by 2006 and to 20 percent by 2011. Both utility-scale and customer-scale renewable resources are encouraged.

As a vertically integrated utility, SMUD operates with renewable energy generation of 228 MW of non-hydro renewables in its system portfolio, roughly 35 percent of which is utility-owned and operated. This includes 15 MW of wind power and 10 MW of photovoltaics. It also owns biomass and small hydro facilities. Large hydro resources account for about 25 percent SMUD customer demands in an average water year.

SMUD recognizes that asset ownership brings project control and operational flexibility. However, power purchases are also part of the portfolio with the advantage of reducing financial liabilities, but adding exposure to increased price volatility. This occurs as well with renewable energy resources. The costs for the majority of renewable generation in SMUD's resource mix are recovered in the rate base.

SMUD also has a voluntary green pricing program, which continues to grow, with 27,000 accounts participating or 4.6 percent of the customer population as of July 2004. The nearly 150,000 MWh/year acquired through the program are supplied from landfill gas, wind and small hydro resources. Customers pay a $6 per month flat rate premium on top of regular energy costs. The rate is designed to cover 100 percent of the energy required for the average residential account. The green pricing program acquires resources separately from SMUD's other renewable energy programs. This assures participants that their voluntary payments fund specific renewable energy projects that would not proceed without their support.

SMUD also encourages customer-scale renewable resources. Net metering is permitted at full retail rates with no limit on the amount of load or number of participants. SMUD sells photovoltaic systems for homes and businesses. In addition to technical assistance, an incentive of $2.50 per watt is paid for systems of at least 30 kW, plus PV systems are exempt from property taxes.

SMUD encouraged geoexchange heat pumps and solar domestic water heaters in past years, but has recently chosen to encourage customer investments in photovoltaic systems. To help achieve long term objectives to increase the contribution of renewable energy resources in its supply mix, SMUD expects to purchase renewable energy credits.

SMUD also cooperates in research and development projects for renewable resources. Designed to reduce costs and improve effectiveness, projects include photovoltaics, wind, biomass and concentrating solar. In addition to all these activities, SMUD has encouraged and helped underwrite more than 300,000 shade trees since 1990 to save energy, improve the air and beautify neighborhoods.

Appendix 4 Sample Check list Questionnaire

Determining an Appropriate Level of Discussions Between the Utility and the Developer

This checklist follows the overall sequence of the guidebook chapters and has two main parts. The first section has questions to help determine if you are ready to talk with a developer, and the second section has questions to help determine if a developer is ready to talk with you.

Answering some of these questions is an admittedly subjective exercise, and there are no clear criteria for what might constitute a "yes" or a "no." However, even thinking through a subjective assessment of these questions should provide valued feedback to a utility manager about their state of readiness to conduct detailed discussions with developers.

Key Question	Enough information is known to have a useful and productive discussion	Advantageous to conduct additional evaluation prior to having any detailed discussions
	Criteria: No. of "yes" answers	*Criteria: No. of "yes" answers*
I Is There a Good Understanding of the Needs and Desires Of Your Stakeholders?	☐ 2-4 "yes" responses ☐ Utility's direction and understanding of stakeholder's needs appear to be well developed.	☐ 0-1 "yes" responses ☐ Utility direction still appears unclear. Beware developer selling what is not an agreed upon need.
II Have You Adequately Defined Your Renewable Energy Objectives?	☐ 3-4 "yes" responses ☐ Resource needs appear to be well understood.	☐ 0-2 "yes" responses ☐ Indicates probable need for more quantitative analysis to define resource needs.
III Have You Adequately Screened Renewable Energy Alternatives?	☐ 6-11 "yes" responses ☐ Utility ready to narrow potential projects. Any need for structured RFP cycle is a key threshold question.	☐ 0-5 "yes" responses ☐ Utility not yet ready to focus on a specific technology; limit any discussions to information sharing only
IV Is the Development Project Financeable?	☐ 6-9 "yes" responses ☐ A viable project probably worth exploring in greater detail	☐ 0-5 "yes" responses ☐ Early stage project, probably more of a concept than a tangible project at this stage.
V Is the Developer Company Financeable?	☐ 6-8 "yes" responses ☐ Appears to be a solid company suitable for a long-term relationship	☐ 0-5 "yes" responses ☐ Considerable reason for concern before entering long-term relationship.
VI Is the Development Contract Financeable	☐ 7-10 "yes" responses ☐ Contract structure appears reasonable	☐ 0-6 "yes" responses ☐ Project has potential obstacles that could spell trouble

Are You Ready To Talk To A Developer?

	Yes	No
I. Is There a Good Understanding of the Needs and Desires of Your Stakeholders?		
1. Have you identified your key stakeholder groups?		
2. Have you contacted or listened to your key stakeholder groups regarding your renewable energy goals?		
3. Do you know what your key stakeholders really want and what they value regarding your renewable energy?		
4. Does your plan and approach adequately involve key stakeholder groups at major decision points?		
II. Have You Adequately Defined Your Renewable Energy Objectives?		
1. Do you have explicit goals for where your renewable energy efforts are heading?		
2. Does the rest of your internal organization and key stakeholder groups understand your goals and how you will reach them?		
3. Can you adequately measure your renewable energy goals and communicate progress to internal or external stakeholders?		
4. Will your organization ever be able to measure and determine if it is succeeding in its renewable energy goals or will it continue to evolve?		
III. Have You Adequately Screened Renewable Energy Alternatives?		
1. Have you identified a preferred renewable energy technology that best suits your utility?		
2. Have you considered, and do you understand, the implications of how this renewable resource will interact with the rest of your portfolio?		
a. Energy needs and costs?		
b. Capacity needs and costs?		
c. Availability needs and costs?		
d. Interaction with rest of portfolio?		
e. Impact of transmission and scheduling requirements?		
f. Geographic considerations and constraints?		
3. Is a structured decision-making process defined or needed?		
a. Can you proceed on sole-source discussions (or is an RFP cycle needed?)		
b. Will decision be well received or is there high potential a decision could be second-guessed in the future?		

Is the Developer Ready To Talk To You?

	Yes	No
IV. Is the *Development Project* Financeable?		
1. Has the developer passed successfully complete key schedule milestones?		
a. Located a specific site for development?		
b. Begun collecting data to support siting process		
c. Adequately validated the energy source (drilled test wells or collected MET tower data)?		
d. Obtained the necessary lease or easement agreements?		
e. Obtained the necessary land permits?		
f. Applied for necessary interconnection or wheeling agreements?		
g. Had any tangible discussions with any other utilities about PPAs?		
h. Had any tangible discussions with any other financing entities		
2. Has any independent assessment of the project been conducted or is available?		
a. Has any 3rd party due diligence been conducted?		

b. Has any specialist validated the energy source (drilled test wells, collected MET tower data or other)?		
c. Has any specialist validated the energy source (drilled test wells, collected MET tower data or other)?		
d. Other (what are some preliminary 3rd party requirements to proceed with financing discussions??		
3. Is the project totally dependent on signing a PPA with you in order for it to move forward?		
IV. Is the *Developer Company* Financeable?		
4. Is the development company adequately experienced?		
5. Are the development team members adequately experienced?		
6. Does the development company have adequate financial strength and resources?		
7. Does the development company display an attractive attitude and responsiveness to your specific needs experienced?		
8. Are other project participants or issues that help or hurt from a financing perspective identified and acceptable?		
a. Developer's subsidiaries?		
b. Developer's corporate structure or deal structure?		
c. Developer's risk exposure to other partners or circumstances?		
V. Is the *Development Contract* Financeable?		
9. Is the price competitive?		
10. Are transmission or deliverability issues identifiable and acceptable?		
11. Will ratings agencies view this project's impact as positive to your financials?		
12. Is the project deal structure clear and straightforward?		
13. Are regulatory uncertainties (federal, state and local) identifiable and acceptable?		
14. Is there a balanced allocation of risks between participants?		
15. Are there balanced timing considerations (e.g. is O&M contract time horizon consistent with PPA)?		
16. Are other project terms and conditions acceptable on the surface?		
17. Could this project help your portfolio's risk exposure?		
18. Are all other potential circumstances or conditions identified and acceptable?		

Notes

Notes

Sec 9.2 Ref 3

SCEG-288

Wind Energy Resource Maps of South Carolina

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June 10, 2005

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EXECUTIVE SUMMARY

This report describes a wind-mapping project conducted by AWS Truewind for the South Carolina Energy Office. Using the MesoMap system, AWS Truewind produced maps of mean annual wind speed in South Carolina for heights of 30, 50, 70, and 100 m above ground, as well as maps of mean annual wind power at 50 and 100 m. AWS also produced data files of the predicted wind speed frequency distribution and speed and energy by direction. The maps and data files are provided on a CD with the ArcReader software, which will enable users to view, print, copy, and query the maps and wind rose data.

The MesoMap system consists of an integrated set of atmospheric simulation models, databases, and computers and storage systems. At the core of MesoMap is MASS (Mesoscale Atmospheric Simulation System), a numerical weather model, which simulates the physics of the atmosphere. MASS is coupled to a simpler wind flow model, WindMap, which is used to refine the spatial resolution of MASS and account for localized effects of terrain and surface roughness. MASS simulates weather conditions over a region for 366 historical days randomly selected from a 15-year period. When the runs are finished, the results are input into WindMap. In this project, the MASS model was run on a grid spacing of 2.5 km and WindMap on a grid spacing of 200 m.

AWS Truewind subsequently validated the wind maps using data from 15 stations. The data were first extrapolated to a height of 50 m. The predicted wind speeds are on average about 0.03 m/s higher than the observed/extrapolated speeds. The standard deviation of the biases is 0.41 m/s, or about 8.6% of the average speed at all the stations. The error margin in meters/second is comparable to that obtained in other MesoMap projects, but in percentage terms it is somewhat larger than usual because of the relatively low average speeds.

The wind maps indicate that the wind resource of South Carolina is relatively good offshore and at exposed points along the coast but declines substantially inland. Well offshore, the mean wind speed at 70 m height ranges from 8.0 to 8.5 m/s, and the wind power density ranges from 600 to 800 W/m² (NREL class 6); nearer the coast, the mean speed at 70 m ranges from 6.5 to 7.5 m/s and the wind power 300 to 400 W/m2 (NREL class 3). The mean wind speed at 70 m height in coastal areas and inland lakes is predicted to be 5.5 to 7.0 m/s, and the predicted mean wind power density at 50 m is 200 to 300 W/m², or NREL class 2. The wind resource in the rest of the state is generally less than 6.0 m/s at 70 m and the wind power density less than 200 W/m² (NREL class 1), except for a few high ridges in the extreme northwestern corner of the state along the North Carolina border, where the mean speed may reach 8 m/s. The wind resource increases significantly with height above ground, however, especially away from the coast. Winds at 100 m are typically 12-15% stronger and contain 40-50% more energy than at 70 m.

1. INTRODUCTION

The South Carolina Energy Office is interested in assessing the potential for wind energy development in South Carolina and assisting developers in finding suitable sites for wind energy projects. Conventional field techniques of wind resource assessment can be time consuming, however, and often depend heavily on local meteorological expertise as well as the availability of reliable and representative wind measurements. Conventional wind flow models, on the other hand, have often proven inaccurate in complex wind regimes, and even in moderate terrain their accuracy can decline substantially with distance from the nearest available reference mast.

Mesoscale-microscale modeling techniques offer a solution to these challenges. By combining a sophisticated numerical weather model capable of simulating large-scale wind patterns with a microscale wind flow model responsive to local terrain and surface conditions, they enable the mapping of wind resources over large regions with much greater accuracy than has been possible in the past. In addition, they do not require surface wind data to make reasonably accurate predictions. While on-site measurements are still required to confirm the predicted wind resource at any particular location, mesoscale-microscale modeling can greatly reduce the time and cost to identify and evaluate potential wind project sites.

AWS Truewind has been the world leader in the development of mesoscale-microscale mapping techniques, having introduced the MesoMap system in the late 1990s. In the past five years, MesoMap has been applied in nearly 30 countries on four continents. In North America alone, MesoMap has been used to map over 30 US states and several provinces of Canada and states of Mexico.

The objective of the current project was to use MesoMap to create high-resolution wind resource maps of South Carolina and to provide wind resource data in a format enabling users to assess potential sites in a GIS. These objectives have been met. In the following sections, we describe the MesoMap system and mapping process in detail; how MesoMap was applied in this project; the validation process and results; the final wind maps and data files; and guidelines for the use of the maps.

2. DESCRIPTION OF THE MESOMAP SYSTEM

The MesoMap system has three main components: models, databases, and computer systems. These components are described below.

2.1. Models

At the core of the MesoMap system is MASS (Mesoscale Atmospheric Simulation System), a numerical weather model that has been developed over the past 20 years by AWS's partner MESO, Inc., both as a research tool and to provide commercial weather forecasting services. MASS simulates the fundamental physics of the atmosphere including conservation of mass, momentum, and energy, as well as the moisture phases, and it contains a turbulent kinetic energy module that accounts for the effects of viscosity and thermal stability on wind shear. As a dynamical model, MASS simulates the evolution of atmospheric conditions in time steps as short as a few seconds. This creates great computational demands, especially when running at high resolution. Hence MASS is usually coupled to a simpler but much faster program, WindMap, a mass-conserving wind flow model. Depending on the size and complexity of the region and requirements of the client, WindMap is used to improve the spatial resolution of the MASS simulations to account for the local effects of terrain and surface roughness variations.

2.2. Data Sources

The MASS model uses a variety of online, global, geophysical and meteorological databases. The main meteorological inputs are reanalysis data, rawinsonde data, and land surface measurements. The reanalysis database – the most important – is a gridded historical weather data set produced by the US National Centers for Environmental Prediction (NCEP) and National Center for Atmospheric Research (NCAR). The data provide a snapshot of atmospheric conditions around the word at all levels of the atmosphere in intervals of six hours. Along with the rawinsonde and surface data, the reanalysis data establish the initial conditions as well as updated lateral boundary conditions for the MASS runs. The MASS model itself determines the evolution of atmospheric conditions within the region based on the interactions among different elements in the atmosphere and between the atmosphere and the surface. Because the reanalysis data are on a relatively coarse, 200 km grid, MASS is run in several nested grids of successfully finer mesh size, each taking as input the output of the previous nest, until the desired grid scale is reached. This is to avoid generating noise at the boundaries that can result from large jumps in grid cell size. The outermost grid typically extends several thousand kilometers.

The main geophysical inputs are elevation, land cover, vegetation greenness (normalized differential vegetation index, or NDVI), soil moisture, and sea-surface temperatures. The global elevation data normally used by MesoMap were produced by the US Geological Survey in a gridded digital elevation model, or DEM, format from a variety of data sources.[1] The US Geological Survey, the University of South Carolina, and the European Commission's Joint Research Centre (JRC) produced the global land cover data in a cooperative project. The land cover classifications are derived from the interpretation of Moderate Imaging Spectroradiometer (MODIS) data collected by satellite. The model translates both land cover and NDVI data into physical parameters such as surface roughness, albedo, and emissivity. The nominal spatial resolution of all of these data sets is 1 km. Thus, the standard output of the MesoMap system is a 1 km gridded wind map. However, much higher resolution maps can be produced where the necessary topographical and land cover data are available. In the United States, the resolution is typically 50 to 200 m.

[1]The US Defense Department's high-resolution Digital Terrain Elevation Data set is the principal source for the global 1 km elevation. Gaps in the DTED data set were filled mainly by an analysis of 1:1,000,000 scale elevation contours in the Digital Chart of the World (now called VMAP).

2.3. Computer and Storage Systems

The MesoMap system requires a very powerful set of computers and storage systems to produce wind resource maps at a sufficiently high spatial resolution in a reasonable amount of time. To meet this need AWS Truewind has created a distributed processing network consisting of 94 Pentium II processors and 3 terabytes of hard disk storage. Since each day simulated by a processor is entirely independent of other days, a project can be run on this system up to 94 times faster than would be possible with any single processor. To put it another way, a typical MesoMap project that would take two years to run on a single processor can be completed in just one week.

2.4. The Mapping Process

The MesoMap system creates a wind resource map in several steps. First, the MASS model simulates weather conditions over 366 days selected from a 15-year period. The days are chosen through a stratified random sampling scheme so that each month and season is represented equally in the sample; only the year is randomized. Each simulation generates wind and other weather variables (including temperature, pressure, moisture, turbulent kinetic energy, and heat flux) in three dimensions throughout the model domain, and the information is stored at hourly intervals. When the runs are finished, the results are compiled into summary data files, which are then input into the WindMap program for the final mapping stage. The two main products are usually (1) color-coded maps of mean wind speed and power density at various heights above ground and (2) data files containing wind speed and direction frequency distribution parameters. The maps and data can then be compared with land and ocean surface wind measurements, and if significant discrepancies are observed, adjustments to the wind maps can be made.

2.5. Factors Affecting Accuracy

In our experience, the most important sources of error in the wind resource estimates produced by MesoMap are the following:

- Finite grid scale of the simulations
- Errors in assumed surface properties such as roughness
- Errors in the topographical and land cover data bases

The finite grid scale of the simulations results in a smoothing of terrain features such as mountains and valleys. For example, a mountain ridge that is 2000 m above sea level may appear to the model to be only 1600 m high. Where the flow is forced over the terrain, this smoothing can result in an underestimation of the mean wind speed or power at the ridge top. Where the mountains block the flow, on the other hand, the smoothing can result in an overestimation of the resource as the model understates the blocking effect. The problem of finite grid scale can be solved by increasing the spatial resolution of the simulations, but at a cost in computer processing and storage.

Errors in the topographical and land cover data can obviously affect wind resource estimates. While elevation data are usually reliable, errors in the size and location of terrain features nonetheless occur from time to time. Errors in the land cover data are more common, usually as a result of the misclassification of aerial or satellite imagery. It has been estimated that the global 1 km land cover database used in the MASS simulations is about 70% accurate. Where possible, more accurate and higher resolution land cover databases should be used in the WindMap stage of the mapping process to correct errors introduced in the MASS simulations. In the United States, we use a 30 m gridded Landsat-derived land cover database for this purpose; a similar 250 m database, called Corine, is available for most of Western Europe.

Even if the land cover types are correctly identified, there is uncertainty in the surface properties that should be assigned to each type, and especially the vegetation height and roughness. The forest category, for example, may include many different varieties of trees with varying heights and density, leaf characteristics, and other features that affect surface roughness. Cropland may be virtually devoid of trees and buildings, or it may have many windbreaks. Uncertainties like these can be resolved only by acquiring more information about the area through aerial photography or field observation. However this is not practical when (as in this project) the area being mapped is very large.

3. IMPLEMENTATION OF MESOMAP FOR THIS PROJECT

The standard MesoMap configuration was used in this project. MASS was run on the following nested grids:

First (outer) grid level: 30 km
Second (intermediate) grid level: 10 km
Third (inner) grid level: 2.5 km

The usual geophysical and meteorological inputs were used. The WindMap program adjusted the wind resource estimates to reflect local topography and surface roughness changes on a grid spacing of 200 m. For the topographical data, we used the National Elevation Dataset, a digital terrain model produced on a 30 m grid by the US Geological Survey (USGS). For the land cover, we used the National Land Cover Dataset, which is derived from Landsat imagery. It was also produced by the USGS on a 30 m grid.[2] Both data sets are of very high quality.

In converting from land cover to surface roughness, the roughness length values shown in Table 1 were assumed. We believe these values to be typical of conditions in states such as South Carolina. However the actual roughness could vary a good deal within each class.

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[2] Information on the National Land Cover Data set can be found at the following web address: http://landcover.usgs.gov/nationallandcover.html. Information on the National Elevation Dataset (NED) can be found at http://edcwww.cr.usgs.gov/products/elevation/ned.html.

Table 1. Range of Surface Roughness Values for Leading Land Cover Types

Description	Roughness (m)
Cropland	0.03
Grasslands/Herbaceous	0.03
Shrubland	0.05
Deciduous Forest	0.9
Evergreen and Mixed Forest	1.125
Residential Development	0.3
Urban Development	0.75
Herbaceous Wetland	0.2
Woody Wetland	0.66

The roughness is not the only surface property with a direct effect on near-surface wind speeds. Where there is dense vegetation the wind can skim along the vegetation canopy, thereby displacing the flow above the ground and reducing the speed observed at a fixed height above ground. The displacement height is defined as the height at which the wind speed becomes zero in the logarithmic shear formula. The shear formula is as follows:

$$\frac{v_2}{v_1} = \frac{\ln\left(\frac{z_2 - d}{z_0}\right)}{\ln\left(\frac{z_1 - d}{z_0}\right)}$$

Here, d is the displacement height, z_1 and z_2 are two different heights at which the speed v is measured, and z_0 is the surface roughness (generally much less than z_2 and z_1). Note that according to this formula, when $z_2 = d + z_0$, $v_2 = 0$.

The displacement height is usually estimated to be about two-thirds to three-fourths the maximum vegetation height. For this project, we assumed that the displacement height was 10 times the surface roughness length, which was in turn defined to be approximately 7.5% of the vegetation height. For deciduous forests with a roughness length of 0.9 m, this resulted in a displacement height of 9 m.

The effect of displacement height is to reduce the wind speed observed near the ground and to increase the apparent wind shear measured with respect to ground level. It can also reduce the wind speed measured in small clearings, since the ground appears to be in a "hole" at a depth d below the vegetation canopy. The impact of this hole on wind speed diminishes as the clearing becomes large enough for the flow to reach equilibrium with the new effective ground height. As a rule of thumb, the clearing width should be at least 20 times the displacement height for the effect to be negligible at the center of the clearing, but under some conditions the minimum width should be even larger.

4. VALIDATION

The wind resource maps were initially produced without any reference to surface wind measurements. We then validated the wind maps by comparing the predicted speed against data from 15 airport stations.

The validation was carried out in the following steps:

1. Station locations were verified and adjusted, if necessary, by comparing the quoted elevations and station descriptions against the elevation and land cover maps. Where there was an obvious error in position, the station was moved to the nearest point with the correct elevation and surface characteristics.

2. The observed mean speed and power were extrapolated to a common reference height of 50 m using the power law. The shear exponent was estimated from available information about the sites. Assumed shear values ranged from 0.21 to 0.30 with an average of 0.25.[3]

3. The error margin for each data point was then estimated as a function of two factors: the tower height and the number of years of measurement. The tower height enters the equation because of uncertainty in the wind shear. We assumed an error margin in the shear exponent of 0.04, reflecting significant uncertainty in the ground cover, tree height, buildings, and other factors. The number of years of data affects the uncertainty because winds recorded over a short period may not be representative of long-term conditions. A rule of thumb is that a mean speed based on one year of data will be within 10% of the true long-term mean with 90% confidence. This translates into a standard error of 6% for one year of data. We assumed that the annual mean varies randomly according to a normal distribution, and thus the error margin varies inversely with the square root of the number of years. An additional uncertainty of 3% was added to account for possible variations in the characteristics of anemometers and data loggers.

4. The various uncertainties were then combined in a least-squares sum as follows:

$$(1)\quad e = \sqrt{0.03^2 + \left(\left(\frac{50}{H}\right)^{0.05} - 1\right)^2 + \left(\frac{0.06}{\sqrt{N}}\right)^2}$$

where H is the height of the anemometer, and N the number of years of measurement. The uncertainty in power (in percentage terms) is assumed to be three times the uncertainty in speed, since the power varies as the cube of the speed.

[3] The power shear exponent is assumed to be 3(α-0.02), where α is the speed shear exponent. The reason for the reduction in effective shear, compared to assuming that the power goes strictly as the cube of the speed, is that the speed frequency distribution tends to become narrower with height above ground because the shear is often higher under light wind conditions.

5. Next, the predicted and measured/extrapolated speed and power were compared, and the map bias (map speed or power minus measured/extrapolated speed or power) was calculated for each point.

Table 2 summarizes the results. The key finding is that the standard deviation of the biases was 0.41 m/s, or 8.6% of the average observed speed.

Table 2. Wind Speed Validation

	Number of Stations	Mean Bias	Standard Deviation of Bias
Speed	15	0.03 m/s (+0.6%)	0.41 m/s (8.6 %)

The scatter plot in Figure 1 compares the predicted and measured-extrapolated wind speeds at 50 m height. The linear trend line is forced through zero. The error bars reflect the uncertainty in the measured/extrapolated long-term wind speed due to short tower heights and short periods of record. They do not include possible errors due to buildings or other obstructions near the masts.

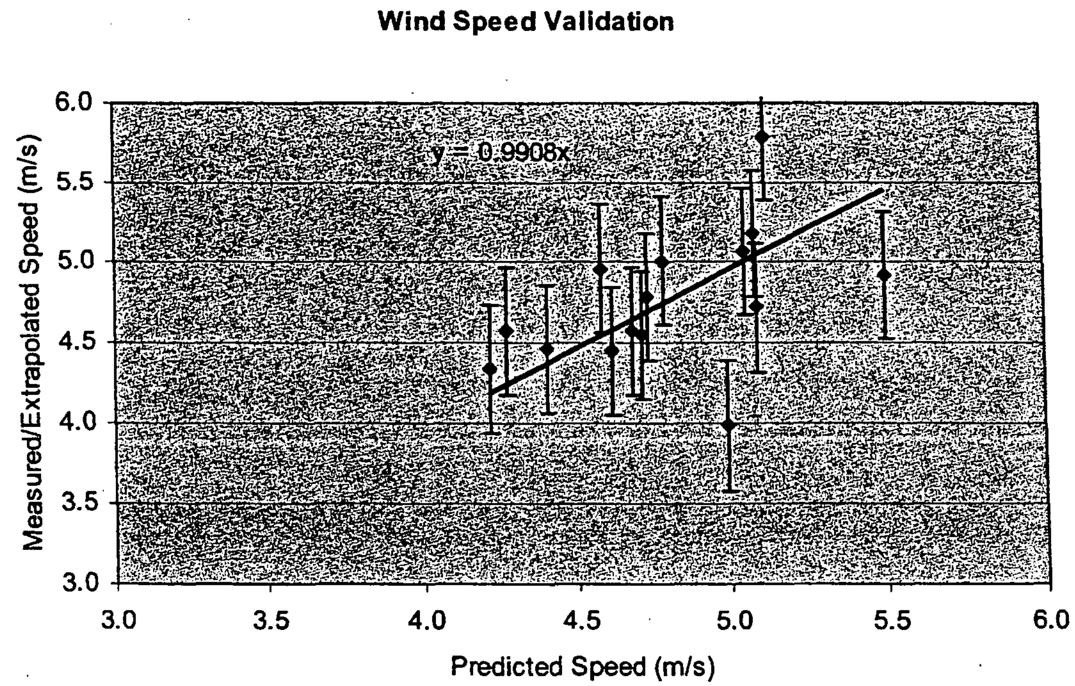


Figure 1. Comparison of the speed map with observed wind speeds at 15 airport stations projected to 50 m height. The error bars reflect period of record, tower height, and anemometer sensitivity, as described in the text. The trend line is forced through the origin.

The agreement between model and data overall is reasonably good considering the uncertainties in the extrapolated data. Although the standard deviation of the bias shown in Table 1 is, in absolute terms, within the expected range for MesoMap projects, it is somewhat larger than usual in percentage terms (the typical error rate being 5-7%). The main reason is the relatively low average speed observed at the airports.

After reviewing the validation results, AWS Truewind determined that no adjustments were necessary to the wind speed or power density maps.

5. WIND MAPS

The accompanying maps show the predicted mean annual wind speed in South Carolina at heights of 30, 50, 70, and 100 m; maps of mean annual wind power at 50 and 100 m are also provided.

The wind maps show that the best wind resource within state borders is generally found along the coastal areas and inland water bodies. The wind speed at 70 m height (a typical height for modern wind turbines) in these regions is predicted to be in the range of 5.5 to 7.0 m/s with an average between 6.0 and 6.5 m/s. The wind power is predicted to range from 100 to 400 W/m^2, or NREL class 1 through 3, with a mean power density ranging from 200 to 300 W/m^2. The remainder of the state has predicted wind speeds less than 5.5 m/s with some locations being as low as 2.5 m/s. The wind power density in these areas averages from 100 to 200 W/m^2, NREL class 1- and 1+ with the lowest wind power density being 15 W/m^2.

The main reasons for the generally low wind speeds onshore are the high surface roughness caused by trees; relatively flat terrain throughout most of the state; and South Carolina's position south of jet stream and the normal winter storm track across North America. However, as the elevation increases further inland and reaches over 1000m, a few ridgelines can been found along the boundary of North Carolina that are predicted to experience wind speeds of up to 8.0 m/s.

The predicted wind speeds are higher offshore, ranging from 6.5 to 7.5 m/s near the coast to 8.0 and 8.5 m/s farther offshore. Here, wind power density ranges from 300 to 400 W/m^2 nearest to the shore and 600 to 800 W/m^2 further offshore. This coincides with an NREL wind resource class from 3 to 6.

It should be stressed that the mean wind speed at any particular location may depart substantially from the predicted values, especially where the elevation, exposure, or surface roughness differs from that assumed by the model, or where the model scale is inadequate to resolve significant features of the terrain.

6. GUIDELINES FOR USE OF THE MAPS

The following are guidelines for interpreting and adjusting the wind speed estimates in the maps, to be used in conjunction with the accompanying ArcReader CD. The ArcReader CD allows users to obtain the "exact" wind speed value at any point, and it provides the elevation and surface roughness data used by the model, which are needed to apply the adjustment formulas given below.

1. The maps assume that all locations are free of obstacles that could disrupt or impede the wind flow. "Obstacle" does not apply to trees if they are common to the landscape, since their effects are already accounted for in the predicted speed. However, a large outcropping of rock or a house would pose an obstacle, as would a nearby shelterbelt of trees or a building in an otherwise open landscape. As a rule of thumb, the effect of such obstacles extends to a height of about twice the obstacle height and to a distance downwind of 10-20 times the obstacle height.

2. Generally speaking, points that lie above the average elevation within a 200×200 m grid cell will be somewhat windier than points that lie below it. A rule of thumb is that every 100 m increase in elevation will raise the mean speed by about 0.5 m/s. This formula is most applicable to small, isolated hills or ridges in flat terrain.

3. The mean wind speed at a location could be affected by the roughness of the land surface – determined mainly by vegetation cover and buildings – up to several kilometers away. If the roughness is much lower than that assumed by the model, the mean wind speed could be higher. Typical values of roughness range from 0.01 m in open, flat ground without significant trees or shrubs, to 0.1 m in land with few trees but some smaller shrubs, to 1 m or more for areas with many trees. These values are only indirectly related to the size of the vegetation.

   The following equation provides an approximate speed adjustment for differences in surface roughness in the direction of the wind:

$$\frac{v_2}{v_1} \approx \frac{\log\left(\dfrac{300-d}{z_{01}}\right)}{\log\left(\dfrac{h-d}{z_{01}}\right)} \times \frac{\log\left(\dfrac{h-d}{z_{02}}\right)}{\log\left(\dfrac{300-d}{z_{02}}\right)}$$

   v_1 and v_2 are the original and adjusted wind speeds at height h (in meters above ground level); z_{01} and z_{02} are the model and actual surface roughness values (in meters); and d_1 and d_2 are the corresponding displacement heights. (This equation assumes the wind is unaffected by localized roughness changes above a height of 300 m.)

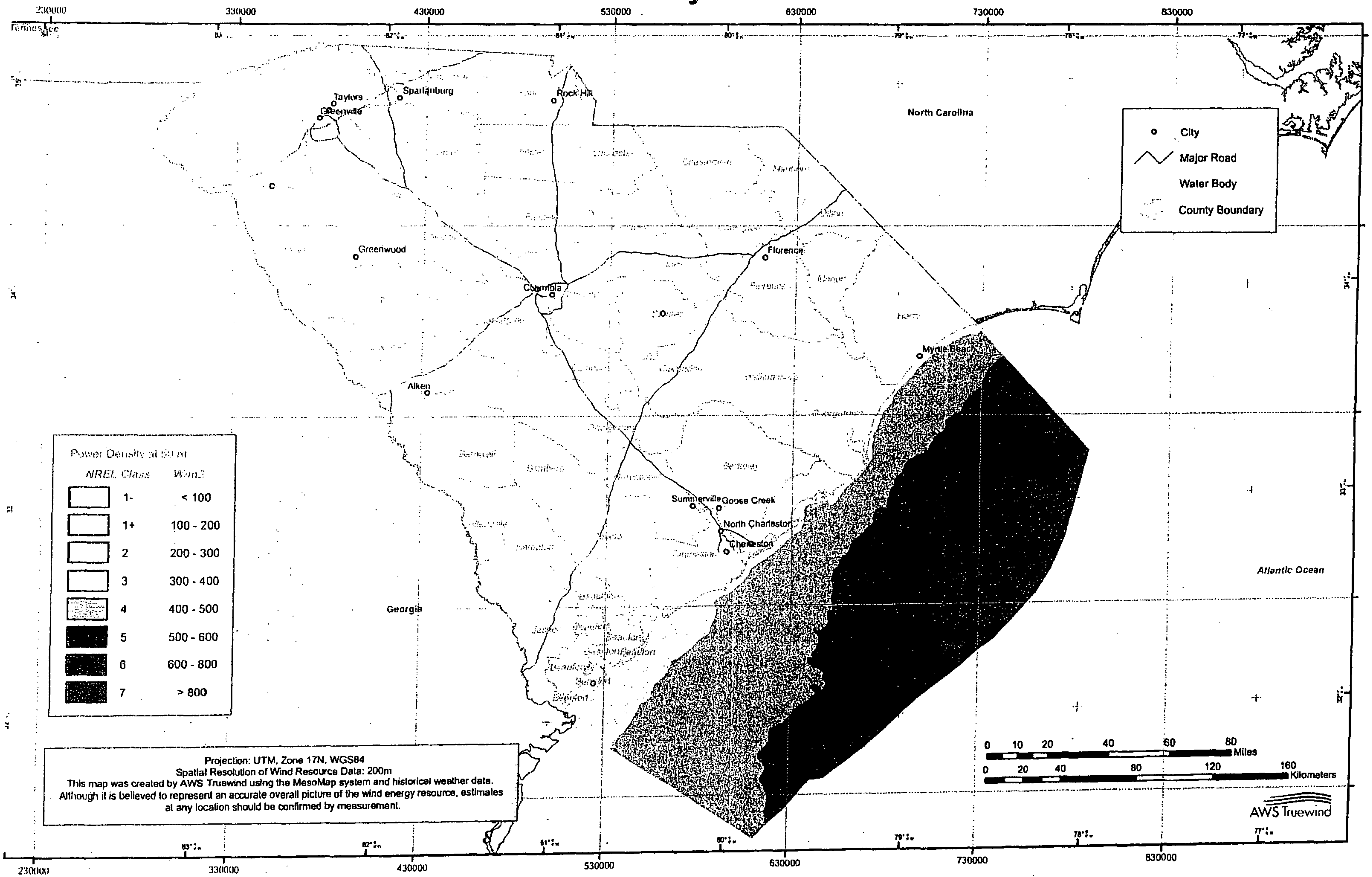
   As an example, suppose the surface roughness assumed by the model was 0.2 m, and the displacement 2 m, whereas the true roughness is 0.75 m and displacement 7.5 m. For $h = 50$ m, the above formula gives

$$\frac{v_2}{v_1} \approx \frac{\log\left(\dfrac{300-2}{0.2}\right)}{\log\left(\dfrac{50-2}{0.2}\right)} \times \frac{\log\left(\dfrac{50-7.5}{0.75}\right)}{\log\left(\dfrac{300-7.5}{0.75}\right)} = 0.90$$

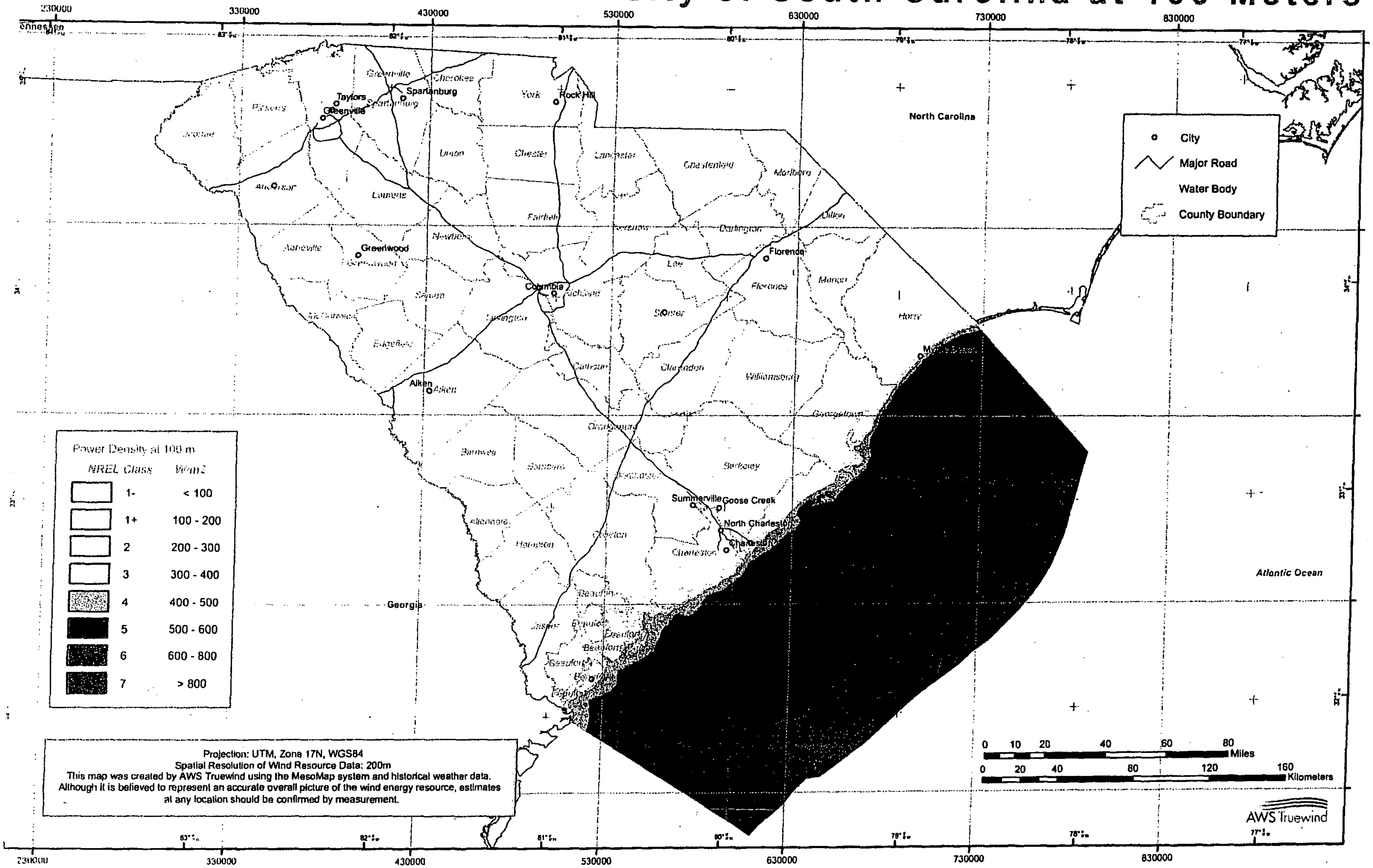
This shows that the predicted wind speed should be reduced by about 10%.

