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August 6, 2008

Arizona Corporation Commission
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Docket Control
Arizona Corporation Commission
1200 W. Washington
Phoenix, AZ 85004

RE: Docket No. E-00000D-07-0376
Fifth Biennial Transmission Assessment

Dear Sir or Madam:

On behalf of the Arizona Transmission Providers, Arizona Public Service Company ("APS" or "Company") is filing the attached Joint Biennial Transmission Assessment Report on Renewable Resources and Available Transmission Capability (Joint BTA Report) to supplement the initial report filed by Southwest Area Transmission (SWAT), on May 15, 2008[1], as well as a set of recommended next steps for assessing renewable resources and available transmission. The Arizona Transmission Providers include Arizona Public Service Company, Salt River Project, Tucson Electric Power Company, and Southwest Transmission Cooperative, Inc. The Joint BTA Report is being attached as Attachment 1.

As part of the Joint BTA Report, the Arizona Transmission Providers engaged Black and Veatch ("B&V"), an independent consulting firm with significant experience in the assessment of renewable resources and related transmission[2], to review the renewable analysis. B&V provided an independent assessment of whether the report appropriately considered all of the factors and issues regarding the identification of transmission requirements for renewable resources, and whether the conceptual plan to access these resources was reasonable. The results of the B&V review and analysis is set forth in the *Assessment of Arizona Renewable Transmission Task Force, BTA Response Report,* which is being attached as Attachment 2.

Additionally, the Arizona Transmission Providers have the following recommendations on the next steps regarding the Report:

1. The conceptual transmission plan should be integrated with potential generation resources and utility resource planning. This integration could include a comparative analysis of the economic and environmental impacts and benefits associated with potential generation resource areas

[1] Southwest Area Transmission filed its initial report in response to Decision No. 69389.
[2] B&V prepared the Arizona Renewable Energy Assessment for Arizona utilities in 2007 and are currently supporting the U.S. Department of Energy-sponsored Western Renewable Energy Zone initiative to identify renewable resource areas in western North American and develop conceptual transmission to interconnect these resources to the electric grid.

identified in the conceptual transmission analysis. Providers would establish the appropriate forum to address this integration.

2. Refinement and further development of the conceptual transmission plan should occur, including:

   (a) Performing more detailed power flow and stability analyses that would be required for the development of such transmission;

   (b) Conducting preliminary analyses to identify study areas for potential corridors for such transmission; and

   (c) Consideration of potential state and federal regulatory requirements or approvals required to develop such transmission.

3. Participation in other regional and sub regional transmission planning initiatives in WECC, such as the Western Governor's Association Renewable Energy Zone process should continue, but a discrete process evaluating renewable transmission issues in Arizona, such as through the BTA should also continue.

If you have any questions, please call Jeff Johnson at 602-250-2661.

Sincerely,

John Lucas

Attachments

CC: Prem Bahl, ACC Staff
Laurie Woodall, KR Saline & Associates
Jerry D. Smith, KR Saline & Associates
Ed Beck, Tucson Electric Power
Rob Kondziolka, Salt River Project
Bruce Evans, Southwest Transmission Cooperative

ATTACHMENT 1

Joint BTA Report on Renewables and Available Transmission Capability

Prepared for the
Arizona Corporation Commission
By
Arizona Public Service Company
On Behalf of
Arizona Transmission Providers: Arizona Public Service Company, Salt River Project, Tucson Electric Power Company, and Southwest Transmission Cooperative, Inc.
August 1, 2008

PREFACE

The Arizona Corporation Commission ("ACC" or "Commission") biennially issues a written decision regarding the adequacy of the existing and planned transmission facilities in this state to meet the present and future energy needs of this state in a reliable manner. In the Fourth Biennial Transmission Assessment (BTA) Decision, the Commission ordered that "...in the next BTA, Commission regulated electric utilities, in consultation with the stakeholders, should prepare an assessment of ATC [Available Transfer Capacity] for renewable energy and prepare a plan, including a description of the location, amount of transmission needs of renewable resources in Arizona, to bring available renewable resources to load.[1]" On May 15, 2008, the Southwest Area Transmission ("SWAT") Sub-Regional Transmission Planning Group filed its initial report in response to Decision No. 69389. This Joint BTA Report further describes the collaborative efforts and analysis that was completed with SWAT to address the issues related to transmission for renewable energy resources; further documentation is included in the Appendix. This Joint BTA Report and its Appendices provides a coordinated response to Decision No. 69389 by the regulated utilities in Arizona

[1] Decision No. 69389 (March 22, 2007), page 8

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Appendix B – Fourth Biennial Transmission Assessment ACC Order, Docket No. E-00000D-05-0040, Decision No. 69389

Appendix C – Arizona Renewable Transmission Task Force Progress Summary, December , 2007

Appendix D – Arizona Renewable Transmission Task Force Stakeholder Meeting Presentation, November 16, 2007

Appendix E - Arizona Renewable Transmission Task Force Stakeholder Meeting Sign-In Form, November 16, 2007

Appendix F - Arizona Renewable Transmission Task Force Stakeholder Meeting Action Items, November 16, 2007

Appendix G - Arizona Renewable Transmission Task Force Stakeholder Meeting Presentation, October 8, 2007

Appendix H - Arizona Renewable Transmission Task Force Stakeholder Meeting Sign-In Sheet, October 8, 2007

Appendix I - Arizona Renewable Transmission Task Force Stakeholder Meeting Action Items, October 8, 2007

Appendix J – Summary Table for Utility Transmission Interconnection Queue – Renewables

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Appendix L – Transfer Capability Stakeholders Meeting (WestConnect), Phoenix, AZ, June 27, 2007

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Appendix O - Email Invitations to the October 8, 2007 and November 16, 2007 BTA Workshops

Appendix P - Arizona Renewable Energy Assessment Final Report, Black and Vetch, September 2007

EXECUTIVE SUMMARY

In Decision No. 69389 the ACC ordered that in the Fifth BTA, Commission-regulated electric utilities were to prepare an assessment of Available Transfer Capability ("ATC") for renewable energy and prepare a plan to bring available renewable resources to load. The Commission specified that stakeholder involvement was a key part of the assessment process.

To fulfill this requirement, Arizona Public Service Company ("APS"), Salt River Project ("SRP"), Tucson Electric Power ("TEP"), and Southwest Transmission Cooperative, Inc. (SWTC) (collectively referred to herein as "Arizona Transmission Providers") engaged SWAT in the process. Because SWAT, which was formed to promote regional planning across the entire southwest area of the Western Electricity Coordinating Council ("WECC"), encouraged collaborative efforts and joint participation to address the development and future of the electric transmission system, the organization was the logical forum to engage stakeholders in assessment of availability of transmission for renewable resources.

In response, the SWAT Renewable Energy Task Force ("RETF") embarked upon the BTA directive. To address the Commission's requirements two stakeholder workshops were held in October and November 2007, to provide input for the ACC's Fifth Biennial Transmission Assessment. An analysis of renewable resource potential was conducted by the stakeholder groups. The participants of the workshops used a process of presentations and discussions to reach consensus on the issues. Stakeholders and utilities participated in development of a resource map, transmission map and assessment of the ATC. From the resource potential assessment, the stakeholders developed resource clusters to aid in determining the potential transmission paths required to bring these resources to load.

It should be noted that this mapping and development of potential transmission interconnections represents the potential transmission lines that would be necessary if all of the renewable resources were to be fully developed within Arizona. The final mapping represents approximately 8,000 megawatts ("MW") of potential resources which may or may not be fully developed. The specific timing and development of transmission projects for renewable resources is dependant on when specific renewable generation projects are developed and when interconnection with the transmission system is sought. Historically, a low percentage of projects proposed and / or requests made into the interconnection queues will be developed. Consideration of this fact should be made when determining the timing or need for future transmission. Figure 1-6 provides a potential configuration for transmission to serve all potential renewable resources in Arizona.

In response to this BTA assessment, the regulated utilities have formed a technical committee under the SWAT RETF to begin work on Phase II of the transmission assessment process. Phase II will further refine the work completed in this initial assessment and integrate regional transmission needs into the analysis.

I. STAKEHOLDER PROCESS

STAKEHOLDER WORKSHOPS

In its Fourth BTA order (Decision No. 69389), the Commission required that the Arizona Transmission Providers analyze available transmission capability related to renewable resources in consultation with stakeholders. To fulfill this requirement, the Arizona Transmission Providers engaged SWAT in the process. Because SWAT, which was formed to promote regional planning across the entire southwest area of WECC, encouraged collaborative efforts and joint participation to address the development and future of the electric transmission system, the organization was the logical forum to engage stakeholders in assessment of availability of transmission for renewable resources. The following summarizes the SWAT process.

After presentations given at the August 21, 2007 SWAT meeting discussing the BTA requirements, the regulated utilities and stakeholders chose to create the SWAT Renewable Energy Task Force ("RETF"), a group under the Arizona/New Mexico subgroup of the SWAT, to lead stakeholder workshops to provide input to this report. In facilitation of this response and under the auspices of the RETF, two stakeholder workshops to provide input for the ACC Fifth Biennial Transmission Assessment were held on October 8, 2007 and November 16, 2007.

The RETF held an open stakeholder process and all interested parties were invited to attend. Meeting notices were publicly posted on the Westconnect.com website, and an email invitation was sent to all those who responded to the notice (attached in Appendix O). Participants that were unable to travel to the meeting site were provided with a conference call number to participate in the workshops by phone.

Approximately 20 to 30 people attended the workshops, including Commission Staff, and representatives from utilities including APS, SRP, TEP, Southwest Transmission Cooperative and Southern California Edison. Several renewable energy companies participated, including Sky Fuel, BP Alternative Energy, Foresight Wind, West Wind Wires, Ausra, Solar Mission and Interwest Energy Alliance. Other entities such as the National Renewable Energy Laboratory, and consulting groups including Genesee Consulting, PDS Consulting, K.R. Saline, Stanley Group and WSES Consulting also attended. A complete list of attendees for both stakeholder workshops is in Appendix E and Appendix H.

The participants of the workshops used a process of presentations and discussions to reach consensus on the issues. Stakeholders and utilities participated in development of a resource map, transmission map and assessment of the ATC. Each workshop had an agenda which is attached in Appendix D and Appendix G.

Several input resources were used by participants in the stakeholder workshop process to inform the discussions. The following is a list of these resources and a brief description of the content that were used in this process:

1. ATC data derived from June 2007 Utility Data developed at the June 2007 ATC workshop. (attached as Appendix L)
2. Arizona Renewable Energy Assessment (Final Report, September 2007) prepared by Black and Vetch, for APS, SRP and TEP ("B&V Assessment"), which assessed the prospects for significant renewable energy development in Arizona. (attached as Appendix P);
3. Utility Transmission Interconnection Queues as of October 15, 2007 – renewable projects (attached as Appendix J);
4. Stakeholder / developer input on prospective development opportunities;
5. The Ten Year Plans of APS, SRP and TEP, which were filed with the Commission on January 31, 2008 in ACC docket number E-00000D-07-0376
6. WECC Transmission Projects that were identified as being in Phase II or III of the WECC Path Rating Process.

The first stakeholder meeting, held October 8, 2007, focused on the review of several documents including the BTA order (Decision No. 69389), anticipated non-renewable energy projects, currently existing ATC in Arizona, utility Ten Year Plans, and projected ATC for the next ten years. The workshop also included discussion of possible transmission scenarios in Arizona.

The second stakeholder meeting held November 16, 2007, included review of several resources including the B&V Assessment, the renewable energy queue in Arizona, and further assessment of the ATC in Arizona. The workshop also included continued discussion of and recommendations for transmission plans in Arizona. Stakeholders and utilities participated in development of a renewable resource and transmission map and assessment of the ATC. From the resource potential assessment, the stakeholders developed resource clusters to aid in determining the potential transmission paths required to bring these resources to load. The renewable resource map, which provides an overview of the potential, but yet undeveloped renewable resource opportunities within Arizona, and the SWAT RETF Report that was filed in this docket on May 15, 2008, is attached as Appendix A.

In response to this BTA assessment, the regulated utilities have formed a technical committee under the SWAT RETF to begin work on Phase II of the transmission assessment process. Phase II will further refine the work completed in this initial assessment and integrate regional transmission needs into the analysis.

[Copies of documentation from the stakeholder meetings are attached: Appendix C - RETF Progress Summary (December 2007); Appendix D – REFT November 16, 2007 meeting presentation; Appendix F- RETF Action Items (Nov. 16, 2007); Appendix G – RETF October 8, 2007 meeting presentation; Appendix I – RETF Action Items (October 8, 2007).]

II. RESOURCE ASSESSMENT

Working from the potential renewable resource assessment, the stakeholders developed resource clusters to aid in determining the potential transmission paths required to bring these resources to load. The results of this process are summarized in this section.

DATA ASSESSMENT

The determination of potential renewable resources in Arizona and their locations was made through the RETF stakeholder process using input data from various resources including the stakeholders themselves. The data supporting the resulting resource potential maps came from three sources, the Arizona Renewable Energy Assessment prepared by Black and Veatch (Sept., 2007), the Arizona transmission interconnection queue and stakeholder input on prospective renewable development projects in Arizona. The data obtained from these resources was then compiled to determine a location and size of potential renewable resources for Arizona.

Arizona Renewable Energy Assessment (2007)

The Arizona Renewable Energy Assessment was developed by Black and Veatch (B&V) for APS, SRP and TEP. The objective of the B&V Assessment was to provide an assessment of significant renewable energy development prospects in Arizona. (It is important to note that the B&V Assessment concentrated on the potential of the renewable energy resources themselves and did not, beyond the inclusion of transmission interconnection costs, address the potential cost or availability of transmission capacity needed to deliver these resources to load.) Figure 1-1 below provides a map of the projected resources and their locations from the B&V Assessment. Initially nineteen renewable energy technologies were assessed. The original nineteen renewable technologies where then reduced to a list of five technologies that were recommended for additional research. These technologies included wind and solar technologies along with geothermal, biomass and hydroelectric opportunities.

The B&V Assessment determined that the majority of renewable resource opportunity in Arizona is solar and wind resources, which B&V projected to be approximately 8,000 MW. However, there are limited opportunities for biomass, geothermal and hydroelectric renewable energy resources. If these potential resources were fully developed, B&V projected that they would provide a total resource of approximately 177MW. To derive this potential for these resources, Black and Veatch used several data sources, including maps, GIS data and databases to identify high potential locations across Arizona for specific renewable technologies. Renewable energy technology specialists quantified the generation potential of each renewable energy resource by using filters, as described below. The "developable potential" was determined by considering constraints on land use, proximity to transmission, resource quality, and theoretical efficiency[2].

[2] B&V Assessment at 7-2, 7-3.

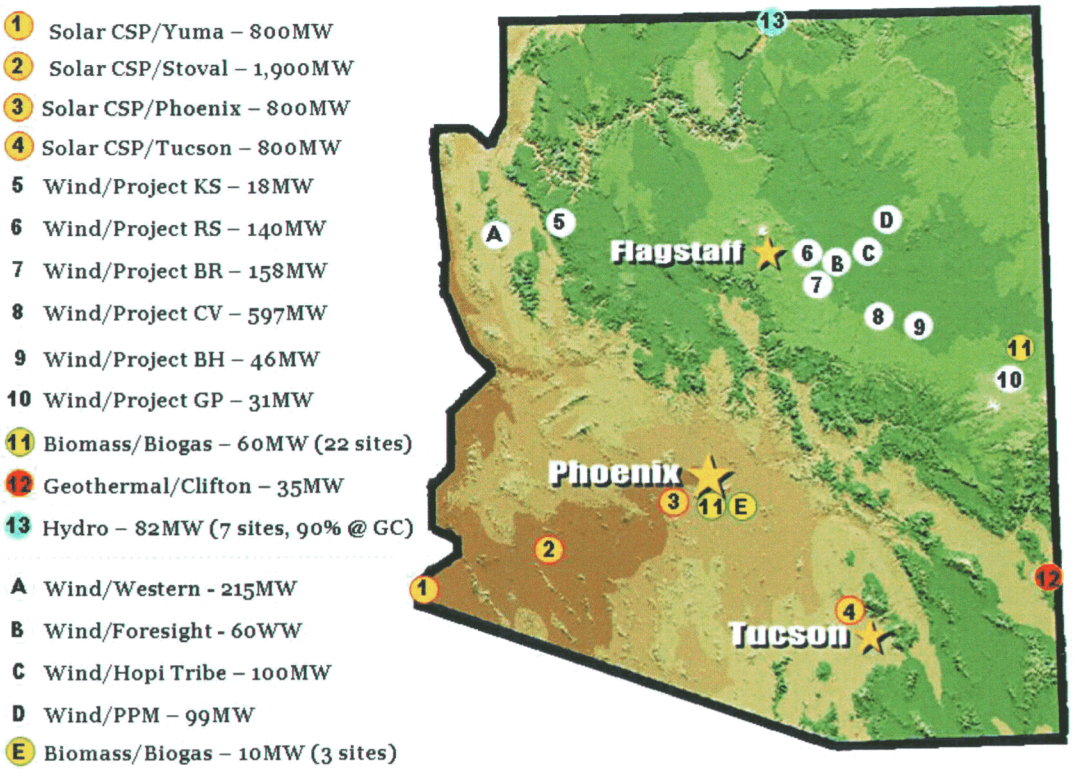

Figure 1-1 Projected Resource Locations

The solar filters used for this analysis were:

- Equipment availability / Supply Chain issues
- Development timelines / engineering support
- Project economics
- Proximity to adequate transmission
- Land availability
- Terrain / Slope issues
- Proximity to federal / environmentally sensitive areas

The wind filters used in this analysis were:

- Equipment availability / Supply chain issues
- Wind Class / Capacity Factors
- Project Economics
- Proximity to adequate transmission
- Proximity to federal / environmentally sensitive areas

A summary of the renewable energy resources determined by Black and Veatch for Arizona in a near to mid-term time frame are shown in Table 1-1 below, which is taken from the B&V Assessment.

Table 1-1. Arizona Renewable Energy Resources Available in the Near- to Mid-Term.

Technology	Location	Cost (2007$/ MWh)	Capacity (MW)	Generation (GWh/yr)
Direct Fired Biomass	Maricopa	143	20	140
Biomass Cofiring	2 potential sites: TEP's Springerville generating station and APS's Cholla generating station	58 - 63	20	140
Landfill Gas	15 potential small projects identified across the state	82 - 99	10	68
Anaerobic Digestion	Snowflake, Buckeye, Chandler, and Maricopa	62 - 128	10	69
Solar Thermal Electric	100 MW project in 2011. 2–4 200 MW sites per year after 2012	161- 176	4,300[a]	10,940[a]
Hydroelectric	7 potential sites[b]	32 - 215	82	320
Wind	6 potential sites near Kingman and the White Mountains[c]	75 - 141	991	2551
Geothermal	Clifton Hot Springs and Gillard Hot Springs	110 - 122	35	215
Total			**5468**	**14,443**

Notes:

[a] The solar potential is vast, and this only includes projects sufficient for meeting Arizona's forecast renewable energy demands through 2025.