This formula assumes that the wind is in equilibrium with the new surface roughness above the height of interest (in this case 50 m). When going from high roughness to low roughness (such as from forested to open land), the clearing should be at least 1000 m wide for the benefit of the lower roughness to be fully realized. However, when going from low to high roughness, the reduction in wind speed may be felt over a much shorter distance. For this and other reasons, the formula should be applied with care.

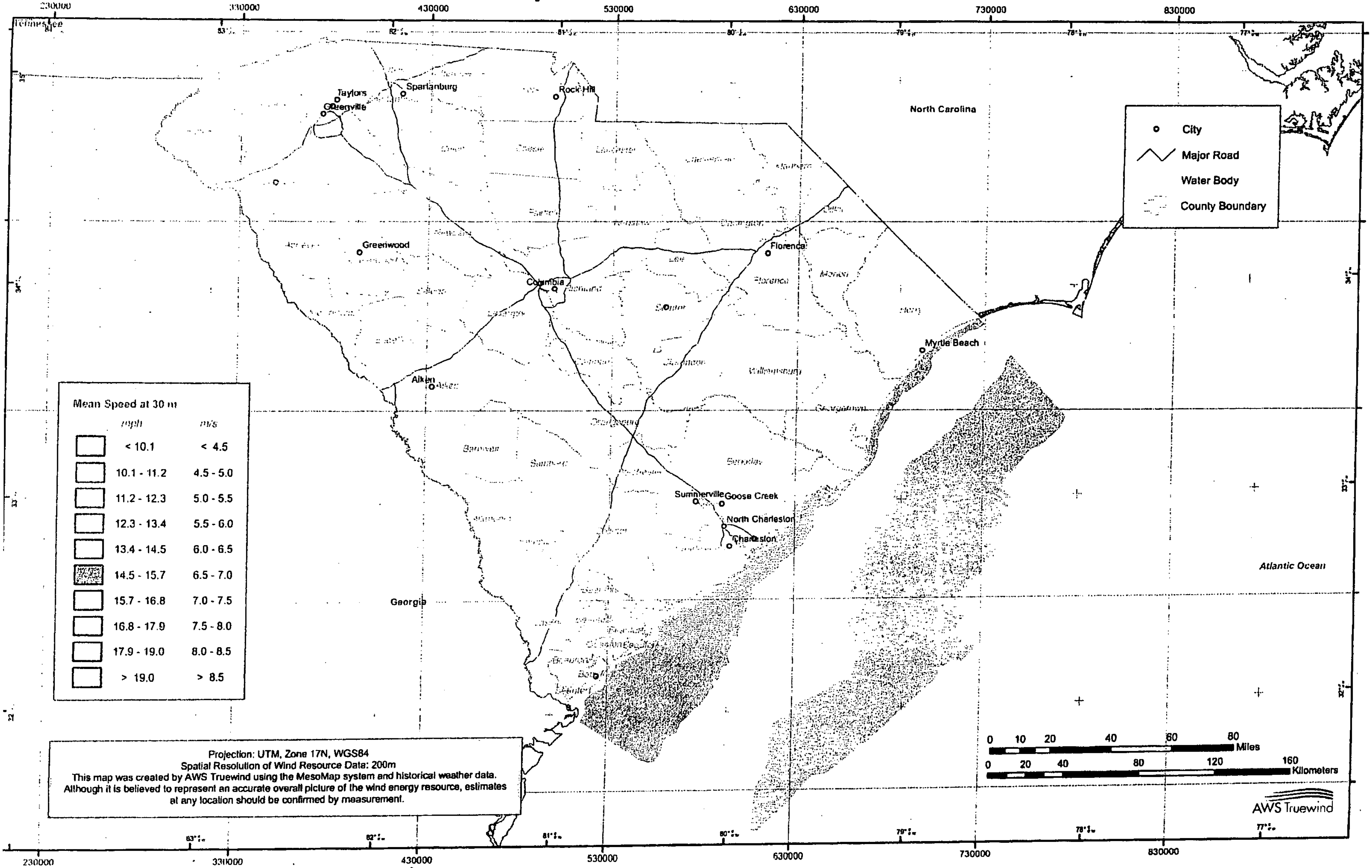
Mean Annual Wind Power Density of South Carolina at 50 Meters



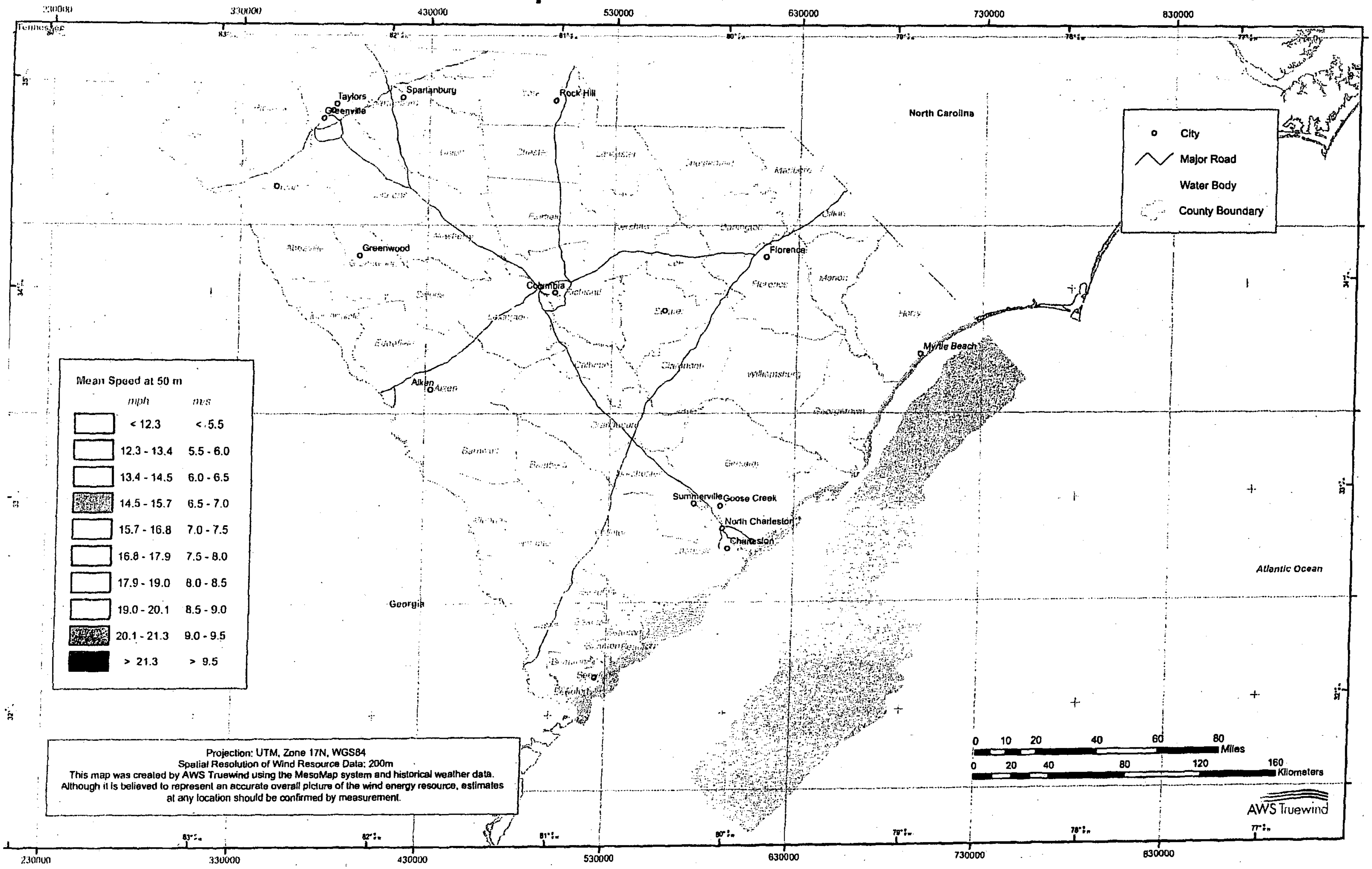
Mean Annual Wind Power Density of South Carolina at 100 Meters



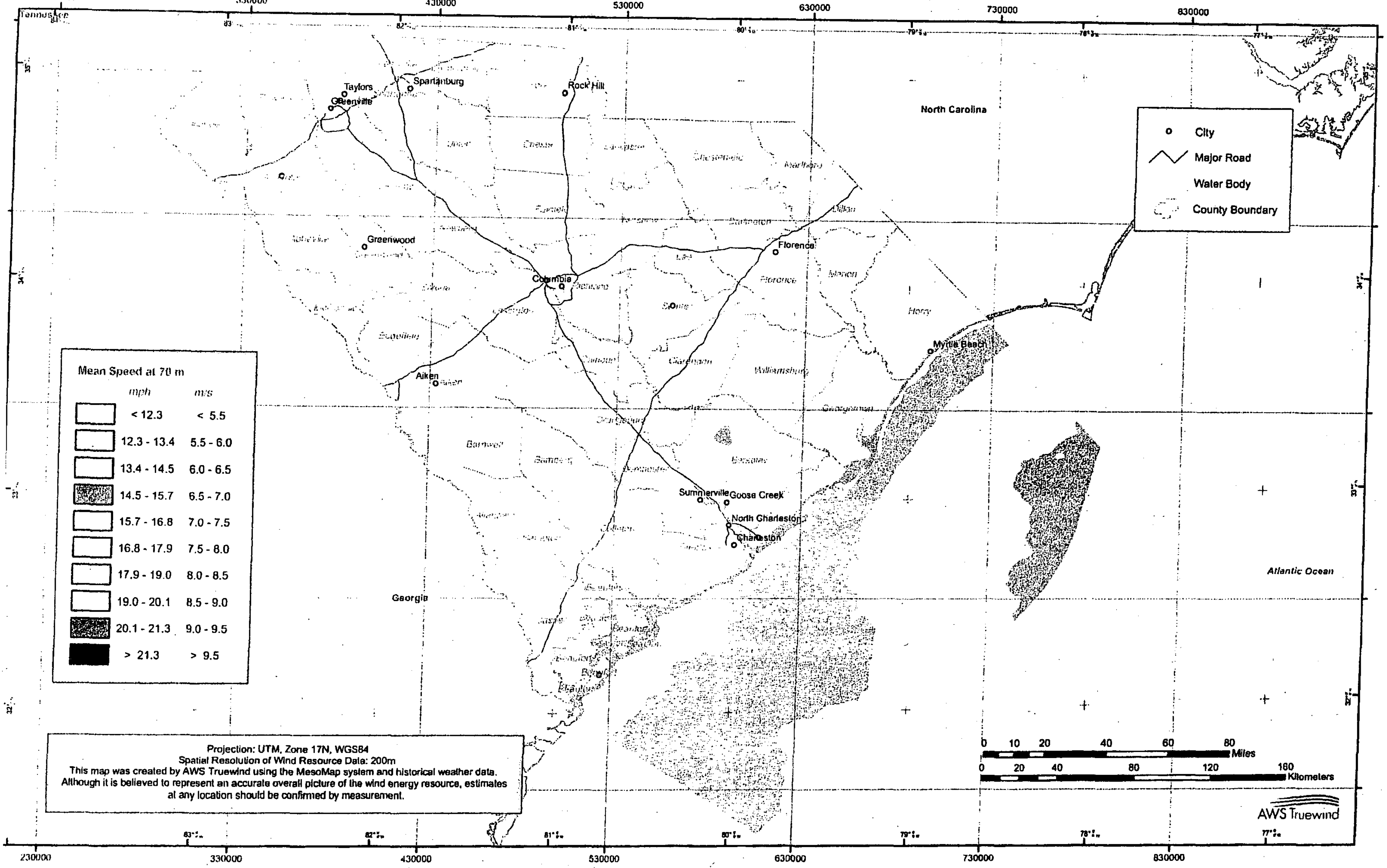
Mean Annual Wind Speed of South Carolina at 30 Meters



Mean Annual Wind Speed of South Carolina at 50 Meters

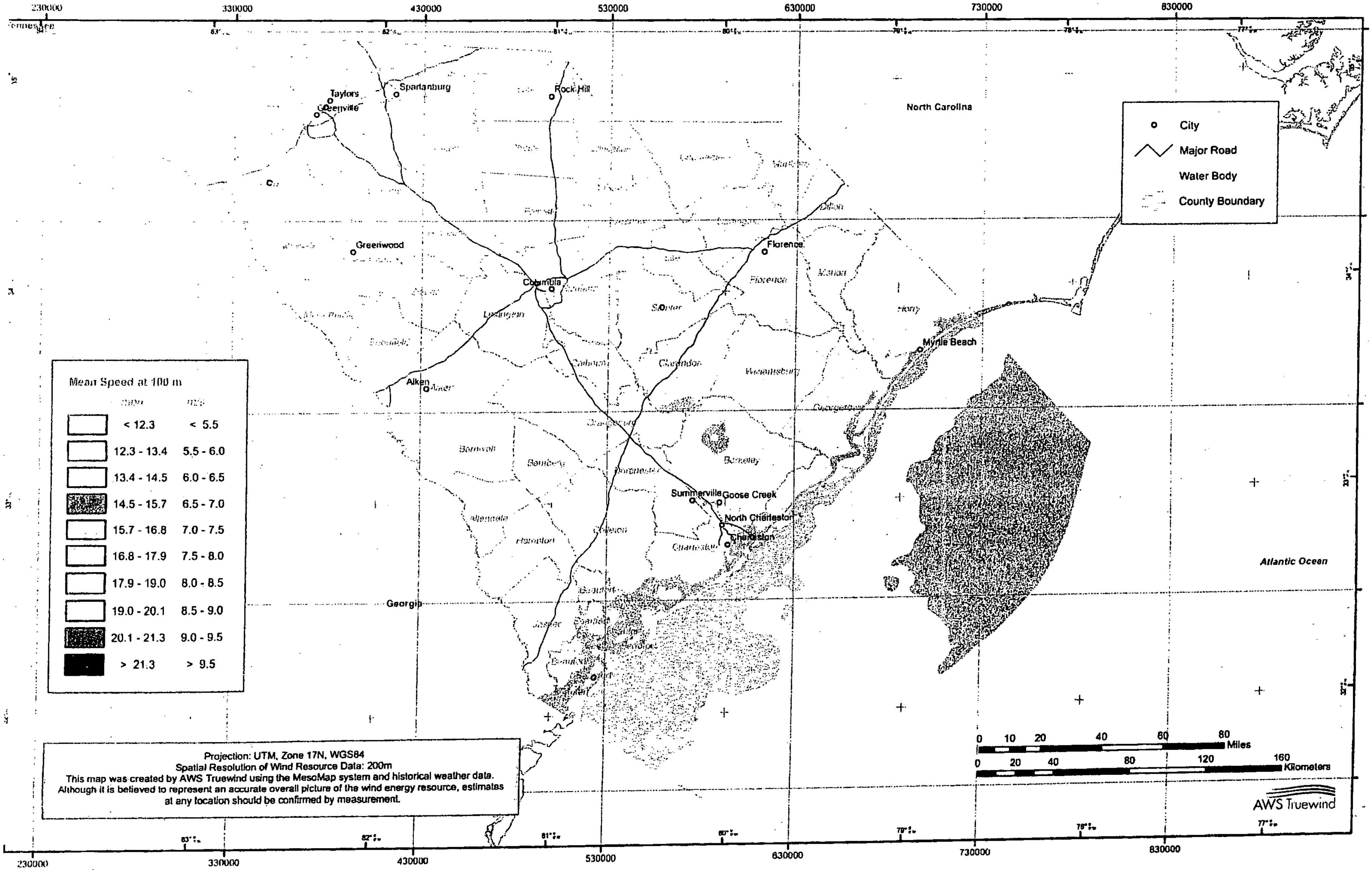


Mean Annual Wind Speed of South Carolina at 70 Meters



Projection: UTM, Zone 17N, WGS84
Spatial Resolution of Wind Resource Data: 200m
This map was created by AWS Truewind using the MesoMap system and historical weather data.
Although it is believed to represent an accurate overall picture of the wind energy resource, estimates at any location should be confirmed by measurement.

Mean Annual Wind Speed of South Carolina at 100 Meters



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years. But the lack of certainty around the availability of the renewable production tax credit has hampered our ability to meet these targets. There is no question that over the short term, at least, the renewable PTC is vital to making many renewable projects economically viable. But the inability of developers and purchasers to know with confidence when the credit will be available—if it is available at all—has stalled renewable energy development, created supply scarcity for turbines, towers, related equipment, and skilled labor, and ultimately raised development costs.

Consequently, PacifiCorp strongly encourages the Congress to adopt a two-track approach to promoting development of renewable energy. Enacting a national RPS that establishes long-term portfolio diversification objectives will give developers and utilities a longer time frame to plan, site, procure, develop, and operate renewable generation. In the near term, extension of the renewable energy production tax credit is essential to the continued development of renewable generation resources, however, until meaningful RPS targets kick in.

4. *A market-driven RPS policy would deliver a range of benefits to consumers and the environment.* Establishing a national system of tradable renewable energy credits would maximize cost-efficiency. A cap on compliance costs may also be built into the national policy to ensure minimal effect on consumers. Overall consumer costs could actually decline due to the reduction of natural gas prices resulting from greater deployment of renewable generation.

By adding a significant amount of new renewable energy generating capacity, utilities will be able to reduce the risk of compliance with any future limits on carbon dioxide emissions. For utilities with growing customer demand, this risk-reduction element is a particularly important.

Mr. Chairman, PacifiCorp recognizes the interest in expanding the portfolio standard approach beyond renewable energy to include other technologies, such as clean coal and nuclear power. It is important to spur the development of a diverse base of technologies and fuel sources. PacifiCorp, for instance, is exploring the addition of an Integrated Gasification Combined Cycle (IGCC) coal plant to our resource mix.

Expanding a national portfolio diversification policy beyond renewables should be approached carefully. Including the significantly larger (in terms of both generating capacity and actual output) size of coal and nuclear facilities would warrant a reconsideration of the targets and timeframes of the RPS proposals that have been introduced in previous sessions. And the inclusion of these large-scale, longer-term technologies should not come at the expense of maintaining incentives for renewable energy development. If Congress desires to expand a portfolio standard requirement to include technologies beyond non-hydro renewable energy, it may be wise to establish separate tiers for renewable and non-renewable sources.

In summary, PacifiCorp believes renewable generation resources are moving closer to economic viability such that they will become a growing part of many utilities' resource portfolios over the next two decades. Renewable energy development will best be achieved through a combination of tax incentives and resource portfolio targets over the short term. For the long term, PacifiCorp supports establishment of reasonable, economically viable standards that increase the share of renewable generation in all power supply portfolios.

Mr. Chairman, this concludes my prepared presentation. I am happy to respond to any questions you and members of the Committee may have.

Senator ALEXANDER. Thank you, Mr. Furman.

Mr. Bowers.

STATEMENT OF KERRY H. BOWERS, TECHNOLOGY MANAGER, SOUTHERN COMPANY, BIRMINGHAM, AL

Mr. BOWERS. Well, good afternoon, Senator Alexander and Senator Salazar.

My name is Kerry Bowers, and I am a technology manager for Southern Company. I am responsible for evaluating emerging technologies related to the generation, delivery, and end use of electric energy. It's my pleasure to present our views on renewable energy to you this afternoon.

Southern Company operates over 39,000 megawatts of electric generation using a diverse fuel portfolio that includes coal, nuclear, natural gas, and hydro. We provide low-cost electric energy to over ten million people in the Southeastern United States.

We support the development and use of cost effective renewable energy resources. The Southeast lacks sufficient resources from which to cost-effectively generate the amount of energy that a renewable mandate would require. Therefore, Southern Company does not support a mandatory renewable portfolio standard.

I will address the major options for utility-scale renewable power generation—hydroelectric, solar, wind, and biomass—and comment on the ability to use these resources cost effectively in the Southeast.

Southern Company obtains about 4 percent of our annual energy output from the 2,400 megawatts of existing hydro capacity. This renewable resource continues to serve an important role in our generating mix, providing a low-cost means of energy storage that helps us meet peak demands on our system.

Solar energy is less available in the Southeast. This chart that's provided shows solar energy reaching the Earth's surface is highest in the Southwest, as indicated by the dark red colors. Solar energy in the Southeast is represented by the lighter greens and yellows, and is about one-half that amount observed in the Southwest. We have tested solar technologies in the Southeast, and we've concluded that solar generation will be prohibitively expensive in our region, and is not practical as a utility-scale power generation.

We have also evaluated wind resources. The second chart—it's already been referred to today—shows how wind resources vary across the country from class one to class seven, with class four or higher being required for cost-effective wind generation. The purple color shows that, except for the few isolated mountain ridgetops, the Southeast lacks sufficient wind speeds to support commercially viable wind generation. Consequently, our assessment is that wind energy is not commercially viable in the Southeast, and could not support a mandated renewables portfolio at any significant level.

Biomass resources are available in the Southeast. We have been evaluating the co-firing of forestry wood wastes and agricultural crops in our existing coal-fired generating plants, and we have proven that biomass can be successfully co-fired with coal. However, our testing concludes that co-firing will be limited to about 5 percent of the energy input to a coal-fired plant. Moreover, the ash residue left from combusting biomass will have a negative impact on the technologies being used to reduce nitrogen-oxide emissions from coal plants; thereby, offsetting a major environmental benefit. Thus, we do not plan widespread use of biomass co-firing technology in Southern's fleet of generating plants.

However, there is an alternative approach to using biomass for power generation. It may be possible to apply gasification technology to biomass to form a synthetic fuel gas. Southern Company has extensive experience with coal gasification, having worked with the U.S. Department of Energy for over 10 years to develop this technology. We've recently initiated R&D efforts in our company to apply our knowledge of gasification to biomass. This R&D program is in its initial stages and will require several years of technology development to prove commercial viability. Pressurized biomass gasification has the potential to be a cost-effective utility-scale renewable option in the Southeast, and we are pursuing it.

In summary, Southern Company has a long history of utilization of renewable energy. Not every renewable technology will be well suited to every region of the country. Hydro is available in the Southeast, and we use it. Solar and wind are not commercially viable renewable technologies for the Southeast. Some biomass is possible, but continued research and development will be needed to estimate its long-term potential.

We are concerned about a "one size fits all" mandate that would require us to use more costly renewable resources or to pay penalties so that renewable technologies can be built elsewhere; thereby, increasing costs to our customers.

We continue to seek cost-effective additions to our generation portfolio based on technology maturity, technical performance, and economic viability. We will continue to work to facilitate generation technology options, including coal, nuclear, natural gas, and renewable energy options that ensures a reliable, affordable, and environmentally sound supply of energy to meet the growing demands for electric power in our region.

Thank you for the opportunity comment, and I'll be happy to address any questions you have.

[The prepared statement of Mr. Bowers follows:]

PREPARED STATEMENT OF KERRY W. BOWERS, TECHNOLOGY MANAGER, SOUTHERN COMPANY, BIRMINGHAM, AL

RENEWABLE ENERGY OPTIONS FOR THE SOUTHEASTERN UNITED STATES

INTRODUCTION

My name is Kerry Bowers and I am a Technology Manager for Southern Company responsible for the assessment of emerging technologies in generation, transmission, distribution and end-use of electric energy. I am a Chemical Engineer by training and I have over 25 years of experience in the energy industry in technology assessment and evaluation. I am testifying today concerning Southern Company's experience with and outlook for renewable energy options in the Southeastern United States.

Southern Company supports the use of cost-effective renewable energy. Southern Company operates over 39,000 MW of electric generating capacity—including more than 8,000 MW of non-emitting hydro and nuclear capacity—to provide low-cost electric energy to over 10 million people in the Southeast. We continually assess renewable generation technologies available to augment our generation portfolio. I will address the major options for utility-scale renewable power generation—hydroelectric, solar, wind, and biomass—and provides comments on the ability to use these resources in the Southeast.

HYDROELECTRIC GENERATION

Southern Company has operated hydroelectric plants for over 70 years. We have 2,400 MW of hydro which supplies about 4% of our annual energy output. Hydro continues to serve an important role in our generating mix, providing a low-cost means of energy storage that helps us meet peak demands on our system. We have identified up to 125 MW of incremental renewable hydroelectric generation that could be obtained from enhancing existing hydro facilities with advanced technologies.

SOLAR GENERATION

The amount of solar energy reaching the earth's surface in the Southeast is approximately one-half that observed in the southwestern U.S. due to variable cloud cover and humidity levels in the South that diffuse solar energy and reduce its intensity. Figure 1* below indicates where solar insolation levels are highest in the United States.

This reduced insolation level—compared to more favorable Southwest locations, clearly reduces the amount of usable electricity that can be generated from solar technologies in the Southeast. Moreover, there is obviously no solar generation possible at night which accounts for over one-half of the year. In addition, early morning and late evening solar intensities are reduced, although tracking systems attempt to compensate. Southern Company has evaluated numerous solar options over the past 20 years, including operation of thermal solar collectors, Solar Dish/Stirling technology, and photovoltaic arrays of the types shown in Figure 2.

These technology evaluations were performed at the Georgia Power operated Shenandoah Solar Center. In addition, Georgia Power, Georgia Institute of Technology and the U.S. Department of Energy installed a 340 kW photovoltaic roof-top generating system on the roof of the Georgia Tech Natatorium used as the Swimming Venue for the 1996 Summer Olympic Games in Atlanta. Southern Company has monitored the energy production from this facility—which at the time it was completed was the largest roof-top solar PV array in the world. The data derived from these technology evaluations, coupled with the moderate amounts of solar insolation in the Southeast along with concerns over intermittency have lead us to conclude that solar energy will be expensive in our region and not practical as a utility-scale power generation option.

WIND GENERATION

Wind generation technology continues to evolve and Southern Company is evaluating installations by other utilities closely. Wind resource evaluations performed by the NREL and others conclude that the Southeastern U.S. lacks sufficient wind speeds to support commercially viable wind generation except for isolated mountain ridge tops, as shown in Figure 3.

Mountain ridge-top locations are remote, requiring incremental costs for developing access roads and power transmission infrastructure. Moreover, the hilly terrain increases the complexity of installation and the overall costs of wind energy due to variations in wind flows observed in mountainous regions compared to flatter landscapes. This variation is depicted in Figure 6, below which illustrates the variable directional wind flow that can exist in mountainous areas. This variation tends to decrease the amount of usable energy that can be extracted from the wind, resulting in lower capacity factors. Reduced capacity factors increase overall cost per kilowatt-hour of energy generated.

Use of mountain ridge tops is of additional concern in the Southeast due to concerns over land use for aesthetic reasons. Southeastern mountain locations are enjoyed for recreation by a large percentage of the public. Scenic vistas are important and Southern Company considers that there would be a considerable public resistance to the use of mountainous areas for the location of wind farms in the Southeast.

In addition, the intermittency and uncertainty of wind adds to the cost of wind installations. Southern Company is a summer peaking utility, but wind energy is at a minimum in the Southeast in the summer months. Consequently, wind generation requires redundant power generation resources to meet seasonal peak loads.

These factors taken together lead us to conclude that wind resources in the Southeast, unlike other areas of the country, are limited, costly and not of sufficient quality to support large amounts of utility-scale wind generation.

BIOMASS GENERATION

Commercially available biomass-based options include landfill gas and co-firing biomass in existing power plants. We have surveyed landfill sites in the Southeast and have concluded that, at a maximum, there may be a total of 200 MW of available capacity scattered throughout our region. Landfills lack the necessary power transmission capability to export electricity and must secure environmental permits to use reciprocating engines for power generation. These factors constrain landfills as cost-effective generation resources.

The Southeast does have abundant biomass resources in the form of wood and other agricultural crops. For over 10 years, we have been evaluating these resources by co-firing biomass fuels in our existing coal-fired generating plants. While we have proven that biomass can be successfully co-fired with coal, it is not without technical challenges. Biomass is much less dense than coal, requiring a large volume of fuel to be handled. Figures 9 and 10, below, indicate the impact of co-firing on power

* All figures have been retained in committee files.

plant operations. Large areas of biomass storage and handling are required to accommodate the low mass density materials. We believe co-firing will be limited to no more than 5% of the energy input to a coal-fired power plant as shown in Figure 11.

Moreover, the ash residue left from combusting biomass contains alkali and alkaline earth elements, such as sodium, potassium and calcium. These compounds bind irreversibly with the catalysts being used in Selective Catalytic Reduction (SCR) reactors that have been installed on Southern Company's large, coal-fired generating plants. See Figure 12. These compounds can lead to increased catalyst plugging and cause deactivation of SCR catalysts, thus reducing or eliminating the ability of this technology to reduce NO_X emissions. Thus, current biomass co-firing technology cannot be deployed on the majority of Southern's fleet of generating plants.

NEW TECHNOLOGY APPROACHES

An alternative technical approach to co-firing is the gasification of biomass to form a synthetic fuel gas. Southern Company has extensive experience with coal-gasification having worked with the U.S. Department of Energy for over 10 years to bring Transport Reactor gasification technology to commercialization based on research conducted at the Power Systems Development Facility, managed and operated by Southern Company. This research culminated in 2004 with an announcement to construct the first commercial plant using Transport Reactor technology. We have recently initiated R&D efforts in our company to use this knowledge for the pressurized gasification of biomass. This R&D program is just starting in a partnership with TVA and EPRI and will require several years of technology development to prove its commercial viability. However, we believe, of all the renewable energy technology choices available to us, pressurized biomass gasification has the best chance to be a cost-effective, utility-scale renewable option in the Southeast and we are pursuing it.

IMPLICATION OF RENEWABLE PORTFOLIO STANDARDS

Against this backdrop of the renewable resources available to us, we are concerned about mandates that would require us to utilize fixed amounts of renewable resources. We prefer to seek cost-effective additions to our generation portfolio based on technology maturity, technical performance, and economic viability. As natural gas prices continue to rise, renewables can be an important hedge against fuel cost increases and provide additional stimulus to pursue advanced biomass gasification.

CONCLUSION

Southern Company has a long history of utilization of renewable energy. We continually assess our generation options—including renewable options—to provide low-cost, reliable energy to meet the growing demands for electric power in our region. Not every technology will be well-suited to every region of the country. We will continue to work to facilitate generation technology options—including renewable options—that ensures a reliable, affordable and environmentally sound supply of energy to meet the growing demands for electric power in our region.

Senator ALEXANDER. Thank you, Mr. Bowers.

Mr. Nogee.

STATEMENT OF ALAN NOGEE, DIRECTOR, CLEAN ENERGY PROGRAM, UNION OF CONCERNED SCIENTISTS, CAMBRIDGE, MA

Mr. NOGEE. Thank you very much, Senator Alexander, Senator Salazar. I appreciate this opportunity. My name is Alan Nogee, the energy program director for the Union of Concerned Scientists.

Since you have my written comments, I'll use my limited time here to respond to some of the arguments against a renewable electricity portfolio standard we've heard today, that it's expensive, that it's unfair to some regions, and that it's an unnecessary mandate.

As Dr. Wiser testified earlier, a wide range of studies has found that increasing renewable energy will reduce the demand for natural gas and the price of natural gas. Those studies have also

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CALIFORNIA
ENERGY
COMMISSION

COMPARATIVE COST OF CALIFORNIA CENTRAL STATION ELECTRICITY GENERATION TECHNOLOGIES

**Prepared in Support of the Electricity and Natural Gas Report under the Integrated Energy Policy Report Proceeding
Docket 02-IEP-01**

FINAL STAFF REPORT

June 5, 2003
100-03-001F

Gray Davis, *Governor*

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Introduction

This Energy Commission staff report presents the levelized cost estimates for several generic central-station electricity generation technologies. This is one of a number of reports that the Energy Commission staff is preparing, under the direction of the Ad Hoc Integrated Energy Policy Report Committee, to support the development of the ***2003 Integrated Energy Policy Report.***

The Energy Commission staff would like to acknowledge the work of several consultants in putting together the information for this project. Dr. Richard McCann, along with Ron Ishii, Ed Miller, Peter Asmus, Larry Slomiski, John Kessler, and L. Knox provided the data the Energy Commission staff used in this report. In addition to providing data, Dr. McCann provided the financial models used in this analysis.

Overview

California has traditionally adopted energy policies that balance the goals of supporting economic development, improving environmental quality and promoting resource diversity. In order to be effective, such policies must be based on comprehensive and timely information. With this goal in mind, the purpose of the report is to provide levelized cost estimates for a set of renewable (e.g., solar) and nonrenewable (e.g., natural gas-fired) central-station electricity generation resources, based on each technology's operation and capital cost. Decision-makers and others can use this information in assessing the generic costs to build a specific technology. This report also identifies the type of fuel used by each technology and a description of the manner in which the technology operates in the generation system.

This report is intended to provide a basic understanding of some of the fundamental attributes that are generally considered when evaluating the cost of building and operating different electricity generation technology resources. But these costs do not reflect the total costs to consumers of adding these technologies to a resource portfolio. The technology costs in this report are not site-specific. If a developer builds a specific power plant at a specific location, the cost of siting that plant at that specific location must be considered. Some projects may require radial transmission additions, fuel delivery, system upgrades or environmental mitigation expenses.

This levelized cost analysis does not capture all of the system, environmental or other relevant attributes that would typically be examined by a portfolio manager when conducting a comprehensive "comparative value analysis" of a variety of competing resource options. A portfolio analysis will vary depending on the particular criteria and measurement goals of each study. For example, some forms of firm capacity are typically needed in conjunction with wind generation to support system reliability requirements. Some projects may also require radial transmission additions, fuel delivery, system upgrades or environmental mitigation expenses.

Staff has made numerous changes to the preliminary draft report that was originally published on February 11, 2003. The Integrated Energy Policy Report Committee held a workshop on February 26, 2003 to take public comments on the matter. The original study focused on capital, rather than developmental costs. The report now includes development, land acquisition, and permitting costs for all technologies based on comments received at the workshop. Certain parties also expressed concern that staff had systematically understated several costs associated with gas-fired plants. In response to this latter set of comments, staff has:

- Changed the heat rate assumed for Combined Cycle units from 6,900 to 7,100 MMBtu/kWh,
- Included water cooling costs for gas-fired units,
- Added air-district-specific emissions costs that are shown in **Table 4**, and
- Made more precise estimates of costs associated with Significant Catalytic Reduction (SCR) operations, solid waste disposal, costs of overhauls, and capacity degradation rates.

Purpose

As part of the Integrated Energy Policy Report proceeding, the California Energy Commission staff developed cost estimates for central-station electricity generation technologies. These estimates are intended to provide a general guideline on the expected costs of different technologies for policy makers and the public, and to assist resource planners in screening generation options.

Technology Costs

Table 1 shows the results of the cost analyses for various technologies. Expected levelized costs, constant annual payments made over the life of the plants, are shown to provide a common basis of measurement. By convention, *levelized costs are given in constant, or real, dollars* and use 2002 as the base year. To the extent possible, this evaluation relies on general economic and electricity system assumptions. Details about assumptions specific to each technology are included in the individual technology characterizations in the attached appendices. These costs are for generalized project descriptions and costs for actual projects will vary from those shown below, depending on a number of possible site-specific considerations. This information should be used only as general estimates of ownership costs for different technologies. They are not intended to be the sole criterion used in an investment decision, which necessarily involves an evaluation of many other factors.