[b] Glen Canyon compromises 90 percent of total potential.

[c] 500 MW of planned wind generation not included.

Table 1-1 Arizona Renewable Energy Resources (Black and Veatch, 2007)

Arizona Transmission Interconnection Queue

The second set of data used to provide an analysis and response to the 2007 BTA Order is the Arizona Transmission Interconnection Queue. The interconnection queues for APS, TEP and the Western Area Power Administration ("WESTERN") were reviewed for interconnection requests identified as renewable resources. This data was summarized using the queues as of October 15, 2007 to provide a snapshot of the renewable interconnection requests. The results of this analysis are shown below in Table 1-2. Figure 1-2 provides a map of Arizona that locates the approximate locations for projects in the utilities interconnection queues as of October 15, 2007.

Generator Interconnection Queue Positions are handled under the FERC approved Open Access Transmission Tariff (OATT). Small generators (up to 20 MW in output) use the Small Generator Interconnection Procedures (SGIP) and large (over 20 MW) use the Large Generator Interconnection Procedures (LGIP). A Queue position is established and published on the utilities public OASIS webpage once a "valid" application is received by the utility. The Queue position lasts until the customer withdraws their project, or they default in some way. It should be noted that a low percentage of the projects in the queue actually complete the interconnection process. Historical records for interconnection queues show that a large percentage of projects that gain a position in the queue do not go on to actually generate energy.

Code	Company	COD	Size (MW)	POI	County	Type
T1	TEP	2005	80	Dolan Springs Sub	Mohave	Wind
T2	TEP	2008	15	Dolan Springs Sub	Mohave	Wind
T3	TEP	2005	15	Dolan Springs Sub	Mohave	Wind
T4	TEP	2007	95	Coronado-Springerville	St Johns	Wind
A1	APS	2008	60	Cholla - Coconino	Coconino	Wind
A2	APS	2008	128	Cholla - Showlow	Coconino	Wind
A3	APS	2007	22	Cholla - Zeniff	Coconino	Biomass
A4	APS	2008	270	Ashfork - Pollock	Coconino	Wind
A5	APS	2009	250.5	Cholla – Show Low	Coconino	Wind
A6	APS	2010	100	Adams - Mural	Cochise	Wind
A7	APS	2011	110	Harquahala Junction	Maricopa	Solar
A8	APS	2011	110	Panda Liberty line	Maricopa	Solar
A9	APS	2010	300	Gila Bend	Maricopa	Solar
A10	APS	2010	400	North Gila Sub	Yuma	Solar
W1	WESTERN	2008	500	Tap on 345kV Glen Canyon-Pinnacle Peak	Coconino	Wind
W2	WESTERN	2008	300	Mead - Davis 230 kV Line	Mohave	Wind
W3	WESTERN	2008	65.1	Goldmine Tap Substation	Imperial	Wind
W4	WESTERN	2008	500	Peacock Substation	Mohave	Wind
N1	Navajo Nation		100			Wind
Total			3420.6	As of 10/15/2007		

Table 1-2 Arizona Renewable Resource Queue

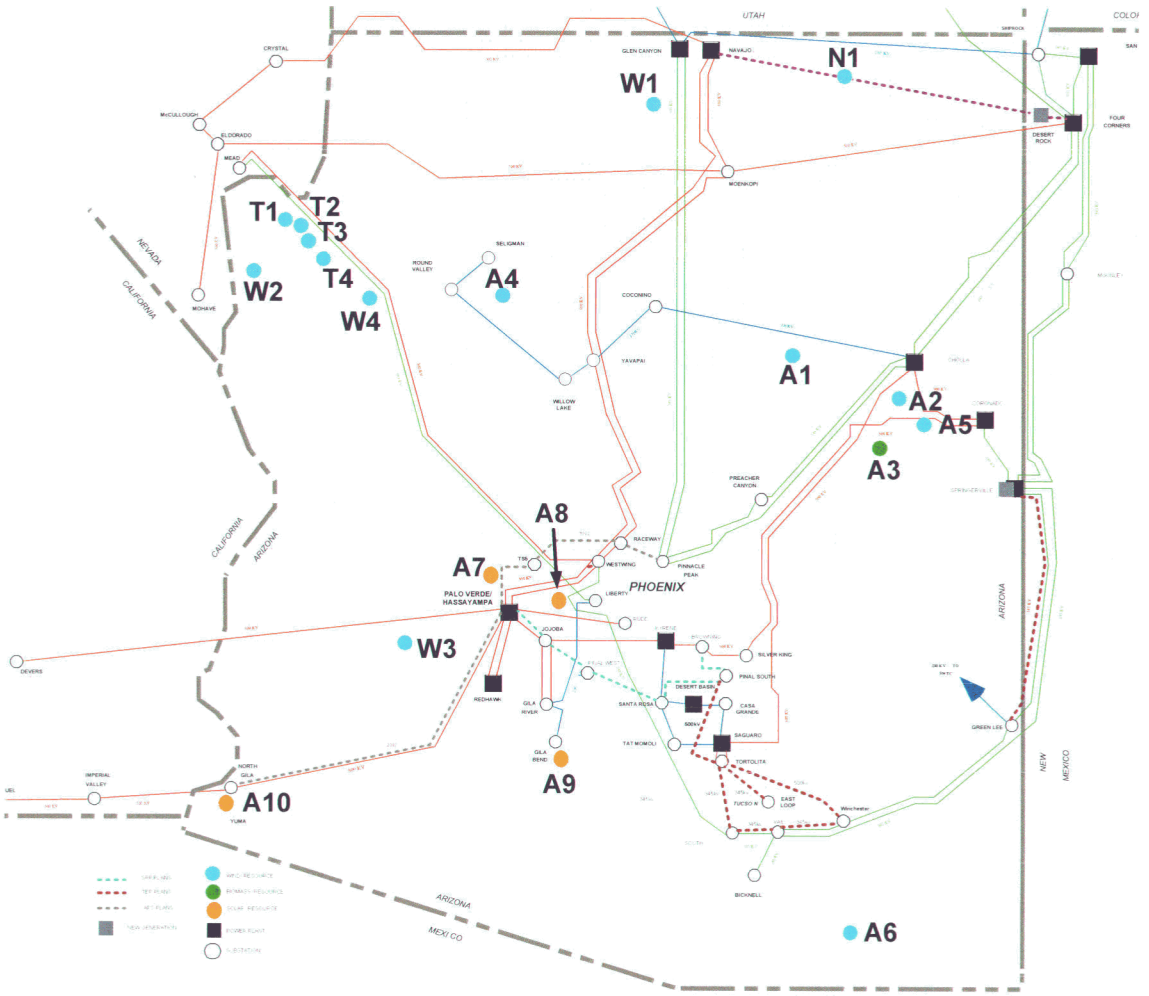

Figure 1-2 Arizona Renewable Resource Queue – Approximate Project Locations

Stakeholder Input

The third set of data used during the analysis of potential resources was stakeholder input. This input during the stakeholder meetings provided information relating to the prospective development opportunities that the stakeholders believed may occur in Arizona at some time in the future, and were not represented in the B&V Assessment or the Arizona Renewable Resource Queue. Stakeholder input will be discussed in greater detail in the Resource Analysis section below.

ANALYSIS OF DATA

The intent of the stakeholder process was to develop a summary map that would provide the general locations of potential renewable resources in Arizona, including solar, wind, biomass, geothermal and hydro resources. To identify these resources locations generally, without defining individual projects, the stakeholders determined that locating the renewable resources in clusters was a reasonable approach.

The development of renewable clusters used the B&V Assessment, the Arizona Renewable Resource Queue resource, and stakeholder input for potential projects. Using these three inputs, the stakeholders decided during the stakeholder process that for development of the resource cluster map, the highest single potential number of MW from the three inputs would be used as the number identified for the resources. Additionally, because geothermal, hydro and biomass / biogas opportunities are small in comparison to solar and wind generation, these were included in the wind and solar clusters.

RESULTS

The cluster map shown in Figure 1-3 below indicates a composite of wind in Northern Arizona. There have been three large areas of wind potential identified: 1) approximately 1,000 MW in northwestern Arizona and south of the Kingman area; 2). approximately 970 MW in the north central Arizona area near Flagstaff; and 3) approximately 1030 MW in the Cholla / Eastern Arizona area. These areas of wind potential were identified by the utility interconnection queues. A 100 MW potential wind project was located in northeastern Arizona through stakeholder input. Additionally, there is a small pocket of potential biomass in the eastern area of Arizona that was identified in this process.

For solar potential, the mapping identified a very large cluster of potential in southwestern Arizona. This solar potential has been approximated at 4,300 MW through the RETF stakeholder process and was identified using the B&W Assessment. A potential renewable cluster was also identified in southeastern Arizona of approximately 350 MW. The majority of potential in this cluster is solar, however, it also includes a small amount of geothermal and wind. The solar identified in this renewable energy cluster was identified through stakeholder input in the RETF meetings.

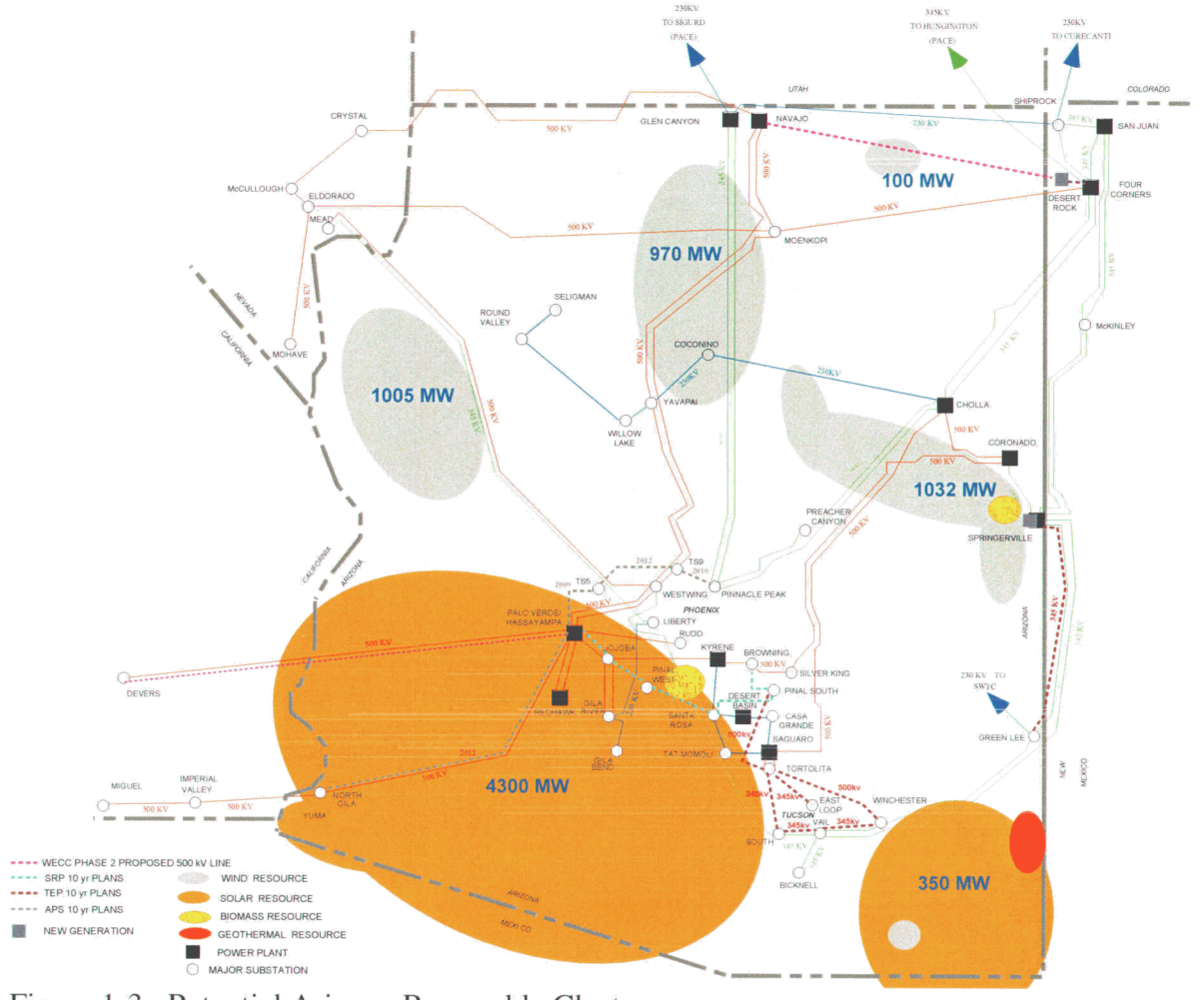

Figure 1-3 Potential Arizona Renewable Clusters

III. Transmission Assessment

The RETF stakeholder process was also utilized to assess the available transfer capability for renewable energy, including a description of the transmission needs to bring these available resources to load. An analysis of the Total Transmission Transfer Capability (TTC) / Available Transfer Capability (ATC) was conducted and presented to the stakeholder groups in October 2007. From this ATC assessment and the resource clusters that were identified in this RETF stakeholder process, potential transmission paths were identified to bring these resources to load. The results of this process are summarized in this section.

Data Assessment

The TTC / ATC in Arizona for APS, TEP, SRP, SWTC, and WESTERN were presented in the Westconnect forum on June 27, 2007. The Westconnect meeting provided a common opportunity for utilities to present this information in a stakeholder forum. The data provided by the utilities was used to prepare the TTC / ATC maps needed for the BTA assessment

process. These maps are included Appendix N - Total Transfer Capability (TTC) and Available Transfer Capability (ATC).

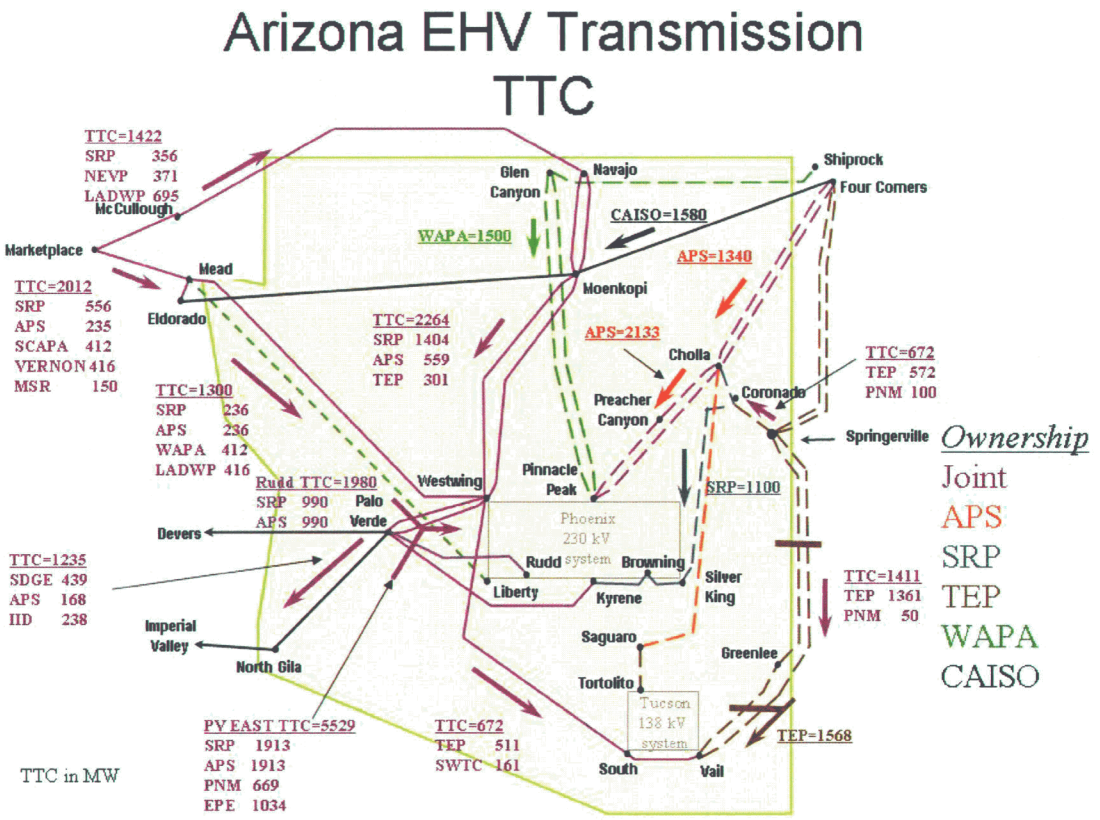

Figure 1-4 Arizona Total Transmission Capability

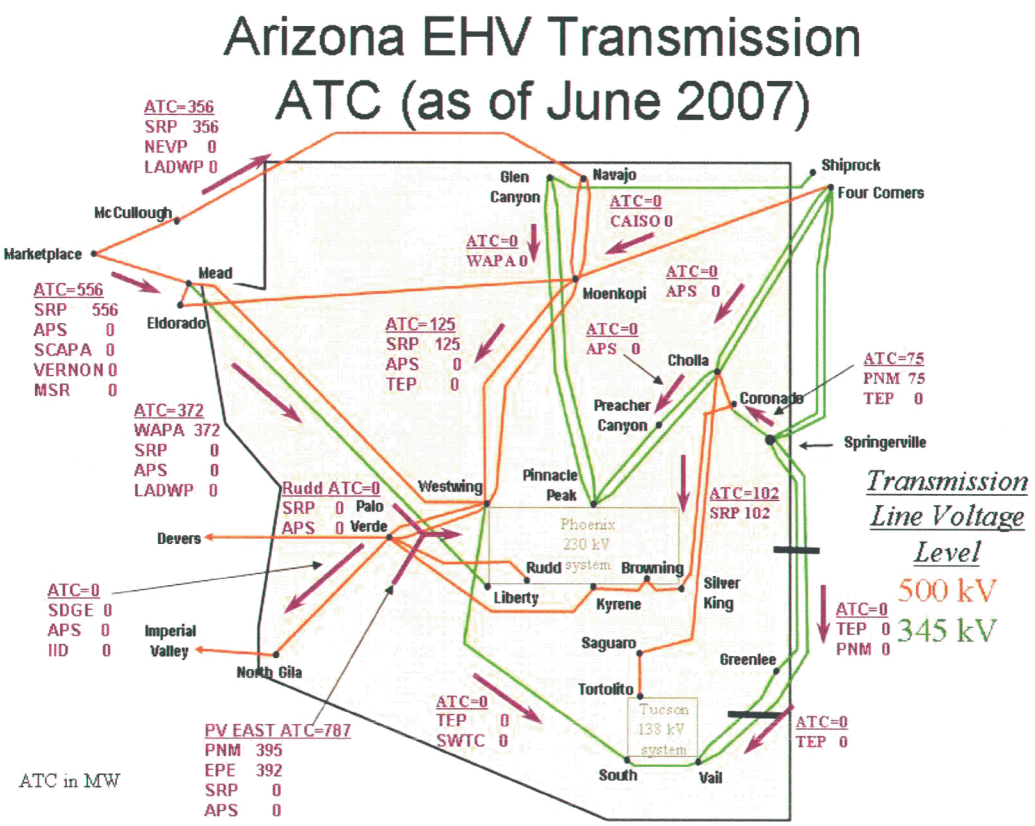

Figure 1-5 Arizona Available Transmission Capability

ANALYSIS OF DATA

The ATC is a dynamic number that can change from day to day. Therefore, for the RETF stakeholder process, the values used for the ATC were based upon the values presented in the Westconnect forum in June of 2007.

The assessment of ATC indicates that in the State of Arizona there is limited ATC on the transmission system to deliver new generation to the load centers. When addressing transmission on the east/west paths, the majority of ATC is zero megawatts (0 MW) for the existing transmission system. As of June, 2007, it should be noted that the Navajo Transmission System had 125 MW available on the Moenkopi-to-Westwing 500kV line and the Coronado-to-Silver King 500kV line had 102 MW available. The Palo Verde east path had 787 MW available, which consisted of Public Service of New Mexico (PNM) and El Paso Electric ATC.

RESULTS

The analysis shows that there are very limited existing transmission resources to bring new renewable generation projects to the load pockets. The next steps in the RETF stakeholder

process was to address these limited transmission resources and to provide a potential plan for additional transmission that would be needed in order to bring the renewable resources to load. Mapping was developed which represented the potential transmission lines that would be necessary if all of the renewable resources were to be developed in Arizona and delivered to load. To accomplish the task of developing potential transmission interconnections, during the first RETF stakeholder group meeting on October 8, 2007, three teams were developed to brainstorm future transmission scenarios. The result of this process was the creation of three different potential transmission maps for Arizona. These maps were further developed and combined into one "Master Transmission Map" during the second RETF stakeholders' meeting that was held on November 16, 2007.

The final goal of the RETF stakeholder process was overall map development for renewable resources and transmission in Arizona including the potential transmission to bring these resources to the load pockets. This final mapping as shown in Figure 1-6 below includes:

- Existing Arizona transmission system
- Proposed lines from the APS, SRP and TEP Ten Year Plans
- WECC projects currently in phase II or III of the WECC Path Rating process
- Potential renewable energy "clusters"
- Potential transmission that could be constructed to bring renewable resources to load

The potential transmission lines that were developed in the stakeholder process include:

- 500kV / 230kV transmission from the wind resource cluster in northwestern Arizona connecting to the Palo Verde("PV")-to-Devers corridor.
- High voltage interconnection from solar resources northeast of Yuma to the North Gila substation
- 500kV interconnection from the Gila River / Gila Bend substation area to the proposed PV-to-North Gila 500kV line
- Various high voltage interconnections at the Hassayampa / PV hub from the northwest
- 230kV interconnection from the renewable resource cluster in southeastern Arizona to the Winchester substation
- 500kV interconnection from Moenkopi Substation through the north central Arizona resource cluster to Cholla-to-Pinnacle Peak Substation
- Various new substation interconnection points within the renewable resource clusters

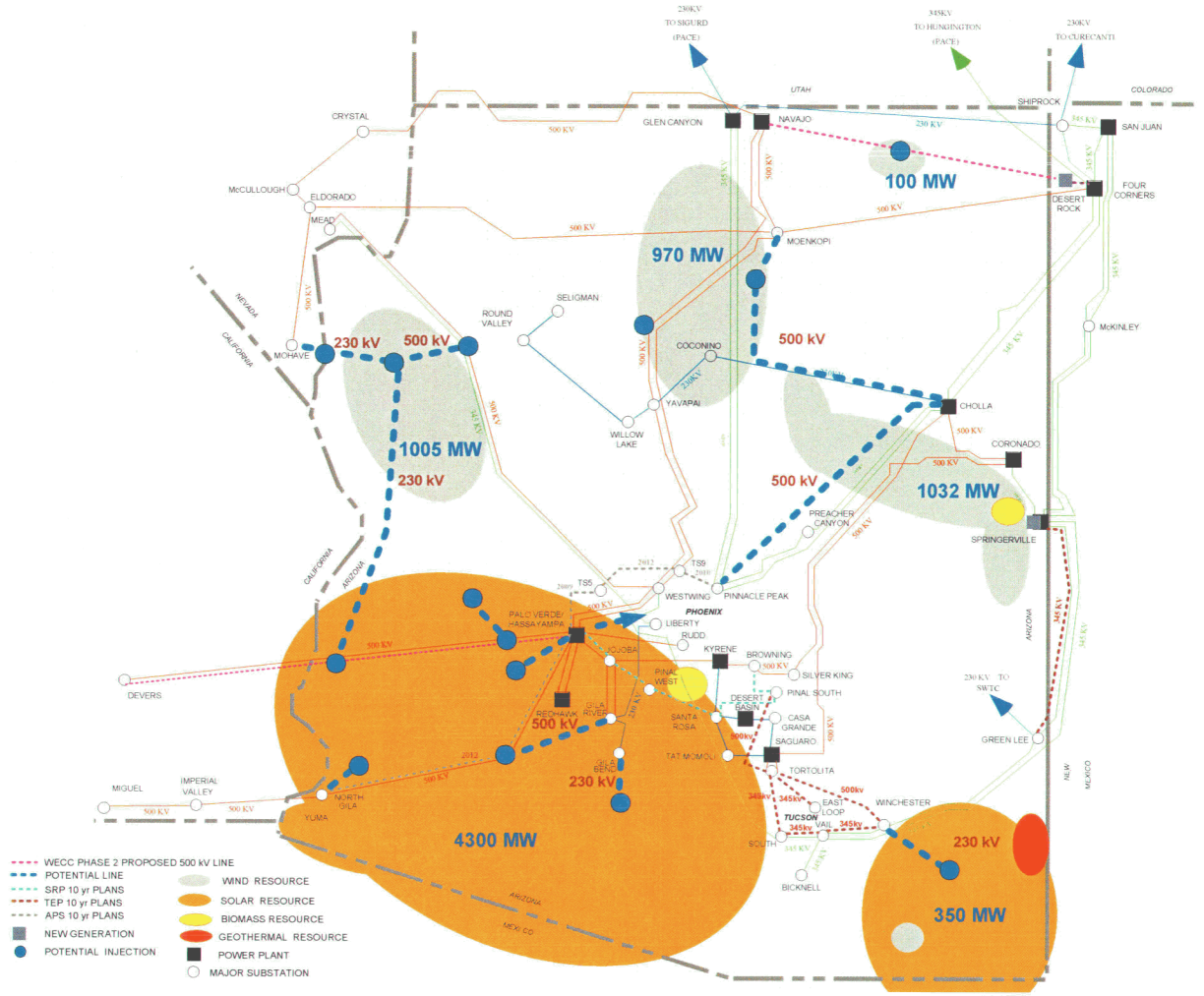

Figure 1-6 Potential Configuration for Transmission to Serve All Potential Renewable Resources in Arizona

It is important to note that the above descriptions of potential new transmission lines assumes that all proposed lines in the utilities Ten Year Plans are built (example: Palo Verde to North Gila II) as well as the transmission projects that are already in Phase II or III of the WECC process (example Devers II). This mapping and development of potential transmission interconnections represents the potential transmission lines that would be necessary if all of the renewable resources were to be fully developed within Arizona. The final mapping represents approximately 8,000 MW of potential resources which may not be fully developed.

APPENDIX

LIST OF APPENDICES

Appendix A – 2007 SWAT Renewable Energy Transmission Task Force Report

Appendix B – Fourth Biennial Transmission Assessment ACC Order, Docket No. E-00000D-05-0040, Decision No. 69389

Appendix C – Arizona Renewable Transmission Task Force Progress Summary, December, 2007

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Appendix P - Arizona Renewable Energy Assessment Final Report, Black and Vetch, September 2007

Appendix A
2007 SWAT Renewable Energy Transmission Task Force Report

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2007 SWAT Renewable Energy Transmission Task Force Report

Prepared for the
Arizona Corporation Commission
By
Arizona Public Service Company
On Behalf of
SWAT Renewable Energy Transmission Task Force

4th BTA ORDER

The Arizona Corporation Commission's ("Commission") Fourth Biennial Transmission Assessment ("BTA") ordered that "in the next BTA, Commission regulated electric utilities, in consultation with the stakeholders, should prepare an assessment of ATC for renewable energy and prepare a plan, including a description of the location, amount and transmission needs of renewable resources in Arizona, to bring available renewable resources to load." (Decision No. 69389 (March 22, 2007), page 8). This report is submitted in compliance with that Order.

BTA ORDER RESPONSE

1. To address the Commission's first requirement that "Commission regulated electric utilities, in consultation with the stakeholders, should prepare an assessment of ATC for renewable energy" the parties to this report respond as follows:

    a. Available Transfer Capacity (ATC) data has been gathered for each utility in Arizona and displayed on the map shown in Figure 1. This information was developed during stakeholder workshops held on October 8 and November 16, 2007 and includes utility (APS, SRP, SWTC, and TEP), and stakeholder input.
    b. ATC is a dynamic number that can change from day to day. For the purposes of this report, the ATC values observed in June 2007 are used to illustrate the status of the ATC in the Arizona transmission system as shown on Figure 1.

2. To address the Commission's second requirement that regulated utilities should "prepare a plan, including a description of the location, amount and transmission needs of renewable resources in Arizona, to bring available renewable resources to load" the parties to this report respond as follows:

    a. In preparing this report, the parties have attempted to identify the location and amount of potential renewable resource opportunities that now exist in Arizona, and to present an overview of the transmission needs associated with such resource opportunities. The specific timing and development of transmission projects from renewable resource generation in Arizona depends on when specific generation projects are developed and seek interconnection with the transmission system.

    b. As shown on Figure 2, the parties prepared a renewable resource map displaying areas where renewable resource development could potentially occur, based on input from three specific areas 1) the Arizona Renewable Energy Assessment recently prepared for APS, SRP and TEP by Black and Veatch (2007); 2) the queue for renewable resource in Arizona requesting potential interconnection (as of October 15, 2007); and 3) stakeholder/developer input on prospective development opportunities. This renewable resource map was developed during workshop meetings on October 8 and November 16, 2007 and includes the location and a theorized potential total amount of renewable energy development opportunities for several different locations in Arizona. These opportunities include wind, solar, biomass, hydro and/or geothermal renewable energy types.

The map shown in Figure 2 provides an overview of the potential, but yet undeveloped renewable resource opportunities within Arizona, and identifies the major wind and solar renewable resources as clusters overlaid on current utility 10-Year Plans and WECC Phase II projects. Since geothermal and biomass/biogas opportunities are small relative to solar and wind opportunities, they have been included within the total MW potential shown as wind and solar clusters.

During the October 8 and November 16, 2007 meetings, the utilities and stakeholders discussed the potential transmission alternatives for bringing the renewable energy resources to load, assuming that each of the resources was fully developed. The map shown in Figure 3 offers a potential transmission map that shows the lines that might be used to transport energy from these potential renewable resources to the major load pockets in Arizona. This map was developed by the utilities and stakeholders during both meetings and includes: (1) existing transmission lines, (2) data contained within the APS, SRP and TEP 10-Year Plans and WECC Phase II projects, and (3) potential transmission lines discussed in the workshop meetings that would be necessary if all of the resources were to be developed.