Estimates of levelized costs are provided for power plants that use natural gas as an energy source and for plants that use renewable energy sources. The costs for these technologies are listed below in **Table 1**. Gas-fired plant costs are derived from Energy Commission staff analyses. The expected levelized cost for a generic new baseload combined cycle plant is

5.18 cents per kWh. However, this estimate increases to 5.34 cents per kWh for a unit located in the South Coast Air Quality Management District. When duct firing is added to the above-mentioned unit, this cost increases further to 5.37 cents per kWh.

Energy Commission staff estimates show that a combustion turbine, with an in-service year of 2004 and used for peaking service with a 10 percent capacity factor, can be expected to deliver this peak capacity and energy at a cost of 15.71 cents per kWh. Geothermal flash technology has the lowest levelized costs at 4.52 cents per kWh, with wind next at 4.93 cents per kWh. Hydropower is projected to provide load-following power at 6.04 cents per kWh. Geothermal binary plants have an expected cost of 7.37 cents per kWh. Solar thermal parabolic trough units have expected levelized costs ranging from 13.52 to 21.53 cents per kWh.

Table 1
Levelized Costs by Technology

Technology	Energy Source Fuel	Operating Mode	Economic Lifetime (years)	Gross Capacity (MW)	Direct Cost Levelized (cents/kWh)
Combined Cycle	Natural Gas	Baseload	20	500	5.18
Simple Cycle	Natural Gas	Peaking	20	100	15.71
Wind	Wind; Resource Limited	Intermittent	30	100	4.93
Hydropower	Water; Resource Limited	Load-Following, Peaking	30	100	6.04
Solar Thermal					
Parabolic Trough	Sun; Resource Limited	Load-Following	30	110	21.53
Parabolic Trough-TES	Sun; Resource Limited	Load-Following	30	110	17.36
Parabolic Trough-Gas	Sun/Natural Gas; Partially resource limited	Load-Following; Peaking	30	110	13.52
Geothermal					
Flash	Water	Baseload	30	50	4.52
Binary	Water	Baseload	30	35	7.37

In considering these figures, it is important to note the relationship between the expected economic (or "book") life of a project and levelized cost. In this report, the standard loan period is 12 years. For project finance, this means that the entire dollar outlay associated with completing the project (or the "instant cost") is allocated during years one-through-twelve of the project. In contrast, levelized cost calculation spreads these costs across *all* years of a project's operation. The levelized cost of a highly capital intensive project, such as hydroelectric, will depend greatly on the project life assumed. If an economic lifetime is assumed to be 50 years, the levelized cost estimate for hydroelectric generation would fall precipitously. This greater economic lifetime would allow the relatively large capital cost to spread over a greater number of years, decreasing its contribution to the levelized cost calculation. The figures in **Table 1** would then overestimate the levelized cost of a hydroelectric project with an economic lifetime of more than 30 years.

Technological advancement plays an important role in determining the actual life of a project. For a mature technology, such as with hydroelectric facilities, generation efficiency has not significantly changed over time. As a result, a project built in 2003 may not be much more efficient than one built in 1983. The same cannot be said for an emerging technology, such as solar thermal generation. In this case, technology can change rapidly and at an unpredictable pace. State-of-the-art products may quickly become obsolete. In these cases, technological advances might induce developers to abandon the projects far short of the hypothesized 20-or 30-year economic lives. Of course, re-computing book lives over shorter time horizons will cause a project's instant costs to be allocated over a smaller number of years, increasing its levelized cost. Projects that exceed their expected economic lifetimes will reduce the levelized costs.

Applicability of Levelized Costs

Different generation operational modes will range from baseload, to intermediate, to a peaking type of facility. A baseload facility generally delivers power at a constant rate whenever the plant is available. A facility may also be used to provide spinning reserve to deliver power during intermittent emergencies on extremely short notice. In between these modes of operation are intermediate/load-following facilities, where a plant follows the daily cycles in load. A peaking facility is called upon only during the highest daily loads during the seasonal peaks. Some facilities may provide ancillary services, where a plant provides system support, such as voltage regulation. An intermittent/variable facility may deliver power whenever the driving resource, such as wind, is available.

Comparing technologies on levelized cost alone is not appropriate, considering that different technologies provide different services. For example, wind is very competitive on the basis of cost per kWh, but it can only provide variable output. Other renewable resources, such as geothermal, have much more predictable output that may be more valuable, although improvements have been made in wind resource predictability as reflected in recent changes in ISO tariffs.

While particular generation technologies may have higher or lower costs than others, ratepayers may not see them unless the power purchase contracts specify that prices are based directly on costs. Power may be sold under a range of contractual and market transaction terms that may have no relationship to the actual cost of producing power from a specific plant. In fact, power contracts terms can be set entirely independently of the type of technology producing the power.

The combination of contract terms and technology type establishes the sharing of risks between ratepayers and generation investors. For a gas-fired plant, when fuel costs rise, it is likely that power market prices will also rise. Some contracts will pass these increases to ratepayers. In other contracts, gas-fired plants may be paid at fixed contract rates over a period of years. In these contracts, generators are exposed to fuel-cost risk, unless they also have signed a fixed-price contract for natural gas delivery. Generally, in exchange for fixed-price contracts, generators will charge a premium above the expected average market price for power to compensate for the shift in risk from ratepayers to generators.

For some renewables, the story is substantially different. If they hold a fixed price contract, ratepayers are not exposed to fuel price risk. If a renewable generator is paid based on the short-term market price, its revenues will vary with gas prices, even though its own costs remain relatively constant. In terms of a single project, ratepayers face virtually the same risk as they would with a gas-fired generator. However, ratepayers may face a smaller price risk when considering renewable projects as a whole. The more renewable projects that are present to improve fuel diversity, the less the price of electricity will likely move with changes in natural gas costs. Although renewable generator returns may fluctuate with the price of natural gas, a fixed-price contract tends to align the annual revenues with its minimal variation in costs, a more favorable outcome. In general, these types of contracts have similar terms to those signed with gas-fired generators. Considering that renewable technologies also provide other system and environmental benefits that are not generally reflected in market prices, public interest programs can improve the economic incentives for new development.

Risk-management strategies generally use some type of financial or contractual methods to reduce the variability of future costs. Without any risk management efforts, all parties are subjected to cost variations inherent in the marketplace. Risk management strategies used in energy markets include participating in forward markets, vertical and horizontal integration through market segments, long-term contracting, commodities hedging on the natural gas and electricity markets and, of course, diversification of fuel supplies, suppliers and technologies. In this sense, adoption of a renewable energy project may be viewed as part of a greater fuel diversification strategy, and the state may deem higher cost renewable projects to be an acceptable investment to pay for natural-gas price risk mitigation.

Methodology

Costs associated with electric power facilities fall into three main categories. The first category is the initial investment costs necessary to plan, permit, construct, and start up a plant. These costs are typically financed through a combination of loans ("debt financing") and investment ownership ("equity financing"). The costs are then repaid to lenders and investors over the life of the project.

Debt financing usually has fairly rigid conditions related to the term of the loan, the required periodic payments and the security of repayment, much like a home mortgage. Equity financing is usually repaid from the residual revenues remaining after paying all other costs and, as a result, has a higher risk of not being fully repaid compared to debt financing. For purposes of cost comparisons, the assumption is made that these investments are recovered on a relatively constant annual basis without regard to the amount of generation output. This annual expenditure is then divided over the annual generation to derive the average cost per kWh for the investment or "capital" component.

For capital costs, common assumptions are used for debt financing such as interest rates, term and other requirements, and for expected investment return rates for equity financing. These assumptions are shown in **Table 2.** The debt interest rate assumptions are based on November, 2001 values when the market was stable. These assumptions cover three types of potential owners—merchant developers, investor-owned utilities, and municipal utilities and non-profit cooperatives. Capital costs specific to each technology are included in **Appendices C** through **S.**

Table 2
Assumptions for Equity Return and Debt Interest Rates

Type of Owner	Return on Equity	Debt by Term (November, 2001)[1]					
		1	5	10	12	20	30
Merchant	16.0%	7.4%	7.4%	7.4%	7.4%	7.8%	8.0%
IOU	10.6%	6.3%	6.3%	6.3%	6.3%	7.1%	7.4%
Muni/Coop	NA	3.9%	3.9%	3.9%	3.9%	4.7%	4.8%

The second category is the annual operations and maintenance (O&M) costs that are relatively invariant with the amount of output, but would cease if plant operations ended. Operational costs include labor and management, insurance and other services, and certain types of consumables. Maintenance costs include scheduled overhauls and periodic upkeep. Unscheduled or "forced" outages that are a function of usage fall into the final category of costs described below. As with capital costs, these costs are summed and divided over the annual generation output to arrive at the average cost per kWh. However, unlike capital costs that are relatively insensitive to operational mode, the mode of operation can greatly affect these types of costs. For example, intervals between overhauls may be extended if a plant shifts from intermediate to peaking operations. Less labor may be required for a plant that operates only during the seasonal peak period rather than in baseload. In addition, these costs typically escalate over time, compared to capital costs which are considered constant and fixed once the initial investment is made. Nevertheless, once the mode of operation is determined, the annual O&M costs will vary little and are highly predictable over time.

The third category is the variable costs that are derived from fuel consumption, maintenance expenditures for forced outages, and other input costs driven directly by hourly plant operations. For a natural gas-fired plant, the largest component of these costs is the

[1] Staff finds that the market and debt interest rates during 2001 were stable compared to current conditions.

consumption of natural gas. Fuel costs can represent two-thirds or more of total average costs. Fuel usage, by technology, is shown in **Table 5** of **Appendices C** through **S.** Renewable resources typically have quite low variable costs because their fuel, other than biomass, have low or zero costs.

Variable input costs, particularly fuel costs, change over time. The fuel costs are often relatively unpredictable compared to other cost components. The staff's December 2002 projection of the price of natural gas for the years 2003-2013 is found in **Table 1, Appendix A**. After 2013, an average escalation factor of 5.60 percent is used to project natural gas price. This is the value of the predicted increase in fuel cost from 2012 to 2013. Variable costs also change directly with plant output and thus can vary substantially from year to year. However, they vary little, if at all, on an average cost basis. On the other hand, capital and O&M costs per kWh are inversely related to plant output—higher output means lower average costs for these components, and vice versa. Assumptions concerning annual plant operation are provided in **Table 6** of **Appendices C** through **S.**

Effects from federal and state tax policies are specified for each type of technology, as shown in **Table 3.** This table summarizes the various federal and state tax programs by technology and type of owner.

The federal corporate income tax rate is assumed to be 34 percent, and 8.84 percent is assumed for the California tax rate. The average property tax rate is 1.069 percent, and the average sales tax is 7.67 percent.[2] In addition, **Table 7** of **Appendices C** through **S** lists the renewable tax benefits applicable to each of the technologies.

To estimate operating and maintenance costs, common assumptions for salaries and associated benefits were developed for each specific technology. Staff used the 1996 United States Labor Department reported data for the different technologies as a conservative labor cost estimate in the analysis. The Labor Department information shows that labor costs were between $20 – $30 per hour, but more recent data shows that labor for some technologies is less than $20.00 per hour.

Assumptions for each technology are shown in **Tables 8 and 9 of Appendices C** through **S.** Based on the technological and financial data contained in this report, staff obtained cost summaries for each of the technologies studied. These summaries are provided in **Table 10** of **Appendices C** through **S.** Staff analyzed the impact of the emission mitigation and the cost of adding the duct firing to gas-fired facilities in different air quality management districts and summarized the results in **Table 4**. The emission cost used in the staff analysis was extracted from "Regional Cost Differences Siting New Power Generation in California Report" dated December, 2002. This report was prepared by the Aspen Environmental Group under a contract with the Energy Commission.

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[2] Elizabeth G. Hill, *California's Tax System: A Primer* (Sacramento, California: Legislative Analyst's Office, State of California, January 2001).

Table 3
Federal and State Tax Programs

	Merchant	IOU	Muni/Coop
Combustion Turbine			
Federal Depreciation	MACRS[3] 20 years	MACRS 20 years	N/A
CA Depreciation	Plant Life	Plant Life	
Investment Tax Credit	No	No	No
Renewable Prod. Credit	No	No	No
Wind			
Federal Depreciation	MACRS 5 year	MACRS 5 year	N/A
CA Depreciation	Plant Life	Plant Life	N/A
Investment Tax Credit	No	No	N/A
Renewable Prod. Credit	Yes	No	Tier I
Solar			
Federal Depreciation	MACRS 5 year	MACRS 5 year	N/A
CA Depreciation	Plant Life	Plant Life	N/A
Investment Tax Credit	Yes	Yes	N/A
Renewable Prod. Credit	No	No	Tier I
Geothermal			
Federal Depreciation	MACRS 5 year	MACRS 5 year	N/A
CA Depreciation	Plant Life	Plant Life	N/A
Investment Tax Credit	Yes	Yes	N/A
Renewable Production Credit	No	No	Tier I

[3] Modified Accelerated Cost Recovery System.

Table 4
Gas-Fired Power Plants Cost Comparisons

Technology	Air District	Gas Utility	Fuel	Operative Mode	Direct Cost Levelized
Combined Cycle	Bay Area	PG&E	Natural Gas	Baseload	$0.0524
Combined Cycle	Sacramento	PG&E	Natural Gas	Baseload	$0.0523
Combined Cycle	Kern County	SoCal	Natural Gas	Baseload	$0.0518
Combined Cycle	Mojave Desert	SoCal	Natural Gas	Baseload	$0.0519
Combined Cycle	South Coast	SoCal	Natural Gas	Baseload	$0.0534
Combined Cycle	San Diego	SDG&E	Natural Gas	Baseload	$0.0527
Combined Cycle w/Duct Firing	Bay Area	PG&E	Natural Gas	Baseload	$0.0526
Combined Cycle w/Duct Firing	Sacramento	PG&E	Natural Gas	Baseload	$0.0525
Combined Cycle w/Duct Firing	Kern County	SoCal	Natural Gas	Baseload	$0.0520
Combined Cycle w/Duct Firing	Mojave Desert	SoCal	Natural Gas	Baseload	$0.0522
Combined Cycle w/Duct Firing	South Coast	SoCal	Natural Gas	Baseload	$0.0537
Combined Cycle w/Duct Firing	San Diego	SDG&E	Natural Gas	Baseload	$0.0529
Simple Cycle CT	Bay Area	PG&E	Natural Gas	Peaking	$0.1574
Simple Cycle CT	Sacramento	PG&E	Natural Gas	Peaking	$0.1575
Simple Cycle CT	Kern County	SoCal	Natural Gas	Peaking	$0.1571
Simple Cycle CT	Mojave Desert	SoCal	Natural Gas	Peaking	$0.1571
Simple Cycle CT	South Coast	SoCal	Natural Gas	Peaking	$0.1576
Simple Cycle CT	San Diego	SDG&E	Natural Gas	Peaking	$0.1579

Caveats

The analysis presents the costs in terms of levelized costs. Levelized costs can be interpreted as a constant level of revenue necessary each year to recover all expenses over the expected economic life of the project, assuming all costs are known. Levelized costs for any power plant are a function of all the fixed and varying annual costs (e.g., financing, operations and maintenance, and fuel).

Capital costs for construction are a function of debt and equity financing terms. Debt financing is typically structured with a fixed term and interest rate, and periodic repayments. Equity financing is usually a residual return from revenues after all other costs, including debt repayment, have been covered. In this analysis, debt financing costs were based on the expected terms for a merchant-financed project with a 12-year loan and a BBB debt rating in November 2001. These terms may have changed significantly, and the industry certainly faces a much wider range of terms than it did at that time. Expected equity returns are typically between 12 and 16 percent. In this analysis, the equity target was set at twice the debt rate. In addition, other significant costs are incurred for arranging project financing. These costs range from 1.5 to 12 percent of total project investment, depending on the size of the project and the deemed creditworthiness of the project developer. This factor was set at zero percent for this analysis because no appropriate level could be chosen without project-specific details.

A second set of costs which vary by project are regional and site specific permitting and infrastructure costs. These cost differences have been documented in a report prepared by Aspen Environmental Group for the Commission in December 2002 "Regional Cost Differences Siting New Power Generation in California Report." The cost of acquiring air quality permits and offsets, and water supply sources vary substantially depending on what region the plant is located. For example, emission offset costs for a 500 MW combined cycle plant can vary from less than \$5 million to over \$20 million. Water supply costs can vary from less than \$200 per acre-foot to over \$600. The costs for gas-fired power plants are presented for specific regions to reflect these differences. However, even these cost estimates may not accurately reflect the specific circumstances for any one project. Installation of pipelines, substations and transmission lines are a function of proximity to utility interconnections, and cannot be easily generalized. In addition, general permitting process costs vary substantially depending on project specifics and jurisdiction. For this reason, these costs are not included in this analysis.

The levelized costs shown in this report are for "greenfield" projects, so they do not include any demolition costs, nor do they reflect any benefits from previously existing infrastructure. The use of levelized costs over a 20 to 40 year time horizon largely mitigates the effects from any short-run price deviations. While prices may achieve short-run spikes for various reasons, including war or other tragedies, those prices may also plunge due to an over-supply. The forecast is intended to reflect an average of the expected range of conditions over time rather than to trace patterns.

On the other hand, projects may provide benefits to the generation portfolio by hedging risks associated with fuel-price or energy-availability volatility. Such benefits can be provided by projects that can deliver power at a consistent rate on demand from energy sources where costs are not correlated with fossil fuel prices. The magnitude of the benefits is a function of:

1. The volatility of natural gas prices and energy availability from intermittent renewables such as hydro and wind power, and
2. The consistency and control of the power output of the resource.

Some of these benefits can be gained through financial contracts that fix fuel prices, but "physical hedges" where the resource energy supply is separate from fossil fuel provide additional societal insurance. This cost model does not include the risk-hedging benefit because that analysis is complex and dependent on the system mix of resources and contracts for those resources.

Natural gas variability is an important factor that can affect the cost of the gas-fired technologies. Hedging natural gas prices and hedging cost could be an important element in determining the actual cost. However, in this analysis, staff did not consider the hedging impact.[4] One must also note that the intermittent nature of wind and run-of-river hydro projects decreases their value relative to dispatchable units.

The costs presented in this report taken alone are not sufficient to choose among technologies. The choice will depend on the resource system portfolio, and how the specific resource performs within that portfolio. Other factors such as reliability, operational flexibility, environmental considerations, and appropriate scale are important as well. Developing the appropriate resource portfolio involves balancing least cost and best fit objectives.

Emerging Technologies

In addition to the technologies mentioned previously in this report, staff also obtained levelized cost estimates for emerging technologies. Such technologies require further breakthroughs in research and development before they will be considered commercially viable on a central-station scale. These technologies include various fuel cell units (costs given in **Appendices E – I**); Solar Photovoltaics, **Appendix M**; and Solar Thermal – Stirling Dish, **Appendix P**. Of these technologies, Solar PV has shown its usefulness as a distributed generation technology. However, the levelized cost, 42.72 cents per kWh for a 50 MW plant, makes it uncompetitive at a central-station scale.

[4] For an estimate of the hedging cost associated with natural-gas-fired plants, see Bolinger, Wiser and Golove, *Quantifying the Value that Wind Power Provides as a Hedge Against Volatile Natural Gas Prices*, (Berkeley, Lawrence Berkeley National Laboratory, June 2002).

Table 5
Levelized Costs for Emerging Technologies

Technology	Energy Source Fuel	Operating Mode	Economic Lifetime (years)	Gross Capacity (MW)	Direct Cost Levelized (cents/kWh)
Solar Thermal-Stirling Dish	Sun; Resource Limited	Load-Following	30	31.5	15.37
Photovoltaic	Sun; Resource Limited	Load-Following	30	50	42.72
Phosphoric Acid	Natural Gas	Baseload	20	25	21.27
Molten Carbonate	Natural Gas	Baseload	20	25	10.15
Solid Oxide	Natural Gas	Baseload	20	25	13.04
Hybrid	Natural Gas	Baseload	20	25	9.41

Appendices A-Q

Appendix A
Natural Gas Price Forecast

Table A-1
Energy Commission December 2002
Natural Gas Price Forecast, 2003-2013

Year	Price
2003	$4.55
2004	$4.10
2005	$3.94
2006	$4.11
2007	$4.29
2008	$4.50
2009	$4.72
2010	$4.97
2011	$5.25
2012	$5.54
2013	$5.83

Appendix B
Financial Information

Table B-1
Financial Parameters

Category	Capital Structure	Capital Cost
Equity	39.1%	16.0%
Preferred Equity	0.0%	0.0%
Debt	60.9%	7.4%
Discount Rate/Net Capital Cost	10.8%	
Debt Limit	100.0%	
Inflation Rate	2.0%	
Debt Coverage Ratio - Minimum	1.5	
Debt Coverage Ratio - Average	1.8	
Loan/Debt Term (years)	12.0	

Appendix C
Combine Cycle-Baseload (No Duct Firing)

Table C-1
Plant Information

Technology Type	Natural Gas
Fuel	Natural Gas
Owner/Investor	Merchant
Base Year	2002
In-service Year	2004

Table C-2
Plant Size

Gross Capacity (MW)	500.0
Parasitic Load (MW)	0.0
Net Capacity (MW)	500.0
Derate Factor (%)	100.0
Firm Capacity (MW)	500.0
Transmission Losses (%)	5.0
Required AS/reserves (%)	7.0
Average Hourly Output Rate (%)	100.0
Effective Load Carry Capacity (MW)	442.0
Annual capacity degradation rate (%)	0.0

Table C-3
Capital Costs

Escalation in Capital Costs	0.0%
AFUDC Rate	10.3%
Cash Cost	100.0%

Table C-4
Construction Costs by Year
Sum: 100%

Years Out from On-Line Date	0	-1	-2	-3	-4
Cost %/Year	75%	20%	5%	0%	0%
Carry Over	$550	$137	$27	$0	$0

Table C-5
Fuel Use

Heat Rate (MMBtu/kWh)	7,100
Fuel Consumption (MMBtu/Hr)	3,550
Start up fuel use (MMBtu/start)	1,850
No. of annual starts	50
Annual Fuel Use (MMBtu)	28,577,700

Table C-6
Operational Information

Availability/Year (%)	100.0
Availability/Year (Hours)	8,760
Equipment Life (Hours)	148,394
Equipment Life (Years)	18
Overhaul Interval (Hours)	14,839
Maintenance Outage (Days)	28
Maintenance Outage Rate (%)	3.8
Forced Outage (Hours/Year)	400
Forced Outage Rate (%)	4.6
Hours per Year Operation	8,024
Capacity Factor (%)	91.6
Annual Net Energy (GWh)	4,012

Table C-7
Renewable Tax Benefits

Investment Tax Credit (%)	0
RETC Calculation ($/kWh)	0
Production Incentive-Investor (¢/kWh)	0
Geothermal Depletion Allowance	0
RE Production Incentive Tier I	0
RE Production Incentive Tier II	0
REPI Tier II Proportion Paid (%)	10

Table C-8
Operation & Maintenance Costs

Employee Category	Full Time Employees	Hours/Year	Compensation per Employee
Managers	4	1,800	$77,031 per year
Plant Operators	12	2,200	$17 per hour
Mechanics	2	2,300	$18 per hour
Laborers	2	2,200	$12 per hour
Support Staff	3	2,000	$13 per hour

Table C-9
Operation & Maintenance Costs (Other)

Fixed O&M ($/kW-Yr)	**3.33**
Fixed O&M/Instant Cost (%)	0.61
O&M Escalation (%)	0.5
Insurance (%)	1.5
Labor Escalation Cost (%)	0.5
Overhead Multiplier	1.6
Other Operating Costs	
Water Supply ($/AF)	197.0
Consumption (AF/Yr)	2,600.0
Plant Scheduling Costs	
Transmission Service ($/MW)	

Table C-10
Cost Summary

Financing Costs ($/kW-Yr)	75
Fixed Operational Costs ($/kW-Yr)	15
Tax (w/Credits) ($/kW-Yr)	1
Fixed Costs	**90**
Fuel Costs ($/kW-Yr)	307
Variable O&M ($/kW-Yr)	19.09
Variable Costs	**326**
Total Levelized Costs ($/kW-Yr)	**416**
Capital ($/MWH)	11.25
Variable ($/MWH)	40.59
Total Levelized Costs ($/MWH)	**51.84**
Capital Costs	
Instant Cost ($/kW)	542
Installed Cost ($/MWH)	592
In-service Cost in 2004 ($/KW)	**616**

Table C-11
Capital Cost Detail

Total ($)	**270,896,567**
Component Cost ($)	**239,289,126**
Turbine/Engine [Not itemized] ($)	234,597,182
Generator/Gearhead ($)	
Boiler/HRSG ($)	
Fuel Pipeline/Tank ($)	
Slab & Engine Mount ($)	
Miscellaneous fitting & hoses ($)	4,691,944
Office space ($)	
Control Room($)	
Financial Transaction Costs (%)	**0**
Land Costs ($)	**1,477,941**
Acreage/Plant	15
Cost per Acre ($)	100,000
Acquisition Cost ($)	1,470,588
Land Prep Costs ($/Acre)	500
Total Land Prep Costs ($)	7,353
Permitting Costs ($)	**5,129,500**
Local building permits ($)	
Environmental permits ($)	
Air Emission Permits ($)	5,129,500
Interconnection Costs ($)	**0**
Transmission Lines ($)	
Substation ($)	
Induction Equipment ($)	
Environmental Controls ($)	**25,000,000**
Installation Costs ($)	25,000,000
Replacement Costs ($)	

Table C-12
Maintenance Cost Detail

Routine Maintenance Costs		Annual Costs
Replacement Interval (Hours)	8,024	
Filter Price ($)	400,000	400,000
Maintenance Interval (Hours)	8,024	
Price ($)	400,000	400,000
Interval (Hours)	1,000	
Item Price ($)	0	0
Labor Hours/Day	0	
Labor Price ($/Hour)	28	0
Annual Routine Maintenance		**0**
Major Overhauls		
Hours to Major Overhaul:	20,000	
Major Overhaul Labor (Man-Hours)	23,000	
Labor Cost ($/Hour)	56	
Major Overhaul Labor Cost ($)	1,288,000	
Major Overhaul Replacement ($)	3,712,000	**5,441,690**
NPV Cost ($)		
Minor Overhauls		
Annual Cost Item 1 ($)	1,200,000	
Hours to Item 1 Job	8,024	1
Annual Cost Item 2 ($)	0	
Hours to Item 2 Job	0	
Annualized Overhauls		**0**
Unscheduled Maintenance		
Forced Outage Hours/Year	400	
Labor Rate ($/Hour)	28	
Hours of Labor	400	
Parts Costs ($)	374,400	
Total ($)	385,600	
Total Annual Maintenance		**4,837,644**
Maintenance ($/kW-Yr)	**9.68**	
Maintenance ($/MWh)	1.21	

Table C-13
Environmental Control Costs

Total Annual Costs ($)	**$2,721,205**
Media & Technology	**Cost**
Air Emissions	
Control Technology (e.g. SCR) ($)	$15,000,000
Installation Cost ($/kW)	$30
Annual Labor (Hours/Year)	100
Loaded Labor Rate ($/Hour)	$28
Labor Cost ($)	$2,800
Annual Consumables-Catalyst ($)	$333,333
Replacement Cost ($/kW)	$20
Component Life (Hours)	141,760
Annualized Cost ($)	$1,028,436
Water Cooling	
Control Technology (e.g. wastewater) ($)	$10,000,000
Installation Cost ($/kW)	$20
Annual Labor (Hours/Year)	1000
Loaded Labor Rate ($/Hour)	$28
Labor Cost ($)	$28,000
Annual Consumables ($)	$300,000
Replacement Cost ($/kW)	$20
Component Life (Hours)	141,760
Annualized Cost ($)	$1,028,436
Solid Waste Disposal	
Non hazardous material	
Tons per Year	1
Collection and hauling ($/Ton)	$10
Landfill tipping fees ($/Ton)	$30
Total Costs ($)	$40
Hazardous materials	
Tons per Year	1
Collection and hauling ($/Ton)	$60
Landfill tipping fees ($/Ton)	$100
Total Disposal Costs ($)	$160

APPENDIX D
Combustion Turbine

Table D-1
Plant Information

Technology Type	Natural Gas
Fuel	Natural Gas
Owner/Investor	Merchant
Base Year	2002
In-service Year	2004

Table D-2
Plant Size

Gross Capacity (MW)	100.0
Parasitic Load (MW)	0.0
Net Capacity (MW)	100.0
Derate Factor (%)	100.0
Firm Capacity (MW)	100.0
Transmission Losses (%)	5.0
Required AS/reserves (%)	7.0
Average Hourly Output Rate (%)	100.0
Effective Load Carry Capacity (MW)	88.0
Annual capacity degradation rate (%)	0.15

Table D-3
Capital Costs

Escalation in Capital Costs	0.0%
AFUDC Rate	10.3%
Cash Cost	100.0%

Table D-4
Construction Costs by Year
Sum: 100%

Years Out from On-Line Date	0	-1	-2	-3	-4
Cost %/Year	75%	20%	5%	0%	0%
Carry Over	$424	$105	$21	$0	$0

Table D-5
Fuel Use

Heat Rate (MMBtu/kWh)	9,300
Fuel Consumption (MMBtu/Hr)	930
Start up fuel use (MMBtu/start)	180
No. of annual starts	120
Annual Fuel Use (MMBtu)	785,682

Table D-6
Operational Information

Availability/Year (%)	10
Availability/Year (Hours)	876
Equipment Life (Hours)	148,394
Equipment Life (Years)	30
Overhaul Interval (Hours)	876
Maintenance Outage (Days)	4
Maintenance Outage Rate (%)	1.2
Forced Outage (Hours/Year)	44
Forced Outage Rate (%)	0.5
Hours per Year Operation	822
Capacity Factor (%)	9.4
Annual Net Energy (GWh)	82

Table D-7
Renewable Tax Benefits

Investment Tax Credit (%)	0
RETC Calculation ($/kWh)	0
Production Incentive-Investor (¢/kWh)	0
Geothermal Depletion Allowance	0
RE Production Incentive Tier I	0
RE Production Incentive Tier II	0
REPI Tier II Proportion Paid (%)	10

Table D-8
Operations & Maintenance Costs (Employees)

Employee Category	Full Time Employees	Hours/Year	Compensation per Employee
Managers	1	1,800	$90,000 per year
Plant Operators	4	1,800	$17 per hour
Mechanics	1	1,800	$18 per hour
Laborers	1	1,800	$12 per hour
Support Staff	1	1,800	$13 per hour

Table D-9
Operations & Maintenance Costs (Other)

Fixed O&M ($/kW-Yr)	**9.81**
Fixed O&M/Instant Cost (%)	2.35
O&M Escalation (%)	0.5
Insurance (%)	1.5
Labor Escalation Cost (%)	0.5
Overhead Multiplier	1.6
Other Operating Costs	
Water Supply ($/AF)	197.0
Consumption (AF/Yr)	520.0
Plant Scheduling Costs	
Transmission Service ($/MW)	

Table D-10
Cost Summary

Financing Costs ($/kW-Yr)	57
Fixed Operational Costs ($/kW-Yr)	20
Tax (w/Credits) ($/kW-Yr)	1
Fixed Costs	**78**
Fuel Costs ($/kW-Yr)	42
Variable O&M ($/kW-Yr)	9
Variable Costs	**51**
Total Levelized Costs ($/kW-Yr)	**129**
Capital ($/MWH)	94.99
Variable ($/MWH)	62.11
Total Levelized Costs ($/MWH)	**157.11**
Capital Costs	
Instant Cost ($/kW)	417
Installed Cost ($/MWH)	456
In-service Cost in 2004 ($/KW)	**475**

Table D-11
Capital Cost Detail

Total ($)	**41,715,152**
Component Cost ($)	**31,620,000**
Turbine/Engine [Not itemized] ($)	31,000,000
Generator/Gearhead ($)	
Boiler/HRSG ($)	
Fuel Pipeline/Tank ($)	
Slab & Engine Mount ($)	
Miscellaneous fitting & hoses ($)	620,000
Office space ($)	
Control Room($)	
Financial Transaction Costs (%)	**0**
Land Costs ($)	**5,007,353**
Acreage/Plant	50
Cost per Acre ($)	100,000
Acquisition Cost ($)	5,000,000
Land Prep Costs ($/Acre)	500
Total Land Prep Costs ($)	7,353
Permitting Costs ($)	**87,799**
Local building permits ($)	
Environmental permits ($)	
Air Emission Permits ($)	87,799
Interconnection Costs ($)	**0**
Transmission Lines ($)	
Substation ($)	
Induction Equipment ($)	
Environmental Controls ($)	**5,000,000**
Installation Costs ($)	5,000,000
Replacement Costs ($)	

Table D-12
Maintenance Cost Detail

Routine Maintenance Costs		Annual Costs
Replacement Interval (Hours)	822	
Filter Price ($)	40,000	40,000
Maintenance Interval (Hours)	822	
Price ($)	40,000	40,000
Interval (Hours)	1,000	
Item Price ($)	0	0
Labor Hours/Day	0.00	
Labor Price ($/Hour)	28	0
Annual Routine Maintenance		**80,000**
Major Overhauls		
Hours to Major Overhaul:	8,360	
Major Overhaul Labor (Man-Hours)	4,600	
Labor Cost ($/Hour)	56	
Major Overhaul Labor Cost ($)	257,600	
Major Overhaul Replacement ($)	3,742,400	**193,253**
NPV Cost ($)		
Minor Overhauls		
Annual Cost Item 1 ($)	100,000	
Hours to Item 1 Job	822	
Annual Cost Item 2 ($)	0	
Hours to Item 2 Job	0	
Annualized Overhauls		**102,212**
Unscheduled Maintenance		
Forced Outage Hours/Year	44	
Labor Rate ($/Hour)	28	
Hours of Labor	44	
Parts Costs ($)	374,400	
Total ($)	375,626	
Total Annual Maintenance		**751,091**
Maintenance ($/kW-Yr)	**7.51**	
Maintenance ($/MWh)	9.14	

Table D-13
Environmental Control Costs

Total Annual Costs ($)	**440,506**
Media & Technology	**Cost**
Air Emissions	
Control Technology (e.g. SCR) ($)	
Installation Cost ($/kW)	30
Annual Labor (Hours/Year)	100
Loaded Labor Rate ($/Hour)	28
Labor Cost ($)	2,800
Annual Consumables-Catalyst ($)	33,333
Replacement Cost ($/kW)	20
Component Life (Hours)	141,760
Annualized Cost ($)	169,286
Water Cooling	
Control Technology (e.g. wastewater) ($)	200,000
Installation Cost ($/kW)	20
Annual Labor (Hours/Year)	200
Loaded Labor Rate ($/Hour)	28
Labor Cost ($)	5,600
Annual Consumables ($)	60,000
Replacement Cost ($/kW)	20
Component Life (Hours)	141,760
Annualized Cost ($)	
Solid Waste Disposal	
Non hazardous material	
Tons per Year	1
Collection and hauling ($/Ton)	10
Landfill tipping fees ($/Ton)	30
Total Costs ($)	40
Hazardous materials	
Tons per Year	1
Collection and hauling ($/Ton)	60
Landfill tipping fees ($/Ton)	100
Total Disposal Costs ($)	160

Appendix E
Fuel Cell - CT Hybrid

Table E-1
Plant Information

Technology Type	Natural Gas
Fuel	Natural Gas
Owner/Investor	Merchant
Base Year	2002
In-service Year	2004

Table E-2
Plant Size

Gross Capacity (MW)	25.0
Parasitic Load (MW)	0.0
Net Capacity (MW)	25.0
Derate Factor (%)	100.0
Firm Capacity (MW)	25.0
Transmission Losses (%)	0.0
Required AS/reserves (%)	0.0
Average Hourly Output Rate (%)	100.0
Effective Load Carry Capacity (MW)	25.0
Annual capacity degradation rate (%)	0.0

Table E-3
Capital Costs

Escalation in Capital Costs	0.0%
AFUDC Rate	10.3%
Cash Cost	100.0%

Table E-4
Construction Costs by Year
Sum: 100%

Years Out from On-Line Date	0	-1	-2	-3	-4
Cost %/Year	100%	0%	0%	0%	0%
Carry Over	$1,164	$0	$0	$0	$0

Table E-5
Fuel Use

Heat Rate (MMBtu/kWh)	5,700.0
Fuel Consumption (MMBtu/Hr)	142.5
Start up fuel use (MMBtu/start)	0.0
No. of annual starts	0.0
Annual Fuel Use (MMBtu)	1,123,470.0

Table E-6
Operational Information

Availability/Year (%)	100
Availability/Year (Hours)	8,760
Equipment Life (Hours)	222,592
Equipment Life (Years)	28
Overhaul Interval (Hours)	7,884
Maintenance Outage (Days)	18
Maintenance Outage Rate (%)	5
Forced Outage (Hours/Year)	438
Forced Outage Rate (%)	5
Hours per Year Operation	7,884
Capacity Factor (%)	90
Annual Net Energy (GWh)	197

Table E-7
Renewable Tax Benefits

Investment Tax Credit (%)	0
RETC Calculation ($/kWh)	0
Production Incentive-Investor (¢/kWh)	0
Geothermal Depletion Allowance	0
RE Production Incentive Tier I	0
RE Production Incentive Tier II	0
REPI Tier II Proportion Paid (%)	10

Table E-8
Maintenance & Operations Costs (Employees)

Employee Category	Full Time Employees	Hours/Year	Compensation per Employee
Managers	1	1,800	$120,000 per year
Plant Operators	4	1,800	$30 per hour
Mechanics	0	1,800	$30 per hour
Laborers	2.5	1,800	$20 per hour
Support Staff	0	1,800	$20 per hour

Table E-9
Maintenance & Operations Costs (Other)

Fixed O&M ($/kW-Yr)	**191.0**
Fixed O&M/Instant Cost (%)	16.40
O&M Escalation (%)	0.5
Insurance (%)	1.5
Labor Escalation Cost (%)	0.5
Overhead Multiplier	1.6
Other Operating Costs	
Water Supply ($/AF)	
Consumption (AF/Yr)	
Plant Scheduling Costs	
Transmission Service ($/MW)	

Table E-10
Cost Summary

Financing Costs ($/kW-Yr)	150
Fixed Operational Costs ($/kW-Yr)	260
Tax (w/Credits) ($/kW-Yr)	7
Fixed Costs	**417**
Fuel Costs ($/kW-Yr)	275
Variable O&M ($/kW-Yr)	50
Variable Costs	**325**
Total Levelized Costs ($/kW-Yr)	**742**
Capital ($/MWH)	52.93
Variable ($/MWH)	41.16
Total Levelized Costs ($/MWH)	**94.10**
Capital Costs	
Instant Cost ($/kW)	1,164
Installed Cost ($/MWH)	1,253
In-service Cost in 2004 ($/KW)	**1,304**

Table E-11
Capital Cost Detail

Total ($)	**29,096,786**
Component Cost ($)	**28,850,000**
SOFC Generator Equipment ($)	8,350,000
SOFC Power Conditioning Equipment ($)	3,675,000
Gas Turbine Generator Equipment ($)	5,000,000
Balance of Plant Equipment ($)	4,450,000
Site Preparation ($)	425,000
Project Management and Engineering ($)	925,000
Overhead and Profit Allowance ($)	6,025,000
Financial Transaction Costs (%)	**0**
Land Costs ($)	**246,786**
Sq Ft/MW	4,300
Acreage/Plant	2.47
Cost per Acre ($)	100,000
Acquisition Cost ($)	246,786
Land Prep Costs ($/Acre)	0
Total Land Prep Costs ($)	0
Permitting Costs [not separate] ($)	**0**
Local building permits ($)	
Environmental permits ($)	
Interconnection Costs ($)	**0**
Transmission Lines ($)	
Substation ($)	
Induction Equipment ($)	

Minutes
Table E-12
Maintenance Cost Detail

Routine Maintenance Costs		Annual Costs
Replacement Interval (Hours)	1	
Filter Price ($)	0	0
Maintenance Interval (Hours)	1	
Price ($)	0	0
Oil Price ($/Gallon)	3.40	
Oil Capacity	0	0
Oil Added per Day	0	0
Interval (Hours)	1,000	
Item Price ($)	0	0
Labor Hours/Day	0	
Labor Price ($/Hour)	48	0
Annual Routine Maintenance		**0**
Major Overhauls		
Hours to Major Overhaul:	0	
Major Overhaul Labor (Man-Hours)	0	
Labor Cost ($/Hour)	48	
Major Overhaul Labor Cost ($)	0	
Major Overhaul Replacement ($)	0	
NPV Cost ($)		
Minor Overhauls		
Annual Cost Item 1 ($)	22,925,101	
Hours to Item 1 Job	40,000	5
Annual Cost Item 2 ($)	4,585,020	
Hours to Item 2 Job	55,188	7
Annualized Overhauls		**4,069,350**
Unscheduled Maintenance		
Forced Outage Hours/Year	438	
Labor Rate ($/Hour)	48	
Hours of Labor	438	
Parts Costs ($)	0	
Total ($)	21,024	
Total Annual Maintenance		**4,090,374**
Maintenance ($/kW-Yr)	**163.61**	
Maintenance ($/MWh)	20.75	

Table E-13
Environmental Control Costs

Total Annual Costs ($)	**0**
Media & Technology	**Cost**
Air Emissions	
Control Technology (e.g. SCR) ($)	
Installation Cost ($/kW)	0
Annual Labor (Hours/Year)	0
Loaded Labor Rate ($/Hour)	48
Labor Cost ($)	0
Annual Consumables-Catalyst ($)	0
Replacement Cost ($/kW)	0
Component Life (Hours)	141,760
Annualized Cost ($)	
Water Cooling	
Control Technology (e.g. wastewater) ($)	
Installation Cost ($/kW)	0
Annual Labor (Hours/Year)	0
Loaded Labor Rate ($/Hour)	48
Labor Cost ($)	0
Annual Consumables ($)	0
Replacement Cost ($/kW)	0
Component Life (Hours)	141,760
Annualized Cost ($)	
Solid Waste Disposal	
Non hazardous material	
Tons per Year	0
Collection and hauling ($/Ton)	10
Landfill tipping fees ($/Ton)	30
Total Costs ($)	0
Hazardous materials	
Tons per Year	0
Collection and hauling ($/Ton)	10
Landfill tipping fees ($/Ton)	30
Total Disposal Costs ($)	0

Appendix F
Fuel Cell - Molten Carbonate

Table F-1
Plant Information

Technology Type	Natural Gas
Fuel	Natural Gas
Owner/Investor	Merchant
Base Year	2001
In-service Year	2004

Table F-2
Plant Size

Gross Capacity (MW)	25.0
Parasitic Load (MW)	0.0
Net Capacity (MW)	25.0
Derate Factor (%)	100.0
Firm Capacity (MW)	25.0
Transmission Losses (%)	0.0
Required AS/reserves (%)	0.0
Average Hourly Output Rate (%)	100.0
Effective Load Carry Capacity (MW)	25.0
Annual capacity degradation rate (%)	0.0

Table F-3
Capital Costs

Escalation in Capital Costs	0.0%
AFUDC Rate	10.3%
Cash Cost	100.0%

Table F-4
Construction Costs by Year
Sum: 100%

Years Out from On-Line Date	0	-1	-2	-3	-4
Cost %/Year	100%	0%	0%	0%	0%
Carry Over	$1,509	$0	$0	$0	$0

Table F-5
Fuel Use

Heat Rate (MMBtu/kWh)	7,511.0
Fuel Consumption (MMBtu/Hr)	187.8
Start up fuel use (MMBtu/start)	0.0
No. of annual starts	0.0
Annual Fuel Use (MMBtu)	1,480,418.0

Table F-6
Operational Information

Availability/Year (%)	100
Availability/Year (Hours)	8,760
Equipment Life (Hours)	222,592
Equipment Life (Years)	28
Overhaul Interval (Hours)	7,884
Maintenance Outage (Days)	18
Maintenance Outage Rate (%)	5
Forced Outage (Hours/Year)	438
Forced Outage Rate (%)	5
Hours per Year Operation	7,884
Capacity Factor (%)	90
Annual Net Energy (GWh)	197

Table F-7
Renewable Tax Benefits

Investment Tax Credit (%)	0
RETC Calculation ($/kWh)	0
Production Incentive-Investor (¢/kWh)	0
Geothermal Depletion Allowance	0
RE Production Incentive Tier I	0
RE Production Incentive Tier II	0
REPI Tier II Proportion Paid (%)	10

Table F-8
Operation & Maintenance Costs

Employee Category	Full Time Employees	Hours/Year	Compensation per Employee
Managers	0	1,800	$80,000 per year
Plant Operators	0	1,800	$30 per hour
Mechanics	0	1,800	$30 per hour
Laborers	0	1,800	$20 per hour
Support Staff	0	1,800	$20 per hour

Table F-9
Operation & Maintenance Costs (Other)

Fixed O&M ($/kW-Yr)	**120.0**
Fixed O&M/Instant Cost (%)	7.99
O&M Escalation (%)	0.5
Insurance (%)	1.5
Labor Escalation Cost (%)	0.5
Overhead Multiplier	1.6
Other Operating Costs	
Water Supply ($/AF)	
Consumption (AF/Yr)	
Plant Scheduling Costs	
Transmission Service ($/MW)	

Table F-10
Cost Summary

Financing Costs ($/kW-Yr)	198
Fixed Operational Costs ($/kW-Yr)	180
Tax (w/Credits) ($/kW-Yr)	10
Fixed Costs	**388**
Fuel Costs ($/kW-Yr)	362
Variable O&M ($/kW-Yr)	50
Variable Costs	**412**
Total Levelized Costs ($/kW-Yr)	**800**
Capital ($/MWH)	49.23
Variable ($/MWH)	52.24
Total Levelized Costs ($/MWH)	**101.47**
Capital Costs	
Instant Cost ($/kW)	1,509
Installed Cost ($/MWH)	1,624
In-service Cost in 2004 ($/KW)	**1,724**

Table F-11
Capital Cost Detail

Total ($)	**37,718,090**
Component Cost ($)	**37,500,000**
[Not itemized-"All In" cost] ($)	37,500,000
Office space	
Control Room	
Other infrastructure	
Financial Transaction Costs (%)	**0**
Land Costs ($)	**218,090**
Sq Ft/MW	3,800
Acreage/Plant	2.18
Cost per Acre ($)	100,000
Acquisition Cost ($)	218,090
Land Prep Costs ($/Acre)	0
Total Land Prep Costs ($)	0
Permitting Costs [not separate] ($)	**0**
Local building permits	
Environmental permits	
Interconnection Costs ($)	**0**
Transmission Lines	
Substation	
Induction Equipment	

Table F-12
Maintenance Cost Detail

Routine Maintenance Costs		Annual Costs
Replacement Interval (Hours)	1	
Filter Price ($)	0	0
Maintenance Interval (Hours)	1	
Price ($)	0	0
Oil Price ($/Gallon)	3.40	
Oil Capacity	0	0
Oil Added per Day	0	0
Interval (Hours)	1,000	
Item Price ($)	0	0
Labor Hours/Day	0	
Labor Price ($/Hour)	48	0
Annual Routine Maintenance		**0**
Major Overhauls		
Hours to Major Overhaul:	0	
Major Overhaul Labor (Man-Hours)	0	
Labor Cost ($/Hour)	48	
Major Overhaul Labor Cost ($)	0	
Major Overhaul Replacement ($)	0	
NPV Cost ($)		
Minor Overhauls		
Annual Cost Item 1 ($)	10,000,000	
Hours to Item 1 Job	23,652	3
Annual Cost Item 2 ($)	0	
Hours to Item 2 Job	55,188	7
Annualized Overhauls		**2,991,198**
Unscheduled Maintenance		
Forced Outage Hours/Year	438	
Labor Rate ($/Hour)	48	
Hours of Labor	438	
Parts Costs ($)	0	
Total ($)	21,024	
Total Annual Maintenance		**3,012,222**
Maintenance ($/kW-Yr)	**120.49**	
Maintenance ($/MWh)	15.28	

Table F-13
Environmental Control Costs

Total Annual Costs ($)	**0**
Media & Technology	**Cost**
Air Emissions	
Control Technology (e.g. SCR) ($)	
Installation Cost ($/kW)	0
Annual Labor (Hours/Year)	0
Loaded Labor Rate ($/Hour)	48
Labor Cost ($)	0
Annual Consumables-Catalyst ($)	0
Replacement Cost ($/kW)	0
Component Life (Hours)	141,760
Annualized Cost ($)	
Water Cooling	
Control Technology (e.g. wastewater) ($)	
Installation Cost ($/kW)	0
Annual Labor (Hours/Year)	0
Loaded Labor Rate ($/Hour)	48
Labor Cost ($)	0
Annual Consumables ($)	0
Replacement Cost ($/kW)	0
Component Life (Hours)	141,760
Annualized Cost ($)	
Solid Waste Disposal	
Non hazardous material	
Tons per Year	0
Collection and hauling ($/Ton)	10
Landfill tipping fees ($/Ton)	30
Total Costs ($)	0
Hazardous materials	
Tons per Year	0
Collection and hauling ($/Ton)	10
Landfill tipping fees ($/Ton)	30
Total Disposal Costs ($)	0

APPENDIX G
Fuel Cell - Phosphoric Acid

Table G-1
Plant Information

Technology Type	Natural Gas
Fuel	Natural Gas
Owner/Investor	Merchant
Base Year	2002
In-service Year	2003

Table G-2
Plant Size

Gross Capacity (MW)	25.0
Parasitic Load (MW)	0.0
Net Capacity (MW)	25.0
Derate Factor (%)	100.0
Firm Capacity (MW)	25.0
Transmission Losses (%)	0.0
Required AS/reserves (%)	0.0
Average Hourly Output Rate (%)	100.0
Effective Load Carry Capacity (MW)	25.0
Annual capacity degradation rate (%)	0.0

Table G-3
Capital Costs

Escalation in Capital Costs	0.0%
AFUDC Rate	10.3%
Cash Cost	100.0%

Table G-4
Construction Costs by Year
Sum: 100%

Years Out from On-Line Date	0	-1	-2	-3	-4
Cost %/Year	100%	0%	0%	0%	0%
Carry Over	$4,520	$0	$0	$0	$0

Table G-5
Fuel Use

Heat Rate (MMBtu/kWh)	9,389.0
Fuel Consumption (MMBtu/Hr)	234.7
Start up fuel use (MMBtu/start)	0.0
No. of annual starts	0.0
Annual Fuel Use (MMBtu)	1,850,572.0

Table G-6
Operational Information

Availability/Year (%)	100
Availability/Year (Hours)	8,760
Equipment Life (Hours)	222,592
Equipment Life (Years)	28
Overhaul Interval (Hours)	7,884
Maintenance Outage (Days)	18
Maintenance Outage Rate (%)	5
Forced Outage (Hours/Year)	438
Forced Outage Rate (%)	5
Hours per Year Operation	7,884
Capacity Factor (%)	90
Annual Net Energy (GWh)	197

Table G-7
Renewable Tax Benefits

Investment Tax Credit (%)	0
RETC Calculation ($/kWh)	0
Production Incentive-Investor (¢/kWh)	0
Geothermal Depletion Allowance	0
RE Production Incentive Tier I	0
RE Production Incentive Tier II	0
REPI Tier II Proportion Paid (%)	10

Table G-8
Operations & Maintenance Costs (Employee)

Employees	Full Time Employees	Hours/Year	Compensation per Employee
Managers	0	1,800	$80,000 per year
Plant Operators	0	1,800	$30 per hour
Mechanics	0	1,800	$30 per hour
Laborers	0	1,800	$20 per hour
Support Staff	0	1,800	$20 per hour

Table G-9
Operation & Maintenance Costs (Other)

Fixed O&M ($/kW-Yr)	**271.0**
Fixed O&M/Instant Cost (%)	5.99
O&M Escalation (%)	0.5
Insurance (%)	1.5
Labor Escalation Cost (%)	0.5
Overhead Multiplier	1.6
Other Operating Costs	
Water Supply ($/AF)	
Consumption (AF/Yr)	
Plant Scheduling Costs	
Transmission Service ($/MW)	

Table G-10
Cost Summary

Financing Costs ($/kW-Yr)	571
Fixed Operational Costs ($/kW-Yr)	424
Tax (w/Credits) ($/kW-Yr)	28
Fixed Costs	**1,023**
Fuel Costs ($/kW-Yr)	437
Variable O&M ($/kW-Yr)	217
Variable Costs	**654**
Total Levelized Costs ($/kW-Yr)	**1,677**
Capital ($/MWH)	129.76
Variable ($/MWH)	82.96
Total Levelized Costs ($/MWH)	**212.72**
Capital Costs	
Instant Cost ($/kW)	4,520
Installed Cost ($/MWH)	4,867
In-service Cost in 2004 ($/KW)	**4,964**

Table G-11
Capital Cost Detail

Total ($)	**113,005,051**
Component Cost ($)	**112,500,000**
[Not itemized="All In" cost] ($)	112,500,000
Office space	
Control Room	
Other infrastructure	
Financial Transaction Costs (%)	**0**
Land Costs ($)	**505,051**
Sq Ft/MW	8,800
Acreage/Plant	5.05
Cost per Acre ($)	100,000
Acquisition Cost ($)	505,051
Land Prep Costs ($/Acre)	0
Total Land Prep Costs ($)	0
Permitting Costs [not separate] ($)	**0**
Local building permits	
Environmental permits	
Interconnection Costs ($)	**0**
Transmission Lines	
Substation	
Induction Equipment	

Table G-12
Maintenance Cost Detail

Routine Maintenance Costs		Annual Costs
Replacement Interval (Hours)	1	
Filter Price ($)	0	0
Maintenance Interval (Hours)	1	
Price ($)	0	0
Oil Price ($/Gallon)	3.40	
Oil Capacity	0	0
Oil Added per Day	0	0
Interval (Hours)	1,000	
Item Price ($)	0	0
Labor Hours/Day	0.00	
Labor Price ($/Hour)	48	0
Annual Routine Maintenance		**0**
Major Overhauls		
Hours to Major Overhaul:	0	
Major Overhaul Labor (Man-Hours)	0	
Labor Cost ($/Hour)	48	
Major Overhaul Labor Cost ($)	0	
Major Overhaul Replacement ($)	0	
NPV Cost ($)		
Minor Overhauls		
Annual Cost Item 1 ($)	37,500,000	
Hours to Item 1 Job	39,420	5
Annual Cost Item 2 ($)	7,500,000	
Hours to Item 2 Job	55,188	7
Annualized Overhauls		**6,746,247**
Unscheduled Maintenance		
Forced Outage Hours/Year	438	
Labor Rate ($/Hour)	48	
Hours of Labor	438	
Parts Costs ($)	0	
Total ($)	21,024	
Total Annual Maintenance		**6,767,271**
Maintenance ($/kW-Yr)	270.69	
Maintenance ($/MWh)	$34.33	

Table G-13
Environmental Control Costs

Total Annual Costs ($)	**0**
Media & Technology	**Cost**
Air Emissions	
Control Technology (e.g. SCR) ($)	
Installation Cost ($/kW)	0
Annual Labor (Hours/Year)	0
Loaded Labor Rate ($/Hour)	48
Labor Cost ($)	0
Annual Consumables-Catalyst ($)	0
Replacement Cost ($/kW)	0
Component Life (Hours)	141,760
Annualized Cost ($)	
Water Cooling	
Control Technology (e.g. wastewater) ($)	
Installation Cost ($/kW)	0
Annual Labor (Hours/Year)	0
Loaded Labor Rate ($/Hour)	48
Labor Cost ($)	0
Annual Consumables ($)	0
Replacement Cost ($/kW)	0
Component Life (Hours)	141,760
Annualized Cost ($)	
Solid Waste Disposal	
Non hazardous material	
Tons per Year	0
Collection and hauling ($/Ton)	10
Landfill tipping fees ($/Ton)	30
Total Costs ($)	0
Hazardous materials	
Tons per Year	0
Collection and hauling ($/Ton)	10
Landfill tipping fees ($/Ton)	30
Total Disposal Costs ($)	0

APPENDIX H
Fuel Cell - Proton Exchange Membrane

Table H-1
Plant Information

Technology Type	Natural Gas
Fuel	Natural Gas
Owner/Investor	Merchant
Base Year	2002
In-service Year	2005

Table H-2
Plant Size

Gross Capacity (MW)	25.0
Parasitic Load (MW)	0.0
Net Capacity (MW)	25.0
Derate Factor (%)	100.0
Firm Capacity (MW)	25.0
Transmission Losses (%)	0.0
Required AS/reserves (%)	0.0
Average Hourly Output Rate (%)	100.0
Effective Load Carry Capacity (MW)	25.0
Annual capacity degradation rate (%)	0.0

Table H-3
Capital Costs

Escalation in Capital Costs	0.0%
AFUDC Rate	10.3%
Cash Cost	100.0%

Table H-4
Construction Costs by Year
Sum: 100%

Years Out from On-Line Date	0	-1	-2	-3	-4
Cost %/Year	100%	0%	0%	0%	0%
Carry Over	$1,511	$0	$0	$0	$0

Table H-5
Fuel Use

Heat Rate (MMBtu/kWh)	9,389.0
Fuel Consumption (MMBtu/Hr)	234.7
Start up fuel use (MMBtu/start)	0.0
No. of annual starts	0.0
Annual Fuel Use (MMBtu)	1,850,572.0

Table H-6
Operational Information

Availability/Year (%)	100
Availability/Year (Hours)	8,760
Equipment Life (Hours)	222,592
Equipment Life (Years)	28
Overhaul Interval (Hours)	7,884
Maintenance Outage (Days)	18
Maintenance Outage Rate (%)	5
Forced Outage (Hours/Year)	438
Forced Outage Rate (%)	5
Hours per Year Operation	7,884
Capacity Factor (%)	90
Annual Net Energy (GWh)	197

Table H-7
Renewable Tax Benefits

Investment Tax Credit (%)	0
RETC Calculation ($/kWh)	0
Production Incentive-Investor (¢/kWh)	0
Geothermal Depletion Allowance	0
RE Production Incentive Tier I	0
RE Production Incentive Tier II	0
REPI Tier II Proportion Paid (%)	10

Table H-8
Operation & Maintenance Costs (Employee)

Employees	Full Time Employees	Hours/Year	Compensation per Employee
Managers	0	1,800	$80,000 per year
Plant Operators	0	1,800	$30 per hour
Mechanics	0	1,800	$30 per hour
Laborers	0	1,800	$20 per hour
Support Staff	0	1,800	$20 per hour

Table H-9
Operation & Maintenance Costs (Other)

Fixed O&M ($/kW-Yr)	**271.0**
Fixed O&M/Instant Cost (%)	17.91
O&M Escalation (%)	0.5
Insurance (%)	1.5
Labor Escalation Cost (%)	0.5
Overhead Multiplier	1.6
Other Operating Costs	
Water Supply ($/AF)	
Consumption (AF/Yr)	
Plant Scheduling Costs	
Transmission Service ($/MW)	

Table H-10
Cost Summary

Financing Costs ($/kW-Yr)	199
Fixed Operational Costs ($/kW-Yr)	367
Tax (w/Credits) ($/kW-Yr)	10
Fixed Costs	**575**
Fuel Costs ($/kW-Yr)	474
Variable O&M ($/kW-Yr)	217
Variable Costs	**691**
Total Levelized Costs ($/kW-Yr)	**1,266**
Capital ($/MWH)	72.92
Variable ($/MWH)	87.68
Total Levelized Costs ($/MWH)	**160.60**
Capital Costs	
Instant Cost ($/kW)	1,511
Installed Cost ($/MWH)	1,627
In-service Cost in 2004 ($/KW)	**1,727**

Table H-11
Capital Cost Detail

Total ($)	**37,781,221**
Component Cost ($)	**37,500,000**
[Not Itemized – "All In" cost]	37,500,000
Office space	
Control Room	
Other Infrastructure	
Financial Transaction Costs (%)	**0**
Land Costs ($)	**281,221**
Sq Ft/MW	4,900
Acreage/Plant	2.81
Cost per Acre ($)	100,000
Acquisition Cost ($)	281,221
Land Prep Costs ($/Acre)	0
Total Land Prep Costs ($)	0
Permitting Costs [not separate ($)	**0**
Local building permits ($)	
Environmental permits ($)	
Interconnection Costs ($)	**0**
Transmission Lines ($)	
Substation ($)	
Induction Equipment ($)	

Table H-12
Maintenance Cost Detail

Routine Maintenance Costs		Annual Costs
Replacement Interval (Hours)	1	
Filter Price ($)	0	0
Maintenance Interval (Hours)	1	
Price ($)	0	0
Oil Price ($/Gallon)	3.40	
Oil Capacity	0	0
Oil Added per Day	0	0
Interval (Hours)	1,000	
Item Price ($)	0	0
Labor Hours/Day	0.00	
Labor Price ($/Hour)	48	0
Annual Routine Maintenance		**0**
Major Overhauls		
Hours to Major Overhaul	0	
Major Overhaul Labor (Man-Hours)	0	
Labor Cost ($/Hour)	48	
Major Overhaul Labor Cost ($)	0	
Major Overhaul Replacement ($)	0	
NPV Cost ($)		
Minor Overhauls		
Annual Cost Item 1 ($)	37,500,000	
Hours to Item 1 Job	39,420	5
Annual Cost Item 2 ($)	7,500,000	
Hours to Item 2 Job	55,188	7
Annualized Overhauls		**6,746,247**
Unscheduled Maintenance		
Forced Outage Hours/Year	438	
Labor Rate ($/Hour)	48	
Hours of Labor	438	
Parts Costs ($)	0	
Total ($)	21,024	
Total Annual Maintenance		**6,767,271**
Maintenance ($/kW-Yr)	270.69	
Maintenance ($/MWh)	34.33	

Table H-13
Environmental Control Costs

Total Annual Costs ($)	**0**
Media & Technology	**Cost**
Air Emissions	
Control Technology (e.g. SCR) ($)	
Installation Cost ($/kW)	0
Annual Labor (Hours/Year)	0
Loaded Labor Rate ($/Hour)	48
Labor Cost ($)	0
Annual Consumables-Catalyst ($)	0
Replacement Cost ($/kW)	0
Component Life (Hours)	141,760
Annualized Cost ($)	
Water Cooling	
Control Technology (e.g. wastewater) ($)	
Installation Cost ($/kW)	0
Annual Labor (Hours/Year)	0
Loaded Labor Rate ($/Hour)	48
Labor Cost ($)	0
Annual Consumables ($)	0
Replacement Cost ($/kW)	0
Component Life (Hours)	141,760
Annualized Cost ($)	
Solid Waste Disposal	
Non hazardous material	
Tons per Year	0
Collection and hauling ($/Ton)	10
Landfill tipping fees ($/Ton)	30
Total Costs ($)	0
Hazardous materials	
Tons per Year	0
Collection and hauling ($/Ton)	10
Landfill tipping fees ($/Ton)	30
Total Disposal Costs ($)	0

APPENDIX I
Fuel Cell - Solid Oxide

Table I-1
Plant Information

Technology Type	Natural Gas
Fuel	Natural Gas
Owner/Investor	Merchant
Base Year	2002
In-service Year	2004

Table I-2
Plant Size

Gross Capacity (MW)	25.0
Parasitic Load (MW)	0.0
Net Capacity (MW)	25.0
Derate Factor (%)	100.0
Firm Capacity (MW)	25.0
Transmission Losses (%)	0.0
Required AS/reserves (%)	0.0
Average Hourly Output Rate (%)	100.0
Effective Load Carry Capacity (MW)	25.0
Annual capacity degradation rate (%)	0.0

Table I-3
Capital Costs

Escalation in Capital Costs	0.0%
AFUDC Rate	10.3%
Cash Cost	100.0%

Table I-4
Construction Costs by Year
Sum: 100%

Years Out from On-Line Date	0	-1	-2	-3	-4
Cost %/Year	100%	0%	0%	0%	0%
Carry Over	$1,577	$0	$0	$0	$0

Table I-5
Fuel Use

Heat Rate (MMBtu/kWh)	8,345.0
Fuel Consumption (MMBtu/Hr)	208.6
Start up fuel use (MMBtu/start)	0.0
No. of annual starts	0.0
Annual Fuel Use (MMBtu)	1,644,800.0

Table I-6
Operational Information

Availability/Year (%)	100
Availability/Year (Hours)	8,760
Equipment Life (Hours)	222,592
Equipment Life (Years)	28
Overhaul Interval (Hours)	7,884
Maintenance Outage (Days)	18
Maintenance Outage Rate (%)	5
Forced Outage (Hours/Year)	438
Forced Outage Rate (%)	5
Hours per Year Operation	7,884
Capacity Factor (%)	90
Annual Net Energy (GWh)	197

Table I-7
Renewable Tax Benefits

Investment Tax Credit (%)	0
RETC Calculation ($/kWh)	0
Production Incentive-Investor (¢/kWh)	0
Geothermal Depletion Allowance	0
RE Production Incentive Tier I	0
RE Production Incentive Tier II	0
REPI Tier II Proportion Paid (%)	10

Table I-8
Operation & Maintenance Costs

Employees	Full Time Employees	Hours/Year	Compensation per Employee
Managers	1	1,800	$120,000 per year
Plant Operators	4	1,800	$30 per hour
Mechanics	0	1,800	$30 per hour
Laborers	2.5	1,800	$20 per hour
Support Staff	0	1,800	$20 per hour

Table I-9
Operation & Maintenance Costs (Other)

Fixed O&M ($/kW-Yr)	**294.0**
Fixed O&M/Instant Cost (%)	18.67
O&M Escalation (%)	0.5
Insurance (%)	1.5
Labor Escalation Cost (%)	0.5
Overhead Multiplier	1.6
Other Operating Costs	
Water Supply ($/AF)	
Consumption (AF/Yr)	
Plant Scheduling Costs	
Transmission Service ($/MW)	

Table I-10
Cost Summary

Financing Costs ($/kW-Yr)	203
Fixed Operational Costs ($/kW-Yr)	397
Tax (w/Credits) ($/kW-Yr)	10
Fixed Costs	**610**
Fuel Costs ($/kW-Yr)	403
Variable O&M ($/kW-Yr)	16
Variable Costs	**418**
Total Levelized Costs ($/kW-Yr)	**1,028**
Capital ($/MWH)	77.34
Variable ($/MWH)	53.04
Total Levelized Costs ($/MWH)	**130.38**
Capital Costs	
Instant Cost ($/kW)	1,577
Installed Cost ($/MWH)	1,698
In-service Cost in 2004 ($/KW)	**1,766**

Table I-11
Capital Cost Detail

Total ($)	**39,423,440**
Component Cost ($)	
Turbine/Engine [Not itemized] ($)	**39,142,219**
Generator/Gearhead ($)	
Boiler/HRSG ($)	13,658,609
Fuel Pipeline/Tank ($)	13,658,609
Slab & Engine Mount ($)	
Miscellaneous fitting & hoses ($)	4,450,000
Office space ($)	425,000
Control Room($)	925,000
Duct Burners ($)	6,025,000
Financial Transaction Costs (%)	
Land Costs ($)	0
Acreage/Plant	**281,221**
Cost per Acre ($)	4,900
Acquisition Cost ($)	2.81
Land Prep Costs ($/Acre)	100,000
Total Land Prep Costs ($)	281,221
Permitting Costs ($)	0
Local building permits ($)	0
Environmental permits ($)	0
Air Emission Permits ($)	**0**
Interconnection Costs ($)	0
Transmission Lines ($)	0
Substation ($)	
Induction Equipment ($)	
Environmental Controls ($)	0
Installation Costs ($)	0
Replacement Costs ($)	0

Table I-12
Maintenance Cost Detail

Routine Maintenance Costs		Annual Costs
Replacement Interval (Hours)	1	
Filter Price ($)	0	0
Maintenance Interval (Hours)	1	
Price ($)	0	0
Oil Price ($/Gallon)	3.40	
Oil Capacity	0	0
Oil Added per Day	0	0
Interval (Hours)	1,000	
Item Price ($)	0	0
Labor Hours/Day	0	
Labor Price ($/Hour)	48	0
Annual Routine Maintenance		**0**
Major Overhauls		
Hours to Major Overhaul	0	
Major Overhaul Labor (Man-Hours)	0	
Labor Cost ($/Hour)	48	
Major Overhaul Labor Cost ($)	0	
Major Overhaul Replacement ($)	0	
NPV Cost ($)		
Minor Overhauls		
Annual Cost Item 1 ($)	37,500,000	
Hours to Item 1 Job	40,000	5
Annual Cost Item 2 ($)	7,500,000	
Hours to Item 2 Job	55,188	7
Annualized Overhauls		**6,656,486**
Unscheduled Maintenance		
Forced Outage Hours/Year	438	
Labor Rate ($/Hour)	48	
Hours of Labor	438	
Parts Costs ($)	0	
Total ($)	21,024	
Total Annual Maintenance		**6,677,510**
Maintenance ($/kW-Yr)	267.10	
Maintenance ($/MWh)	33.88	

Table I-13
Environmental Control Costs

Total Annual Costs ($)	**0**
Media & Technology	**Cost**
Air Emissions	
Control Technology (e.g. SCR) ($)	
Installation Cost ($/kW)	0
Annual Labor (Hours/Year)	0
Loaded Labor Rate ($/Hour)	48
Labor Cost ($)	0
Annual Consumables-Catalyst ($)	0
Replacement Cost ($/kW)	0
Component Life (Hours)	141,760
Annualized Cost ($)	
Water Cooling	
Control Technology (e.g. wastewater) ($)	
Installation Cost ($/kW)	0
Annual Labor (Hours/Year)	0
Loaded Labor Rate ($/Hour)	48
Labor Cost ($)	0
Annual Consumables ($)	0
Replacement Cost ($/kW)	0
Component Life (Hours)	141,760
Annualized Cost ($)	
Solid Waste Disposal	
Non hazardous material	
Tons per Year	0
Collection and hauling ($/Ton)	10
Landfill tipping fees ($/Ton)	30
Total Costs ($)	0
Hazardous materials	
Tons per Year	0
Collection and hauling ($/Ton)	10
Landfill tipping fees ($/Ton)	30
Total Disposal Costs ($)	0

APPENDIX J
Geothermal Binary 35 MW

Table J-1
Plant Information

Technology Type	Geothermal
Fuel	Geothermal
Owner/Investor	Merchant
Base Year	2002
In-service Year	2005

Table J-2
Plant Size

Gross Capacity (MW)	35.0
Parasitic Load (MW)	10.0
Net Capacity (MW)	25.0
Derate Factor (%)	100.0
Firm Capacity (MW)	25.0
Transmission Losses (%)	2.0
Required AS/reserves (%)	0.0
Average Hourly Output Rate (%)	100.0
Effective Load Carry Capacity (MW)	25.0
Annual capacity degradation rate (%)	0.0

Table J-3
Capital Costs

Escalation in Capital Costs	0.0%
AFUDC Rate	10.3%
Cash Cost	100.0%

Table J-4
Construction Costs by Year
Sum: 100%

Years Out from On-Line Date	0	-1	-2	-3	-4
Cost %/Year	20%	70%	10%	0%	0%
Carry Over	$3,360	$2,585	$321	$0	$0

Table J-5
Fuel Use

Heat Rate (MMBtu/kWh)	N/A
Fuel Consumption (MMBtu/hour)	0.0
Start up fuel use (MMBtu/start)	0.0
Make-up water (Gallons)	250,000.0

Table J-6
Operational Information

Availability/Year (%)	99
Availability/Year (Hours)	8,672
Equipment Life (Hours)	260,000
Equipment Life (Years)	30
Overhaul Interval (Hours)	45,000
Maintenance Outage (Days)	5
Maintenance Outage Rate (%)	0.3
Forced Outage (Hours/Year)	24
Forced Outage Rate (%)	0.3
Hours per Year Operation	8,624
Capacity Factor (%)	98.5
Annual Net Energy (GWh)	216

Table J-7
Renewable Tax Benefits

Investment Tax Credit (%)	10
RETC Calculation ($/kWh)	384
Production Incentive-Investor (¢/kWh)	0
Geothermal Depletion Allowance	Yes
RE Production Incentive Tier I	0
RE Production Incentive Tier II	0
REPI Tier II Proportion Paid (%)	10

Table J-8
Operation & Maintenance Costs (Employees)

Employee Category	Full Time Employees	Hours/Year	Compensation per Employee
Managers	1	1,800	$80,000 per year
Plant Operators	8	1,800	$30 per hour
Mechanics	1	1,800	$30 per hour
Laborers	2	1,800	$20 per hour
Support Staff	0	1,800	$20 per hour

Table J-9
Operation & Maintenance Costs (Other)

Fixed O&M ($/kW-Yr)	**158.0**
Fixed O&M/Instant Cost (%)	4.93
O&M Escalation (%)	0.5
Insurance (%)	1.5
Labor Escalation Cost (%)	0.5
Overhead Multiplier	2.0
Other Operating Costs	
Water Supply ($/AF)	250,000.0
Consumption (AF/Yr)	25,000.0
Plant Scheduling Costs	
Transmission Service ($/MW)	156,000.0

Table J-10
Cost Summary

Financing Costs ($/kW-Yr)	442
Fixed Operational Costs ($/kW-Yr)	265
Tax (w/Credits) ($/kW-Yr)	(78)
Fixed Costs	**628**
Fuel Costs ($/kW-Yr)	7
Variable O&M ($/kW-Yr)	0
Variable Costs	**7**
Total Levelized Costs ($/kW-Yr)	**635**
Capital ($/MWH)	72.83
Variable ($/MWH)	0.82
Total Levelized Costs ($/MWH)	**73.65**
Capital Costs	
Instant Cost ($/kW)	3,210
Installed Cost ($/MWH)	3,618
In-service Cost in 2004 ($/KW)	**3,839**

Table J-11
Capital Cost Detail

Total ($)	**80,255,463**
Component Cost ($)	**79,700,000**
Exploration Costs ($)	3,000,000
Wellfield Development ($)	34,700,000
Plant Equipment ($)	42,000,000
Financial Transaction Costs (%)	0
Land Costs ($)	**555,463**
Occupied Acreage	40
Total Project Area (Acres)	12000
BLM Pre-Development Lease Fee	44
Total Land "Cost Burden"	531,463
Land Prep Costs ($/Acre)	600
Total Land Prep Costs ($)	24,000
Permitting Costs ($)	**0**
Local building permits ($)	
Environmental permits ($)	
Interconnection Costs ($)	**300,000**
Transmission Lines ($)	
Substation ($)	
Environmental Controls ($)	**0**
Installation Costs ($)	0
Replacement Costs ($)	