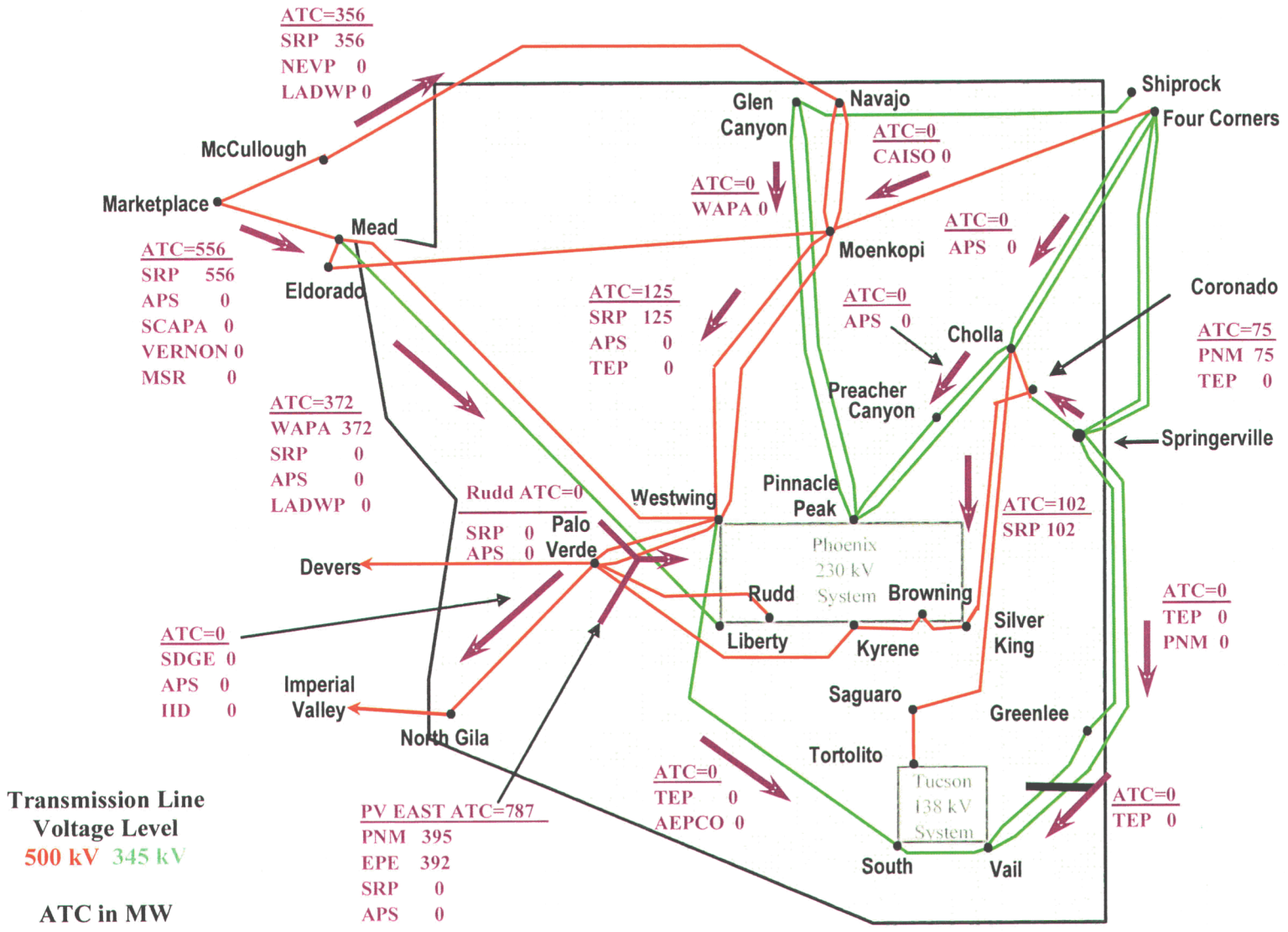


Figure 1: ATC for Arizona Paths in June 2007

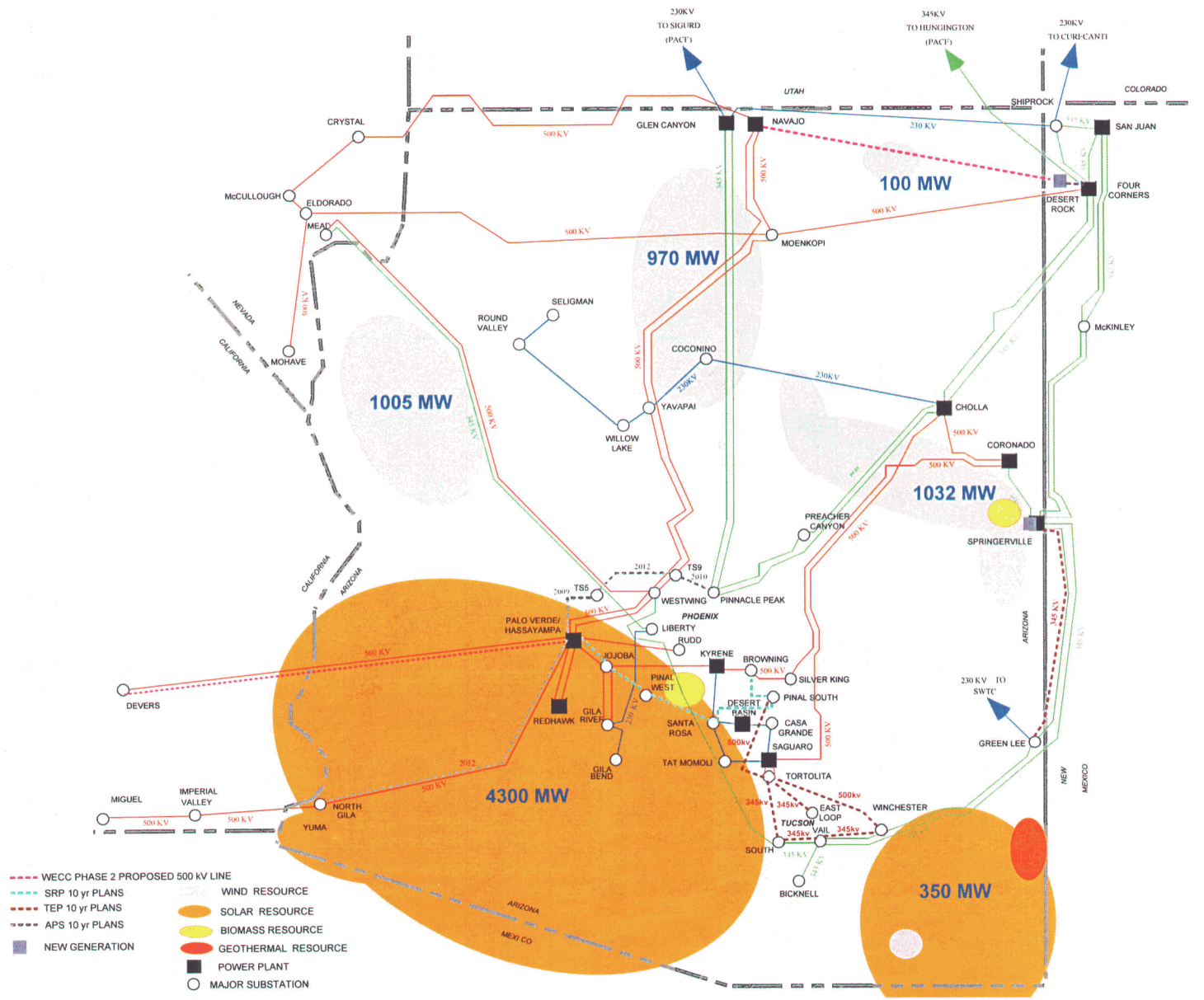


Figure 2: Potential Arizona Renewable Resources

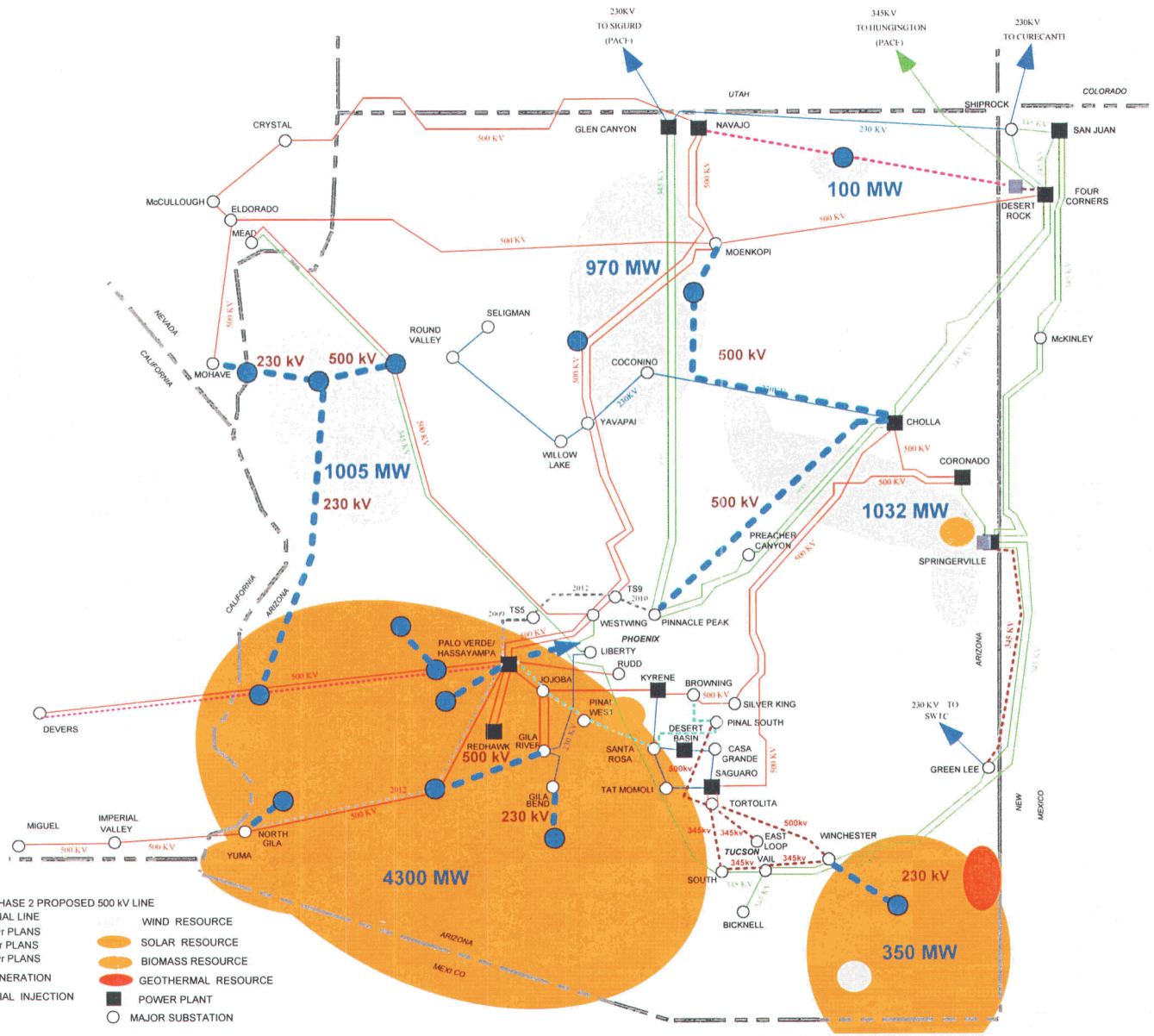


Figure 3: A Potential Configuration for Transmission to Serve All Available Renewable Resources in Arizona

Arizona Renewable Transmission Task Force BTA Response

Chairman of SWAT RTTF
Peter Krzykos
BTA Workshop
May 22-23 2008

BTA Order

"IT IS FURTHER ORDERED that in the next BTA, Commission regulated electric utilities, in consultation with the stakeholders, should prepare an assessment of ATC for renewable energy and prepare a plan, including a description of the location, amount and transmission needs of renewable resources in Arizona, to bring available renewable resources to load."

SWAT RTTF Phase #1
Integration of Renewable Resources into Arizona Transmission Network
BTA Response

- Three Parts to the BTA Response
  - Assessment of ATC in Arizona
  - Potential renewable resources in Arizona
  - Potential transmission configuration to deliver the renewable resources in Arizona

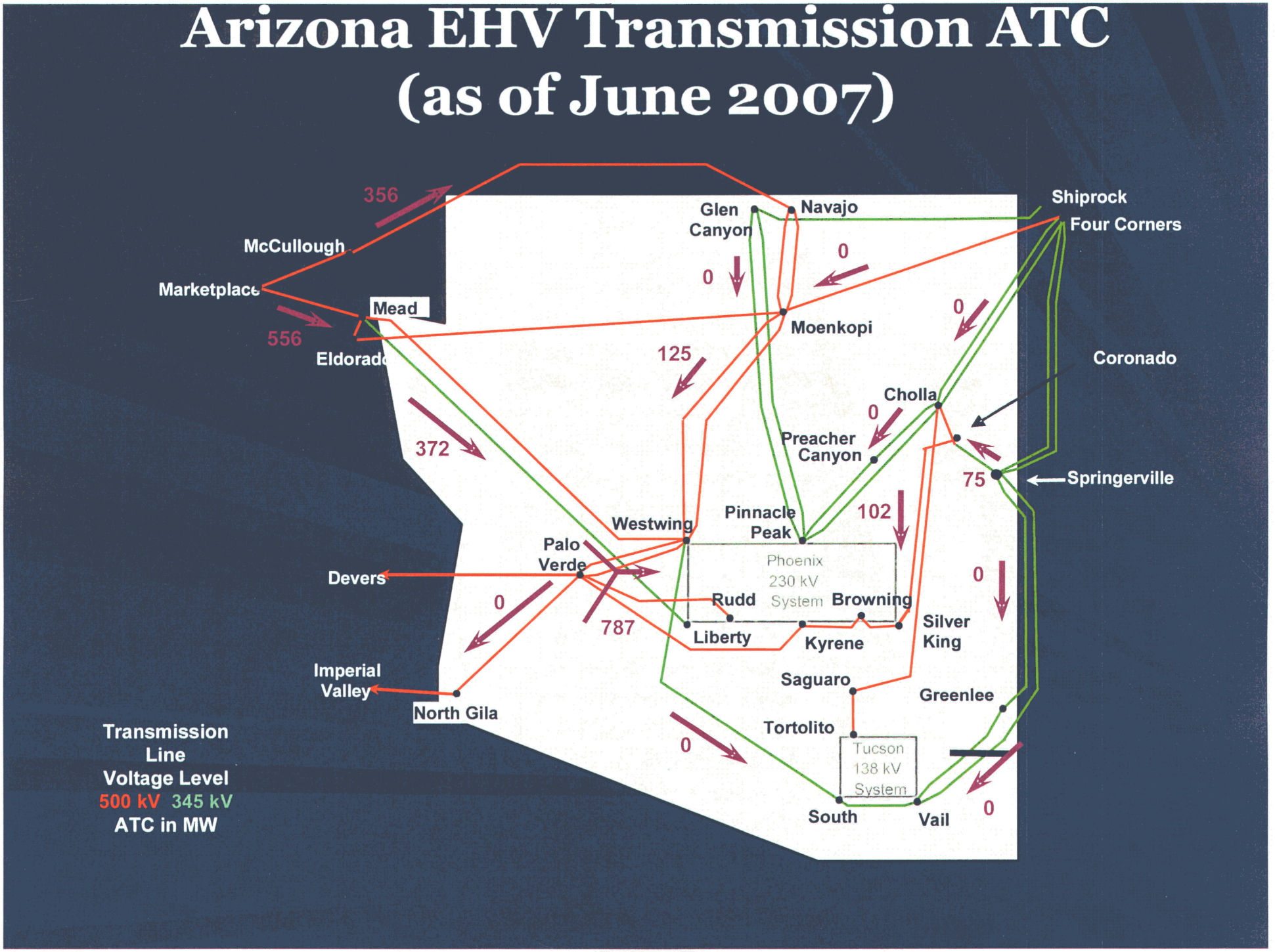
SWAT RTTF Phase #1
AZ BTA Order Response Task Force Meetings

- Two meetings(October 8th and November 16th 2007)
  - Stakeholders and utilities attended
    - Arizona Corporation Commission
    - Utilities
      - Arizona Public Service
      - Salt River Project
      - Tucson Electric Power
      - Southwest Transmission Corporative
      - Southern California Edison
    - Renewable Energy Companies
      - Sky fuel
      - BP Alternative Energy
      - Foresight Wind
      - West Wind Wires
      - Ausra
      - Solar Mission
      - Interwest Energy Alliance
    - Other Stakeholders
      - National Renewable Energy Laboratory
      - Genesee Consulting
      - PDS Consulting
      - K R Saline
      - Stanley Group
      - WSES Consulting
  - 20-30 people were at each meeting
  - Stakeholders and utilities participated in development of a resource map, transmission map, and assess the ATC in Arizona in an open forum to address the BTA

SWAT RTTF
Part 1 -ATC Assessment

- This information was developed during stakeholder workshops held October 8th and November 16th 2007 and includes utility (APS, SRP, SWTC, and TEP) ACC staff and stakeholder input.
- Available Transfer Capability (ATC) has been gathered for each utility in Arizona
- ATC is a dynamic number that can change from day to day. Values observed in June 2007 are used to illustrate the status of the ATC in the Arizona transmission system.

Arizona EHV Transmission ATC (as of June 2007)



SWAT RTTF
Part 2 - Resource Projection

- The renewable resource map was developed during workshop meetings on Oct 8th and Nov 16th 2007
- A renewable resource map displaying areas where resources development potentially could occur and was developed with input from three specific areas
  - The Arizona Renewable Energy Assessment recently prepared for APS, SRP and TEP by Black and Veatch (2007)
  - The queue for renewable resource in Arizona requesting potential interconnection (as of October 15th 2007)
  - Stakeholder/developer input on prospective development opportunities.
  - The # of MW display on the map is the highest out of the three inputs.

Black & Veatch Summary

Projected Resource Locations

1. Solar CSP/Yuma – 800MW
2. Solar CSP/Stoval – 1,900MW
3. Solar CSP/Phoenix – 800MW
4. Solar CSP/Tucson – 800MW
5. Wind/Project KS – 18MW
6. Wind/Project RS – 140MW
7. Wind/Project BR – 158MW
8. Wind/Project CV – 597MW
9. Wind/Project BH – 46MW
10. Wind/Project GP – 31MW
11. Biomass/Biogas – 60MW (22 sites)
12. Geothermal/Clifton – 35MW
13. Hydro – 82MW (7 sites, 90% @ GC)

September 21st 2007

B & V Summary Filters

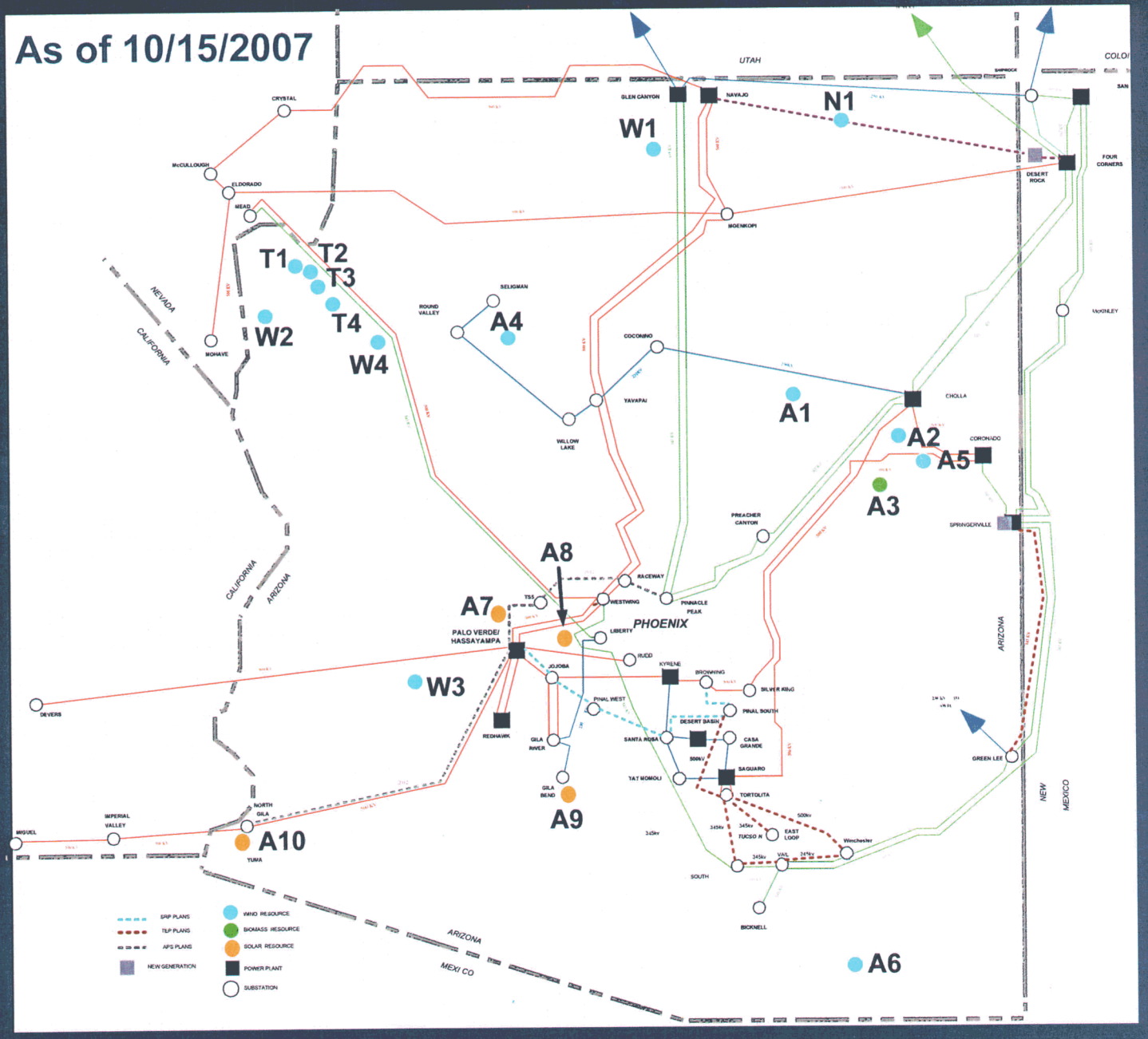
- Solar Thermal
  - Equipment availability/supply chain
  - Development timelines/engineering support
  - Project economics
  - Proximity to adequate transmission
  - Land availability/terrain slope/proximity to sensitive areas
- Wind
  - Equipment availability/supply chain
  - Class/Capacity factor
  - Project economics
  - Proximity to adequate transmission
  - Proximity to federal/environmental sensitive areas

Arizona Renewable Resource Queue

Code	Company	COD	MW Size	POI	County	Type
T1	TEP	2005	80	Dolan Springs Sub	Mohave	Wind
T2	TEP	2008	15	Dolan Springs Sub	Mohave	Wind
T3	TEP	2005	15	Dolan Springs Sub	Mohave	Wind
T4	TEP	2007	95	Co-Spr	St Johns	Wind
A1	APS	2008	60	Cholla - Coconino	Coconino	Wind
A2	APS	2008	128	Cholla Show	Coconino	Wind
A3	APS	2007	22	Cholla zeniff	Coconino	Biomass
A4	APS	2008	270	Ashofork - Pollock	Coconino	Wind
A5	APS	2009	250.5	cholla - show	Coconino	Wind
A6	APS	2010	100	Adams - Mural	Cochise	Wind
A7	APS	2011	110	Harquahala Jnc	Maricopa	Solar
A8	APS	2011	110	Panda Liberty line	Maricopa	Solar
A9	APS	2010	300	Gila Bend	Maricopa	Solar
A10	APS	2010	400	North Gila Sub	Yuma	Solar
W1	WAPA	2008	500	Tap on 345kV Glen Canyon-Pinnacle Peak	Coconino	Wind
W2	WAPA	2008	300	Mead - Davis 230 kV Line	Mohave	Wind
W3	WAPA	2008	65.1	Goldmine Tap Substation	Imperial	Wind
W4	WAPA	2008	500	Peacock Substation	Mohave	Wind
N1	Navajo Nation		100			Wind
Total			3420.6	As of 10/15/2007		