Table J-12
Maintenance Cost Detail

Routine Maintenance Costs	Annual Costs
Plant costs	
OECs	250,000
Elec. & Control System	50,000
Cooling systems	76,000
Auxiliary Systems	26,000
Cooling water Chemicals	212,000
Isopentane system	75,000
Miscellaneous Consumables	50,000
Wellfield Costs	
Wellfield Costs	
Well clean out	185,000
Well pumps maintenance	50,000
Brine chemicals	100,000
Miscellaneous	35,000
Annual Routine Maintenance	**1,109,000**
Major Overhauls	
Hours to Major Overhaul:	45,000
Major Overhaul Labor (Man-hours)	200
Labor Cost ($/Hour)	60
Major Overhaul Labor Cost ($)	12,000
Major Overhaul Replacement ($)	1,000,000
NPV Cost ($)	
Minor Overhauls	
Well Work Over ($)	50,000
Hours to Item 1 Job	6,000
Well Replacement ($)	2,300,000
Hours to Item 2 Job	42,500
Pump Replacement ($)	350,000
Hours to Item 3Job	3,500
Annualized Overhauls ($)	**1,062,686**
Unscheduled Maintenance	
Forced Outage (Hours/Year)	24
Labor Rate ($/Hour)	60
Hours of Labor	12
Parts Costs ($)	25,000
Total ($)	25,720
Total Annual Maintenance ($)	**2,197,406**
Maintenance ($/kW-Yr)	87.90
Maintenance ($/MWh)	10.19

Table J-13
Environmental Control Costs

Total Annual Costs ($)	**50,000**
Media & Technology	**Cost**
Air Emissions	
Control Technology (e.g. SCR) ($)	
Installation Cost ($/kW)	0
Annual Labor (Hours/Year)	0
Loaded Labor Rate ($/Hour)	60
Labor Cost ($)	0
Annual Consumables-Catalyst ($)	0
Replacement Cost ($/kW)	0
Component Life (Hours)	0
Annualized Cost ($)	
Water Cooling	
Control Technology (e.g. wastewater) ($)	
Installation Cost ($/kW)	0
Annual Labor (Hours/Year)	0
Loaded Labor Rate ($/Hour)	60
Labor Cost ($)	0
Annual Consumables ($)	0
Replacement Cost ($/kW)	0
Component Life (Hours)	0
Annualized Cost ($)	
Solid Waste Disposal	
Non hazardous material	
Tons per Year	0
Collection and hauling ($/Ton)	30
Landfill tipping fees ($/Ton)	0
Total Costs ($)	0
Hazardous materials	
Tons per Year	10000
Collection and hauling ($/Ton)	0
Landfill tipping fees ($/Ton)	5
Total Disposal Costs ($)	50,000

APPENDIX K
Geothermal Flash 50 MW

Table K-1
Plant Information

Technology Type	Geothermal
Fuel	Geothermal
Owner/Investor	Merchant
Base Year	2002
In-service Year	2005

Table K-2
Plant Size

Gross Capacity (MW)	49.9
Parasitic Load (MW)	5.0
Net Capacity (MW)	45.0
Derate Factor (%)	100.0
Firm Capacity (MW)	45.0
Transmission Losses (%)	2.0
Required AS/reserves (%)	0.0
Average Hourly Output Rate (%)	100.0
Effective Load Carry Capacity (MW)	44.0
Annual capacity degradation rate (%)	0.0

Table K-3
Capital Costs

Escalation in Capital Costs	0.0%
AFUDC Rate	10.3%
Cash Cost	100.0%

Table K-4
Construction Costs by Year
Sum: 100%

Years Out from On-Line Date	0	-1	-2	-3	-4
Cost %/Year	20%	60%	20%	0%	0%
Carry Over	$2,239	$1,724	$426	$0	$0

Table K-5
Fuel Use

Heat Rate	N/A
Fuel Consumption (MMBtu/Hr)	0.0
Start up fuel use (MMBtu/Start)	0.0
Make-up water (Gallons)	12,000.0

Table K-6
Operational Information

Availability/Year (%)	97.2
Availability/Year (Hours)	8,515
Equipment Life (Hours)	260,000
Equipment Life (Years)	30
Overhaul Interval (Hours)	25,000
Maintenance Outage (Days)	7
Maintenance Outage Rate (%)	0.6
Forced Outage (Hours/Year)	50
Forced Outage Rate (%)	0.6
Hours per Year Operation	8,409
Capacity Factor (%)	96.0
Annual Net Energy (GWh)	378

Table K-7
Renewable Tax Benefits

Investment Tax Credit (%)	10
RETC Calculation ($/kWh)	256
Production Incentive-Investor (¢/kWh)	0
Geothermal Depletion Allowance	Yes
RE Production Incentive Tier I	0
RE Production Incentive Tier II	0
REPI Tier II Proportion Paid (%)	10

Table K-8
Operation & Maintenance Costs (Employees)

Employees	Full Time Employees	Hours/Year	Compensation per Employee
Managers	1	1,800	$80,000 per year
Plant Operators	8	1,800	$30 per hour
Mechanics	1	1,800	$30 per hour
Laborers	2	1,800	$20 per hour
Support Staff	0	1,800	$20 per hour

Table K-9
Operation & Maintenance Costs (Other)

Fixed O&M ($/kW-Yr)	**60.0**
Fixed O&M/Instant Cost (%)	2.81
O&M Escalation (%)	0.5
Insurance (%)	1.5
Labor Escalation Cost (%)	0.5
Overhead Multiplier	1.6
Other Operating Costs	
Water Supply ($/AF)	12,000.0
Consumption (AF/Yr)	25,000.0
Plant Scheduling Costs	
Transmission Service ($/MW)	156,000.0

Table K-10
Cost Summary

Financing Costs ($/kW-Yr)	294
Fixed Operational Costs ($/kW-Yr)	120
Tax (w/Credits) ($/kW-Yr)	(45)
Fixed Costs	**369**
Fuel Costs ($/kW-Yr)	10
Variable O&M ($/kW-Yr)	1
Variable Costs	**11**
Total Levelized Costs ($/kW-Yr)	**380**
Capital ($/MWH)	43.91
Variable ($/MWH)	1.30
Total Levelized Costs ($/MWH)	**45.21**
Capital Costs	
Instant Cost ($/kW)	2,128
Installed Cost ($/MWH)	2,410
In-service Cost in 2004 ($/KW)	**2,558**

Table K-11
Capital Cost Detail

Total ($)	**95,539,694**
Component Cost ($)	**95,200,000**
Exploration Costs ($)	3,000,000
Wellfield Development ($)	32,200,000
Plant Equipment ($)	60,000,000
Financial Transaction Costs (%)	**0**
Land Costs ($)	**339,694**
Occupied Acreage	40
Total Project Area (Acres)	6000
Lease Fee ($/Acre)	53
Total Land "Cost Burden"	315,694
Land Prep Costs ($/Acre)	600
Total Land Prep Costs ($)	24,000
Permitting Costs ($)	**0**
Local building permits ($)	
Environmental permits ($)	
Interconnection Costs ($)	**300,000**
Transmission Lines ($)	
Substation ($)	
Environmental Controls ($)	**0**
Installation Costs ($)	0
Replacement Costs ($)	

Table K-12
Maintenance Cost Detail

Routine Maintenance Costs	Annual Costs
Plant costs	
Turbine/Generator ($)	55,000
Electrical & Control System ($)	86,000
Cooling systems ($)	12,000
Auxiliary Systems ($)	26,000
Cooling water Chemicals ($)	93,000
Miscellaneous Consumables ($)	50,000
Wellfield Costs	
Well clean out ($)	185,000
Brine chemicals ($)	100,000
Miscellaneous ($)	35,000
Annual Routine Maintenance ($)	**642,000**
Major Overhauls	
Hours to Major Overhaul	25,000
Major Overhaul Labor (Man-Hours)	400
Labor Cost ($/Hour)	48
Major Overhaul Labor Cost ($)	19,200
Major Overhaul Replacement ($)	1,300,000
NPV Cost ($)	
Minor Overhauls	
Well Work Over ($)	50,000
Hours to Item 1 Job	6,000
Well Replacement ($)	2,300,000
Hours to Item 2 Job	25,000
Annualized Overhauls ($)	**762,755**
Unscheduled Maintenance	
Forced Outage (Hours/Year)	50
Labor Rate ($/Hour)	48
Hours of Labor	25
Parts Costs ($)	50,000
	51,200
Total Annual Maintenance ($)	**1,455,955**
Maintenance/kW-yr	32.43
Maintenance/MWh	3.86

Table K-13
Environmental Control Costs

Total Annual Costs ($)	**174,000**
Media & Technology	**Cost**
Air Emissions	
Control Technology (e.g. SCR) ($)	
Installation Cost ($/kW)	0
Annual Labor (Hours/Year)	0
Loaded Labor Rate ($/Hour)	48
Labor Cost ($)	0
Annual Consumables-Catalyst ($)	0
Replacement Cost ($/kW)	0
Component Life (Hours)	0
Annualized Cost ($)	
Water Cooling	
Control Technology (e.g. wastewater) ($)	
Installation Cost ($/kW)	0
Annual Labor (Hours/Year)	0
Loaded Labor Rate ($/Hour)	48
Labor Cost ($)	0
Annual Consumables ($)	0
Replacement Cost ($/kW)	0
Component Life (Hours)	0
Annualized Cost ($)	
Solid Waste Disposal	
Non hazardous material	
Tons per Year	5800
Collection and hauling ($/Ton)	30
Landfill tipping fees ($/Ton)	0
Total Costs ($)	174,000
Hazardous materials	
Tons per Year	0
Collection and hauling ($/Ton)	0
Landfill tipping fees ($/Ton)	30
Total Disposal Costs ($)	0

APPENDIX L
HYDROPOWER

Table L-1
Plant Information

Technology Type	Hydro
Fuel	None
Owner/Investor	Merchant
Base Year	2002
In-service Year	2007

Table L-2
Plant Size

Gross Capacity (MW)	100.0
Parasitic Load (MW)	0.1
Net Capacity (MW)	100.0
Derate Factor (%)	100.0
Firm Capacity (MW)	100.0
Transmission Losses (%)	2.5
Required AS/reserves (%)	0.0
Average Hourly Output Rate (%)	100.0
Effective Load Carry Capacity (MW)	97.0
Annual capacity degradation rate (%)	0.0

Table L-3
Capital Costs

Escalation in Capital Costs	0.0%
AFUDC Rate	10.3%
Cash Cost	100.0%

Table L-4
Construction Costs by Year
Sum: 100%

Years Out from On-Line Date	0	-1	-2	-3	-4
Cost %/Year	45%	45%	4%	3%	3%
Carry Over	$1,198	$646	$121	$71	$35

Table L-5
Fuel Use

Heat Rate (MMBtu/kWh)	N/A
Fuel Consumption (MMBtu/Hr)	0.0
Start up fuel use (MMBtu/start)	0.0
No. of annual starts	0.0
Annual Fuel Use (MMBtu)	0.0

Table L-6
Operational Information

Availability/Year (%)	42.5
Availability/Year (Hours)	3,723
Equipment Life (Hours)	262,800
Equipment Life (Years)	30
Overhaul Interval (Hours)	8,400
Maintenance Outage (Days)	10
Maintenance Outage Rate (%)	1.4
Forced Outage (Hours/Year)	120
Forced Outage Rate (%)	1.4
Hours per Year Operation	3,483
Capacity Factor (%)	39.8
Annual Net Energy (GWh)	348

Table L-7
Renewable Tax Benefits

Investment Tax Credit (%)	0
RETC Calculation ($/kWh)	0
Production Incentive-Investor (¢/kWh)	0
Geothermal Depletion Allowance	
RE Production Incentive Tier I	0
RE Production Incentive Tier II	0
REPI Tier II Proportion Paid (%)	10

Table L-8
Operation & Maintenance Costs (Employees)

Employees	Full Time Employees	Hours/Year	Compensation per Employee
Managers	3	1,800	$80,000 per year
Plant Operators	3	1,800	$30 per hour
Mechanics	2	1,800	$30 per hour
Laborers	1	1,800	$20 per hour
Support Staff	1	1,800	$20 per hour

Table L-9
Operation & Maintenance Costs (Other)

Fixed O&M ($/kW-Yr)	**10.0**
Fixed O&M/Instant Cost (%)	0.90
O&M Escalation (%)	0.5
Insurance (%)	1.5
Labor Escalation Cost (%)	0.5
Overhead Multiplier	1.6
Other Operating Costs	
Water Supply ($/AF)	
Consumption (AF/Yr)	
Plant Scheduling Costs	
Transmission Service ($/MW)	

Table L-10
Cost Summary

Financing Costs ($/kW-Yr)	161
Fixed Operational Costs ($/kW-Yr)	39
Tax (w/Credits) ($/kW-Yr)	10
Fixed Costs	**210**
Fuel Costs ($/kW-Yr)	0
Variable O&M ($/kW-Yr)	0
Variable Costs	**0**
Total Levelized Costs ($/kW-Yr)	**210**
Capital ($/MWH)	60.37
Variable ($/MWH)	0.00
Total Levelized Costs ($/MWH)	**60.37**
Capital Costs	
Instant Cost ($/kW)	1,153
Installed Cost ($/MWH)	1,290
In-service Cost in 2004 ($/KW)	**1,424**

Table L-11
Capital Cost Detail

Total ($)	**115,188,000**
Component Cost ($)	**109,000,000**
Turbine/Engine ($)	5,000,000
Generator/Gearhead ($)	6,000,000
Penstock & Surge Tank ($)	30,000,000
Building & Foundation ($)	3,000,000
Miscellaneous fitting & hoses ($)	3,500,000
Office space ($)	
Control Room($)	1,500,000
Dam & Reservoir ($)	60,000,000
Financial Transaction Costs (%)	**0**
Land Costs ($)	**6,188,000**
Acreage/Plant	1,400
Cost per Acre ($)	1,420
Acquisition Cost ($)	1,988,000
Land Prep Costs ($/Acre)	3,000
Total Land Prep Costs ($)	4,200,000
Permitting Costs ($)	**0**
Local building permits ($)	
Environmental permits ($)	
Interconnection Costs ($)	**0**
Transmission Lines ($)	0
Substation ($)	0
Induction Equipment ($)	
Environmental Controls ($)	**0**
Installation Costs ($)	0
Replacement Costs ($)	

Table L-12
Maintenance Detail

Routine Maintenance Costs		Annual Costs
Replacement Interval (Hours)	1	
Filter Price ($)	0	0
Maintenance Interval (Hours)	1	
Price ($)	0	0
Oil Price ($/Gallon)	3.40	
Oil Capacity	0	0
Oil Added per Day	0	0
Interval (Hours)	1,000	
Item Price ($)	0	0
Labor Hours/Day	0	
Labor Price ($/Hour)	48	0
Annual Routine Maintenance		**0**
Major Overhauls		
Hours to Major Overhaul:	43,800	
Major Overhaul Labor (Man-Hours)	600	
Labor Cost ($/Hour)	48	
Major Overhaul Labor Cost ($)	28,800	
Major Overhaul Replacement ($)	2,300,000	101,626.13
NPV Cost ($)		
Minor Overhauls		
Annual Cost Item 1 ($)	0	
Hours to Item 1 Job	8,760	3
Annual Cost Item 2 ($)	0	
Hours to Item 2 Job	0	7
Annualized Overhauls		**0**
Unscheduled Maintenance		
Forced Outage Hours/Year	120	
Labor Rate ($/Hour)	48	
Hours of Labor	120	
Parts Costs ($)	0	
Total ($)	5,760	
Total Annual Maintenance		**107,386**
Maintenance ($/kW-Yr)	1.07	
Maintenance ($/MWh)	0.31	

Table L-13
Environmental Control Costs

Total Annual Costs ($)	**0**
Media & Technology	**Cost**
Air Emissions	
Control Technology (e.g. SCR) ($)	
Installation Cost ($/kW)	0
Annual Labor (Hours/Year)	0
Loaded Labor Rate ($/Hour)	48
Labor Cost ($)	0
Annual Consumables-Catalyst ($)	0
Replacement Cost ($/kW)	0
Component Life (Hours)	141,760
Annualized Cost ($)	
Water Cooling	
Control Technology (e.g. wastewater) ($)	
Installation Cost ($/kW)	0
Annual Labor (Hours/Year)	0
Loaded Labor Rate ($/Hour)	48
Labor Cost ($)	0
Annual Consumables ($)	0
Replacement Cost ($/kW)	0
Component Life (Hours)	141,760
Annualized Cost ($)	
Solid Waste Disposal	
Non hazardous material	
Tons per Year	0
Collection and hauling ($/Ton)	10
Landfill tipping fees ($/Ton)	30
Total Costs ($)	0
Hazardous materials	
Tons per Year	0
Collection and hauling ($/Ton)	10
Landfill tipping fees ($/Ton)	30
Total Disposal Costs ($)	0

APPENDIX M
SOLAR PHOTOVOLTAICS

Table M-1
Plant Information

Technology Type	Solar
Fuel	None
Owner/Investor	Merchant
Base Year	2002
In-service Year	2003

Table M-2
Plant Size

Gross Capacity (MW)	50.0
Parasitic Load (MW)	0.0
Net Capacity (MW)	50.0
Derate Factor (%)	100.0
Firm Capacity (MW)	50.0
Transmission Losses (%)	5.0
Required AS/reserves (%)	0.0
Average Hourly Output Rate (%)	100.0
Effective Load Carry Capacity (MW)	48.0
Annual capacity degradation rate (%)	1.0

Table M-3
Capital Costs

Escalation in Capital Costs	0.0%
AFUDC Rate	10.3%
Cash Cost	100.0%

Table M-4
Construction Costs by Year
Sum: 100%

Years Out from On-Line Date	0	-1	-2	-3	-4
Cost %/Year	100%	0%	0%	0%	0%
Carry Over	$6,653	$0	$0	$0	$0

Table M-5
Fuel Use

Heat Rate (MMBtu/kWh)	N/A
Fuel Consumption (MMBtu/Hr)	0.0
Start up fuel use (MMBtu/start)	0.0
No. of annual starts	0.0
Annual Fuel Use (MMBtu)	0.0

Table M-6
Operational Information

Availability/Year (%)	25
Availability/Year (Hours)	2,190
Equipment Life (Hours)	62,580
Equipment Life (Years)	30
Overhaul Interval (Hours)	2,190
Maintenance Outage (Days)	4
Maintenance Outage Rate (%)	1.1
Forced Outage (Hours/Year)	8
Forced Outage Rate (%)	0.1
Hours per Year Operation	2,086
Capacity Factor (%)	23.8
Annual Net Energy (GWh)	104

Table M-7
Renewable Tax Benefits

Investment Tax Credit (%)	10
RETC Calculation ($/kWh)	731
Production Incentive-Investor (¢/kWh)	0
Geothermal Depletion Allowance	
RE Production Incentive Tier I	0
RE Production Incentive Tier II	0
REPI Tier II Proportion Paid (%)	10

Table M-8
Operation & Maintenance Costs (Employees)

Employees	Full Time Employees	Hours/Year	Compensation per Employee
Managers	1	1,800	$80,000 per year
Plant Operators	1	1,800	$30 per hour
Mechanics	2	1,800	$30 per hour
Laborers	2	1,800	$20 per hour
Support Staff	0	1,800	$20 per hour

Table M-9
Operation & Maintenance Costs (Other)

Fixed O&M ($/kW-Yr)	**10.0**
Fixed O&M/Instant Cost (%)	0.15
O&M Escalation (%)	0.5
Insurance (%)	1.5
Labor Escalation Cost (%)	0.5
Overhead Multiplier	1.6
Other Operating Costs	
Water Supply ($/AF)	
Consumption (AF/Yr)	
Plant Scheduling Costs	
Transmission Service ($/MW)	

Table M-10
Cost Summary

Financing Costs ($/kW-Yr)	841
Fixed Operational Costs ($/kW-Yr)	142
Tax (w/Credits) ($/kW-Yr)	(92)
Fixed Costs	**891**
Fuel Costs ($/kW-Yr)	0
Variable O&M ($/kW-Yr)	0
Variable Costs	**0**
Total Levelized Costs ($/kW-Yr)	**891**
Capital ($/MWH)	427.16
Variable ($/MWH)	0.00
Total Levelized Costs ($/MWH)	**427.16**
Capital Costs	
Instant Cost ($/kW)	6,653
Installed Cost ($/MWH)	7,163
In-service Cost in 2004 ($/KW)	**7,306**

Table M-11
Capital Cost Detail

Total ($)	**332,630,100**
Component Cost ($)	**330,000,000**
PV Modules ($)	225,000,000
Structures ($)	25,000,000
Inverter ($)	25,000,000
Installation ($)	37,500,000
Engr, Const, Proj Management ($)	17,500,000
Financial Transaction Costs (%)	**0**
Land Costs ($)	**2,630,100**
Acreage/Plant	250
Cost per Acre ($)	3,100
Acquisition Cost ($)	775,000
Land Prep Costs ($/Acre)	7,420
Total Land Prep Costs ($)	1,855,100
Permitting Costs ($)	**0**
Local building permits ($)	
Environmental permits ($)	
Interconnection Costs ($)	**0**
Transmission Lines ($)	
Substation ($)	
Induction Equipment ($)	
Environmental Controls ($)	**0**
Installation Costs ($)	0
Replacement Costs ($)	

Table M-12
Maintenance Cost Detail

Routine Maintenance Costs		Annual Costs
Replacement Interval (Hours)	1	
Filter Price ($)	0	0
Maintenance Interval (Hours)	1	
Price ($)	0	0
Oil Price ($/Gallon)	3.40	
Oil Capacity	0	0
Oil Added per Day	0	0
Interval (Hours)	1,000	
Item Price ($)	0	0
Labor Hours/Day	0	
Labor Price ($/Hour)	48	0
Annual Routine Maintenance		**0**
Major Overhauls		
Hours to Major Overhaul	31,290	
Major Overhaul Labor (Man-Hours)	1,250	
Labor Cost ($/Hour)	48	
Major Overhaul Labor Cost ($)	60,000	
Major Overhaul Replacement ($)	0	1,499.73
NPV Cost ($)		
Annual Cost Item 1 ($)	0	
Hours to Item 1 Job	2,086	1
Annual Cost Item 2 ($)	0	
Hours to Item 2 Job	0	7
Annualized Overhauls		**0**
Unscheduled Maintenance		
Forced Outage Hours/Year	8	
Labor Rate ($/Hour)	48	
Hours of Labor	8	
Parts Costs ($)	1,000	
Total ($)	1,384	
Total Annual Maintenance		**2,884**
Maintenance ($/kW-Yr)	0.06	
Maintenance ($/MWh)	0.03	

Table M-13
Environmental Control Costs

Total Annual Costs ($)	**0**
Media & Technology	**Cost**
Air Emissions	
Control Technology (e.g. SCR) ($)	
Installation Cost ($/kW)	0
Annual Labor (Hours/Year)	0
Loaded Labor Rate ($/Hour)	48
Labor Cost ($)	0
Annual Consumables-Catalyst ($)	0
Replacement Cost ($/kW)	0
Component Life (Hours)	141,760
Annualized Cost ($)	
Water Cooling	
Control Technology (e.g. wastewater) ($)	
Installation Cost ($/kW)	0
Annual Labor (Hours/Year)	0
Loaded Labor Rate ($/Hour)	48
Labor Cost ($)	0
Annual Consumables ($)	0
Replacement Cost ($/kW)	0
Component Life (Hours)	141,760
Annualized Cost ($)	
Solid Waste Disposal	
Non hazardous material	
Tons per Year	0
Collection and hauling ($/Ton)	10
Landfill tipping fees ($/Ton)	30
Total Costs ($)	0
Hazardous materials	
Tons per Year	0
Collection and hauling ($/Ton)	10
Landfill tipping fees ($/Ton)	30
Total Disposal Costs ($)	0

APPENDIX N
Solar Parabolic w/o Thermally-Enhanced Storage or Gas

Table N-1
Plant Information

Technology Type	Solar
Fuel	None
Owner/Investor	Merchant
Base Year	2002
In-service Year	2003

Table N-2
Plant Size

Gross Capacity (MW)	110.0
Parasitic Load (MW)	10.0
Net Capacity (MW)	100.0
Derate Factor (%)	100.0
Firm Capacity (MW)	100.0
Transmission Losses (%)	1.5
Required AS/reserves (%)	0.0
Average Hourly Output Rate (%)	60.0
Effective Load Carry Capacity (MW)	59.0
Annual capacity degradation rate (%)	0.0

Table N-3
Capital Costs

Escalation in Capital Costs	0.0%
AFUDC Rate	10.3%
Cash Cost	100.0%

Table N-4
Construction Costs by Year
Sum: 100%

Years Out from On-Line Date	0	-1	-2	-3	-4
Cost %/Year	100%	0%	0%	0%	0%
Carry Over	$2,600	$0	$0	$0	$0

Table N-5
Fuel Use

Heat Rate (MMBtu/kWh)	N/A
Fuel Consumption (MMBtu/Hr)	0.0
Start up fuel use (MMBtu/start)	0.0
No. of annual starts	346.0
Annual Fuel Use (MMBtu)	0.0

Table N-6
Operational Information

Availability/Year (%)	41.7
Availability/Year (Hours)	3,650
Equipment Life (Hours)	70,000
Equipment Life (Years)	22
Overhaul Interval (Hours)	3,210
Maintenance Outage (Days)	10
Maintenance Outage Rate (%)	2.7
Forced Outage (Hours/Year)	200
Forced Outage Rate (%)	2.3
Hours per Year Operation	3,210
Capacity Factor (%)	22.0
Annual Net Energy (GWh)	193

Table N-7
Renewable Tax Benefits

Investment Tax Credit (%)	10
RETC Calculation ($/kWh)	286
Production Incentive-Investor (¢/kWh)	0
Geothermal Depletion Allowance	
RE Production Incentive Tier I	0
RE Production Incentive Tier II	0
REPI Tier II Proportion Paid (%)	10

Table N-8
Operation & Maintenance Costs (Employees)

Employees	Full Time Employees	Hours/Year	Compensation per Employee
Managers	1	1,800	$80,000 per year
Plant Operators	10	1,800	$30 per hour
Mechanics	6	1,800	$30 per hour
Laborers	3	1,800	$20 per hour
Support Staff	1	1,800	$20 per hour

Table N-9
Operation & Maintenance Costs (Other)

Fixed O&M ($/kW-Yr)	**26.0**
Fixed O&M/Instant Cost (%)	1.01
O&M Escalation (%)	0.5
Insurance (%)	1.5
Labor Escalation Cost (%)	0.5
Overhead Multiplier	1.6
Other Operating Costs	
Water Supply ($/AF)	
Consumption (AF/Yr)	
Plant Scheduling Costs	
Transmission Service ($/MW)	

Table N-10
Cost Summary

Financing Costs ($/kW-Yr)	345
Fixed Operational Costs ($/kW-Yr)	80
Tax (w/Credits) ($/kW-Yr)	(50)
Fixed Costs	**375**
Fuel Costs ($/kW-Yr)	0
Variable O&M ($/kW-Yr)	40
Variable Costs	**40**
Total Levelized Costs ($/kW-Yr)	**415**
Capital ($/MWH)	194.73
Variable ($/MWH)	20.58
Total Levelized Costs ($/MWH)	**215.31**
Capital Costs	
Instant Cost ($/kW)	2,600
Installed Cost ($/MWH)	2,799
In-service Cost in 2004 ($/KW)	**2,855**

Table N-11
Capital Cost Detail

Total ($)	**259,998,383**
Component Cost ($)	**254,212,164**
Structure & Improvements ($)	2,720,813
Collector System ($)	147,795,374
Thermal Storage System	0
Steam Gen or HX System ($)	10,764,670
Aux Heater/Boiler ($)	0
EPGS ($)	47,651,991
Master Control System ($)	0
Balance of Plant ($)	27,706,701
Engr, Const, Proj Management ($)	17,572,616
Financial Transaction Costs (%)	**0**
Land Costs ($)	**5,786,219**
Acreage/MW	5
Acreage/Plant	550
Cost per Acre ($)	3,100
Acquisition Cost ($)	1,705,000
Land Prep Costs ($/Acre)	7,420
Total Land Prep Costs ($)	4,081,219
Permitting Costs ($)	**0**
Local building permits ($)	
Environmental permits ($)	
Interconnection Costs ($)	**0**
Transmission Lines ($)	0
Substation ($)	0
Induction Equipment ($)	
Environmental Controls ($)	**0**
Installation Costs ($)	0
Replacement Costs ($)	

Table N-12
Maintenance Cost Detail

Routine Maintenance Costs		Annual Costs
Replacement Interval (Hours)	1	
Filter Price ($)	0	0
Maintenance Interval (Hours)	1	
Price ($)	0	0
Oil Price ($/Gallon)	3.40	
Oil Capacity	0	0
Oil Added per Day	0	0
Interval (Hours)	1,000	
Item Price ($)	0	0
Labor Hours/Day	0.00	
Labor Price ($/Hour)	48	0
Annual Routine Maintenance		**0**
Major Overhauls		
Hours to Major Overhaul:	35,000	
Major Overhaul Labor (Man-Hours)	125	
Labor Cost ($/Hour)	48	
Major Overhaul Labor Cost ($)	6,000	
Major Overhaul Replacement ($)	0	240.00
NPV Cost ($)		
Minor Overhauls		
Annual Cost Item 1 ($)	925,019	
Hours to Item 1 Job	3,210	1
Annual Cost Item 2 ($)	0	
Hours to Item 2 Job	0	7
Annualized Overhauls		**883,617**
Unscheduled Maintenance		
Forced Outage Hours/Year	200	
Labor Rate ($/Hour)	48	
Hours of Labor	200	
Parts Costs ($)	0	
Total ($)	9,600	
Total Annual Maintenance		**893,457**
Maintenance ($/kW-Yr)	8.93	
Maintenance ($/MWh)	4.64	

Table N-13
Environmental Control Costs

Total Annual Costs ($)	**0**
Media & Technology	**Cost**
Air Emissions	
Control Technology (e.g. SCR) ($)	
Installation Cost ($/kW)	0
Annual Labor (Hours/Year)	0
Loaded Labor Rate ($/Hour)	48
Labor Cost ($)	0
Annual Consumables-Catalyst ($)	0
Replacement Cost ($/kW)	0
Component Life (Hours)	141,760
Annualized Cost ($)	
Water Cooling	
Control Technology (e.g. wastewater) ($)	
Installation Cost ($/kW)	0
Annual Labor (Hours/Year)	0
Loaded Labor Rate ($/Hour)	48
Labor Cost ($)	0
Annual Consumables ($)	0
Replacement Cost ($/kW)	0
Component Life (Hours)	141,760
Annualized Cost ($)	
Solid Waste Disposal	
Non hazardous material	
Tons per Year	0
Collection and hauling ($/Ton)	10
Landfill tipping fees ($/Ton)	30
Total Costs ($)	0
Hazardous materials	
Tons per Year	0
Collection and hauling ($/Ton)	10
Landfill tipping fees ($/Ton)	30
Total Disposal Costs ($)	0

APPENDIX O
Solar Parabolic with Gas Only

Table O-1
Plant Information

Technology Type	Solar
Fuel	Natural Gas
Owner/Investor	Merchant
Base Year	2002
In-service Year	2003

Table O-2
Plant Size

Gross Capacity (MW)	110.0
Parasitic Load (MW)	10.0
Net Capacity (MW)	100.0
Derate Factor (%)	100.0
Firm Capacity (MW)	100.0
Transmission Losses (%)	1.5
Required AS/reserves (%)	0.0
Average Hourly Output Rate (%)	60.0
Effective Load Carry Capacity (MW)	59.0
Annual capacity degradation rate (%)	0.0

Table O-3
Capital Costs

Escalation in Capital Costs	0.0%
AFUDC Rate	10.3%
Cash Cost	100.0%

Table O-4
Construction Costs by Year
Sum: 100%

Years Out from On-Line Date	0	-1	-2	-3	-4
Cost %/Year	100%	0%	0%	0%	0%
Carry Over	$2,841	$0	$0	$0	$0

Table O-5
Fuel Use

Heat Rate (MMBtu/kWh)	2,480
Fuel Consumption (MMBtu/Hr)	248
Start up fuel use (MMBtu/start)	0
No. of annual starts	346
Annual Fuel Use (MMBtu)	1,520,240

Table O-6
Operational Information

Availability/Year (%)	75.0
Availability/Year (Hours)	6,570
Equipment Life (Hours)	70,000
Equipment Life (Years)	11
Overhaul Interval (Hours)	6,130
Maintenance Outage (Days)	10
Maintenance Outage Rate (%)	2.7
Forced Outage (Hours/Year)	200
Forced Outage Rate (%)	2.3
Hours per Year Operation	6,130
Capacity Factor (%)	42.0
Annual Net Energy (GWh)	368

Table O-7
Renewable Tax Benefits

Investment Tax Credit (%)	10
RETC Calculation ($/kWh)	312
Production Incentive-Investor (¢/kWh)	0
Geothermal Depletion Allowance	
RE Production Incentive Tier I	0
RE Production Incentive Tier II	0
REPI Tier II Proportion Paid (%)	10

Table O-8
Operation & Maintenance Costs (Employees)

Employees	Full Time Employees	Hours/Year	Compensation per Employee
Managers	1	1,800	$80,000 per year
Plant Operators	10	1,800	$30 per hour
Mechanics	6	1,800	$30 per hour
Laborers	3	1,800	$20 per hour
Support Staff	1	1,800	$20 per hour

Table O-9
Operation & Maintenance Costs (Other)

Fixed O&M ($/kW-Yr)	**40.0**
Fixed O&M/Instant Cost (%)	1.42
O&M Escalation (%)	0.5
Insurance (%)	1.5
Labor Escalation Cost (%)	0.5
Overhead Multiplier	1.6
Other Operating Costs	
Water Supply ($/AF)	462.0
Consumption (AF/Yr)	200.0
Plant Scheduling Costs	
Transmission Service ($/MW)	

Table O-10
Cost Summary

Financing Costs ($/kW-Yr)	377
Fixed Operational Costs ($/kW-Yr)	101
Tax (w/Credits) ($/kW-Yr)	(55)
Fixed Costs	**423**
Fuel Costs ($/kW-Yr)	48
Variable O&M ($/kW-Yr)	26
Variable Costs	**74**
Total Levelized Costs ($/kW-Yr)	**497**
Capital ($/MWH)	115.14
Variable ($/MWH)	20.08
Total Levelized Costs ($/MWH)	**135.21**
Capital Costs	
Instant Cost ($/kW)	2,841
Installed Cost ($/MWH)	3,059
In-service Cost in 2004 ($/KW)	**3,120**

Table O-11
Capital Cost Detail

Total ($)	**284,065,853**
Component Cost ($)	**276,835,787**
Structure & Improvements ($)	2,720,813
Collector System ($)	147,795,374
Thermal Storage System	0
Steam Gen or HX System ($)	11,251,870
Aux Heater/Boiler ($)	20,597,257
EPGS ($)	47,651,991
Master Control System ($)	0
Balance of Plant ($)	27,706,701
Engr, Const, Proj Management ($)	19,111,781
Financial Transaction Costs (%)	**0**
Land Costs ($)	**5,786,219**
Acreage/MW	5
Acreage/Plant	550
Cost per Acre ($)	3,100
Acquisition Cost ($)	1,705,000
Land Prep Costs ($/Acre)	7,420
Total Land Prep Costs ($)	4,081,219
Permitting Costs ($)	**343,847**
Local building permits ($)	0
Environmental permits ($)	343,847
Interconnection Costs ($)	**0**
Transmission Lines ($)	0
Substation ($)	0
Induction Equipment ($)	
Environmental Controls ($)	**1,100,000**
Installation Costs ($)	1,100,000
Replacement Costs ($)	

Table O-12
Maintenance Cost Detail

Routine Maintenance Costs		Annual Costs
Replacement Interval (Hours)	1	
Filter Price ($)	0	0
Maintenance Interval (Hours)	1	
Price ($)	0	0
Oil Price ($/Gallon)	3.40	
Oil Capacity	0	0
Oil Added per Day	0	0
Interval (Hours)	1,000	
Item Price ($)	0	0
Labor Hours/Day	0	
Labor Price ($/Hour)	48	0
Annual Routine Maintenance		**0**
Major Overhauls		
Hours to Major Overhaul:	35,000	
Major Overhaul Labor (Man-Hours)	125	
Labor Cost ($/Hour)	48	
Major Overhaul Labor Cost ($)	6,000	
Major Overhaul Replacement ($)	0	1,015.72
NPV Cost ($)		
Minor Overhauls		
Annual Cost Item 1 ($)	925,019	
Hours to Item 1 Job	6,130	1
Annual Cost Item 2 ($)	0	
Hours to Item 2 Job	0	7
Annualized Overhauls		**1,184,298**
Unscheduled Maintenance		
Forced Outage Hours/Year	200	
Labor Rate ($/Hour)	48	
Hours of Labor	200	
Parts Costs ($)	0	
Total ($)	9,600	
Total Annual Maintenance		**1,194,913**
Maintenance ($/kW-Yr)	11.95	
Maintenance ($/MWh)	3.25	

Table O-13
Environmental Control Costs

Total Annual Costs ($)	**1,100,000**
Media & Technology	**Cost**
Air Emissions	
Control Technology (e.g. SCR) ($)	1,100,000
Installation Cost ($/kW)	10
Annual Labor (Hours/Year)	0
Loaded Labor Rate ($/Hour)	48
Labor Cost ($)	0
Annual Consumables-Catalyst ($)	0
Replacement Cost ($/kW)	0
Component Life (Hours)	141,760
Annualized Cost ($)	
Water Cooling	
Control Technology (e.g. wastewater) ($)	
Installation Cost ($/kW)	0
Annual Labor (Hours/Year)	0
Loaded Labor Rate ($/Hour)	48
Labor Cost ($)	0
Annual Consumables ($)	0
Replacement Cost ($/kW)	0
Component Life (Hours)	141,760
Annualized Cost ($)	
Solid Waste Disposal	
Non hazardous material	
Tons per Year	0
Collection and hauling ($/Ton)	10
Landfill tipping fees ($/Ton)	30
Total Costs ($)	0
Hazardous materials	
Tons per Year	0
Collection and hauling ($/Ton)	10
Landfill tipping fees ($/Ton)	30
Total Disposal Costs ($)	0

APPENDIX P
Solar Thermal-Stirling Dish

Table P-1
Plant Information

Technology Type	Solar
Fuel	None
Owner/Investor	Merchant
Base Year	2002
In-service Year	2003

Table P-2
Plant Size

Gross Capacity (MW)	31.5
Parasitic Load (MW)	1.5
Net Capacity (MW)	30.0
Derate Factor (%)	100.0
Firm Capacity (MW)	30.0
Transmission Losses (%)	1.5
Required AS/reserves (%)	0.0
Average Hourly Output Rate (%)	100.0
Effective Load Carry Capacity (MW)	30.0
Annual capacity degradation rate (%)	0.0

Table P-3
Capital Costs

Escalation in Capital Costs	0.0%
AFUDC Rate	10.3%
Cash Cost	100.0%

Table P-4
Construction Costs by Year
Sum: 100%

Years Out from On-Line Date	0	-1	-2	-3	-4
Cost %/Year	100%	0%	0%	0%	0%
Carry Over	$3,270	$0	$0	$0	$0

Table P-5
Fuel Use

Heat Rate (MMBtu/kWh)	N/A
Fuel Consumption (MMBtu/Hr)	0
Start up fuel use (MMBtu/start)	0
No. of annual starts	0
Annual Fuel Use (MMBtu)	0

Table P-6
Operational Information

Availability/Year (%)	40.0
Availability/Year (Hours)	3,504
Equipment Life (Hours)	10,000
Equipment Life (Years)	3
Overhaul Interval (Hours)	3,000
Maintenance Outage (Days)	5
Maintenance Outage Rate (%)	1.4
Forced Outage (Hours/Year)	200
Forced Outage Rate (%)	2.3
Hours per Year Operation	3,184
Capacity Factor (%)	36.3
Annual Net Energy (GWh)	96

Table P-7
Renewable Tax Benefits

Investment Tax Credit (%)	10
RETC Calculation ($/kWh)	359
Production Incentive-Investor (¢/kWh)	0
Geothermal Depletion Allowance	
RE Production Incentive Tier I	0
RE Production Incentive Tier II	0
REPI Tier II Proportion Paid (%)	10

Table P-8
Operation & Maintenance Costs (Employees)

Employees	Full Time Employees	Hours/Year	Compensation per Employee
Managers	1	1,800	$80,000 per year
Plant Operators	4	1,800	$30 per hour
Mechanics	3	1,800	$30 per hour
Laborers	3	1,800	$20 per hour
Support Staff	1	1,800	$20 per hour

Table P-9
Operation & Maintenance Costs (Other)

Fixed O&M ($/kW-Yr)	**48.0**
Fixed O&M/Instant Cost (%)	1.48
O&M Escalation (%)	0.5
Insurance (%)	1.5
Labor Escalation Cost (%)	0.5
Overhead Multiplier	1.6
Other Operating Costs	
Water Supply ($/AF)	
Consumption (AF/Yr)	
Plant Scheduling Costs	
Transmission Service ($/MW)	

Table P-10
Cost Summary

Financing Costs ($/kW-Yr)	434
Fixed Operational Costs ($/kW-Yr)	119
Tax (w/Credits) ($/kW-Yr)	(64)
Fixed Costs	**489**
Fuel Costs ($/kW-Yr)	0
Variable O&M ($/kW-Yr)	0
Variable Costs	**0**
Total Levelized Costs ($/kW-Yr)	**489**
Capital ($/MWH)	153.67
Variable ($/MWH)	0.00
Total Levelized Costs ($/MWH)	**153.67**
Capital Costs	
Instant Cost ($/kW)	3,270
Installed Cost ($/MWH)	3,520
In-service Cost in 2004 ($/KW)	**3,591**

Table P-11
Capital Cost Detail

Total ($)	**98,090,550**
Component Cost ($)	**92,607,300**
Concentrator ($)	51,615,000
Receiver ($)	2,664,000
Engine ($)	8,658,000
Generator ($)	1,498,500
Cooling System ($)	1,332,000
Electrical ($)	1,165,500
Balance of Plant ($)	9,990,000
General Plant Facilities ($)	4,995,000
Engineering & Startup ($)	10,689,300
Financial Transaction Costs (%)	**0**
Land Costs ($)	**5,483,250**
Acres/MW	5
Acreage/Plant	157.5
Cost per Acre ($)	3,100
Acquisition Cost ($)	488,250
Land Prep Costs ($/Acre)	31,714
Total Land Prep Costs ($)	4,995,000
Permitting Costs ($)	**0**
Local building permits ($)	
Environmental permits ($)	
Interconnection Costs ($)	**0**
Transmission Lines ($)	0
Substation ($)	0
Induction Equipment ($)	
Environmental Controls ($)	**0**
Installation Costs ($)	0
Replacement Costs ($)	

Table P-12
Maintenance Cost Detail

Routine Maintenance Costs		Annual Costs
Replacement Interval (Hours)	1	
Filter Price ($)	0	0
Maintenance Interval (Hours)	1	
Price ($)	0	0
Oil Price ($/Gallon)	3.40	
Oil Capacity	0	0
Oil Added per Day	0	0
Interval (Hours)	1,000	
Item Price ($)	0	0
Labor Hours/Day	0	
Labor Price ($/Hour)	48	0
Annual Routine Maintenance		**0**
Major Overhauls		
Hours to Major Overhaul:	3,000	
Major Overhaul Labor (Man-Hours)	36	
Labor Cost ($/Hour)	48	
Major Overhaul Labor Cost ($)	1,728	
Major Overhaul Replacement ($)	0	5,573
NPV Cost ($)		
Minor Overhauls		
Annual Cost Item 1 ($)	484,000	
Hours to Item 1 Job	3,184	1
Annual Cost Item 2 ($)	0	
Hours to Item 2 Job	0	7
Annualized Overhauls		**475,829**
Unscheduled Maintenance		
Forced Outage Hours/Year	200	
Labor Rate ($/Hour)	48	
Hours of Labor	200	
Parts Costs ($)	0	
Total ($)	9,600	
Total Annual Maintenance		**491,002**
Maintenance ($/kW-Yr)	16.37	
Maintenance ($/MWh)	5.14	

Table P-13
Environmental Control Costs

Total Annual Costs ($)	**0**
Media & Technology	**Cost**
Air Emissions	
Control Technology (e.g. SCR) ($)	
Installation Cost ($/kW)	0
Annual Labor (Hours/Year)	0
Loaded Labor Rate ($/Hour)	48
Labor Cost ($)	0
Annual Consumables-Catalyst ($)	0
Replacement Cost ($/kW)	0
Component Life (Hours)	141,760
Annualized Cost ($)	
Water Cooling	
Control Technology (e.g. wastewater) ($)	
Installation Cost ($/kW)	0
Annual Labor (Hours/Year)	0
Loaded Labor Rate ($/Hour)	48
Labor Cost ($)	0
Annual Consumables ($)	0
Replacement Cost ($/kW)	0
Component Life (Hours)	141,760
Annualized Cost ($)	
Solid Waste Disposal	
Non hazardous material	
Tons per Year	0
Collection and hauling ($/Ton)	10
Landfill tipping fees ($/Ton)	30
Total Costs ($)	0
Hazardous materials	
Tons per Year	0
Collection and hauling ($/Ton)	10
Landfill tipping fees ($/Ton)	30
Total Disposal Costs ($)	0

APPENDIX Q
Solar Parabolic w/ Thermally-Enhanced Storage Only

Table Q-1
Plant Information

Technology Type	Solar
Fuel	None
Owner/Investor	Merchant
Base Year	2002
In-service Year	2003

Table Q-2
Plant Size

Gross Capacity (MW)	110.0
Parasitic Load (MW)	10.0
Net Capacity (MW)	100.0
Derate Factor (%)	100.0
Firm Capacity (MW)	100.0
Transmission Losses (%)	1.5
Required AS/reserves (%)	0.0
Average Hourly Output Rate (%)	60.0
Effective Load Carry Capacity (MW)	59.0
Annual capacity degradation rate (%)	0.0

Table Q-3
Capital Costs

Escalation in Capital Costs	0.0%
AFUDC Rate	10.3%
Cash Cost	100.0%

Table Q-4
Construction Costs by Year
Sum: 100%

Years Out from On-Line Date	0	-1	-2	-3	-4
Cost %/Year	100%	0%	0%	0%	0%
Carry Over	$3,993	$0	$0	$0	$0

Table Q-5
Fuel Use

Heat Rate (MMBtu/kWh)	N/A
Fuel Consumption (MMBtu/Hr)	0
Start up fuel use (MMBtu/start)	0
No. of annual starts	346
Annual Fuel Use (MMBtu)	0

Table Q-6
Operational Information

Availability/Year (%)	75.0
Availability/Year (Hours)	6,570
Equipment Life (Hours)	70,000
Equipment Life (Years)	11
Overhaul Interval (Hours)	6,130
Maintenance Outage (Days)	10
Maintenance Outage Rate (%)	2.7
Forced Outage (Hours/Year)	200
Forced Outage Rate (%)	2.3
Hours per Year Operation	6,130
Capacity Factor (%)	42.0
Annual Net Energy (GWh)	368

Table Q-7
Renewable Tax Benefits

Investment Tax Credit (%)	10
RETC Calculation ($/kWh)	438
Production Incentive-Investor (¢/kWh)	0
Geothermal Depletion Allowance	
RE Production Incentive Tier I	0
RE Production Incentive Tier II	0
REPI Tier II Proportion Paid (%)	10

Table Q-8
Operation & Maintenance Costs (Employees)

Employees	Full Time Employees	Hours/Year	Compensation per Employee
Managers	1	1,800	$80,000 per year
Plant Operators	10	1,800	$30 per hour
Mechanics	6	1,800	$30 per hour
Laborers	3	1,800	$20 per hour
Support Staff	1	1,800	$20 per hour

Table Q-9
Operation & Maintenance Costs (Other)

Fixed O&M ($/kW-Yr)	**29.0**
Fixed O&M/Instant Cost (%)	0.74
O&M Escalation (%)	0.5
Insurance (%)	1.5
Labor Escalation Cost (%)	0.5
Overhead Multiplier	1.6
Other Operating Costs	
Water Supply ($/AF)	
Consumption (AF/Yr)	
Plant Scheduling Costs	
Transmission Service ($/MW)	

Table Q-10
Cost Summary

Financing Costs ($/kW-Yr)	530
Fixed Operational Costs ($/kW-Yr)	110
Tax (w/Credits) ($/kW-Yr)	(77)
Fixed Costs	**563**
Fuel Costs ($/kW-Yr)	0
Variable O&M ($/kW-Yr)	76
Variable Costs	**76**
Total Levelized Costs ($/kW-Yr)	**639**
Capital ($/MWH)	153.05
Variable ($/MWH)	20.58
Total Levelized Costs ($/MWH)	**173.64**
Capital Costs	
Instant Cost ($/kW)	3,993
Installed Cost ($/MWH)	4,299
In-service Cost in 2004 ($/KW)	**4,385**

Table Q-11
Capital Cost Detail

Total ($)	**399,264,733**
Component Cost ($)	**391,702,016**
Structure & Improvements ($)	3,450,478
Collector System ($)	207,425,745
Thermal Storage System	66,593,338
Steam Gen or HX System ($)	11,872,762
Aux Heater/Boiler ($)	0
EPGS ($)	47,651,991
Master Control System ($)	0
Balance of Plant ($)	27,706,701
Engr, Const, Proj Management ($)	27,001,001
Financial Transaction Costs (%)	**0**
Land Cost ($)	**7,562,716**
Acreage/MW	7
Acreage/Plant	770
Cost per Acre ($)	3,100
Acquisition Cost ($)	2,387,000
Land Prep Costs ($/Acre)	6,722
Total Land Prep Costs ($)	5,175,716
Permitting Costs ($)	**0**
Local building permits ($)	
Environmental permits ($)	
Interconnection Costs ($)	**0**
Transmission Lines ($)	0
Substation ($)	0
Induction Equipment ($)	
Environmental Controls ($)	**0**
Installation Costs ($)	0
Replacement Costs ($)	

Table Q-12
Maintenance Cost Detail

Routine Maintenance Costs		Annual Costs
Replacement Interval (Hours)	1	
Filter Price ($)	0	0
Maintenance Interval (Hours)	1	
Price ($)	0	0
Oil Price ($/Gallon)	3.40	
Oil Capacity	0	0
Oil Added per Day	0	0
Interval (Hours)	1,000	
Item Price ($)	0	0
Labor Hours/Day	0	
Labor Price ($/Hour)	48	0
Annual Routine Maintenance		**0**
Major Overhauls		
Hours to Major Overhaul:	35,000	
Major Overhaul Labor (Man-Hours)	125	
Labor Cost ($/Hour)	48	
Major Overhaul Labor Cost ($)	6,000	
Major Overhaul Replacement ($)	0	1,015.72
NPV Cost ($)		
Minor Overhauls		
Annual Cost Item 1 ($)	925,019	
Hours to Item 1 Job	6,130	1
Annual Cost Item 2 ($)	0	
Hours to Item 2 Job	0	7
Annualized Overhauls		**1,184,298**
Unscheduled Maintenance		
Forced Outage Hours/Year	200	
Labor Rate ($/Hour)	48	
Hours of Labor	200	
Parts Costs ($)	0	
Total ($)	9,600	
Total Annual Maintenance		**1,194,913**
Maintenance ($/kW-Yr)	11.95	
Maintenance ($/MWh)	3.25	

Table Q-13
Environmental Control Costs

Total Annual Costs ($)	**0**
Media & Technology	**Cost**
Air Emissions	
Control Technology (e.g. SCR) ($)	
Installation Cost ($/kW)	0
Annual Labor (Hours/Year)	0
Loaded Labor Rate ($/Hour)	48
Labor Cost ($)	0
Annual Consumables-Catalyst ($)	0
Replacement Cost ($/kW)	0
Component Life (Hours)	141,760
Annualized Cost ($)	
Water Cooling	
Control Technology (e.g. wastewater) ($)	
Installation Cost ($/kW)	0
Annual Labor (Hours/Year)	0
Loaded Labor Rate ($/Hour)	48
Labor Cost ($)	0
Annual Consumables ($)	0
Replacement Cost ($/kW)	0
Component Life (Hours)	141,760
Annualized Cost ($)	
Solid Waste Disposal	
Non hazardous material	
Tons per Year	0
Collection and hauling ($/Ton)	10
Landfill tipping fees ($/Ton)	30
Total Costs ($)	0
Hazardous materials	
Tons per Year	0
Collection and hauling ($/Ton)	10
Landfill tipping fees ($/Ton)	30
Total Disposal Costs ($)	0

APPENDIX R
Wind Farm

Table R-1
Plant Information

Technology Type	Wind
Fuel	None
Owner/Investor	Merchant
Base Year	2001
In-service Year	2004

Table R-2
Plant Size

Gross Capacity (MW)	100.0
Parasitic Load (MW)	0.1
Net Capacity (MW)	100.0
Derate Factor (%)	40.0
Firm Capacity (MW)	40.0
Transmission Losses (%)	5.0
Required AS/reserves (%)	7.0
Average Hourly Output Rate (%)	66.0
Effective Load Carry Capacity (MW)	58.0
Annual capacity degradation rate (%)	0.1

Table R-3
Capital Costs

Escalation in Capital Costs	0.0%
AFUDC Rate	10.3%
Cash Cost	100.0%

Table R-4
Construction Costs by Year
Sum: 100%

Years Out from On-Line Date	0	-1	-2	-3	-4
Cost %/Year	100%	0%	0%	0%	0%
Carry Over	$887	$0	$0	$0	$0

Table R-5
Fuel Use

Heat Rate (MMBtu/kWh)	N/A
Fuel Consumption (MMBtu/Hr)	0
Start up fuel use (MMBtu/start)	0
No. of annual starts	0
Annual Fuel Use (MMBtu)	0

Table R-6
Operational Information

Availability/Year (%)	70.0
Availability/Year (Hours)	6,132
Equipment Life (Hours)	66,700
Equipment Life (Years)	13
Overhaul Interval (Hours)	40,000
Maintenance Outage (Days)	28
Maintenance Outage Rate (%)	1.1
Forced Outage (Hours/Year)	700
Forced Outage Rate (%)	8.0
Hours per Year Operation	5,336
Capacity Factor (%)	40.2
Annual Net Energy (GWh)	352

Table R-7
Renewable Tax Benefits

Investment Tax Credit (%)	0
RETC Calculation ($/kWh)	0
Production Incentive-Investor (¢/kWh)	1.695
Geothermal Depletion Allowance	
RE Production Incentive Tier I	0
RE Production Incentive Tier II	0
REPI Tier II Proportion Paid (%)	10

Table R-8
Operation & Maintenance Costs (Employees)

Employees	Full Time Employees	Hours/Year	Compensation per Employee
Managers	2	1,800	$80,000 per year
Plant Operators	2	1,800	$30 per hour
Mechanics	6	1,800	$30 per hour
Laborers	4	1,800	$20 per hour
Support Staff	2	1,800	$20 per hour

Table R-9
Operation & Maintenance Costs (Other)

Fixed O&M ($/kW-Yr)	**39.0**
Fixed O&M/Instant Cost (%)	4.35
O&M Escalation (%)	0.5
Insurance (%)	1.5
Labor Escalation Cost (%)	0.5
Overhead Multiplier	1.6
Other Operating Costs	
Water Supply ($/AF)	
Consumption (AF/Yr)	
Plant Scheduling Costs	
Transmission Service ($/MW)	

Table R-10
Cost Summary

Financing Costs ($/kW-Yr)	123
Fixed Operational Costs ($/kW-Yr)	63
Tax (w/Credits) ($/kW-Yr)	(12)
Fixed Costs	**174**
Fuel Costs ($/kW-Yr)	0
Variable O&M ($/kW-Yr)	0
Variable Costs	**0**
Total Levelized Costs ($/kW-Yr)	**174**
Capital ($/MWH)	49.33
Variable ($/MWH)	0.00
Total Levelized Costs ($/MWH)	**49.33**
Capital Costs	
Instant Cost ($/kW)	887
Installed Cost ($/MWH)	955
In-service Cost in 2004 ($/KW)	**1,014**

Table R-11
Capital Cost Detail

Total ($)	**399,264,733**
Component Cost ($)	**391,702,016**
Structures & Improvements ($)	3,450,478
Collector System ($)	207,425,745
Thermal Storage System ($)	66,593,338
Steam Gen or HX System ($)	11,872,762
Auxiliary Heater/Boiler ($)	0
EPGS ($)	47,651,991
Master Control System ($)	0
Balance of Plant ($)	27,706,701
Engineering, Construction, Project Management	27,001,001
Financial Transaction Costs (%)	**0**
Land Costs ($)	**7,562,716**
Acreage/MW	7
Acreage/Plant	770
Cost per Acre ($)	3,100
Acquisition Cost ($)	2,387,000
Land Prep Costs ($/Acre)	6,722
Permitting Costs ($)	5,175,716
Local building permits ($)	**0**
Environmental permits ($)	
Air Emission Permits ($)	
Interconnection Costs ($)	**0**
Transmission Lines ($)	0
Substation ($)	0
Induction Equipment ($)	
Environmental Controls ($)	**0**
Installation Costs ($)	0
Replacement Costs ($)	

Table R-12
Maintenance Cost Detail

Routine Maintenance Costs		Annual Costs
Replacement Interval (Hours)	1	
Filter Price ($)	0	0
Maintenance Interval (Hours)	1	
Price ($)	0	0
Oil Price ($/Gallon)	3.40	
Oil Capacity	0	0
Oil Added per Day	0	0
Interval (Hours)	1,000	
Item Price ($)	0	0
Labor Hours/Day	0	
Labor Price ($/Hour)	48	0
Annual Routine Maintenance		**0**
Major Overhauls		
Hours to Major Overhaul:	35,000	
Major Overhaul Labor (Man-Hours)	125	
Labor Cost ($/Hour)	48	
Major Overhaul Labor Cost ($)	6,000	
Major Overhaul Replacement ($)	0	1,015.72
NPV Cost ($)		
Minor Overhauls		
Annual Cost Item 1 ($)	925,019	
Hours to Item 1 Job	6,130	1
Annual Cost Item 2 ($)	0	
Hours to Item 2 Job	0	7
Annualized Overhauls		**1,184,298**
Unscheduled Maintenance		
Forced Outage Hours/Year	200	
Labor Rate ($/Hour)	48	
Hours of Labor	200	
Parts Costs ($)	0	
Total ($)	9,600	
Total Annual Maintenance		**1,194,913**
Maintenance ($/kW-Yr)	11.95	
Maintenance ($/MWh)	3.25	

Table R-13
Environmental Control Costs

Total Annual Costs ($)	**0**
Media & Technology	**Cost**
Air Emissions	
Control Technology (e.g. SCR) ($)	
Installation Cost ($/kW)	0
Annual Labor (Hours/Year)	0
Loaded Labor Rate ($/Hour)	48
Labor Cost ($)	0
Annual Consumables-Catalyst ($)	0
Replacement Cost ($/kW)	0
Component Life (Hours)	141,760
Annualized Cost ($)	
Water Cooling	
Control Technology (e.g. wastewater) ($)	
Installation Cost ($/kW)	0
Annual Labor (Hours/Year)	0
Loaded Labor Rate ($/Hour)	48
Labor Cost ($)	0
Annual Consumables ($)	0
Replacement Cost ($/kW)	0
Component Life (Hours)	141,760
Annualized Cost ($)	
Solid Waste Disposal	
Non hazardous material	
Tons per Year	0
Collection and hauling ($/Ton)	10
Landfill tipping fees ($/Ton)	30
Total Costs ($)	0
Hazardous materials	
Tons per Year	0
Collection and hauling ($/Ton)	10
Landfill tipping fees ($/Ton)	30
Total Disposal Costs ($)	0

Appendix S
Combine Cycle-Baseload (With Duct Firing)

Table S-1
Plant Information

Technology Type	Natural Gas
Fuel	Natural Gas
Owner/Investor	Merchant
Base Year	2002
In-service Year	2004

Table S-2
Plant Size

Gross Capacity (MW)	100.0
Parasitic Load (MW)	0.0
Net Capacity (MW)	100.0
Derate Factor (%)	100.0
Firm Capacity (MW)	520.0
Transmission Losses (%)	5.0
Required AS/reserves (%)	7.0
Average Hourly Output Rate (%)	100.0
Effective Load Carry Capacity (MW)	88.0
Annual capacity degradation rate (%)	0.0

Table S-3
Capital Costs

Escalation in Capital Costs	0.0%
AFUDC Rate	10.3%
Cash Cost	100.0%

Table S-4
Construction Costs by Year
Sum: 100%

Years Out from On-Line Date	0	-1	-2	-3	-4
Cost %/Year	75%	20%	5%	0%	0%
Carry Over	$424	$105	$21	$0	$0

Table S-5
Fuel Use

Base Heat Rate (MMBtu/kWh)	9,300
Fuel Consumption (MMBtu/Hr)	930
Start up fuel use (MMBtu/Start)	180
No. of annual starts	120

Table S-6
Operational Information

Availability/Year (%)	10.0
Availability/Year (Hours)	876
Equipment Life (Hours)	148,394
Equipment Life (Years)	30
Overhaul Interval (Hours)	876
Maintenance Outage (Days)	4
Maintenance Outage Rate (%)	1.2
Forced Outage (Hours/Year)	44
Forced Outage Rate (%)	0.5
Hours per Year Operation	822
Capacity Factor (%)	9.4
Annual Net Energy (GWh)	82

Table S-7
Renewable Tax Benefits

Investment Tax Credit (%)	0
RETC Calculation ($/kWh)	0
Production Incentive-Investor (¢/kWh)	0
Geothermal Depletion Allowance	
RE Production Incentive Tier I	0
RE Production Incentive Tier II	0
REPI Tier II Proportion Paid (%)	10

Table S-8
Operation & Maintenance Costs

Employee Category	Full Time Employees	Hours/Year	Compensation per Employee
Managers	1	1,800	$77,031 per year
Plant Operators	12	2,200	$17 per hour
Mechanics	4	2,300	$18 per hour
Laborers	2	2,200	$12 per hour
Support Staff	3	2,000	$13 per hour

Table S-9
Operation & Maintenance Costs (Other)

Fixed O&M ($/kW-Yr)	**3.20**
Fixed O&M/Instant Cost (%)	0.60
O&M Escalation (%)	0.5
Insurance (%)	1.5
Labor Escalation Cost (%)	0.5
Overhead Multiplier	1.6
Other Operating Costs	
Water Supply ($/AF)	197.0
Consumption (AF/Yr)	2,704.0
Plant Scheduling Costs	
Transmission Service ($/MW)	

Table S-10
Cost Summary

Financing Costs ($/kW-Yr)	73
Fixed Operational Costs ($/kW-Yr)	14
Tax (w/Credits) ($/kW-Yr)	1
Fixed Costs	**88**
Fuel Costs ($/kW-Yr)	295
Variable O&M ($/kW-Yr)	18.59
Variable Costs	**314**
Total Levelized Costs ($/kW-Yr)	**402**
Capital ($/MWH)	11.42
Variable ($/MWH)	40.62
Total Levelized Costs ($/MWH)	**52.04**
Capital Costs	
Instant Cost ($/kW)	531
Installed Cost ($/MWH)	580
In-service Cost in 2004 ($/KW)	**604**

Table S-11
Capital Cost Detail

Total ($)	**275896567**
Component Cost ($)	**243,289,126**
Turbine/Engine [Not itemized] ($)	234,597,182
Generator/Gearhead ($)	
Boiler/HRSG ($)	
Fuel Pipeline/Tank ($)	
Slab & Engine Mount ($)	
Miscellaneous fitting & hoses ($)	4,691,944
Office space ($)	
Control Room($)	
Duct Burners ($)	4,000,000
Financial Transaction Costs (%)	**0**
Land Costs ($)	**1,477,941**
Acreage/Plant	15
Cost per Acre ($)	100,000
Acquisition Cost ($)	1,470,588
Land Prep Costs ($/Acre)	500
Total Land Prep Costs ($)	7,353
Permitting Costs ($)	**5,129,500**
Local building permits ($)	
Environmental permits ($)	
Air Emission Permits ($)	5,129,500
Interconnection Costs ($)	**0**
Transmission Lines ($)	
Substation ($)	
Induction Equipment ($)	
Environmental Controls ($)	**26,000,000**
Installation Costs ($)	26,000,000
Replacement Costs ($)	

Table S-12
Maintenance Cost Detail

Routine Maintenance Costs		Annual Costs
Replacement Interval (Hours)	1	
Filter Price ($)	0	0
Maintenance Interval (Hours)	1	
Price ($)	0	0
Oil Price ($/Gallon)	3.40	
Oil Capacity	0	0
Oil Added per Day	0	0
Interval (Hours)	1,000	
Item Price ($)	0	0
Labor Hours/Day	0	
Labor Price ($/Hour)	48	0
Annual Routine Maintenance		**0**
Major Overhauls		
Hours to Major Overhaul:	14,839	
Major Overhaul Labor (Man-Hours)	50,000	
Labor Cost ($/Hour)	48	
Major Overhaul Labor Cost ($)	2,400,000	
Major Overhaul Replacement ($)	8,000,000	**5,441,690**
NPV Cost ($)		
Minor Overhauls		
Annual Cost Item 1 ($)	0	
Hours to Item 1 Job	7,420	1
Annual Cost Item 2 ($)	0	
Hours to Item 2 Job	0	
Annualized Overhauls		**0**
Unscheduled Maintenance		
Forced Outage Hours/Year	400	
Labor Rate ($/Hour)	48	
Hours of Labor	400	
Parts Costs ($)	374,400	
Total ($)	393,600	
Total Annual Maintenance		**5,835,290**
Maintenance ($/kW-Yr)	11.22	
Maintenance ($/MWh)	1.45	

Table S-13
Environmental Control Costs

Total Annual Costs ($)	**1,019,680**
Media & Technology	**Cost**
Air Emissions	
Control Technology (e.g. SCR) ($)	15,600,000
Installation Cost ($/kW)	30
Annual Labor (Hours/Year)	100
Loaded Labor Rate ($/Hour)	48
Labor Cost ($)	4,800
Annual Consumables-Catalyst ($)	1,000,000
Replacement Cost ($/kW)	20
Component Life (Hours)	141,760
Annualized Cost ($)	8,548,981
Water Cooling	
Control Technology (e.g. wastewater) ($)	
Installation Cost ($/kW)	20
Annual Labor (Hours/Year)	100
Loaded Labor Rate ($/Hour)	48
Labor Cost ($)	4,800
Annual Consumables ($)	10,000
Replacement Cost ($/kW)	20
Component Life (Hours)	141,760
Annualized Cost ($)	
Solid Waste Disposal	
Non hazardous material	
Tons per Year	1
Collection and hauling ($/Ton)	10
Landfill tipping fees ($/Ton)	30
Total Costs ($)	40
Hazardous materials	
Tons per Year	1
Collection and hauling ($/Ton)	10
Landfill tipping fees ($/Ton)	30
Total Disposal Costs ($)	40

Sec 9.2 Ref 6

Conner et al. 1998

DOE/ID-10430.2

U.S. Hydropower Resource Assessment Final Report

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Published December 1998

:G-300

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Prepared for the
U.S. Department of Energy
Assistant Secretary for Energy Efficiency and Renewable Energy
Under DOE Idaho Operations Office
Contract DE-AC07-94ID13223

U.S. Hydropower Resource Assessment Final Report

INTRODUCTION

In June 1989, the U.S. Department of Energy (DOE) initiated the development of a National Energy Strategy to identify the energy resources available to support the expanding demand for energy in the United States. Public hearings conducted as part of the strategy development process indicated that the undeveloped hydropower resources were not well defined. One of the reasons was that no agency had previously estimated the undeveloped hydropower capacity based on site characteristics, stream flow data, and available hydraulic heads. The Federal Energy Regulatory Commission's (FERC's) Hydropower Resource Assessment (HPRA) database was used as the basis for this evaluation. The undeveloped capacity data is based on individual site evaluations that included capacity estimation. It was this information that for the first time was reviewed by the various state agencies and then modeled based on environmental, legal, and institutional constraints. As a result, DOE established an interagency Hydropower Resource Assessment Team to ascertain the country's undeveloped hydropower potential. The team consisted of representatives from each power marketing administration (Alaska Power Administration, Bonneville Power Administration, Western Area Power Administration, Southwestern Power Administration, and Southeastern Power Administration), the Bureau of Reclamation, the Army Corps of Engineers, the Federal Energy Regulatory Commission (FERC), the Idaho National Engineering and Environmental Laboratory (INEEL), and the Oak Ridge National Laboratory. The interagency team drafted a preliminary assessment of potential hydropower resources in February 1990. This assessment estimated that 52,900 MW of undeveloped hydropower energy existed in the United States.

Partial analysis of the hydropower resource database by groups in the hydropower industry indicated that the hydropower data included redundancies and errors that reduced confidence in the published estimates of developable hydropower capacity. The DOE has continued assessing hydropower resources to correct these deficiencies, improve estimates of developable hydropower, and determine future policy. To support these efforts by the DOE, the INEEL designed the Hydropower Evaluation Software (HES).

This report summarizes and discusses the undeveloped conventional hydropower capacity for the 5,677 sites within the United States. However, this capacity does not include that produced by pumped storage sites. The resource assessment is limited to sites with conventional undeveloped hydropower potential. In addition, while every reasonable effort was made to include all sites with undeveloped potential, the authors acknowledge that not every site in the United States with undeveloped hydropower potential was included. Only sites that have been either previously identified by third parties and included in the FERC HPRA database, or sites that local state agencies are aware of, are included in the database.

Need For Uniform Criteria

The INEEL's HES, both a database and a probability-factor computer model, is a menu-driven software application that is intended to be user-friendly. Computer screens and report generation capabilities were developed to meet the needs of users nationwide. HES considers a uniform set of possible site-specific environmental attributes to assess the likelihood of developing the undeveloped hydropower resources of regions and states. These site-specific environmental attributes, derived from the Nationwide Rivers Inventory, include whether a site has Wild and Scenic Protection or is on a tributary of a site with such protection;

ASSESSMENT PROCESS AND ASSUMPTIONS

The assessment process uses a logical extraction of data from the two primary data sources discussed previously: the Nationwide Rivers Inventory and the HPRA databases. The basic site data is relatively easy to download. However, extracting the environmental attributes data is somewhat tedious because of the cross-referencing needed between the two database sources and the interpretation of narrative descriptions of outstanding environmental attributes.

Environmental attributes for sites on river reaches listed in the Nationwide Rivers Inventory can be assigned several ways. The first and simplest is to assign the environmental attributes of a Nationwide Rivers Inventory reach to any undeveloped hydropower project that is located in the same state and county and on the same river that is listed in the Nationwide Rivers Inventory. This method relies on the state, county, and river identifiers in the HPRA database for location; these identifiers are unlikely to be inaccurate.

A second method for assigning Nationwide Rivers Inventory attributes to projects is to (a) use the river mile designations for Nationwide Rivers Inventory reaches to locate the reaches on FERC river basin maps, (b) use the Geographic Information System to map the projects at the same scale, and (c) overlay the project maps on the Nationwide Rivers Inventory reach maps to see which projects fall on Nationwide Rivers Inventory reaches. This method is potentially more accurate since only the projects actually on the Nationwide Rivers Inventory reach would be identified. Sites within a specified distance upstream or downstream of the Nationwide Rivers Inventory reach could also be identified and assigned the environmental attributes of the Nationwide Rivers Inventory reach. The main disadvantage of this method is that it uses the latitude-longitude coordinates of projects from the HPRA database, which are occasionally missing or inaccurate. For this and other reasons, the first method was used. The first method also ensures that any upstream or downstream impacts from development are also considered.

The application of suitability factors is straightforward once all of the environmental attributes have been identified. One simply follows the specifications in Table 2.

The underlying assumption in the evaluation process is that the suitability factors being assigned to environmental attributes represent the degree to which these attributes will decrease the likelihood of developing a site. One must also assume that the combination of suitability factors is not multiplicative but can be represented by the weighing scheme shown in Table 3.

Table 4. Hydropower capacity summary modeled by HES.

State	Category	Number Of Projects	Name Plate Capacity (MW)	HES Adjusted Capacity (MW)
Alabama	With Power	4	71	35
	W/O Power	21	281	216
	Undeveloped	8	146	112
	State Total	33	498	363
Alaska	With Power	3	65	58
	W/O Power	60	2,866	1,610
	Undeveloped	56	1,111	490
	State Total	119	4,042	2,158
Arizona	With Power	2	207	157
	W/O Power	6	51	15
	Undeveloped	13	1,552	166
	State Total	21	1,810	338
Arkansas	With Power	13	193	174
	W/O Power	28	378	332
	Undeveloped	20	638	231
	State Total	61	1,209	737
California	With Power	26	1,745	653
	W/O Power	274	4,812	1,894
	Undeveloped	463	3,834	843
	State Total	763	10,391	3,390
Colorado	With Power	5	156	78
	W/O Power	91	782	377
	Undeveloped	155	1,408	209
	State Total	251	2,346	664

Table 4. (continued).

State	Category	Number Of Projects	Name Plate Capacity (MW)	HES Adjusted Capacity (MW)
Illinois	With Power	9	80	41
	W/O Power	35	457	242
	Undeveloped	5	58	18
	State Total	49	595	301
Indiana	With Power	3	16	8
	W/O Power	24	51	34
	Undeveloped	3	17	2
	State Total	30	84	44
Iowa	With Power	7	115	61
	W/O Power	69	310	219
	Undeveloped	3	30	25
	State Total	79	455	305
Kansas	With Power	1	0.06	0.03
	W/O Power	12	53	45
	Undeveloped	5	100	38
	State Total	18	153	83
Kentucky	With Power	1	19	10
	W/O Power	46	851	425
	Undeveloped	4	43	4
	State Total	51	913	439
Louisiana	With Power	0	0	0
	W/O Power	14	78	67
	Undeveloped	8	148	133
	State Total	22	226	200

Table 4. (continued).

State	Category	Number Of Projects	Name Plate Capacity (MW)	HES Adjusted Capacity (MW)
Missouri	With Power	6	116	104
	W/O Power	12	203	181
	Undeveloped	11	378	38
	State Total	29	697	323
Montana	With Power	7	470	235
	W/O Power	72	1,129	502
	Undeveloped	79	2,073	277
	State Total	158	3,672	1,014
Nebraska	With Power	3	46	28
	W/O Power	23	117	62
	Undeveloped	19	182	59
	State Total	45	345	149
Nevada	With Power	9	5	4
	W/O Power	48	41	31
	Undeveloped	124	80	32
	State Total	181	126	67
New Hampshire	With Power	0	0	0
	W/O Power	63	51	25
	Undeveloped	34	65	7
	State Total	97	116	32
New Jersey	With Power	0	0	0
	W/O Power	9	6	5
	Undeveloped	3	5	4
	State Total	12	11	9

Table 4. (continued).