Arizona Renewable Resource Queue

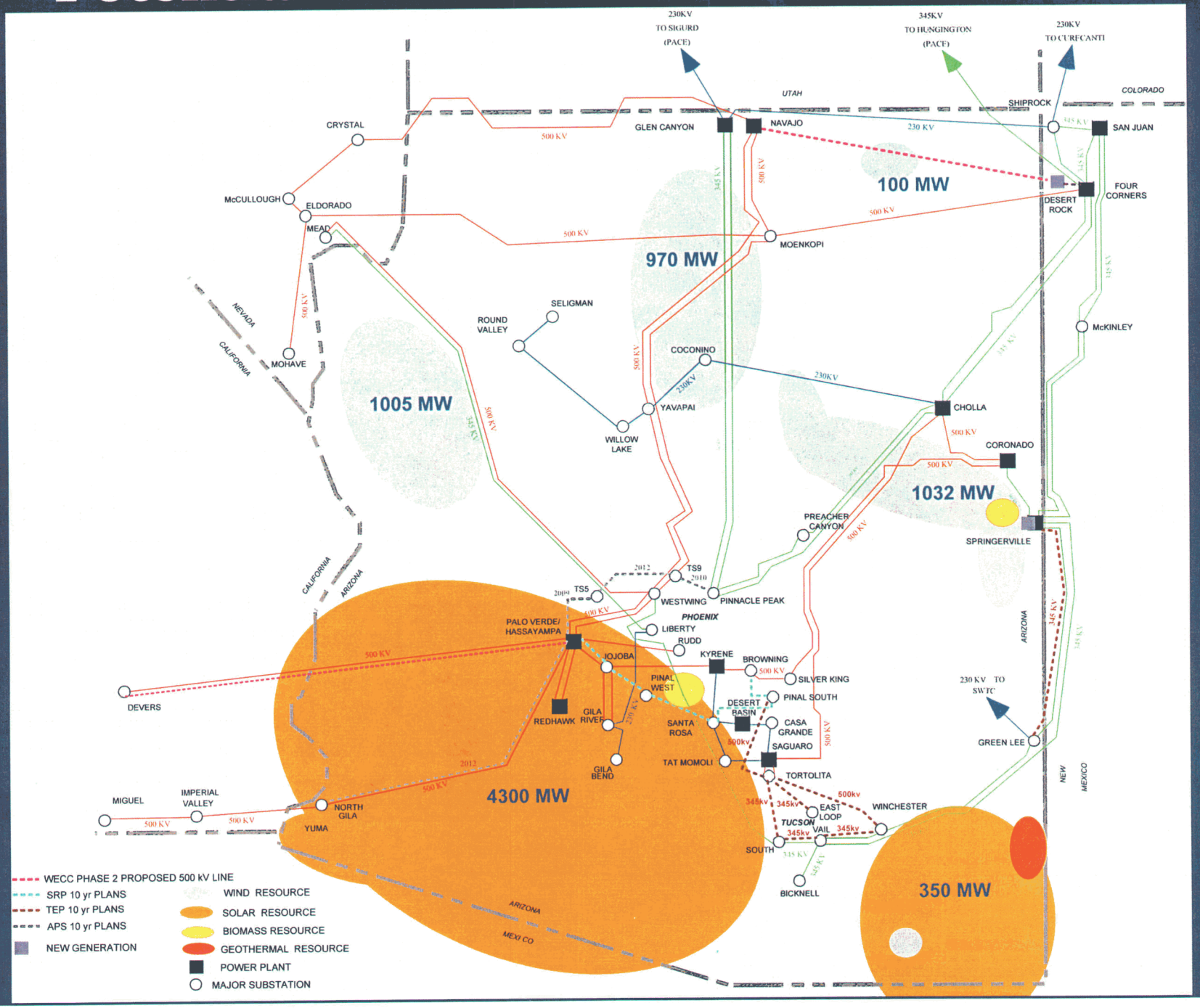
Code	MW Size
T1	80
T2	15
T3	15
T4	95
A1	60
A2	128
A3	22
A4	270
A5	250.5
A6	100
A7	110
A8	110
A9	300
A10	400
W1	500
W2	300
W3	65.1
W4	500
N1	100



SWAT RTTF
Part 2 - Resource Projection

- The map is intended to provide an overview of the potential, renewable resources within Arizona, which include wind, solar, biomass, hydro and/or geothermal and identifies those resources as clusters.
- Since both geothermal and biomass/biogas opportunities are small relative to both solar and wind opportunities, they have been included within the total which is described as generally wind and solar clusters.

Potential Arizona Renewable Resources



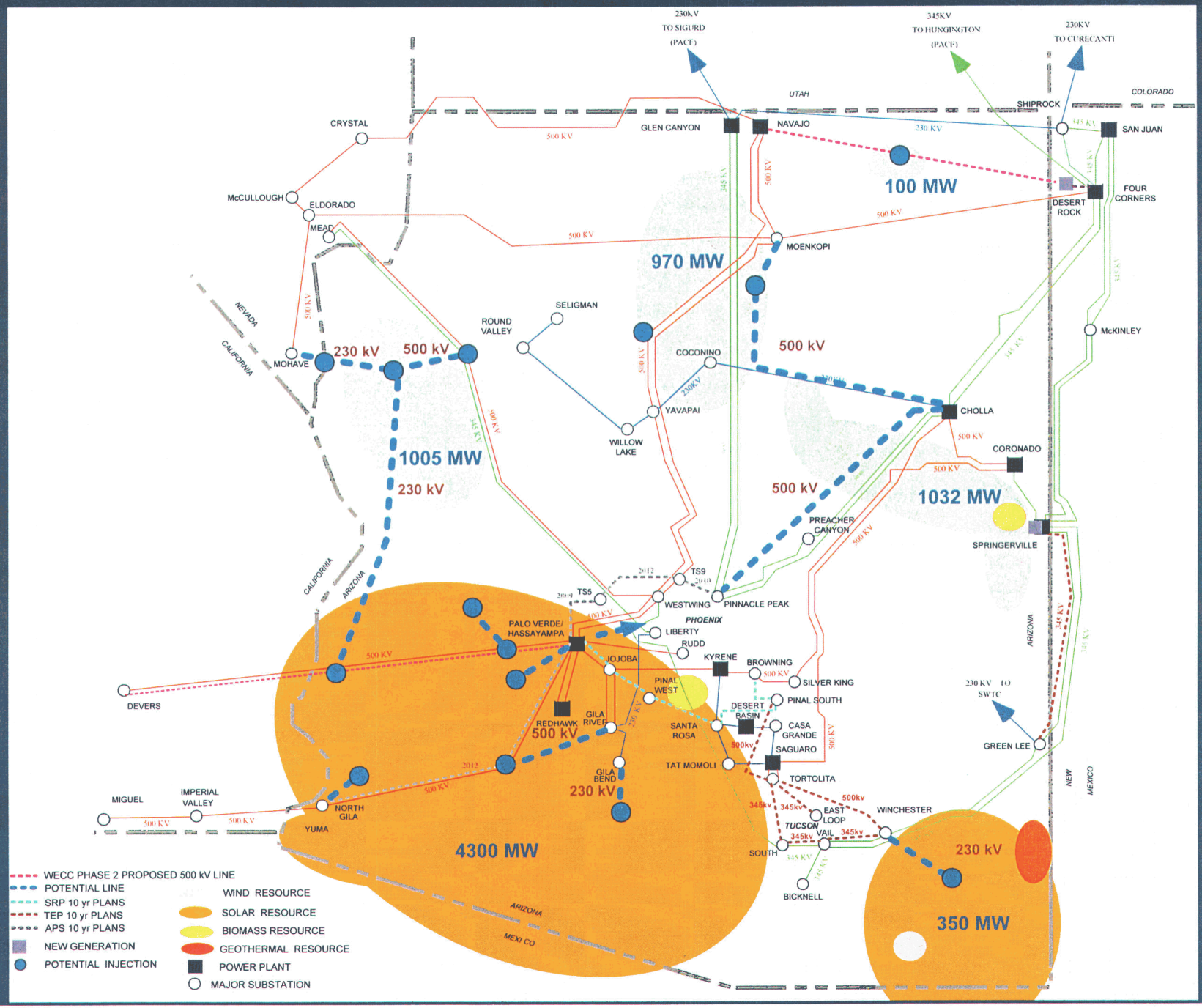
SWAT RTTF
Part 3 - Transmission System

- During the October 8th and November 16th 2007 meetings, transmission alternatives for bringing the renewable energy resources to load were discussed.
- Mapping was developed which represents the potential transmission lines that would be necessary if ***all*** of the renewable resources were to be developed in Arizona.

SWAT RTTF
Part 3 - Transmission System

- Included in the map are:
  - existing transmission lines
  - APS, SRP and TEP 10 year plans
  - other WECC Projects in Phase II process
  - potential transmission lines

Potential Configuration for Transmission to Serve All Available Renewable Resources in Arizona



Substation Additions	
Voltage (kV)	# of Substations Added
500	11
230	3

Transmission Circuits	
Voltage (kV)	Miles
500	445
230	247

Estimated Construction Costs

Totals	
	Cost (Million)
Substations	$130
Lines	$1,500
Total	$1,630

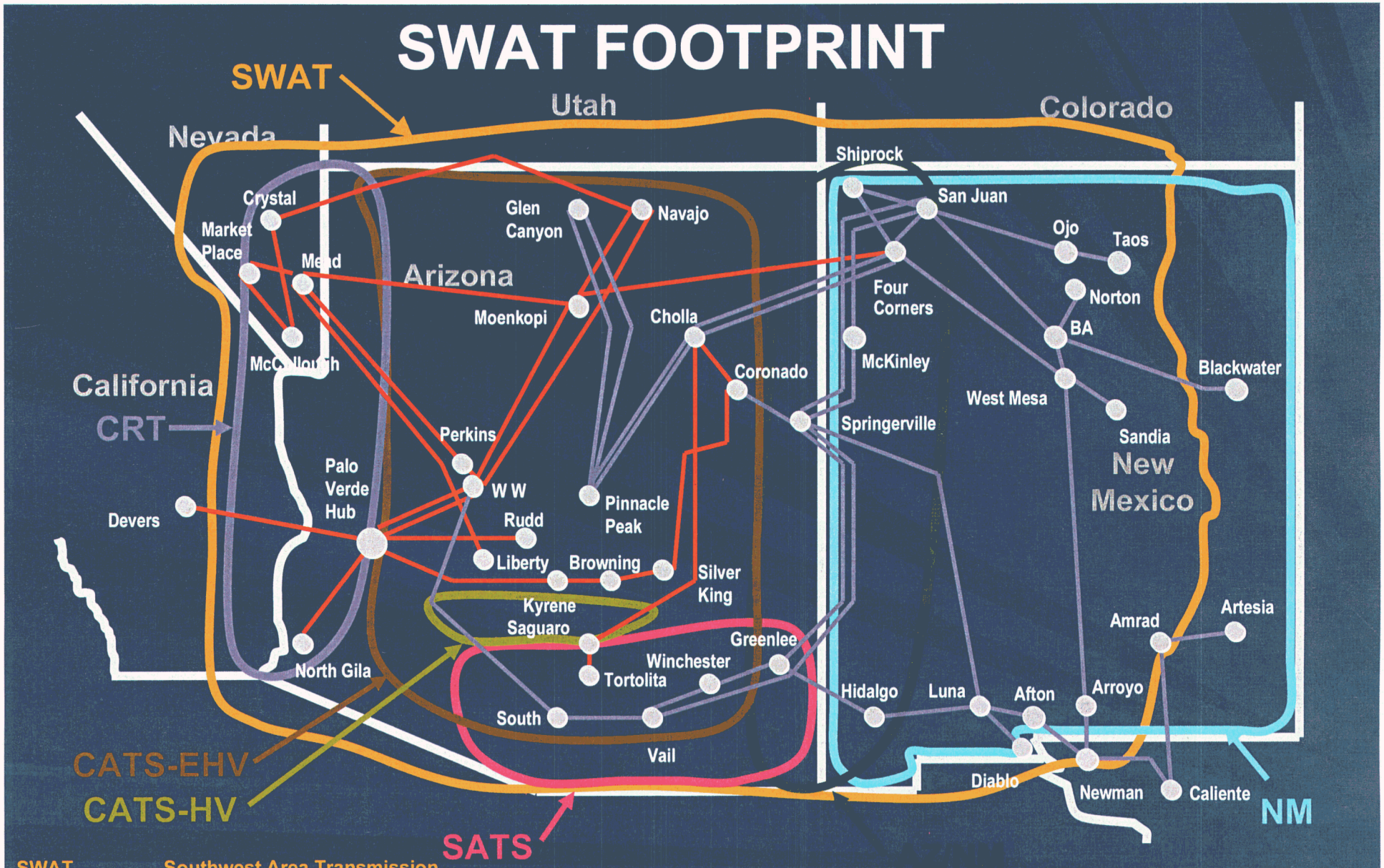
SWAT RTTF
Phase #2 – Evaluation and Integration of Renewable Resources into the Southwest Transmission Network

- Workshop Meetings held on April 7th and May 19th 2008
  - Renewable resource projection development
  - Potential transmission additions are in development for the entire SWAT area
- Renewable Taskforce has been extended to the entire SWAT area and includes Arizona, New Mexico, Nevada and Eastern California
- Power flow studies will be developed based on the transmission alternatives

SWAT Footprint
One of the WestConnect Sub-Regional Planning Groups

http://www.westconnect.com

SWAT FOOTPRINT



SWAT	Southwest Area Transmission
CRT	Colorado River Transmission
CATS – EHV	Central Arizona Transmission Study Extra High Voltage
CATS – HV	Central Arizona Transmission Study High Voltage
SATS	Southeast Arizona Transmission Study
AZ/NM	Arizona New Mexico Border Area Transmission
NM	New Mexico Transmission

500kV
345kV

Web Sites

WestConnect: http://www.westconnect.com/init_swat.php

Arizona Renewable Transmission Task Force BTA Response

Chairman of SWAT RTTF
Peter Krzykos
BTA Workshop
May 22-23 2008

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Appendix B
Fourth Biennial Transmission Assessment ACC Order, Docket No. E-00000D-05-0040, Decision No. 69389

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BEFORE THE ARIZONA CORPORATION COMMISSION

MIKE GLEASON
Chairman
WILLIAM A. MUNDELL
Commissioner
JEFF HATCH-MILLER
Commissioner
KRISTIN K. MAYES
Commissioner
GARY PIERCE
Commissioner

Arizona Corporation Commission
DOCKETED
MAR 22 2007
DOCKETED BY

IN THE MATTER OF THE COMMISSION'S FOURTH BIENNIAL TRANSMISSION ASSESSMENT ("BTA"), PURSUANT TO THE ADEQUACY OF EXISTING AND PLANNED TRANSMISSION FACILITIES TO MEET ARIZONA'S ENERGY NEEDS IN A RELIABLE MANNER

DOCKET NO. E-00000D-05-0040

DECISION NO. 69389

ORDER

Open Meeting
March 14, 2007
Phoenix, Arizona

BY THE COMMISSION:

FINDINGS OF FACT

1. The Utilities Division Staff ("Staff") of the Commission and its consultant, KEMA, Inc., have completed the fourth biennial assessment of Arizona's existing and planned transmission system. The Fourth Biennial Transmission Assessment, 2006-2015 ("Assessment" or "BTA") was filed with the Commission on February 14, 2007. The report was also posted on the Commission website at http://www.cc.state.az.us/utility/electric/biennial.htm under Hot Topics.

2. The Commission Staff held two workshops to gather stakeholders' input. Workshops were held on June 6, 2006 and September 8, 2006. The input received from the workshops and subsequent correspondence has been incorporated into the BTA.

3. Staff's report addresses the adequacy and reliability of Arizona's existing and planned transmission system and offers conclusions and recommendations for the Commission's consideration and action.

4. The ten-year transmission plans and study reports filed by the participants with the Commission are necessary to evaluate the adequacy and reliability of a transmission system. Staff was assisted by a consulting organization, KEMA, Inc., in analyzing the technical reports and documents filed by various organizations. Staff assembled and reviewed a broad spectrum of information and technical reports addressing transmission assessments from a national, western interconnection, regional, state and local utility perspective.

5. The electricity industry responded formally to the findings in the first, second and third biennial transmission assessment in a variety of ways. Regional transmission planning has been expanded, transmission facilities are being developed to increase transmission capacity out of the Palo Verde Hub, and local transmission import constraints are being sufficiently mitigated.

6. This transmission assessment represents the professional opinion of Staff and its Consultant, KEMA. The BTA is not an evaluation of individual transmission provider's facilities or quality of service. This BTA report does not set Commission policy and does not recommend specific action for any individual Arizona transmission provider. It assesses the adequacy of Arizona's transmission system to reliably meet existing and future energy needs of the state. Staff concludes in its report that the utility industry has implemented steps to address the regional transmission planning issues, provide transmission enhancements and additions, develop solutions for transmission import constraints in various load pockets, and address local transmission system inadequacies. These conclusions are based upon the following findings:

1. The electric industry in Arizona has been very responsive to concerns raised in Staff's Third BTA. In particular, the industry has performed studies and advanced projects that address Palo Verde Hub reliability issues. Palo Verde's transmission system capability to handle full generation output, and reliability must run ("RMR") concerns in the Phoenix and Yuma load areas.

2. The efforts of transmission providers and other stakeholders in the BTA continue to result in an improved work product and more collaborative study processes. Extensive regional studies addressing transmission needs have been conducted in a proactive and collaborative manner. This has also led to numerous jointly sponsored projects and synergies that increase the value of transmission projects to Arizona.

3. Numerous new transmission and generation projects have been constructed, announced and filed with the Commission since the prior BTAs. Some

transmission projects filed in prior BTAs have been cancelled, delayed or advanced based on changes in load, generation and import conditions. Staff finds these changes acceptable.

4. While there have been laudable efforts by stakeholders in support of coordinated regional planning activities, Staff recognizes that not all transmission projects are regional in nature. In fact, many smaller projects which are essential to serve local load areas or generators, by their very nature, do not require the participation of other stakeholders.

5. Transmission providers have performed updated RMR studies for each local transmission import constrained area (except Santa Cruz County and Mohave County) and have addressed the Third BTA RMR requirements. Uncertainty exists regarding RMR requirements in Santa Cruz County beginning 2008 and Mohave County beginning 2012, which should be addressed in filings due January 2008 for the 5th BTA.