State	Category	Number Of Projects	Name Plate Capacity (MW)	HES Adjusted Capacity (MW)
Oregon	With Power	3	45	11
	W/O Power	101	2,549	1,916
	Undeveloped	118	950	318
	State Total	222	3,544	2,245
Pennsylvania	With Power	5	207	105
	W/O Power	67	310	187
	Undeveloped	32	1,701	411
	State Total	104	2,218	703
Rhode Island	With Power	0	0	0
	W/O Power	27	12	10
	Undeveloped	3	2	1
	State Total	30	14	11
South Carolina	With Power	2	6	3
	W/O Power	31	855	444
	Undeveloped	16	273	33
	State Total	49	1,134	480
South Dakota	With Power	5	569	285
	W/O Power	25	548	405
	Undeveloped	3	6	5
	State Total	33	1,123	695
Tennessee	With Power	0	0	0
	W/O Power	11	20	10
	Undeveloped	11	476	128
	State Total	22	496	138

CONCLUSIONS

The trend for hydropower development is downward because of current environmental attributes and legal and institutional constraints. After loading hydropower data for the states into HES and checking the data with the respective states, the analysis indicates that undeveloped hydropower capacity will drop by about 43%. The greatest decrease for any state is always at undeveloped sites. However, with the development of new technologies (e.g., environmentally friendly turbines, ultra-low head turbines), or changes in the energy picture (e.g., another oil crisis), hydropower production could increase.

The results of the HES are obtained in a viable, low-cost manner and can be used by developers as a preliminary means for identifying developable sites. These results provide a peerless means for identifying the undeveloped hydropower capacity essential for continued energy growth, which in turn is necessary for the continued economic strength of the United States.

Application of HES to current data significantly reduces state and regional totals for undeveloped hydropower capacity. However, an abundance of potential sites remain that are likely to be developed, given the current environmental awareness and geopolitical constraints. Strategies may need to be formulated to further assess those sites with the most potential for development.

CEC 2003

CALIFORNIA
ENERGY
COMMISSION

COMPARATIVE COST OF CALIFORNIA CENTRAL STATION ELECTRICITY GENERATION TECHNOLOGIES

Prepared in Support of the Electricity and Natural Gas Report under the Integrated Energy Policy Report Proceeding
Docket 02-IEP-01

FINAL STAFF REPORT

June 5, 2003
100-03-001F

Gray Davis, *Governor*

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Staff has made numerous changes to the preliminary draft report that was originally published on February 11, 2003. The Integrated Energy Policy Report Committee held a workshop on February 26, 2003 to take public comments on the matter. The original study focused on capital, rather than developmental costs. The report now includes development, land acquisition, and permitting costs for all technologies based on comments received at the workshop. Certain parties also expressed concern that staff had systematically understated several costs associated with gas-fired plants. In response to this latter set of comments, staff has:

- Changed the heat rate assumed for Combined Cycle units from 6,900 to 7,100 MMBtu/kWh,
- Included water cooling costs for gas-fired units,
- Added air-district-specific emissions costs that are shown in **Table 4**, and
- Made more precise estimates of costs associated with Significant Catalytic Reduction (SCR) operations, solid waste disposal, costs of overhauls, and capacity degradation rates.

Purpose

As part of the Integrated Energy Policy Report proceeding, the California Energy Commission staff developed cost estimates for central-station electricity generation technologies. These estimates are intended to provide a general guideline on the expected costs of different technologies for policy makers and the public, and to assist resource planners in screening generation options.

Technology Costs

Table 1 shows the results of the cost analyses for various technologies. Expected levelized costs, constant annual payments made over the life of the plants, are shown to provide a common basis of measurement. By convention, *levelized costs are given in constant, or real, dollars* and use 2002 as the base year. To the extent possible, this evaluation relies on general economic and electricity system assumptions. Details about assumptions specific to each technology are included in the individual technology characterizations in the attached appendices. These costs are for generalized project descriptions and costs for actual projects will vary from those shown below, depending on a number of possible site-specific considerations. This information should be used only as general estimates of ownership costs for different technologies. They are not intended to be the sole criterion used in an investment decision, which necessarily involves an evaluation of many other factors.

Estimates of levelized costs are provided for power plants that use natural gas as an energy source and for plants that use renewable energy sources. The costs for these technologies are listed below in **Table 1**. Gas-fired plant costs are derived from Energy Commission staff analyses. The expected levelized cost for a generic new baseload combined cycle plant is hydroelectric, will depend greatly on the project life assumed. If an economic lifetime is assumed to be 50 years, the levelized cost estimate for hydroelectric generation would fall precipitously. This greater economic lifetime would allow the relatively large capital cost to spread over a greater number of years, decreasing its contribution to the levelized cost calculation. The figures in **Table 1** would then overestimate the levelized cost of a hydroelectric project with an economic lifetime of more than 30 years.

Technological advancement plays an important role in determining the actual life of a project. For a mature technology, such as with hydroelectric facilities, generation efficiency has not significantly changed over time. As a result, a project built in 2003 may not be much more efficient than one built in 1983. The same cannot be said for an emerging technology, such as solar thermal generation. In this case, technology can change rapidly and at an unpredictable pace. State-of-the-art products may quickly become obsolete. In these cases, technological advances might induce developers to abandon the projects far short of the hypothesized 20-or 30-year economic lives. Of course, re-computing book lives over shorter time horizons will cause a project's instant costs to be allocated over a smaller number of years, increasing its levelized cost. Projects that exceed their expected economic lifetimes will reduce the levelized costs.

Applicability of Levelized Costs

Different generation operational modes will range from baseload, to intermediate, to a peaking type of facility. A baseload facility generally delivers power at a constant rate whenever the plant is available. A facility may also be used to provide spinning reserve to deliver power during intermittent emergencies on extremely short notice. In between these modes of operation are intermediate/load-following facilities, where a plant follows the daily cycles in load. A peaking facility is called upon only during the highest daily loads during the seasonal peaks. Some facilities may provide ancillary services, where a plant provides system support, such as voltage regulation. An intermittent/variable facility may deliver power whenever the driving resource, such as wind, is available.

Comparing technologies on levelized cost alone is not appropriate, considering that different technologies provide different services. For example, wind is very competitive on the basis of cost per kWh, but it can only provide variable output. Other renewable resources, such as geothermal, have much more predictable output that may be more valuable, although improvements have been made in wind resource predictability as reflected in recent changes in ISO tariffs.

While particular generation technologies may have higher or lower costs than others, ratepayers may not see them unless the power purchase contracts specify that prices are based directly on costs. Power may be sold under a range of contractual and market transaction terms that may have no relationship to the actual cost of producing power from a specific plant. In fact, power contracts terms can be set entirely independently of the type of technology producing the power.

and, as a result, has a higher risk of not being fully repaid compared to debt financing. For purposes of cost comparisons, the assumption is made that these investments are recovered on a relatively constant annual basis without regard to the amount of generation output. This annual expenditure is then divided over the annual generation to derive the average cost per kWh for the investment or "capital" component.

For capital costs, common assumptions are used for debt financing such as interest rates, term and other requirements, and for expected investment return rates for equity financing. These assumptions are shown in **Table 2.** The debt interest rate assumptions are based on November, 2001 values when the market was stable. These assumptions cover three types of potential owners—merchant developers, investor-owned utilities, and municipal utilities and non-profit cooperatives. Capital costs specific to each technology are included in **Appendices C** through **S.**

Table 2
Assumptions for Equity Return and Debt Interest Rates

Type of Owner	Return on Equity	Debt by Term (November, 2001)[1]					
		1	5	10	12	20	30
Merchant	16.0%	7.4%	7.4%	7.4%	7.4%	7.8%	8.0%
IOU	10.6%	6.3%	6.3%	6.3%	6.3%	7.1%	7.4%
Muni/Coop	NA	3.9%	3.9%	3.9%	3.9%	4.7%	4.8%

The second category is the annual operations and maintenance (O&M) costs that are relatively invariant with the amount of output, but would cease if plant operations ended. Operational costs include labor and management, insurance and other services, and certain types of consumables. Maintenance costs include scheduled overhauls and periodic upkeep. Unscheduled or "forced" outages that are a function of usage fall into the final category of costs described below. As with capital costs, these costs are summed and divided over the annual generation output to arrive at the average cost per kWh. However, unlike capital costs that are relatively insensitive to operational mode, the mode of operation can greatly affect these types of costs. For example, intervals between overhauls may be extended if a plant shifts from intermediate to peaking operations. Less labor may be required for a plant that operates only during the seasonal peak period rather than in baseload. In addition, these costs typically escalate over time, compared to capital costs which are considered constant and fixed once the initial investment is made. Nevertheless, once the mode of operation is determined, the annual O&M costs will vary little and are highly predictable over time.

The third category is the variable costs that are derived from fuel consumption, maintenance expenditures for forced outages, and other input costs driven directly by hourly plant operations. For a natural gas-fired plant, the largest component of these costs is the

---

[1] Staff finds that the market and debt interest rates during 2001 were stable compared to current conditions.

Table 3
Federal and State Tax Programs

	Merchant	IOU	Muni/Coop
Combustion Turbine			
Federal Depreciation	MACRS[3] 20 years	MACRS 20 years	N/A
CA Depreciation	Plant Life	Plant Life	
Investment Tax Credit	No	No	No
Renewable Prod. Credit	No	No	No
Wind			
Federal Depreciation	MACRS 5 year	MACRS 5 year	N/A
CA Depreciation	Plant Life	Plant Life	N/A
Investment Tax Credit	No	No	N/A
Renewable Prod. Credit	Yes	No	Tier I
Solar			
Federal Depreciation	MACRS 5 year	MACRS 5 year	N/A
CA Depreciation	Plant Life	Plant Life	N/A
Investment Tax Credit	Yes	Yes	N/A
Renewable Prod. Credit	No	No	Tier I
Geothermal			
Federal Depreciation	MACRS 5 year	MACRS 5 year	N/A
CA Depreciation	Plant Life	Plant Life	N/A
Investment Tax Credit	Yes	Yes	N/A
Renewable Production Credit	No	No	Tier I

[3] Modified Accelerated Cost Recovery System.

plant are a function of all the fixed and varying annual costs (e.g., financing, operations and maintenance, and fuel).

Capital costs for construction are a function of debt and equity financing terms. Debt financing is typically structured with a fixed term and interest rate, and periodic repayments. Equity financing is usually a residual return from revenues after all other costs, including debt repayment, have been covered. In this analysis, debt financing costs were based on the expected terms for a merchant-financed project with a 12-year loan and a BBB debt rating in November 2001. These terms may have changed significantly, and the industry certainly faces a much wider range of terms than it did at that time. Expected equity returns are typically between 12 and 16 percent. In this analysis, the equity target was set at twice the debt rate. In addition, other significant costs are incurred for arranging project financing. These costs range from 1.5 to 12 percent of total project investment, depending on the size of the project and the deemed creditworthiness of the project developer. This factor was set at zero percent for this analysis because no appropriate level could be chosen without project-specific details.

A second set of costs which vary by project are regional and site specific permitting and infrastructure costs. These cost differences have been documented in a report prepared by Aspen Environmental Group for the Commission in December 2002 "Regional Cost Differences Siting New Power Generation in California Report." The cost of acquiring air quality permits and offsets, and water supply sources vary substantially depending on what region the plant is located. For example, emission offset costs for a 500 MW combined cycle plant can vary from less than $5 million to over $20 million. Water supply costs can vary from less than $200 per acre-foot to over $600. The costs for gas-fired power plants are presented for specific regions to reflect these differences. However, even these cost estimates may not accurately reflect the specific circumstances for any one project. Installation of pipelines, substations and transmission lines are a function of proximity to utility interconnections, and cannot be easily generalized. In addition, general permitting process costs vary substantially depending on project specifics and jurisdiction. For this reason, these costs are not included in this analysis.

The levelized costs shown in this report are for "greenfield" projects, so they do not include any demolition costs, nor do they reflect any benefits from previously existing infrastructure. The use of levelized costs over a 20 to 40 year time horizon largely mitigates the effects from any short-run price deviations. While prices may achieve short-run spikes for various reasons, including war or other tragedies, those prices may also plunge due to an over-supply. The forecast is intended to reflect an average of the expected range of conditions over time rather than to trace patterns.

On the other hand, projects may provide benefits to the generation portfolio by hedging risks associated with fuel-price or energy-availability volatility. Such benefits can be provided by projects that can deliver power at a consistent rate on demand from energy sources where costs are not correlated with fossil fuel prices. The magnitude of the benefits is a function of:

Table 5
Levelized Costs for Emerging Technologies

Technology	Energy Source Fuel	Operating Mode	Economic Lifetime (years)	Gross Capacity (MW)	Direct Cost Levelized (cents/kWh)
Solar Thermal-Stirling Dish	Sun; Resource Limited	Load-Following	30	31.5	15.37
Photovoltaic	Sun; Resource Limited	Load-Following	30	50	42.72
Phosphoric Acid	Natural Gas	Baseload	20	25	21.27
Molten Carbonate	Natural Gas	Baseload	20	25	10.15
Solid Oxide	Natural Gas	Baseload	20	25	13.04
Hybrid	Natural Gas	Baseload	20	25	9.41

NA not stand alone

Appendix B
Financial Information

Table B-1
Financial Parameters

Category	Capital Structure	Capital Cost
Equity	39.1%	16.0%
Preferred Equity	0.0%	0.0%
Debt	60.9%	7.4%
Discount Rate/Net Capital Cost	10.8%	
Debt Limit	100.0%	
Inflation Rate	2.0%	
Debt Coverage Ratio - Minimum	1.5	
Debt Coverage Ratio - Average	1.8	
Loan/Debt Term (years)	12.0	

Table C-5
Fuel Use

Heat Rate (MMBtu/kWh)	7,100
Fuel Consumption (MMBtu/Hr)	3,550
Start up fuel use (MMBtu/start)	1,850
No. of annual starts	50
Annual Fuel Use (MMBtu)	28,577,700

Table C-6
Operational Information

Availability/Year (%)	100.0
Availability/Year (Hours)	8,760
Equipment Life (Hours)	148,394
Equipment Life (Years)	18
Overhaul Interval (Hours)	14,839
Maintenance Outage (Days)	28
Maintenance Outage Rate (%)	3.8
Forced Outage (Hours/Year)	400
Forced Outage Rate (%)	4.6
Hours per Year Operation	8,024
Capacity Factor (%)	91.6
Annual Net Energy (GWh)	4,012

Table C-7
Renewable Tax Benefits

Investment Tax Credit (%)	0
RETC Calculation ($/kWh)	0
Production Incentive-Investor (¢/kWh)	0
Geothermal Depletion Allowance	0
RE Production Incentive Tier I	0
RE Production Incentive Tier II	0
REPI Tier II Proportion Paid (%)	10

Table C-8
Operation & Maintenance Costs

Employee Category	Full Time Employees	Hours/Year	Compensation per Employee
Managers	4	1,800	$77,031 per year
Plant Operators	12	2,200	$17 per hour
Mechanics	2	2,300	$18 per hour
Laborers	2	2,200	$12 per hour
Support Staff	3	2,000	$13 per hour

Table C-11
Capital Cost Detail

Total ($)	**270,896,567**
Component Cost ($)	**239,289,126**
Turbine/Engine [Not itemized] ($)	234,597,182
Generator/Gearhead ($)	
Boiler/HRSG ($)	
Fuel Pipeline/Tank ($)	
Slab & Engine Mount ($)	
Miscellaneous fitting & hoses ($)	4,691,944
Office space ($)	
Control Room($)	
Financial Transaction Costs (%)	**0**
Land Costs ($)	**1,477,941**
Acreage/Plant	15
Cost per Acre ($)	100,000
Acquisition Cost ($)	1,470,588
Land Prep Costs ($/Acre)	500
Total Land Prep Costs ($)	7,353
Permitting Costs ($)	**5,129,500**
Local building permits ($)	
Environmental permits ($)	
Air Emission Permits ($)	5,129,500
Interconnection Costs ($)	**0**
Transmission Lines ($)	
Substation ($)	
Induction Equipment ($)	
Environmental Controls ($)	**25,000,000**
Installation Costs ($)	25,000,000
Replacement Costs ($)	

Table C-13
Environmental Control Costs

Total Annual Costs ($)	**$2,721,205**
Media & Technology	**Cost**
Air Emissions	
Control Technology (e.g. SCR) ($)	$15,000,000
Installation Cost ($/kW)	$30
Annual Labor (Hours/Year)	100
Loaded Labor Rate ($/Hour)	$28
Labor Cost ($)	$2,800
Annual Consumables-Catalyst ($)	$333,333
Replacement Cost ($/kW)	$20
Component Life (Hours)	141,760
Annualized Cost ($)	$1,028,436
Water Cooling	
Control Technology (e.g. wastewater) ($)	$10,000,000
Installation Cost ($/kW)	$20
Annual Labor (Hours/Year)	1000
Loaded Labor Rate ($/Hour)	$28
Labor Cost ($)	$28,000
Annual Consumables ($)	$300,000
Replacement Cost ($/kW)	$20
Component Life (Hours)	141,760
Annualized Cost ($)	$1,028,436
Solid Waste Disposal	
Non hazardous material	
Tons per Year	1
Collection and hauling ($/Ton)	$10
Landfill tipping fees ($/Ton)	$30
Total Costs ($)	$40
Hazardous materials	
Tons per Year	1
Collection and hauling ($/Ton)	$60
Landfill tipping fees ($/Ton)	$100
Total Disposal Costs ($)	$160

Table D-5
Fuel Use

Heat Rate (MMBtu/kWh)	9,300
Fuel Consumption (MMBtu/Hr)	930
Start up fuel use (MMBtu/start)	180
No. of annual starts	120
Annual Fuel Use (MMBtu)	785,682

Table D-6
Operational Information

Availability/Year (%)	10
Availability/Year (Hours)	876
Equipment Life (Hours)	148,394
Equipment Life (Years)	30
Overhaul Interval (Hours)	876
Maintenance Outage (Days)	4
Maintenance Outage Rate (%)	1.2
Forced Outage (Hours/Year)	44
Forced Outage Rate (%)	0.5
Hours per Year Operation	822
Capacity Factor (%)	9.4
Annual Net Energy (GWh)	82

Table D-7
Renewable Tax Benefits

Investment Tax Credit (%)	0
RETC Calculation ($/kWh)	0
Production Incentive-Investor (¢/kWh)	0
Geothermal Depletion Allowance	0
RE Production Incentive Tier I	0
RE Production Incentive Tier II	0
REPI Tier II Proportion Paid (%)	10

Table D-8
Operations & Maintenance Costs (Employees)

Employee Category	Full Time Employees	Hours/Year	Compensation per Employee
Managers	1	1,800	$90,000 per year
Plant Operators	4	1,800	$17 per hour
Mechanics	1	1,800	$18 per hour
Laborers	1	1,800	$12 per hour
Support Staff	1	1,800	$13 per hour

Table D-11
Capital Cost Detail

Total ($)	**41,715,152**
Component Cost ($)	**31,620,000**
Turbine/Engine [Not itemized] ($)	31,000,000
Generator/Gearhead ($)	
Boiler/HRSG ($)	
Fuel Pipeline/Tank ($)	
Slab & Engine Mount ($)	
Miscellaneous fitting & hoses ($)	620,000
Office space ($)	
Control Room($)	
Financial Transaction Costs (%)	**0**
Land Costs ($)	**5,007,353**
Acreage/Plant	50
Cost per Acre ($)	100,000
Acquisition Cost ($)	5,000,000
Land Prep Costs ($/Acre)	500
Total Land Prep Costs ($)	7,353
Permitting Costs ($)	**87,799**
Local building permits ($)	
Environmental permits ($)	
Air Emission Permits ($)	87,799
Interconnection Costs ($)	**0**
Transmission Lines ($)	
Substation ($)	
Induction Equipment ($)	
Environmental Controls ($)	**5,000,000**
Installation Costs ($)	5,000,000
Replacement Costs ($)	

Table D-13
Environmental Control Costs

Total Annual Costs ($)	**440,506**
Media & Technology	**Cost**
Air Emissions	
Control Technology (e.g. SCR) ($)	
Installation Cost ($/kW)	30
Annual Labor (Hours/Year)	100
Loaded Labor Rate ($/Hour)	28
Labor Cost ($)	2,800
Annual Consumables-Catalyst ($)	33,333
Replacement Cost ($/kW)	20
Component Life (Hours)	141,760
Annualized Cost ($)	169,286
Water Cooling	
Control Technology (e.g. wastewater) ($)	200,000
Installation Cost ($/kW)	20
Annual Labor (Hours/Year)	200
Loaded Labor Rate ($/Hour)	28
Labor Cost ($)	5,600
Annual Consumables ($)	60,000
Replacement Cost ($/kW)	20
Component Life (Hours)	141,760
Annualized Cost ($)	
Solid Waste Disposal	
Non hazardous material	
Tons per Year	1
Collection and hauling ($/Ton)	10
Landfill tipping fees ($/Ton)	30
Total Costs ($)	40
Hazardous materials	
Tons per Year	1
Collection and hauling ($/Ton)	60
Landfill tipping fees ($/Ton)	100
Total Disposal Costs ($)	160

Table E-5
Fuel Use

Heat Rate (MMBtu/kWh)	5,700.0
Fuel Consumption (MMBtu/Hr)	142.5
Start up fuel use (MMBtu/start)	0.0
No. of annual starts	0.0
Annual Fuel Use (MMBtu)	1,123,470.0

Table E-6
Operational Information

Availability/Year (%)	100
Availability/Year (Hours)	8,760
Equipment Life (Hours)	222,592
Equipment Life (Years)	28
Overhaul Interval (Hours)	7,884
Maintenance Outage (Days)	18
Maintenance Outage Rate (%)	5
Forced Outage (Hours/Year)	438
Forced Outage Rate (%)	5
Hours per Year Operation	7,884
Capacity Factor (%)	90
Annual Net Energy (GWh)	197

Table E-7
Renewable Tax Benefits

Investment Tax Credit (%)	0
RETC Calculation ($/kWh)	0
Production Incentive-Investor (¢/kWh)	0
Geothermal Depletion Allowance	0
RE Production Incentive Tier I	0
RE Production Incentive Tier II	0
REPI Tier II Proportion Paid (%)	10

Table E-8
Maintenance & Operations Costs (Employees)

Employee Category	Full Time Employees	Hours/Year	Compensation per Employee
Managers	1	1,800	$120,000 per year
Plant Operators	4	1,800	$30 per hour
Mechanics	0	1,800	$30 per hour
Laborers	2.5	1,800	$20 per hour
Support Staff	0	1,800	$20 per hour

Table E-11
Capital Cost Detail

Total ($)	**29,096,786**
Component Cost ($)	**28,850,000**
SOFC Generator Equipment ($)	8,350,000
SOFC Power Conditioning Equipment ($)	3,675,000
Gas Turbine Generator Equipment ($)	5,000,000
Balance of Plant Equipment ($)	4,450,000
Site Preparation ($)	425,000
Project Management and Engineering ($)	925,000
Overhead and Profit Allowance ($)	6,025,000
Financial Transaction Costs (%)	**0**
Land Costs ($)	**246,786**
Sq Ft/MW	4,300
Acreage/Plant	2.47
Cost per Acre ($)	100,000
Acquisition Cost ($)	246,786
Land Prep Costs ($/Acre)	0
Total Land Prep Costs ($)	0
Permitting Costs [not separate] ($)	**0**
Local building permits ($)	
Environmental permits ($)	
Interconnection Costs ($)	**0**
Transmission Lines ($)	
Substation ($)	
Induction Equipment ($)	

Table E-13
Environmental Control Costs

Total Annual Costs ($)	0
Media & Technology	**Cost**
Air Emissions	
Control Technology (e.g. SCR) ($)	
Installation Cost ($/kW)	0
Annual Labor (Hours/Year)	0
Loaded Labor Rate ($/Hour)	48
Labor Cost ($)	0
Annual Consumables-Catalyst ($)	0
Replacement Cost ($/kW)	0
Component Life (Hours)	141,760
Annualized Cost ($)	
Water Cooling	
Control Technology (e.g. wastewater) ($)	
Installation Cost ($/kW)	0
Annual Labor (Hours/Year)	0
Loaded Labor Rate ($/Hour)	48
Labor Cost ($)	0
Annual Consumables ($)	0
Replacement Cost ($/kW)	0
Component Life (Hours)	141,760
Annualized Cost ($)	
Solid Waste Disposal	
Non hazardous material	
Tons per Year	0
Collection and hauling ($/Ton)	10
Landfill tipping fees ($/Ton)	30
Total Costs ($)	0
Hazardous materials	
Tons per Year	0
Collection and hauling ($/Ton)	10
Landfill tipping fees ($/Ton)	30
Total Disposal Costs ($)	0

Table F-5
Fuel Use

Heat Rate (MMBtu/kWh)	7,511.0
Fuel Consumption (MMBtu/Hr)	187.8
Start up fuel use (MMBtu/start)	0.0
No. of annual starts	0.0
Annual Fuel Use (MMBtu)	1,480,418.0

Table F-6
Operational Information

Availability/Year (%)	100
Availability/Year (Hours)	8,760
Equipment Life (Hours)	222,592
Equipment Life (Years)	28
Overhaul Interval (Hours)	7,884
Maintenance Outage (Days)	18
Maintenance Outage Rate (%)	5
Forced Outage (Hours/Year)	438
Forced Outage Rate (%)	5
Hours per Year Operation	7,884
Capacity Factor (%)	90
Annual Net Energy (GWh)	197

Table F-7
Renewable Tax Benefits

Investment Tax Credit (%)	0
RETC Calculation ($/kWh)	0
Production Incentive-Investor (¢/kWh)	0
Geothermal Depletion Allowance	0
RE Production Incentive Tier I	0
RE Production Incentive Tier II	0
REPI Tier II Proportion Paid (%)	10

Table F-8
Operation & Maintenance Costs

Employee Category	Full Time Employees	Hours/Year	Compensation per Employee
Managers	0	1,800	$80,000 per year
Plant Operators	0	1,800	$30 per hour
Mechanics	0	1,800	$30 per hour
Laborers	0	1,800	$20 per hour
Support Staff	0	1,800	$20 per hour

Table F-11
Capital Cost Detail

Total ($)	**37,718,090**
Component Cost ($)	**37,500,000**
[Not itemized-"All In" cost] ($)	37,500,000
Office space	
Control Room	
Other infrastructure	
Financial Transaction Costs (%)	**0**
Land Costs ($)	**218,090**
Sq Ft/MW	3,800
Acreage/Plant	2.18
Cost per Acre ($)	100,000
Acquisition Cost ($)	218,090
Land Prep Costs ($/Acre)	0
Total Land Prep Costs ($)	0
Permitting Costs [not separate] ($)	**0**
Local building permits	
Environmental permits	
Interconnection Costs ($)	**0**
Transmission Lines	
Substation	
Induction Equipment	

Table F-13
Environmental Control Costs

Total Annual Costs ($)	0
Media & Technology	**Cost**
Air Emissions	
Control Technology (e.g. SCR) ($)	
Installation Cost ($/kW)	0
Annual Labor (Hours/Year)	0
Loaded Labor Rate ($/Hour)	48
Labor Cost ($)	0
Annual Consumables-Catalyst ($)	0
Replacement Cost ($/kW)	0
Component Life (Hours)	141,760
Annualized Cost ($)	
Water Cooling	
Control Technology (e.g. wastewater) ($)	
Installation Cost ($/kW)	0
Annual Labor (Hours/Year)	0
Loaded Labor Rate ($/Hour)	48
Labor Cost ($)	0
Annual Consumables ($)	0
Replacement Cost ($/kW)	0
Component Life (Hours)	141,760
Annualized Cost ($)	
Solid Waste Disposal	
Non hazardous material	
Tons per Year	0
Collection and hauling ($/Ton)	10
Landfill tipping fees ($/Ton)	30
Total Costs ($)	0
Hazardous materials	
Tons per Year	0
Collection and hauling ($/Ton)	10
Landfill tipping fees ($/Ton)	30
Total Disposal Costs ($)	0

Table G-5
Fuel Use

Heat Rate (MMBtu/kWh)	9,389.0
Fuel Consumption (MMBtu/Hr)	234.7
Start up fuel use (MMBtu/start)	0.0
No. of annual starts	0.0
Annual Fuel Use (MMBtu)	1,850,572.0

Table G-6
Operational Information

Availability/Year (%)	100
Availability/Year (Hours)	8,760
Equipment Life (Hours)	222,592
Equipment Life (Years)	28
Overhaul Interval (Hours)	7,884
Maintenance Outage (Days)	18
Maintenance Outage Rate (%)	5
Forced Outage (Hours/Year)	438
Forced Outage Rate (%)	5
Hours per Year Operation	7,884
Capacity Factor (%)	90
Annual Net Energy (GWh)	197

Table G-7
Renewable Tax Benefits

Investment Tax Credit (%)	0
RETC Calculation ($/kWh)	0
Production Incentive-Investor (¢/kWh)	0
Geothermal Depletion Allowance	0
RE Production Incentive Tier I	0
RE Production Incentive Tier II	0
REPI Tier II Proportion Paid (%)	10

Table G-8
Operations & Maintenance Costs (Employee)

Employees	Full Time Employees	Hours/Year	Compensation per Employee
Managers	0	1,800	$80,000 per year
Plant Operators	0	1,800	$30 per hour
Mechanics	0	1,800	$30 per hour
Laborers	0	1,800	$20 per hour
Support Staff	0	1,800	$20 per hour

Table G-11
Capital Cost Detail

Total ($)	**113,005,051**
Component Cost ($)	**112,500,000**
[Not itemized="All In" cost] ($)	112,500,000
Office space	
Control Room	
Other infrastructure	
Financial Transaction Costs (%)	**0**
Land Costs ($)	**505,051**
Sq Ft/MW	8,800
Acreage/Plant	5.05
Cost per Acre ($)	100,000
Acquisition Cost ($)	505,051
Land Prep Costs ($/Acre)	0
Total Land Prep Costs ($)	0
Permitting Costs [not separate] ($)	**0**
Local building permits	
Environmental permits	
Interconnection Costs ($)	**0**
Transmission Lines	
Substation	
Induction Equipment	

Table G-13
Environmental Control Costs

Total Annual Costs ($)	**0**
Media & Technology	**Cost**
Air Emissions	
Control Technology (e.g. SCR) ($)	
Installation Cost ($/kW)	0
Annual Labor (Hours/Year)	0
Loaded Labor Rate ($/Hour)	48
Labor Cost ($)	0
Annual Consumables-Catalyst ($)	0
Replacement Cost ($/kW)	0
Component Life (Hours)	141,760
Annualized Cost ($)	
Water Cooling	
Control Technology (e.g. wastewater) ($)	
Installation Cost ($/kW)	0
Annual Labor (Hours/Year)	0
Loaded Labor Rate ($/Hour)	48
Labor Cost ($)	0
Annual Consumables ($)	0
Replacement Cost ($/kW)	0
Component Life (Hours)	141,760
Annualized Cost ($)	
Solid Waste Disposal	
Non hazardous material	
Tons per Year	0
Collection and hauling ($/Ton)	10
Landfill tipping fees ($/Ton)	30
Total Costs ($)	0
Hazardous materials	
Tons per Year	0
Collection and hauling ($/Ton)	10
Landfill tipping fees ($/Ton)	30
Total Disposal Costs ($)	0

Table H-5
Fuel Use

Heat Rate (MMBtu/kWh)	9,389.0
Fuel Consumption (MMBtu/Hr)	234.7
Start up fuel use (MMBtu/start)	0.0
No. of annual starts	0.0
Annual Fuel Use (MMBtu)	1,850,572.0

Table H-6
Operational Information

Availability/Year (%)	100
Availability/Year (Hours)	8,760
Equipment Life (Hours)	222,592
Equipment Life (Years)	28
Overhaul Interval (Hours)	7,884
Maintenance Outage (Days)	18
Maintenance Outage Rate (%)	5
Forced Outage (Hours/Year)	438
Forced Outage Rate (%)	5
Hours per Year Operation	7,884
Capacity Factor (%)	90
Annual Net Energy (GWh)	197

Table H-7
Renewable Tax Benefits

Investment Tax Credit (%)	0
RETC Calculation ($/kWh)	0
Production Incentive-Investor (¢/kWh)	0
Geothermal Depletion Allowance	0
RE Production Incentive Tier I	0
RE Production Incentive Tier II	0
REPI Tier II Proportion Paid (%)	10

Table H-8
Operation & Maintenance Costs (Employee)

Employees	Full Time Employees	Hours/Year	Compensation per Employee
Managers	0	1,800	$80,000 per year
Plant Operators	0	1,800	$30 per hour
Mechanics	0	1,800	$30 per hour
Laborers	0	1,800	$20 per hour
Support Staff	0	1,800	$20 per hour

Table H-11
Capital Cost Detail

Total ($)	**37,781,221**
Component Cost ($)	**37,500,000**
[Not Itemized – "All In" cost]	37,500,000
Office space	
Control Room	
Other Infrastructure	
Financial Transaction Costs (%)	**0**
Land Costs ($)	**281,221**
Sq Ft/MW	4,900
Acreage/Plant	2.81
Cost per Acre ($)	100,000
Acquisition Cost ($)	281,221
Land Prep Costs ($/Acre)	0
Total Land Prep Costs ($)	0
Permitting Costs [not separate ($)	**0**
Local building permits ($)	
Environmental permits ($)	
Interconnection Costs ($)	**0**
Transmission Lines ($)	
Substation ($)	
Induction Equipment ($)	

Table H-13
Environmental Control Costs

Total Annual Costs ($)	**0**
Media & Technology	**Cost**
Air Emissions	
Control Technology (e.g. SCR) ($)	
Installation Cost ($/kW)	0
Annual Labor (Hours/Year)	0
Loaded Labor Rate ($/Hour)	48
Labor Cost ($)	0
Annual Consumables-Catalyst ($)	0
Replacement Cost ($/kW)	0
Component Life (Hours)	141,760
Annualized Cost ($)	
Water Cooling	
Control Technology (e.g. wastewater) ($)	
Installation Cost ($/kW)	0
Annual Labor (Hours/Year)	0
Loaded Labor Rate ($/Hour)	48
Labor Cost ($)	0
Annual Consumables ($)	0
Replacement Cost ($/kW)	0
Component Life (Hours)	141,760
Annualized Cost ($)	
Solid Waste Disposal	
Non hazardous material	
Tons per Year	0
Collection and hauling ($/Ton)	10
Landfill tipping fees ($/Ton)	30
Total Costs ($)	0
Hazardous materials	
Tons per Year	0
Collection and hauling ($/Ton)	10
Landfill tipping fees ($/Ton)	30
Total Disposal Costs ($)	0

Table I-5
Fuel Use

Heat Rate (MMBtu/kWh)	8,345.0
Fuel Consumption (MMBtu/Hr)	208.6
Start up fuel use (MMBtu/start)	0.0
No. of annual starts	0.0
Annual Fuel Use (MMBtu)	1,644,800.0

Table I-6
Operational Information

Availability/Year (%)	100
Availability/Year (Hours)	8,760
Equipment Life (Hours)	222,592
Equipment Life (Years)	28
Overhaul Interval (Hours)	7,884
Maintenance Outage (Days)	18
Maintenance Outage Rate (%)	5
Forced Outage (Hours/Year)	438
Forced Outage Rate (%)	5
Hours per Year Operation	7,884
Capacity Factor (%)	90
Annual Net Energy (GWh)	197

Table I-7
Renewable Tax Benefits

Investment Tax Credit (%)	0
RETC Calculation ($/kWh)	0
Production Incentive-Investor (¢/kWh)	0
Geothermal Depletion Allowance	0
RE Production Incentive Tier I	0
RE Production Incentive Tier II	0
REPI Tier II Proportion Paid (%)	10

Table I-8
Operation & Maintenance Costs

Employees	Full Time Employees	Hours/Year	Compensation per Employee
Managers	1	1,800	$120,000 per year
Plant Operators	4	1,800	$30 per hour
Mechanics	0	1,800	$30 per hour
Laborers	2.5	1,800	$20 per hour
Support Staff	0	1,800	$20 per hour

Table I-11
Capital Cost Detail

Total ($)	**39,423,440**
Component Cost ($)	
Turbine/Engine [Not itemized] ($)	**39,142,219**
Generator/Gearhead ($)	
Boiler/HRSG ($)	13,658,609
Fuel Pipeline/Tank ($)	13,658,609
Slab & Engine Mount ($)	
Miscellaneous fitting & hoses ($)	4,450,000
Office space ($)	425,000
Control Room($)	925,000
Duct Burners ($)	6,025,000
Financial Transaction Costs (%)	
Land Costs ($)	0
Acreage/Plant	**281,221**
Cost per Acre ($)	4,900
Acquisition Cost ($)	2.81
Land Prep Costs ($/Acre)	100,000
Total Land Prep Costs ($)	281,221
Permitting Costs ($)	0
Local building permits ($)	0
Environmental permits ($)	0
Air Emission Permits ($)	**0**
Interconnection Costs ($)	0
Transmission Lines ($)	0
Substation ($)	
Induction Equipment ($)	
Environmental Controls ($)	0
Installation Costs ($)	0
Replacement Costs ($)	0

Table I-13
Environmental Control Costs

Total Annual Costs ($)	**0**
Media & Technology	**Cost**
Air Emissions	
Control Technology (e.g. SCR) ($)	
Installation Cost ($/kW)	0
Annual Labor (Hours/Year)	0
Loaded Labor Rate ($/Hour)	48
Labor Cost ($)	0
Annual Consumables-Catalyst ($)	0
Replacement Cost ($/kW)	0
Component Life (Hours)	141,760
Annualized Cost ($)	
Water Cooling	
Control Technology (e.g. wastewater) ($)	
Installation Cost ($/kW)	0
Annual Labor (Hours/Year)	0
Loaded Labor Rate ($/Hour)	48
Labor Cost ($)	0
Annual Consumables ($)	0
Replacement Cost ($/kW)	0
Component Life (Hours)	141,760
Annualized Cost ($)	
Solid Waste Disposal	
Non hazardous material	
Tons per Year	0
Collection and hauling ($/Ton)	10
Landfill tipping fees ($/Ton)	30
Total Costs ($)	0
Hazardous materials	
Tons per Year	0
Collection and hauling ($/Ton)	10
Landfill tipping fees ($/Ton)	30
Total Disposal Costs ($)	0

Table J-5
Fuel Use

Heat Rate (MMBtu/kWh)	N/A
Fuel Consumption (MMBtu/hour)	0.0
Start up fuel use (MMBtu/start)	0.0
Make-up water (Gallons)	250,000.0

Table J-6
Operational Information

Availability/Year (%)	99
Availability/Year (Hours)	8,672
Equipment Life (Hours)	260,000
Equipment Life (Years)	30
Overhaul Interval (Hours)	45,000
Maintenance Outage (Days)	5
Maintenance Outage Rate (%)	0.3
Forced Outage (Hours/Year)	24
Forced Outage Rate (%)	0.3
Hours per Year Operation	8,624
Capacity Factor (%)	98.5
Annual Net Energy (GWh)	216

Table J-7
Renewable Tax Benefits

Investment Tax Credit (%)	10
RETC Calculation ($/kWh)	384
Production Incentive-Investor (¢/kWh)	0
Geothermal Depletion Allowance	Yes
RE Production Incentive Tier I	0
RE Production Incentive Tier II	0
REPI Tier II Proportion Paid (%)	10

Table J-8
Operation & Maintenance Costs (Employees)

Employee Category	Full Time Employees	Hours/Year	Compensation per Employee
Managers	1	1,800	$80,000 per year
Plant Operators	8	1,800	$30 per hour
Mechanics	1	1,800	$30 per hour
Laborers	2	1,800	$20 per hour
Support Staff	0	1,800	$20 per hour

Table J-11
Capital Cost Detail

Total ($)	**80,255,463**
Component Cost ($)	**79,700,000**
Exploration Costs ($)	3,000,000
Wellfield Development ($)	34,700,000
Plant Equipment ($)	42,000,000
Financial Transaction Costs (%)	0
Land Costs ($)	**555,463**
Occupied Acreage	40
Total Project Area (Acres)	12000
BLM Pre-Development Lease Fee	44
Total Land "Cost Burden"	531,463
Land Prep Costs ($/Acre)	600
Total Land Prep Costs ($)	24,000
Permitting Costs ($)	**0**
Local building permits ($)	
Environmental permits ($)	
Interconnection Costs ($)	**300,000**
Transmission Lines ($)	
Substation ($)	
Environmental Controls ($)	**0**
Installation Costs ($)	0
Replacement Costs ($)	

Table J-13
Environmental Control Costs

Total Annual Costs ($)	**50,000**
Media & Technology	**Cost**
Air Emissions	
Control Technology (e.g. SCR) ($)	
Installation Cost ($/kW)	0
Annual Labor (Hours/Year)	0
Loaded Labor Rate ($/Hour)	60
Labor Cost ($)	0
Annual Consumables-Catalyst ($)	0
Replacement Cost ($/kW)	0
Component Life (Hours)	0
Annualized Cost ($)	
Water Cooling	
Control Technology (e.g. wastewater) ($)	
Installation Cost ($/kW)	0
Annual Labor (Hours/Year)	0
Loaded Labor Rate ($/Hour)	60
Labor Cost ($)	0
Annual Consumables ($)	0
Replacement Cost ($/kW)	0
Component Life (Hours)	0
Annualized Cost ($)	
Solid Waste Disposal	
Non hazardous material	
Tons per Year	0
Collection and hauling ($/Ton)	30
Landfill tipping fees ($/Ton)	0
Total Costs ($)	0
Hazardous materials	
Tons per Year	10000
Collection and hauling ($/Ton)	0
Landfill tipping fees ($/Ton)	5
Total Disposal Costs ($)	50,000

Table K-5
Fuel Use

Heat Rate	N/A
Fuel Consumption (MMBtu/Hr)	0.0
Start up fuel use (MMBtu/Start)	0.0
Make-up water (Gallons)	12,000.0

Table K-6
Operational Information

Availability/Year (%)	97.2
Availability/Year (Hours)	8,515
Equipment Life (Hours)	260,000
Equipment Life (Years)	30
Overhaul Interval (Hours)	25,000
Maintenance Outage (Days)	7
Maintenance Outage Rate (%)	0.6
Forced Outage (Hours/Year)	50
Forced Outage Rate (%)	0.6
Hours per Year Operation	8,409
Capacity Factor (%)	96.0
Annual Net Energy (GWh)	378

Table K-7
Renewable Tax Benefits

Investment Tax Credit (%)	10
RETC Calculation ($/kWh)	256
Production Incentive-Investor (¢/kWh)	0
Geothermal Depletion Allowance	Yes
RE Production Incentive Tier I	0
RE Production Incentive Tier II	0
REPI Tier II Proportion Paid (%)	10

Table K-8
Operation & Maintenance Costs (Employees)

Employees	Full Time Employees	Hours/Year	Compensation per Employee
Managers	1	1,800	$80,000 per year
Plant Operators	8	1,800	$30 per hour
Mechanics	1	1,800	$30 per hour
Laborers	2	1,800	$20 per hour
Support Staff	0	1,800	$20 per hour

Table K-11
Capital Cost Detail

Total ($)	**95,539,694**
Component Cost ($)	**95,200,000**
Exploration Costs ($)	3,000,000
Wellfield Development ($)	32,200,000
Plant Equipment ($)	60,000,000
Financial Transaction Costs (%)	**0**
Land Costs ($)	**339,694**
Occupied Acreage	40
Total Project Area (Acres)	6000
Lease Fee ($/Acre)	53
Total Land "Cost Burden"	315,694
Land Prep Costs ($/Acre)	600
Total Land Prep Costs ($)	24,000
Permitting Costs ($)	**0**
Local building permits ($)	
Environmental permits ($)	
Interconnection Costs ($)	**300,000**
Transmission Lines ($)	
Substation ($)	
Environmental Controls ($)	**0**
Installation Costs ($)	0
Replacement Costs ($)	

Table K-13
Environmental Control Costs

Total Annual Costs ($)	**174,000**
Media & Technology	**Cost**
Air Emissions	
Control Technology (e.g. SCR) ($)	
Installation Cost ($/kW)	0
Annual Labor (Hours/Year)	0
Loaded Labor Rate ($/Hour)	48
Labor Cost ($)	0
Annual Consumables-Catalyst ($)	0
Replacement Cost ($/kW)	0
Component Life (Hours)	0
Annualized Cost ($)	
Water Cooling	
Control Technology (e.g. wastewater) ($)	
Installation Cost ($/kW)	0
Annual Labor (Hours/Year)	0
Loaded Labor Rate ($/Hour)	48
Labor Cost ($)	0
Annual Consumables ($)	0
Replacement Cost ($/kW)	0
Component Life (Hours)	0
Annualized Cost ($)	
Solid Waste Disposal	
Non hazardous material	
Tons per Year	5800
Collection and hauling ($/Ton)	30
Landfill tipping fees ($/Ton)	0
Total Costs ($)	174,000
Hazardous materials	
Tons per Year	0
Collection and hauling ($/Ton)	0
Landfill tipping fees ($/Ton)	30
Total Disposal Costs ($)	0

Table L-5
Fuel Use

Heat Rate (MMBtu/kWh)	N/A
Fuel Consumption (MMBtu/Hr)	0.0
Start up fuel use (MMBtu/start)	0.0
No. of annual starts	0.0
Annual Fuel Use (MMBtu)	0.0

Table L-6
Operational Information

Availability/Year (%)	42.5
Availability/Year (Hours)	3,723
Equipment Life (Hours)	262,800
Equipment Life (Years)	30
Overhaul Interval (Hours)	8,400
Maintenance Outage (Days)	10
Maintenance Outage Rate (%)	1.4
Forced Outage (Hours/Year)	120
Forced Outage Rate (%)	1.4
Hours per Year Operation	3,483
Capacity Factor (%)	39.8
Annual Net Energy (GWh)	348

Table L-7
Renewable Tax Benefits

Investment Tax Credit (%)	0
RETC Calculation ($/kWh)	0
Production Incentive-Investor (¢/kWh)	0
Geothermal Depletion Allowance	
RE Production Incentive Tier I	0
RE Production Incentive Tier II	0
REPI Tier II Proportion Paid (%)	10

Table L-8
Operation & Maintenance Costs (Employees)

Employees	Full Time Employees	Hours/Year	Compensation per Employee
Managers	3	1,800	$80,000 per year
Plant Operators	3	1,800	$30 per hour
Mechanics	2	1,800	$30 per hour
Laborers	1	1,800	$20 per hour
Support Staff	1	1,800	$20 per hour

Table L-11
Capital Cost Detail

Total ($)	**115,188,000**
Component Cost ($)	**109,000,000**
Turbine/Engine ($)	5,000,000
Generator/Gearhead ($)	6,000,000
Penstock & Surge Tank ($)	30,000,000
Building & Foundation ($)	3,000,000
Miscellaneous fitting & hoses ($)	3,500,000
Office space ($)	
Control Room($)	1,500,000
Dam & Reservoir ($)	60,000,000
Financial Transaction Costs (%)	**0**
Land Costs ($)	**6,188,000**
Acreage/Plant	1,400
Cost per Acre ($)	1,420
Acquisition Cost ($)	1,988,000
Land Prep Costs ($/Acre)	3,000
Total Land Prep Costs ($)	4,200,000
Permitting Costs ($)	**0**
Local building permits ($)	
Environmental permits ($)	
Interconnection Costs ($)	**0**
Transmission Lines ($)	0
Substation ($)	0
Induction Equipment ($)	
Environmental Controls ($)	**0**
Installation Costs ($)	0
Replacement Costs ($)	

Table L-13
Environmental Control Costs

Total Annual Costs ($)	**0**
Media & Technology	**Cost**
Air Emissions	
Control Technology (e.g. SCR) ($)	
Installation Cost ($/kW)	0
Annual Labor (Hours/Year)	0
Loaded Labor Rate ($/Hour)	48
Labor Cost ($)	0
Annual Consumables-Catalyst ($)	0
Replacement Cost ($/kW)	0
Component Life (Hours)	141,760
Annualized Cost ($)	
Water Cooling	
Control Technology (e.g. wastewater) ($)	
Installation Cost ($/kW)	0
Annual Labor (Hours/Year)	0
Loaded Labor Rate ($/Hour)	48
Labor Cost ($)	0
Annual Consumables ($)	0
Replacement Cost ($/kW)	0
Component Life (Hours)	141,760
Annualized Cost ($)	
Solid Waste Disposal	
Non hazardous material	
Tons per Year	0
Collection and hauling ($/Ton)	10
Landfill tipping fees ($/Ton)	30
Total Costs ($)	0
Hazardous materials	
Tons per Year	0
Collection and hauling ($/Ton)	10
Landfill tipping fees ($/Ton)	30
Total Disposal Costs ($)	0

Table M-5
Fuel Use

Heat Rate (MMBtu/kWh)	N/A
Fuel Consumption (MMBtu/Hr)	0.0
Start up fuel use (MMBtu/start)	0.0
No. of annual starts	0.0
Annual Fuel Use (MMBtu)	0.0

Table M-6
Operational Information

Availability/Year (%)	25
Availability/Year (Hours)	2,190
Equipment Life (Hours)	62,580
Equipment Life (Years)	30
Overhaul Interval (Hours)	2,190
Maintenance Outage (Days)	4
Maintenance Outage Rate (%)	1.1
Forced Outage (Hours/Year)	8
Forced Outage Rate (%)	0.1
Hours per Year Operation	2,086
Capacity Factor (%)	23.8
Annual Net Energy (GWh)	104

Table M-7
Renewable Tax Benefits

Investment Tax Credit (%)	10
RETC Calculation ($/kWh)	731
Production Incentive-Investor (¢/kWh)	0
Geothermal Depletion Allowance	
RE Production Incentive Tier I	0
RE Production Incentive Tier II	0
REPI Tier II Proportion Paid (%)	10

Table M-8
Operation & Maintenance Costs (Employees)

Employees	Full Time Employees	Hours/Year	Compensation per Employee
Managers	1	1,800	$80,000 per year
Plant Operators	1	1,800	$30 per hour
Mechanics	2	1,800	$30 per hour
Laborers	2	1,800	$20 per hour
Support Staff	0	1,800	$20 per hour

Table M-11
Capital Cost Detail

Total ($)	**332,630,100**
Component Cost ($)	**330,000,000**
PV Modules ($)	225,000,000
Structures ($)	25,000,000
Inverter ($)	25,000,000
Installation ($)	37,500,000
Engr, Const, Proj Management ($)	17,500,000
Financial Transaction Costs (%)	**0**
Land Costs ($)	**2,630,100**
Acreage/Plant	250
Cost per Acre ($)	3,100
Acquisition Cost ($)	775,000
Land Prep Costs ($/Acre)	7,420
Total Land Prep Costs ($)	1,855,100
Permitting Costs ($)	**0**
Local building permits ($)	
Environmental permits ($)	
Interconnection Costs ($)	**0**
Transmission Lines ($)	
Substation ($)	
Induction Equipment ($)	
Environmental Controls ($)	**0**
Installation Costs ($)	0
Replacement Costs ($)	

Table M-13
Environmental Control Costs

Total Annual Costs ($)	0
Media & Technology	**Cost**
Air Emissions	
Control Technology (e.g. SCR) ($)	
Installation Cost ($/kW)	0
Annual Labor (Hours/Year)	0
Loaded Labor Rate ($/Hour)	48
Labor Cost ($)	0
Annual Consumables-Catalyst ($)	0
Replacement Cost ($/kW)	0
Component Life (Hours)	141,760
Annualized Cost ($)	
Water Cooling	
Control Technology (e.g. wastewater) ($)	
Installation Cost ($/kW)	0
Annual Labor (Hours/Year)	0
Loaded Labor Rate ($/Hour)	48
Labor Cost ($)	0
Annual Consumables ($)	0
Replacement Cost ($/kW)	0
Component Life (Hours)	141,760
Annualized Cost ($)	
Solid Waste Disposal	
Non hazardous material	
Tons per Year	0
Collection and hauling ($/Ton)	10
Landfill tipping fees ($/Ton)	30
Total Costs ($)	0
Hazardous materials	
Tons per Year	0
Collection and hauling ($/Ton)	10
Landfill tipping fees ($/Ton)	30
Total Disposal Costs ($)	0

Table N-5
Fuel Use

Heat Rate (MMBtu/kWh)	N/A
Fuel Consumption (MMBtu/Hr)	0.0
Start up fuel use (MMBtu/start)	0.0
No. of annual starts	346.0
Annual Fuel Use (MMBtu)	0.0

Table N-6
Operational Information

Availability/Year (%)	41.7
Availability/Year (Hours)	3,650
Equipment Life (Hours)	70,000
Equipment Life (Years)	22
Overhaul Interval (Hours)	3,210
Maintenance Outage (Days)	10
Maintenance Outage Rate (%)	2.7
Forced Outage (Hours/Year)	200
Forced Outage Rate (%)	2.3
Hours per Year Operation	3,210
Capacity Factor (%)	22.0
Annual Net Energy (GWh)	193

Table N-7
Renewable Tax Benefits

Investment Tax Credit (%)	10
RETC Calculation ($/kWh)	286
Production Incentive-Investor (¢/kWh)	0
Geothermal Depletion Allowance	
RE Production Incentive Tier I	0
RE Production Incentive Tier II	0
REPI Tier II Proportion Paid (%)	10

Table N-8
Operation & Maintenance Costs (Employees)

Employees	Full Time Employees	Hours/Year	Compensation per Employee
Managers	1	1,800	$80,000 per year
Plant Operators	10	1,800	$30 per hour
Mechanics	6	1,800	$30 per hour
Laborers	3	1,800	$20 per hour
Support Staff	1	1,800	$20 per hour

Table N-11
Capital Cost Detail

Total ($)	259,998,383
Component Cost ($)	**254,212,164**
Structure & Improvements ($)	2,720,813
Collector System ($)	147,795,374
Thermal Storage System	0
Steam Gen or HX System ($)	10,764,670
Aux Heater/Boiler ($)	0
EPGS ($)	47,651,991
Master Control System ($)	0
Balance of Plant ($)	27,706,701
Engr, Const, Proj Management ($)	17,572,616
Financial Transaction Costs (%)	**0**
Land Costs ($)	**5,786,219**
Acreage/MW	5
Acreage/Plant	550
Cost per Acre ($)	3,100
Acquisition Cost ($)	1,705,000
Land Prep Costs ($/Acre)	7,420
Total Land Prep Costs ($)	4,081,219
Permitting Costs ($)	**0**
Local building permits ($)	
Environmental permits ($)	
Interconnection Costs ($)	**0**
Transmission Lines ($)	0
Substation ($)	0
Induction Equipment ($)	
Environmental Controls ($)	**0**
Installation Costs ($)	0
Replacement Costs ($)	

Table N-13
Environmental Control Costs

Total Annual Costs ($)	0
Media & Technology	**Cost**
Air Emissions	
Control Technology (e.g. SCR) ($)	
Installation Cost ($/kW)	0
Annual Labor (Hours/Year)	0
Loaded Labor Rate ($/Hour)	48
Labor Cost ($)	0
Annual Consumables-Catalyst ($)	0
Replacement Cost ($/kW)	0
Component Life (Hours)	141,760
Annualized Cost ($)	
Water Cooling	
Control Technology (e.g. wastewater) ($)	
Installation Cost ($/kW)	0
Annual Labor (Hours/Year)	0
Loaded Labor Rate ($/Hour)	48
Labor Cost ($)	0
Annual Consumables ($)	0
Replacement Cost ($/kW)	0
Component Life (Hours)	141,760
Annualized Cost ($)	
Solid Waste Disposal	
Non hazardous material	
Tons per Year	0
Collection and hauling ($/Ton)	10
Landfill tipping fees ($/Ton)	30
Total Costs ($)	0
Hazardous materials	
Tons per Year	0
Collection and hauling ($/Ton)	10
Landfill tipping fees ($/Ton)	30
Total Disposal Costs ($)	0

Table O-5
Fuel Use

Heat Rate (MMBtu/kWh)	2,480
Fuel Consumption (MMBtu/Hr)	248
Start up fuel use (MMBtu/start)	0
No. of annual starts	346
Annual Fuel Use (MMBtu)	1,520,240

Table O-6
Operational Information

Availability/Year (%)	75.0
Availability/Year (Hours)	6,570
Equipment Life (Hours)	70,000
Equipment Life (Years)	11
Overhaul Interval (Hours)	6,130
Maintenance Outage (Days)	10
Maintenance Outage Rate (%)	2.7
Forced Outage (Hours/Year)	200
Forced Outage Rate (%)	2.3
Hours per Year Operation	6,130
Capacity Factor (%)	42.0
Annual Net Energy (GWh)	368

Table O-7
Renewable Tax Benefits

Investment Tax Credit (%)	10
RETC Calculation ($/kWh)	312
Production Incentive-Investor (¢/kWh)	0
Geothermal Depletion Allowance	
RE Production Incentive Tier I	0
RE Production Incentive Tier II	0
REPI Tier II Proportion Paid (%)	10

Table O-8
Operation & Maintenance Costs (Employees)

Employees	Full Time Employees	Hours/Year	Compensation per Employee
Managers	1	1,800	$80,000 per year
Plant Operators	10	1,800	$30 per hour
Mechanics	6	1,800	$30 per hour
Laborers	3	1,800	$20 per hour
Support Staff	1	1,800	$20 per hour

Table O-11
Capital Cost Detail

Total ($)	**284,065,853**
Component Cost ($)	**276,835,787**
Structure & Improvements ($)	2,720,813
Collector System ($)	147,795,374
Thermal Storage System	0
Steam Gen or HX System ($)	11,251,870
Aux Heater/Boiler ($)	20,597,257
EPGS ($)	47,651,991
Master Control System ($)	0
Balance of Plant ($)	27,706,701
Engr, Const, Proj Management ($)	19,111,781
Financial Transaction Costs (%)	**0**
Land Costs ($)	**5,786,219**
Acreage/MW	5
Acreage/Plant	550
Cost per Acre ($)	3,100
Acquisition Cost ($)	1,705,000
Land Prep Costs ($/Acre)	7,420
Total Land Prep Costs ($)	4,081,219
Permitting Costs ($)	**343,847**
Local building permits ($)	0
Environmental permits ($)	343,847
Interconnection Costs ($)	**0**
Transmission Lines ($)	0
Substation ($)	0
Induction Equipment ($)	
Environmental Controls ($)	**1,100,000**
Installation Costs ($)	1,100,000
Replacement Costs ($)	

Table O-13
Environmental Control Costs

Total Annual Costs ($)	**1,100,000**
Media & Technology	**Cost**
Air Emissions	
Control Technology (e.g. SCR) ($)	1,100,000
Installation Cost ($/kW)	10
Annual Labor (Hours/Year)	0
Loaded Labor Rate ($/Hour)	48
Labor Cost ($)	0
Annual Consumables-Catalyst ($)	0
Replacement Cost ($/kW)	0
Component Life (Hours)	141,760
Annualized Cost ($)	
Water Cooling	
Control Technology (e.g. wastewater) ($)	
Installation Cost ($/kW)	0
Annual Labor (Hours/Year)	0
Loaded Labor Rate ($/Hour)	48
Labor Cost ($)	0
Annual Consumables ($)	0
Replacement Cost ($/kW)	0
Component Life (Hours)	141,760
Annualized Cost ($)	
Solid Waste Disposal	
Non hazardous material	
Tons per Year	0
Collection and hauling ($/Ton)	10
Landfill tipping fees ($/Ton)	30
Total Costs ($)	0
Hazardous materials	
Tons per Year	0
Collection and hauling ($/Ton)	10
Landfill tipping fees ($/Ton)	30
Total Disposal Costs ($)	0

Table P-5
Fuel Use

Heat Rate (MMBtu/kWh)	N/A
Fuel Consumption (MMBtu/Hr)	0
Start up fuel use (MMBtu/start)	0
No. of annual starts	0
Annual Fuel Use (MMBtu)	0

Table P-6
Operational Information

Availability/Year (%)	40.0
Availability/Year (Hours)	3,504
Equipment Life (Hours)	10,000
Equipment Life (Years)	3
Overhaul Interval (Hours)	3,000
Maintenance Outage (Days)	5
Maintenance Outage Rate (%)	1.4
Forced Outage (Hours/Year)	200
Forced Outage Rate (%)	2.3
Hours per Year Operation	3,184
Capacity Factor (%)	36.3
Annual Net Energy (GWh)	96

Table P-7
Renewable Tax Benefits

Investment Tax Credit (%)	10
RETC Calculation ($/kWh)	359
Production Incentive-Investor (¢/kWh)	0
Geothermal Depletion Allowance	
RE Production Incentive Tier I	0
RE Production Incentive Tier II	0
REPI Tier II Proportion Paid (%)	10

Table P-8
Operation & Maintenance Costs (Employees)

Employees	Full Time Employees	Hours/Year	Compensation per Employee
Managers	1	1,800	$80,000 per year
Plant Operators	4	1,800	$30 per hour
Mechanics	3	1,800	$30 per hour
Laborers	3	1,800	$20 per hour
Support Staff	1	1,800	$20 per hour

Table P-11
Capital Cost Detail

Total ($)	**98,090,550**
Component Cost ($)	**92,607,300**
Concentrator ($)	51,615,000
Receiver ($)	2,664,000
Engine ($)	8,658,000
Generator ($)	1,498,500
Cooling System ($)	1,332,000
Electrical ($)	1,165,500
Balance of Plant ($)	9,990,000
General Plant Facilities ($)	4,995,000
Engineering & Startup ($)	10,689,300
Financial Transaction Costs (%)	**0**
Land Costs ($)	**5,483,250**
Acres/MW	5
Acreage/Plant	157.5
Cost per Acre ($)	3,100
Acquisition Cost ($)	488,250
Land Prep Costs ($/Acre)	31,714
Total Land Prep Costs ($)	4,995,000
Permitting Costs ($)	**0**
Local building permits ($)	
Environmental permits ($)	
Interconnection Costs ($)	**0**
Transmission Lines ($)	0
Substation ($)	0
Induction Equipment ($)	
Environmental Controls ($)	**0**
Installation Costs ($)	0
Replacement Costs ($)	

Table P-13
Environmental Control Costs

Total Annual Costs ($)	**0**
Media & Technology	**Cost**
Air Emissions	
Control Technology (e.g. SCR) ($)	
Installation Cost ($/kW)	0
Annual Labor (Hours/Year)	0
Loaded Labor Rate ($/Hour)	48
Labor Cost ($)	0
Annual Consumables-Catalyst ($)	0
Replacement Cost ($/kW)	0
Component Life (Hours)	141,760
Annualized Cost ($)	
Water Cooling	
Control Technology (e.g. wastewater) ($)	
Installation Cost ($/kW)	0
Annual Labor (Hours/Year)	0
Loaded Labor Rate ($/Hour)	48
Labor Cost ($)	0
Annual Consumables ($)	0
Replacement Cost ($/kW)	0
Component Life (Hours)	141,760
Annualized Cost ($)	
Solid Waste Disposal	
Non hazardous material	
Tons per Year	0
Collection and hauling ($/Ton)	10
Landfill tipping fees ($/Ton)	30
Total Costs ($)	0
Hazardous materials	
Tons per Year	0
Collection and hauling ($/Ton)	10
Landfill tipping fees ($/Ton)	30
Total Disposal Costs ($)	0

Table Q-5
Fuel Use

Heat Rate (MMBtu/kWh)	N/A
Fuel Consumption (MMBtu/Hr)	0
Start up fuel use (MMBtu/start)	0
No. of annual starts	346
Annual Fuel Use (MMBtu)	0

Table Q-6
Operational Information

Availability/Year (%)	75.0
Availability/Year (Hours)	6,570
Equipment Life (Hours)	70,000
Equipment Life (Years)	11
Overhaul Interval (Hours)	6,130
Maintenance Outage (Days)	10
Maintenance Outage Rate (%)	2.7
Forced Outage (Hours/Year)	200
Forced Outage Rate (%)	2.3
Hours per Year Operation	6,130
Capacity Factor (%)	42.0
Annual Net Energy (GWh)	368

Table Q-7
Renewable Tax Benefits

Investment Tax Credit (%)	10
RETC Calculation ($/kWh)	438
Production Incentive-Investor (¢/kWh)	0
Geothermal Depletion Allowance	
RE Production Incentive Tier I	0
RE Production Incentive Tier II	0
REPI Tier II Proportion Paid (%)	10

Table Q-8
Operation & Maintenance Costs (Employees)

Employees	Full Time Employees	Hours/Year	Compensation per Employee
Managers	1	1,800	$80,000 per year
Plant Operators	10	1,800	$30 per hour
Mechanics	6	1,800	$30 per hour
Laborers	3	1,800	$20 per hour
Support Staff	1	1,800	$20 per hour

Table Q-11
Capital Cost Detail

Total ($)	**399,264,733**
Component Cost ($)	**391,702,016**
Structure & Improvements ($)	3,450,478
Collector System ($)	207,425,745
Thermal Storage System	66,593,338
Steam Gen or HX System ($)	11,872,762
Aux Heater/Boiler ($)	0
EPGS ($)	47,651,991
Master Control System ($)	0
Balance of Plant ($)	27,706,701
Engr, Const, Proj Management ($)	27,001,001
Financial Transaction Costs (%)	**0**
Land Cost ($)	**7,562,716**
Acreage/MW	7
Acreage/Plant	770
Cost per Acre ($)	3,100
Acquisition Cost ($)	2,387,000
Land Prep Costs ($/Acre)	6,722
Total Land Prep Costs ($)	5,175,716
Permitting Costs ($)	**0**
Local building permits ($)	
Environmental permits ($)	
Interconnection Costs ($)	**0**
Transmission Lines ($)	0
Substation ($)	0
Induction Equipment ($)	
Environmental Controls ($)	**0**
Installation Costs ($)	0
Replacement Costs ($)	

Table Q-13
Environmental Control Costs

Total Annual Costs ($)	**0**
Media & Technology	**Cost**
Air Emissions	
Control Technology (e.g. SCR) ($)	
Installation Cost ($/kW)	0
Annual Labor (Hours/Year)	0
Loaded Labor Rate ($/Hour)	48
Labor Cost ($)	0
Annual Consumables-Catalyst ($)	0
Replacement Cost ($/kW)	0
Component Life (Hours)	141,760
Annualized Cost ($)	
Water Cooling	
Control Technology (e.g. wastewater) ($)	
Installation Cost ($/kW)	0
Annual Labor (Hours/Year)	0
Loaded Labor Rate ($/Hour)	48
Labor Cost ($)	0
Annual Consumables ($)	0
Replacement Cost ($/kW)	0
Component Life (Hours)	141,760
Annualized Cost ($)	
Solid Waste Disposal	
Non hazardous material	
Tons per Year	0
Collection and hauling ($/Ton)	10
Landfill tipping fees ($/Ton)	30
Total Costs ($)	0
Hazardous materials	
Tons per Year	0
Collection and hauling ($/Ton)	10
Landfill tipping fees ($/Ton)	30
Total Disposal Costs ($)	0

Table R-5
Fuel Use

Heat Rate (MMBtu/kWh)	N/A
Fuel Consumption (MMBtu/Hr)	0
Start up fuel use (MMBtu/start)	0
No. of annual starts	0
Annual Fuel Use (MMBtu)	0

Table R-6
Operational Information

Availability/Year (%)	70.0
Availability/Year (Hours)	6,132
Equipment Life (Hours)	66,700
Equipment Life (Years)	13
Overhaul Interval (Hours)	40,000
Maintenance Outage (Days)	28
Maintenance Outage Rate (%)	1.1
Forced Outage (Hours/Year)	700
Forced Outage Rate (%)	8.0
Hours per Year Operation	5,336
Capacity Factor (%)	40.2
Annual Net Energy (GWh)	352

Table R-7
Renewable Tax Benefits

Investment Tax Credit (%)	0
RETC Calculation ($/kWh)	0
Production Incentive-Investor (¢/kWh)	1.695
Geothermal Depletion Allowance	
RE Production Incentive Tier I	0
RE Production Incentive Tier II	0
REPI Tier II Proportion Paid (%)	10

Table R-8
Operation & Maintenance Costs (Employees)

Employees	Full Time Employees	Hours/Year	Compensation per Employee
Managers	2	1,800	$80,000 per year
Plant Operators	2	1,800	$30 per hour
Mechanics	6	1,800	$30 per hour
Laborers	4	1,800	$20 per hour
Support Staff	2	1,800	$20 per hour

Table R-11
Capital Cost Detail

Total ($)	**399,264,733**
Component Cost ($)	**391,702,016**
Structures & Improvements ($)	3,450,478
Collector System ($)	207,425,745
Thermal Storage System ($)	66,593,338
Steam Gen or HX System ($)	11,872,762
Auxiliary Heater/Boiler ($)	0
EPGS ($)	47,651,991
Master Control System ($)	0
Balance of Plant ($)	27,706,701
Engineering, Construction, Project Management	27,001,001
Financial Transaction Costs (%)	**0**
Land Costs ($)	**7,562,716**
Acreage/MW	7
Acreage/Plant	770
Cost per Acre ($)	3,100
Acquisition Cost ($)	2,387,000
Land Prep Costs ($/Acre)	6,722
Permitting Costs ($)	5,175,716
Local building permits ($)	**0**
Environmental permits ($)	
Air Emission Permits ($)	
Interconnection Costs ($)	**0**
Transmission Lines ($)	0
Substation ($)	0
Induction Equipment ($)	
Environmental Controls ($)	**0**
Installation Costs ($)	0
Replacement Costs ($)	

Table R-13
Environmental Control Costs

Total Annual Costs ($)	**0**
Media & Technology	**Cost**
Air Emissions	
Control Technology (e.g. SCR) ($)	
Installation Cost ($/kW)	0
Annual Labor (Hours/Year)	0
Loaded Labor Rate ($/Hour)	48
Labor Cost ($)	0
Annual Consumables-Catalyst ($)	0
Replacement Cost ($/kW)	0
Component Life (Hours)	141,760
Annualized Cost ($)	
Water Cooling	
Control Technology (e.g. wastewater) ($)	
Installation Cost ($/kW)	0
Annual Labor (Hours/Year)	0
Loaded Labor Rate ($/Hour)	48
Labor Cost ($)	0
Annual Consumables ($)	0
Replacement Cost ($/kW)	0
Component Life (Hours)	141,760
Annualized Cost ($)	
Solid Waste Disposal	
Non hazardous material	
Tons per Year	0
Collection and hauling ($/Ton)	10
Landfill tipping fees ($/Ton)	30
Total Costs ($)	0
Hazardous materials	
Tons per Year	0
Collection and hauling ($/Ton)	10
Landfill tipping fees ($/Ton)	30
Total Disposal Costs ($)	0

Table S-5
Fuel Use

Base Heat Rate (MMBtu/kWh)	9,300
Fuel Consumption (MMBtu/Hr)	930
Start up fuel use (MMBtu/Start)	180
No. of annual starts	120

Table S-6
Operational Information

Availability/Year (%)	10.0
Availability/Year (Hours)	876
Equipment Life (Hours)	148,394
Equipment Life (Years)	30
Overhaul Interval (Hours)	876
Maintenance Outage (Days)	4
Maintenance Outage Rate (%)	1.2
Forced Outage (Hours/Year)	44
Forced Outage Rate (%)	0.5
Hours per Year Operation	822
Capacity Factor (%)	9.4
Annual Net Energy (GWh)	82

Table S-7
Renewable Tax Benefits

Investment Tax Credit (%)	0
RETC Calculation ($/kWh)	0
Production Incentive-Investor (¢/kWh)	0
Geothermal Depletion Allowance	
RE Production Incentive Tier I	0
RE Production Incentive Tier II	0
REPI Tier II Proportion Paid (%)	10

Table S-8
Operation & Maintenance Costs

Employee Category	Full Time Employees	Hours/Year	Compensation per Employee
Managers	1	1,800	$77,031 per year
Plant Operators	12	2,200	$17 per hour
Mechanics	4	2,300	$18 per hour
Laborers	2	2,200	$12 per hour
Support Staff	3	2,000	$13 per hour

Table S-11
Capital Cost Detail

Total ($)	**275896567**
Component Cost ($)	**243,289,126**
Turbine/Engine [Not itemized] ($)	234,597,182
Generator/Gearhead ($)	
Boiler/HRSG ($)	
Fuel Pipeline/Tank ($)	
Slab & Engine Mount ($)	
Miscellaneous fitting & hoses ($)	4,691,944
Office space ($)	
Control Room($)	
Duct Burners ($)	4,000,000
Financial Transaction Costs (%)	**0**
Land Costs ($)	**1,477,941**
Acreage/Plant	15
Cost per Acre ($)	100,000
Acquisition Cost ($)	1,470,588
Land Prep Costs ($/Acre)	500
Total Land Prep Costs ($)	7,353
Permitting Costs ($)	**5,129,500**
Local building permits ($)	
Environmental permits ($)	
Air Emission Permits ($)	5,129,500
Interconnection Costs ($)	**0**
Transmission Lines ($)	
Substation ($)	
Induction Equipment ($)	
Environmental Controls ($)	**26,000,000**
Installation Costs ($)	26,000,000
Replacement Costs ($)	

Table S-13
Environmental Control Costs

Total Annual Costs ($)	**1,019,680**
Media & Technology	**Cost**
Air Emissions	
Control Technology (e.g. SCR) ($)	15,600,000
Installation Cost ($/kW)	30
Annual Labor (Hours/Year)	100
Loaded Labor Rate ($/Hour)	48
Labor Cost ($)	4,800
Annual Consumables-Catalyst ($)	1,000,000
Replacement Cost ($/kW)	20
Component Life (Hours)	141,760
Annualized Cost ($)	8,548,981
Water Cooling	
Control Technology (e.g. wastewater) ($)	
Installation Cost ($/kW)	20
Annual Labor (Hours/Year)	100
Loaded Labor Rate ($/Hour)	48
Labor Cost ($)	4,800
Annual Consumables ($)	10,000
Replacement Cost ($/kW)	20
Component Life (Hours)	141,760
Annualized Cost ($)	
Solid Waste Disposal	
Non hazardous material	
Tons per Year	1
Collection and hauling ($/Ton)	10
Landfill tipping fees ($/Ton)	30
Total Costs ($)	40
Hazardous materials	
Tons per Year	1
Collection and hauling ($/Ton)	10
Landfill tipping fees ($/Ton)	30
Total Disposal Costs ($)	40