6. In general, the existing and proposed Arizona transmission system meets the load serving requirements of the state in a reliable manner:

   a. Many planned Extra High Voltage ("EHV") and High Voltage ("HV") projects will increase transmission system capability to support increased interstate power transfers and provide reliable transfers within the state of Arizona.

   b. The EHV system appears to be adequate throughout the study period and the planned facilities identified in the ten-year planning process appear to be consistent with good utility practice. As is often the case, plans for the later years of the period are less well defined than those in the early years. As requested in the Third BTA, this new round of reports includes more discussion of alternate additions considered for the final five years of the study period. Given the number of alternative projects identified in the longer range plans it should be possible to supply future Arizona electric system loads in an economical and reliable fashion. Early identification of such alternatives in the BTA process allows the Staff and public to be better informed regarding future possibilities and should continue in future filings.

   c. The RMR studies show that the RMR areas will have load-serving capacity sufficient to provide reliable supply during the next ten-year period (with the exceptions noted in Conclusion 5). Problems identified during the Third BTA in the Yuma area in 2004 and the Phoenix area in 2013 are addressed and resolved in the 2006 RMR study.

   d. For the Phoenix and Yuma areas, based upon the study results reported for the two years examined (2008 and 2015), Staff concludes that the RMR costs and emission impacts should be negligible throughout the 2006-2015 period. For the Phoenix metropolitan area, Staff concludes that the simultaneous import limits ("SIL") and maximum load serving capability ("MLSC") increases are attributable to the transmission improvements described in the 2006 BTA

filings by Arizona Public Service Company ("APS") and Salt River Project ("SRP"). Installation of a second North Gila 500/69 kV transformer in 2005, along with the proposed Yucca 100 MW generation addition and second 500 kV Palo Verde-North Gila line appear to effectively meet RMR requirements in the Yuma area.[1] It is possible that Tucson area RMR requirements could be eliminated and the load area could have unlimited access to lower cost resources from the outside market if incremental upgrades are economically justified. Staff requests that Tucson Electric Power Company ("TEP") provide an economic analysis of this option in its 2008 BTA filing.

e. The planned Arizona transmission system meets the Western Electricity Coordinating Council ("WECC") and North American Electric Reliability Council ("NERC") single contingency criteria (n-1). Satisfactory performance of the system has also been demonstrated during the Fourth BTA for significant overlapping contingencies (n-1-1 and n-2) as requested in the Third BTA.

f. Arizona transmission providers are doing an effective job of planning transmission upgrades and additions that improve access to capacity from merchant plants at Palo Verde in a reliable manner, which in the past has been stranded to some extent when the market has desired access. Some improvement has already been achieved in 2006 and significant improvement is expected with the addition of the Hassayampa-Pinal West-Santa Rosa 500 kV and Palo Verde-TS5 500 kV line additions in 2008 and 2009, respectively. In conjunction with other proposed transmission upgrades, these projects should significantly mitigate market limitations between Arizona, California and southern Nevada.

g. The Fourth BTA also concludes that after the addition of Hassayampa-Pinal West-Santa Rosa 500 kV and Palo Verde-TS5 500 kV lines the need for load shedding in Arizona following a common corridor outage of 500 kV lines leaving the Palo Verde Hub will be eliminated.

7. Studies investigating transmission expansion options between Arizona, southern Nevada and New Mexico continue to explore the scope, participation and timing of alternative projects. Other transmission expansion projects proposed in Nevada may bring additional resources closer to the borders of Arizona. APS has also initiated regional stakeholder discussions for a conceptual TransWest Express 500 kV Project that could significantly increase import capability into Arizona from future coal and wind resources in Wyoming. Such regional projects may provide both economic and reliability benefits to Arizona consumers and increase import/export capabilities between Arizona and surrounding markets.

8. Some new power plants have interconnected to Arizona's bulk transmission system via single transmission line or tie rather than using Arizona's best engineering practices of multiple lines emanating from power plants. As interconnection of new transmission lines are considered for the Palo Verde Hub,

[1] It should be noted that APS' Yucca generation solicitation is the subject of a separate proceeding before the Commission.

the concerned parties should be encouraged to terminate at these new power plant switchyards in order to mitigate this regional reliability concern.

9. The Southwest Area Transmission Central Arizona Transmission System ("SWAT-CATS") EHV study participants conducted a joint 2015 "Tenth Year Snap-Shot (N-1) Study" for Central Arizona to assess the collective impact of individual transmission owner plans for the area. The study determined that there are no n-1 violations in the planned EHV system. Some problems were identified in lower voltage systems, however. These will need to be addressed in the respective planning processes of the individual transmission owners. Certain n-1 contingency violations occurring in the Southwest Transmission Cooperative ("SWTC") 2015 planning study and certain n-2 and extreme contingency results in TEP's 2016 case still need to be resolved. These issues occur at or beyond the last year of the current 10-year plan and there is still sufficient time to satisfactorily resolve these concerns.

10. Staff concludes that the direction of collaborative planning processes by transmission providers and stakeholders in Arizona is consistent with the spirit of the requirements for transmission planning described in Energy Policy Act-05 ("EPAct") and Federal Energy Regulatory Commission ("FERC") Order 888. This collaborative planning processes is reinforced by the recent decision of the WECC to form a Transmission Expansion Planning Policy Committee to provide a transparent West-wide stakeholder process for related data and studies.

11. Regarding the CATS-HV interim study; since the rate of population and load growth in the area of study could be quite rapid, revisiting the study every 3-5 years would be preferable to the 5-10 year cycle suggested in the report.

7. Concerns outlined by Staff in the above conclusions are not easily or quickly resolved. The public's best interest warrants effective and decisive remedies. Therefore, Staff offers the following recommendations for Commission consideration and action:

1. Continue to support use of:

   a. "Guiding Principles for ACC Staff Determination of Electric System Adequacy and Reliability" to aid Staff in its determination of adequacy and reliability of power plant and transmission line projects.

   b. NERC and WECC criteria and FERC policies regarding the transmission system reliability, and

   c. Collaborative study activities between transmission providers and merchant plant developers for the purpose of:

      i. Ensuring consumer benefits of generation additions and cost-effective transmission enhancements and interconnections, and

...

ii. Facilitating restructuring of the electric utility industry to reliably serve Arizona consumers at just and reasonable rates via competitive wholesale market.

2. Endorse Staff's recommendations that:

a. RMR studies continue to be performed and filed with ten year plans in even numbered years for inclusion in future BTA reports and that

i. Future RMR studies continue to provide more transparent information on input data and economic dispatch assumptions.

ii. More stringent study criteria and assumptions be explored and implemented for RMR areas as has been done in other jurisdictions for recognized load pocket areas.

b. Accept the results of the following studies provided as part of the Fourth BTA filings:

i. Compliance with single contingency criteria overlapped with the bulk power system facilities maintenance (n-1-1) for the first year of the BTA analysis period as required by WECC and NERC.

ii. Extreme contingency outages studied for Arizona's major generation hubs and major transmission stations and associated risks and consequences documented if mitigating infrastructure improvements are not planned.

iii. TEP should file comments by June 30, 2007 to resolve concerns inside neighboring New Mexico and Western Area Power Administration ("WAPA") facilities identified in its preliminary study results for 2016.

c. Generation interconnections should be granted a Certificate of Environmental Compatibility by the Commission only when they meet regional and national reliability criteria and the requirements of the Commission's decisions in the 2004 BTA and Track A related to power plant interconnections.

d. Grant SWTC an extension to January 2008 to resolve certain n-1 contingency violations in its 2015 planning study and to file expansion plans to resolve these issues as part of its 2008-2017 plan.

e. Assuming that WAPA timely and fully provides the necessary information, UniSource is prepared to file an updated RMR Study for Mohave County, as well as for Santa Cruz County, in January of 2008.

8. Staff has recommended that the Commission adopt Staff's Fourth Biennial Transmission Assessment, 2006-2015 as set forth above.

...

9. While the Fourth BTA does not directly address the implementation of renewable energy resources in Arizona, the Assessment does include a discussion at Section 7.2 of the usefulness of including in future BTA's information regarding the location, amounts, and transmission available for renewable resources in Arizona. The BTA also notes that a recent report to the Western Governors Association called on states to urge utilities to maximize the use of existing transmission and to urge utilities to analyze Available Transmission Capacity ("ATC"). It is the Commission's view that in the next BTA, Commission regulated electric utilities, in consultation with the stakeholders, should prepare an assessment of Available Transmission Capacity for renewable energy and prepare a plan to bring available renewable resources to load. The plan should include a description of the location, amount and transmission needs of renewable resources in Arizona. Inclusion of this information in the BTA would advance the goals of the Commission's Renewable Energy Standard rules, the Western Governors Association's Clean and Diversified Energy Advisory Committee ("CEDEAC") report and FERC Order 890.

CONCLUSIONS OF LAW

1. According to A.R.S. § 40-360.02.A, "Every person contemplating construction of any transmission line within the state during any ten year period shall file a ten year plan with the Commission on or before January 31 of each year."

2. According to A.R.S. §40-360.02.G, "The plans shall be reviewed biennially by the Commission and the Commission shall issue a written decision regarding the adequacy of the existing and planned transmission facilities in this state to meet the present and future energy needs of this state in a reliable manner."

3. The Commission, having reviewed the Fourth Biennial Transmission Assessment 2006-2015, concludes that the assessment complies with A.R.S. §40-360.02.

ORDER

THEREFORE, IT IS ORDERED that the Fourth Biennial Transmission Assessment 2006 - 2015 is hereby issued as the Commission's biennial assessment in accordance with A.R.S. §40-360.02.G.

IT IS FURTHER ORDERED that in the next BTA, Commission regulated electric utilities, in consultation with the stakeholders, should prepare an assessment of ATC for renewable energy and prepare a plan, including a description of the location, amount and transmission needs of renewable resources in Arizona, to bring available renewable resources to load.

IT IS FURTHER ORDERED that the above ATC plan shall be discussed and commented on by Staff in the Fifth BTA.

IT IS FURTHER ORDERED that Staff recommendations contained herein are hereby adopted by the Commission.

IT IS FURTHER ORDERED that this Order shall become effective immediately.

BY THE ORDER OF THE ARIZONA CORPORATION COMMISSION

CHAIRMAN COMMISSIONER

COMMISSIONER COMMISSIONER COMMISSIONER

IN WITNESS WHEREOF, I BRIAN C. McNEIL, Executive Director of the Arizona Corporation Commission, have hereunto, set my hand and caused the official seal of this Commission to be affixed at the Capitol, in the City of Phoenix, this 22nd day of March, 2007.

BRIAN C. McNEIL
Executive Director

DISSENT: _____

DISSENT: _____

EGJ:PKB:lhm\CH

Decision No. 69389

SERVICE LIST FOR: Biennial Transmission Assessment
DOCKET NO. E-00000D-05-0040

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Appendix C
Arizona Renewable Transmission Task Force Progress Summary,
December, 2007

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Arizona Renewable Transmission Task Force

Progress Summary

December 2007

BTA Order

"IT IS FURTHER ORDERED that in the next BTA, Commission regulated electric utilities, in consolation with the stakeholders, should prepare an assessment of ATC for renewable energy and prepare a plan, including a description of the location, amount and transmission needs of renewable resources in Arizona, to bring available renewable resources to load."

Outline

- October 8th 2007 meeting
- November 16th 2007 meeting
- Renewable resource queue in Arizona
- Projected resource locations and potential
- Master transmission map developed at November 16th 2007 meeting
- ATC in Arizona

Arizona Renewable Transmission Task Force

October 8th 2007

Meeting Recap

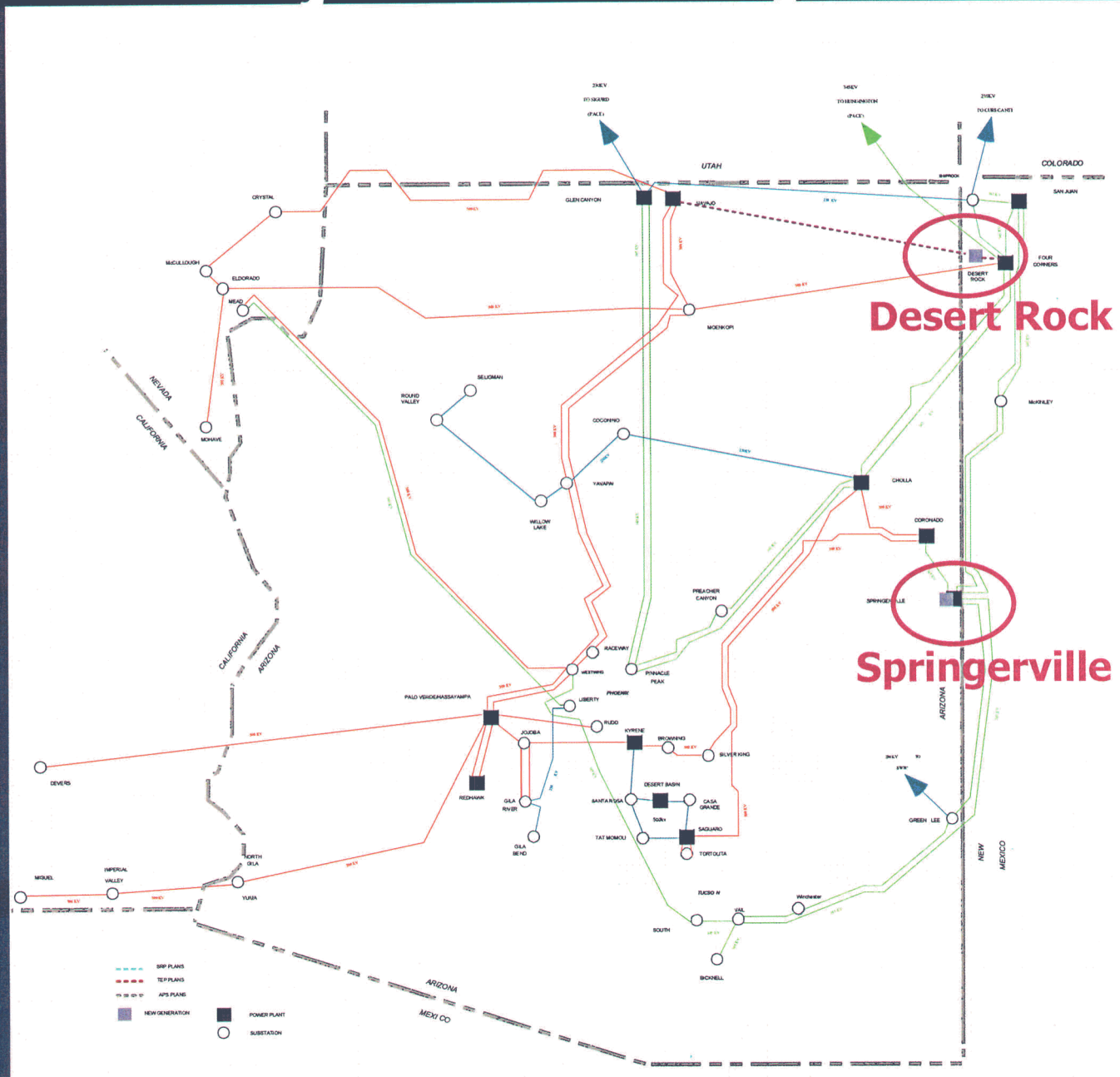
Agenda

- BTA order
- Projected resource projects (non-renewable)
- Existing ATC in Arizona
- SRP, APS, and TEP 10 year plans
- Projected ATC in the next 10 years
- Discussion / recommended transmission plans in Arizona

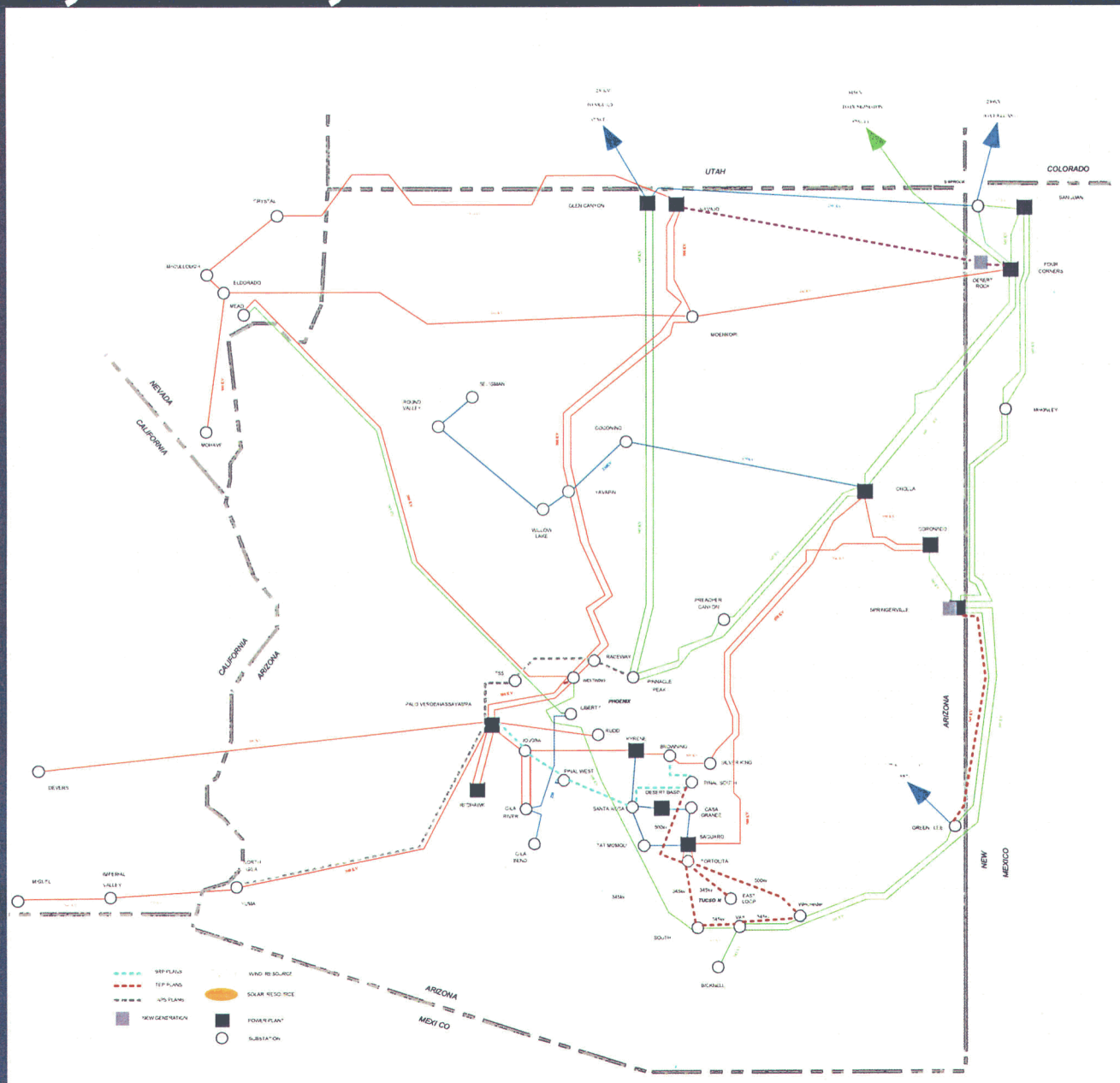
Projected Resource Projects in Arizona (non-renewable)

- Desert Rock (APS)
  - 1400 MW
  - To be implemented in 2012
  - Located in northeast Arizona
- Springerville (SRP)
  - 430 MW
  - To be implemented in 2009

Projected Projects



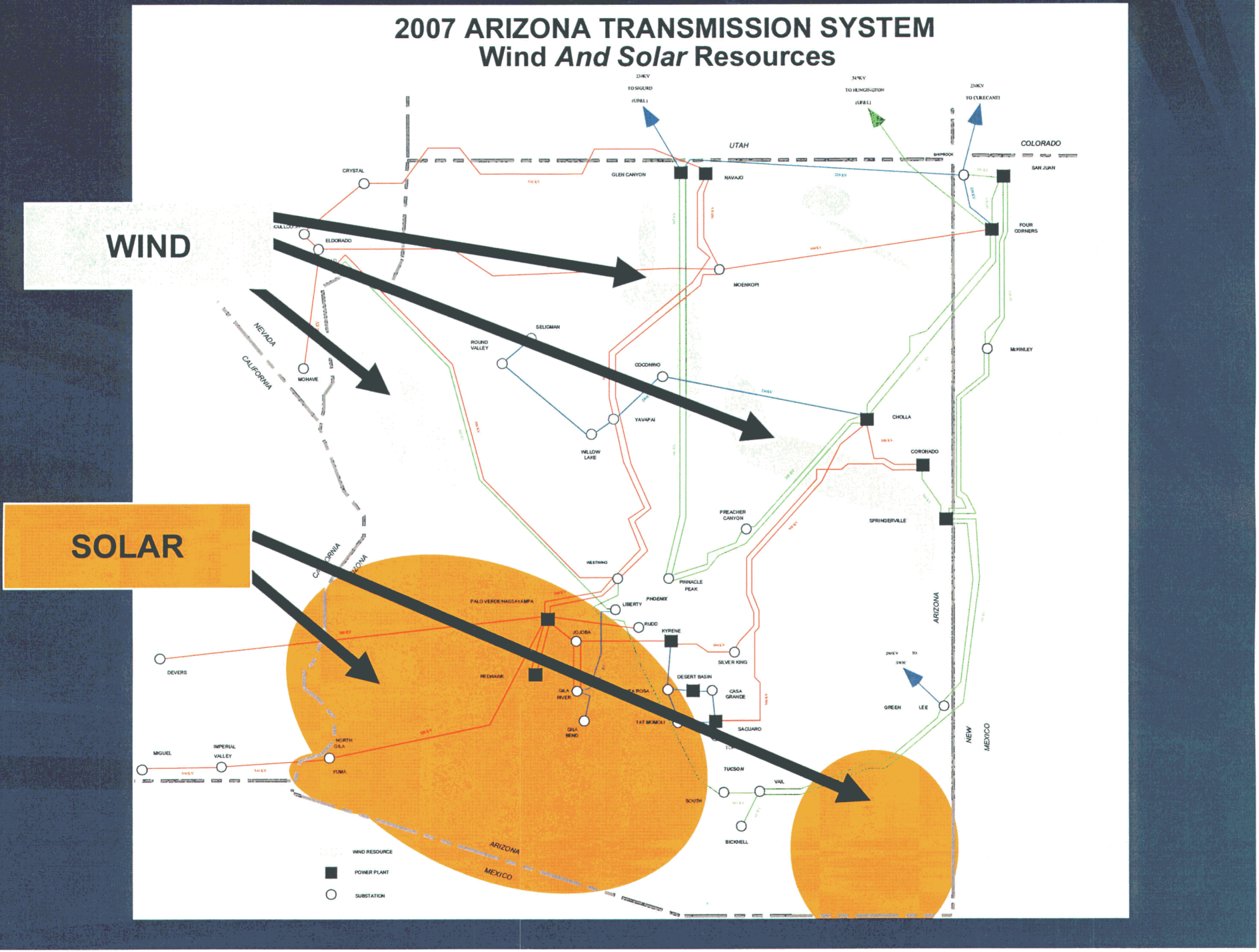
APS, SRP, TEP 10 Year Plans



Renewable Resources

- Major resources
  - Wind
    - Primarily in northern Arizona
  - Solar
    - Primarily in southern Arizona
- Other resources
  - Geothermal
  - Biomass
  - Hydro

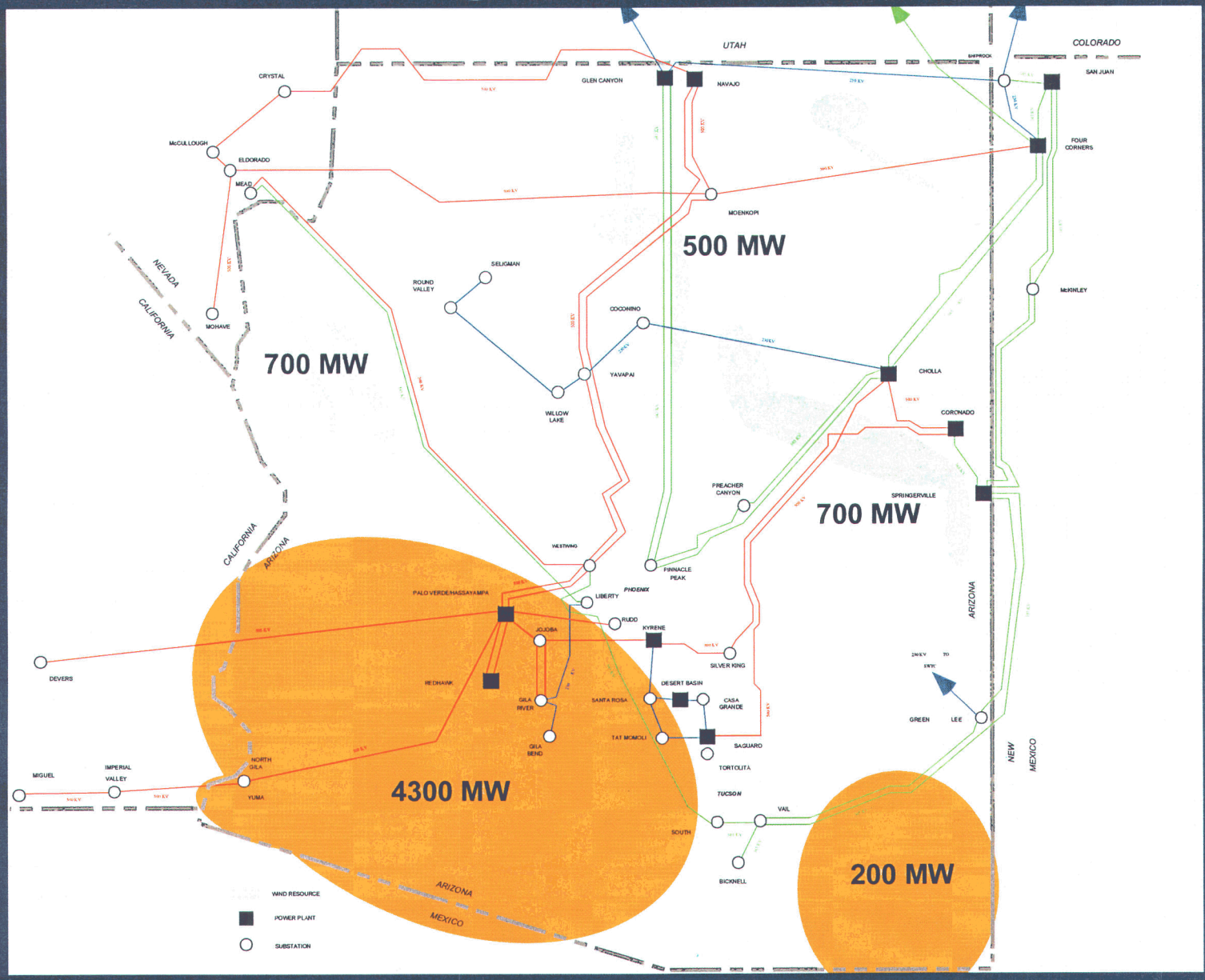
2007 ARIZONA TRANSMISSION SYSTEM
Wind *And Solar* Resources



Results From Oct. 8th Meeting

- Initial estimates of renewable resources were augmented
- Three groups were formed to brainstorm possible future transmission scenarios in the Arizona
- Three different Arizona transmission maps were created, and to be merged at a later date

Changes To Renewable Energy Potential During Oct 8th Meeting



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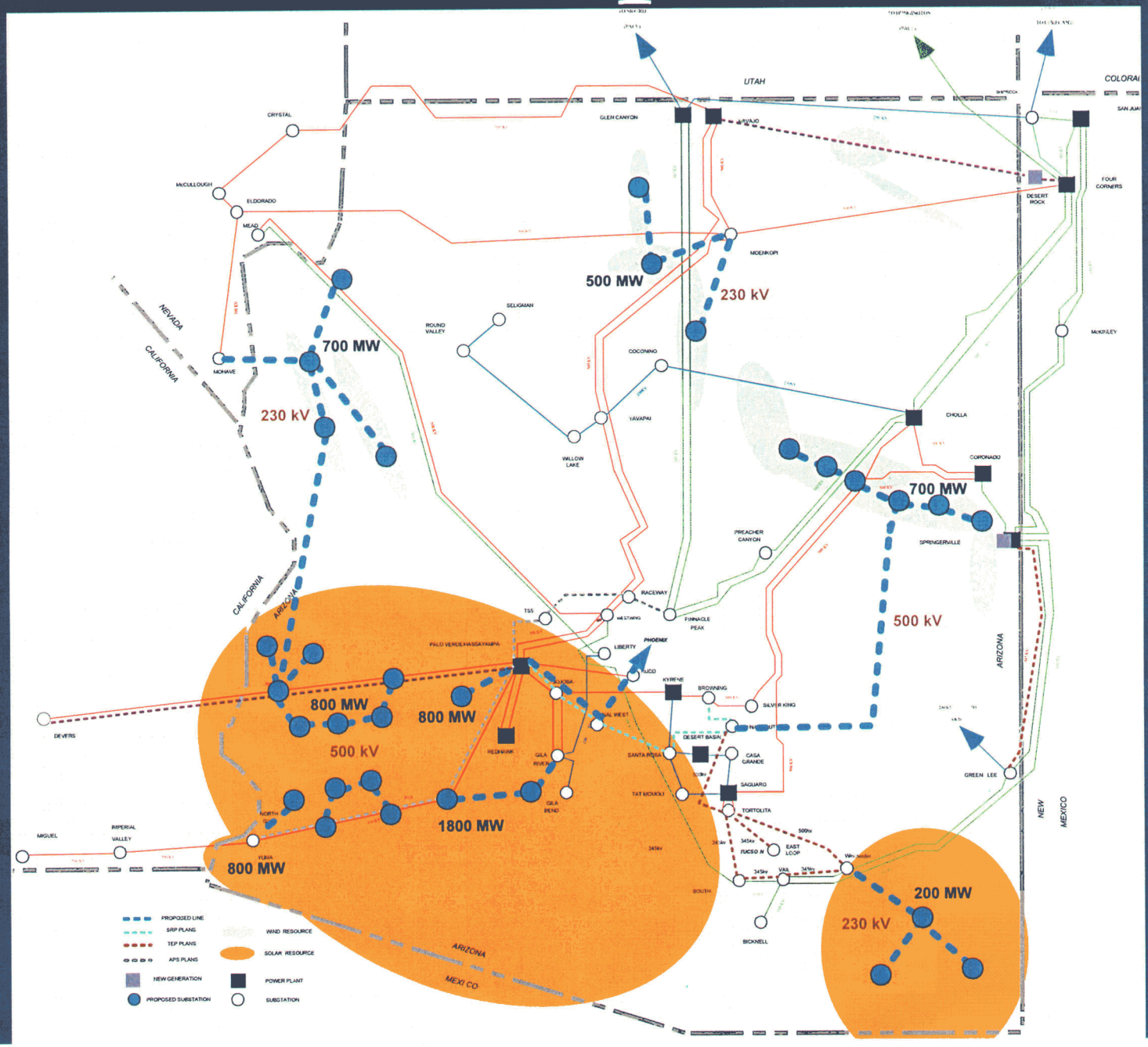
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CRYSTAL
GLEN CANYON
McCULLOUGH
ELDORADO
MEAD
NAVAJO
DESERT ROCK
FOUR CORNERS
MOENKOPI
500 MW
230 kV
NEVADA
CALIFORNIA
SELIGMAN
ROUND VALLEY
700 MW
MOHAVE
230 kV
COCONINO
McKINLEY
YAVAPAI
CHOLLA
WILLOW LAKE
CORONADO
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PREACHER CANYON
SPRINGERVILLE
RACEWAY
500 kV
CALIFORNIA
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WESTWING
FINNIGLE PEAK
PALO VERDE/HASSAYAMPA
LIBERTY
PHOENIX
ARIZONA
KYRENE
BROWNING
SILVER KING
800 MW
800 MW
500 kV
DEVERS
REDHAWK
GILA RIVER
SOUTH WEST
DESERT BASIN
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SANTA ROSA
GREEN LEE
SAGUARO
TAT MOMOLI
GILA BEND
TORTOLITA
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MIGUEL
IMPERIAL VALLEY
YUMA
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TEP PLANS
APS PLANS
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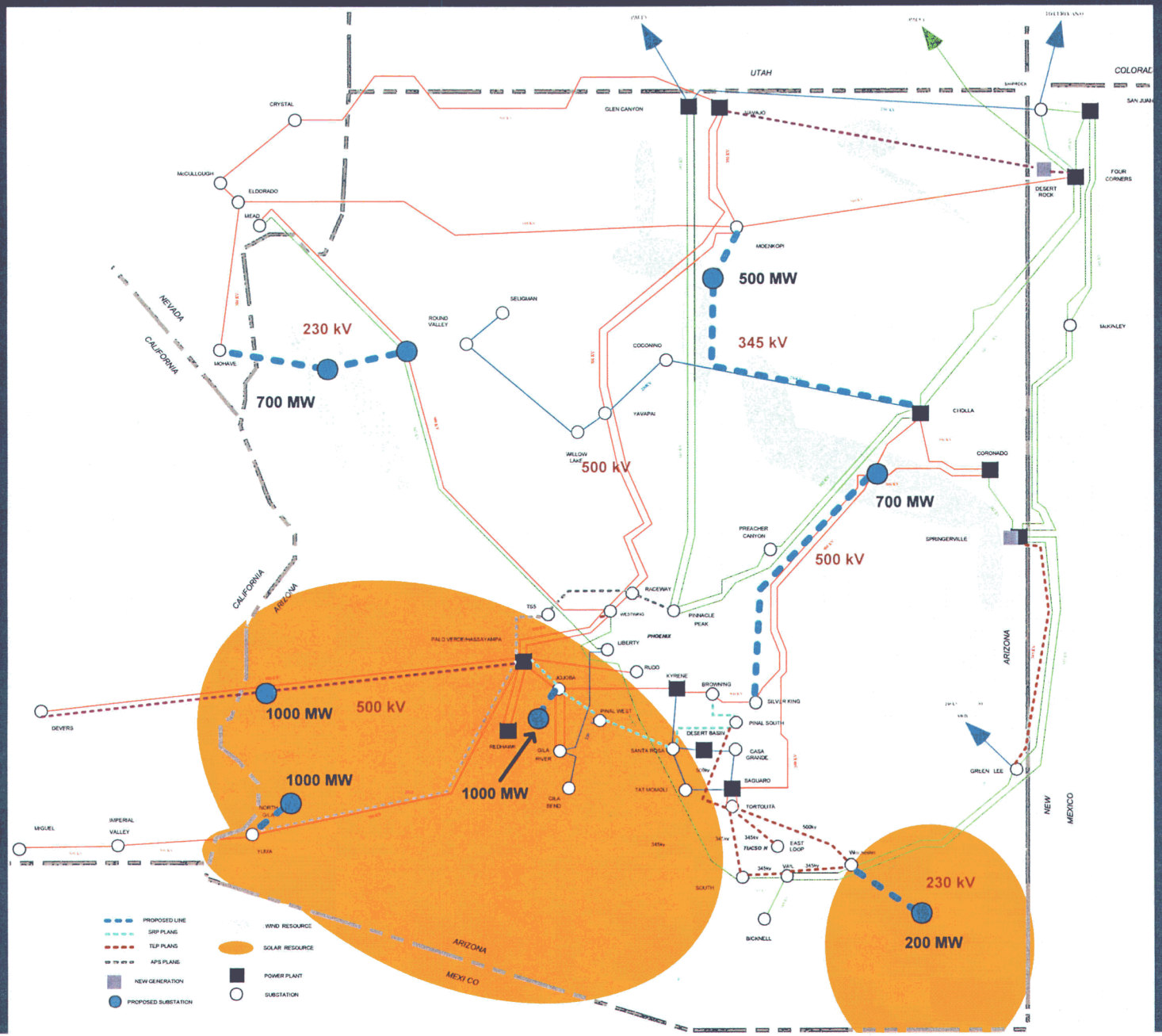
Group B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DEVERS
MIGUEL
IMPERIAL VALLEY
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1000 MW
500 kV
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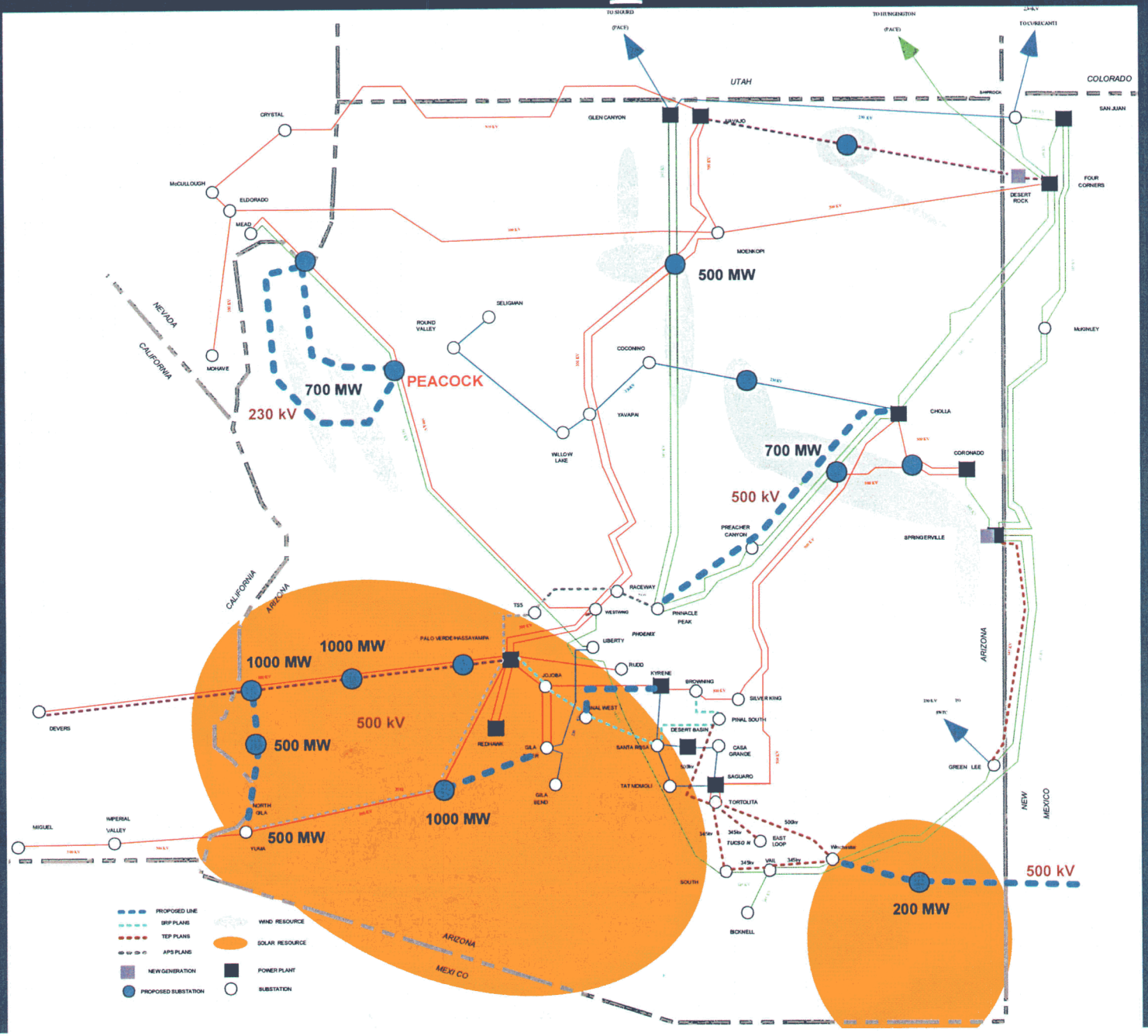
200 MW
PROPOSED LINE
SRP PLANS
TEP PLANS
APS PLANS
NEW GENERATION
PROPOSED SUBSTATION
WIND RESOURCE
SOLAR RESOURCE
POWER PLANT
SUBSTATION

Group C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LAVAJO
SAN JUAN
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DESERT ROCK
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YELLOW LAKE
McKINLEY
700 MW
PEACOCK
230 kV
CHOLLA
CORONADO
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PREACHER CANYON
SPRINGERVILLE
RACEWAY
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WESTWING
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PALO VERDE/HASSAYAMPA
1000 MW
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500 MW
DEVERS
JOJOBA
RUDD
KYRENE
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PROPOSED LINE
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NEW GENERATION
PROPOSED SUBSTATION
WIND RESOURCE
SOLAR RESOURCE
POWER PLANT
SUBSTATION

Arizona Renewable Transmission Task Force

November 16th 2007

Meeting Recap

Agenda

- October 8th meeting recap
- Black and Veatch summary
- Renewable energy queue in Arizona
- ATC in Arizona
- Discussion / recommend transmission plans in Arizona

Black & Veatch Summary

Projected Resource Locations

1. Solar CSP/Yuma – 800MW
2. Solar CSP/Stoval – 1,900MW
3. Solar CSP/Phoenix – 800MW
4. Solar CSP/Tucson – 800MW
5. Wind/Project KS – 18MW
6. Wind/Project RS – 140MW
7. Wind/Project BR – 158MW
8. Wind/Project CV – 597MW
9. Wind/Project BH – 46MW
10. Wind/Project GP – 31MW
11. Biomass/Biogas – 60MW (22 sites)
12. Geothermal/Clifton – 35MW
13. Hydro – 82MW (7 sites, 90% @ GC)

Black & Veatch Summary

Announced Resource Locations

- **A** Wind/Western - 215MW
- **B** Wind/Foresight - 60WW
- **C** Wind/Hopi Tribe – 100MW
- **D** Wind/PPM – 99MW
- **E** Biomass/Biogas – 10MW (3 sites)

Black & Veatch Summary

Combined Resource Areas

1. Solar CSP/Yuma – 800MW
2. Solar CSP/Stoval – 1,900MW
3. Solar CSP/Phoenix – 800MW
4. Solar CSP/Tucson – 800MW
5. Wind/Project KS – 18MW
6. Wind/Project RS – 140MW
7. Wind/Project BR – 158MW
8. Wind/Project CV – 597MW
9. Wind/Project BH – 46MW
10. Wind/Project GP – 31MW
11. Biomass/Biogas – 60MW (22 sites)
12. Geothermal/Clifton – 35MW
13. Hydro – 82MW (7 sites, 90% @ GC)

- A. Wind/Western - 215MW
- B. Wind/Foresight - 60WW
- C. Wind/Hopi Tribe – 100MW
- D. Wind/PPM – 99MW
- E. Biomass/Biogas – 10MW (3 sites)

Black & Veatch Summary

Data Source - Projected

Table 1-1. Arizona Renewable Energy Resources Available in the Near- to Mid-Term.

Technology	Location	Cost (2007$/MWh)	Capacity (MW)	Generation (GWh/yr)
Direct Fired Biomass	Maricopa	143	20	140
Biomass Cofiring	2 potential sites: TEP's Springerville generating station and APS's Cholla generating station	58 - 63	20	140
Landfill Gas	15 potential small projects identified across the state	82 - 99	10	68
Anaerobic Digestion	Snowflake, Buckeye, Chandler, and Maricopa	62 - 128	10	69
Solar Thermal Electric	100 MW project in 2011. 2–4 200 MW sites per year after 2012	161- 176	4,300[a]	10,940[a]
Hydroelectric	7 potential sites[b]	32 - 215	82	320
Wind	6 potential sites near Kingman and the White Mountains[c]	75 - 141	991	2551
Geothermal	Clifton Hot Springs and Gillard Hot Springs	110 - 122	35	215
Total			**5468**	**14,443**

Notes:

[a] The solar potential is vast, and this only includes projects sufficient for meeting Arizona's forecast renewable energy demands through 2025.

[b] Glen Canyon compromises 90 percent of total potential.

[c] 500 MW of planned wind generation not included.

Black & Veatch Summary

Data Source - Announced

Table 3-2. Renewable Energy Projects in Arizona.

Technology / Project Name	Owner	MW	COD
Biomass			
Los Reales Landfill Cofiring	TEP	4	1999
Tri Cities Landfill	SRP	5	2001
Eagar Biomass	Western Renewable Energy	3.7 to 4.7*	2008*
Skunk Creek Landfill	Ameresco	3	2008**
27th Ave. Landfill	Cambrian	3	2009**
Snowflake White Mountain Power	NZLegacy Energy LLC	24	2008**
Hydroelectric			
Arizona Falls	SRP	0.8	2003
Solar			
Santan Solar	SRP	0.097	1998
Santan Solar	SRP	0.097	1999
Star	APS	0.2	2000
Flagstaff	APS	0.08	1997
Ocotillo	APS	0.1	1998
Tempe	APS	0.18	1998
Gilbert (AZ)	APS	0.12	1999
Municipal Rooftops	APS	0.1	1999
Ocotillo	APS	0.1	1999
Scottsdale	APS	0.03	1999
Microelectronics Rooftop	APS	0.02	2000
Glendale	APS	0.2	2001
Prescott ERAU Solar	APS	0.2	2001
Agua Fria	SRP	0.2	2001
Yucca	APS	0.1	2001
Prescott Airport Solar Plant	APS	3.4	2002-06
Springerville Generating Station	TEP	5.1	2002-03
Saguaro	APS	1	2005
Wind* **			
Steel Park Wind	Western Wind Energy	15	2007**
Sunshine Wind Energy Park	Foresight Energy Co	60	2007**
Sunset Mountains Wind	Hopi Tribe (Tbe)	100	2007**
Dry Lake Wind	PPM Energy Inc	99	2008**
Steel Park Wind	Western Wind Energy	100	2008**
Steel Park Wind	Western Wind Energy	100	2009**
Total Existing		**24**	
Total Proposed		**504**	

Source: Utilities, GED

Notes:

* Generator is 4.7MW, boiler damaged, was not capable of powering the generator at 4.7MW. May replace with larger boiler.

** Planned / Proposed Projects (COD subject to change).

*** None of the wind projects are currently under contract to sell power.

Black & Veatch Summary
Project Sensitivities/Filters

- Solar Thermal
  - Equipment availability/supply chain
  - Development timelines/engineering support
  - Project economics
  - Proximity to adequate transmission
  - Land availability/terrain slope/proximity to sensitive areas
- Wind
  - Equipment availability/supply chain
  - Class/Capacity factor
  - Project economics
  - Proximity to adequate transmission
  - Proximity to federal/environmental sensitive areas

Black & Veatch Summary

Data Source - Solar

Specific site locations were not identified at this stage of analysis. Generic projects have been identified for four areas in Arizona: • Stoval, Yuma, Phoenix, Tucson. The characteristics for these plants are shown below:

Project	Capacity, MW	CF, %	Generation, GWh	First Year Available
Stoval Trough 1	100	30%	261	2011
Stoval Trough 2	200	30%	522	2013
Stoval Trough 3	200	30%	522	2013
Stoval Trough 4	200	30%	522	2014
Stoval Trough 5	200	30%	522	2014
Stoval Trough 6	200	30%	522	2015
Stoval Trough 7	200	30%	522	2015
Stoval Trough 8	200	30%	522	2016
Stoval Trough 9	200	30%	522	2016
Stoval Trough 10	200	30%	522	2016
Phoenix Trough 1	200	27%	478	2019
Phoenix Trough 2	200	27%	478	2019
Phoenix Trough 3	200	27%	478	2019
Phoenix Trough 4	200	27%	478	2019
Tucson Trough 1	200	29%	503	2018
Tucson Trough 2	200	29%	503	2018
Tucson Trough 3	200	29%	503	2018
Tucson Trough 4	200	29%	503	2018
Yuma Trough 1	200	29%	513	2017
Yuma Trough 2	200	29%	513	2017
Yuma Trough 3	200	29%	513	2017
Yuma Trough 4	200	29%	513	2017

The Stoval area, about 80 miles southwest of Phoenix along Interstate 8, has the highest DNI of the potential sites (7.4 kwh/m2/day – per satellite data), with potential areas of low land slope. Because of the improved performance, it has been assumed that initial project deployment would occur at Stoval. A key issue with this area is that a large portion of the land in the region is within the Barry M. Goldwater Air Force Range.

The Yuma site would be southeast of Yuma in the Yuma Desert. The Yuma area has a high satellite DNI of 7.3 kwh/m2/day. Like the Stoval area, the Yuma area could be subject to constraints because of the Barry M. Goldwater Air Force Range.

The Phoenix area would generally be west of Phoenix because of terrain constraints. The area has a satellite DNI of 6.8 kwh/m2/day. The Phoenix TMY2 DNI is 6.9 kWh/m2/day.

The Tucson area could include areas such as the Avra Valley to the west of Tucson and the Sulphur Springs Valley to the east. The area has a satellite DNI of 7.2 kwh/m2/day.

Black & Veatch Summary

Data Source - Wind

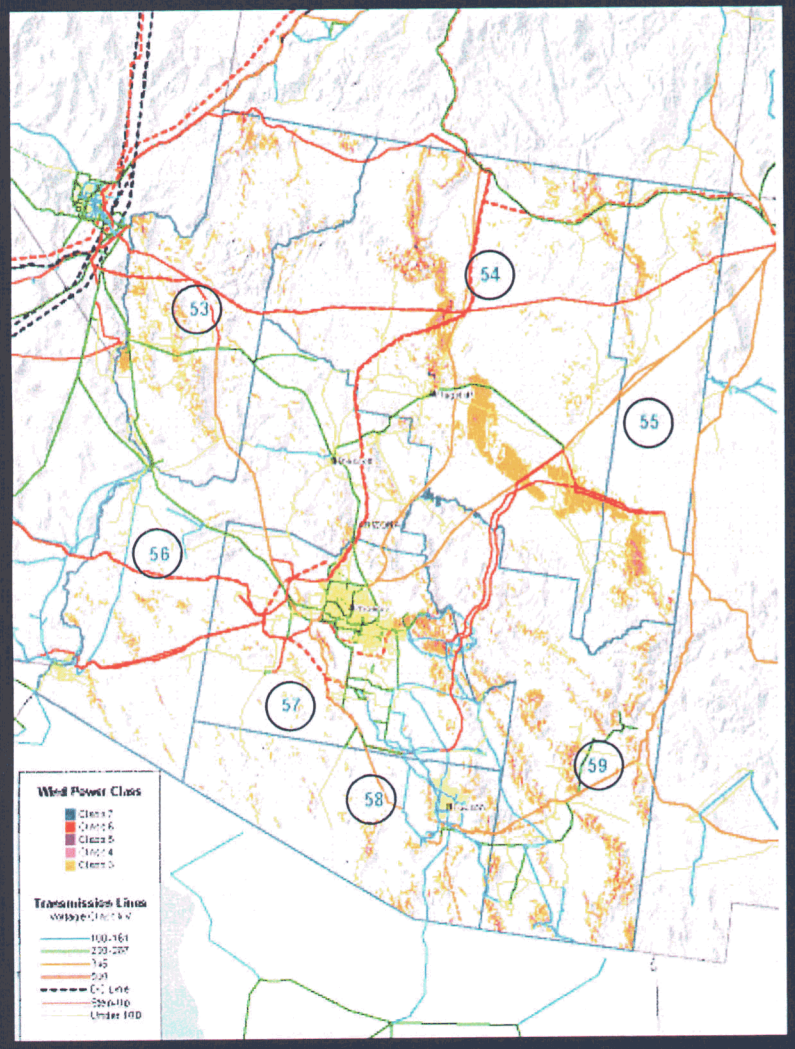


Table 4-21. Arizona Wind Technical Potential

Region	Capacity by Wind Power Class					Total Capacity
	3	4	5	6	7	
53	2,042	255	47	9	1	2,355
54	12,764	586	240	104	12	13,706
55	3,376	407	62	18	1	3,864
56	129	22	2	0	0	152
57	713	115	33	16	2	879
58	194	60	12	2	0	267
59	1,321	370	123	53	4	1,870
Total	20,538	1,814	519	202	20	23,093

Source: Donna Heimiller, NREL, 2006

Note: Total technical potential, assuming 5 MW of capacity per square km.

Table 4-21 The initial screen shows the theoretical potential capacity from wind power class in seven regions in Arizona as estimated by NREL. The regions correspond to the large regions shown in the wind resource map. This theoretical or technical potential is not bound by the constraints of product availability (backordered turbines, for instance), site-specific constraints such as transmission capacity, environmental restrictions, or cost.

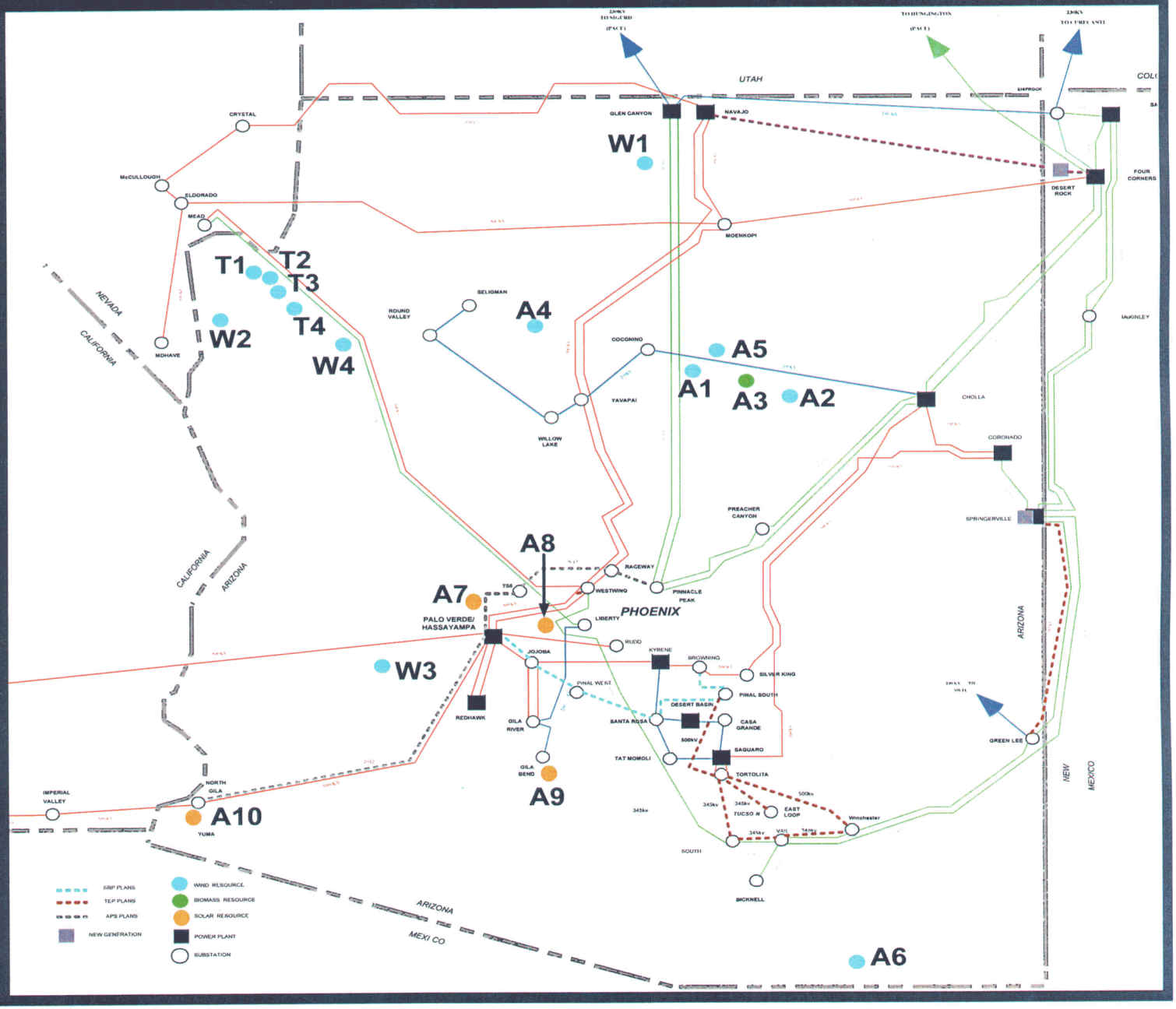
To determine near-term developable potential for wind, sites were reviewed in light of proximity to adequate transmission (greater than 69 kV), proximity to federal or environmentally sensitive areas, and constructability. The results developed a much smaller set of resources that could potentially be built and financed in the near term.

Arizona Renewable Resource Queue

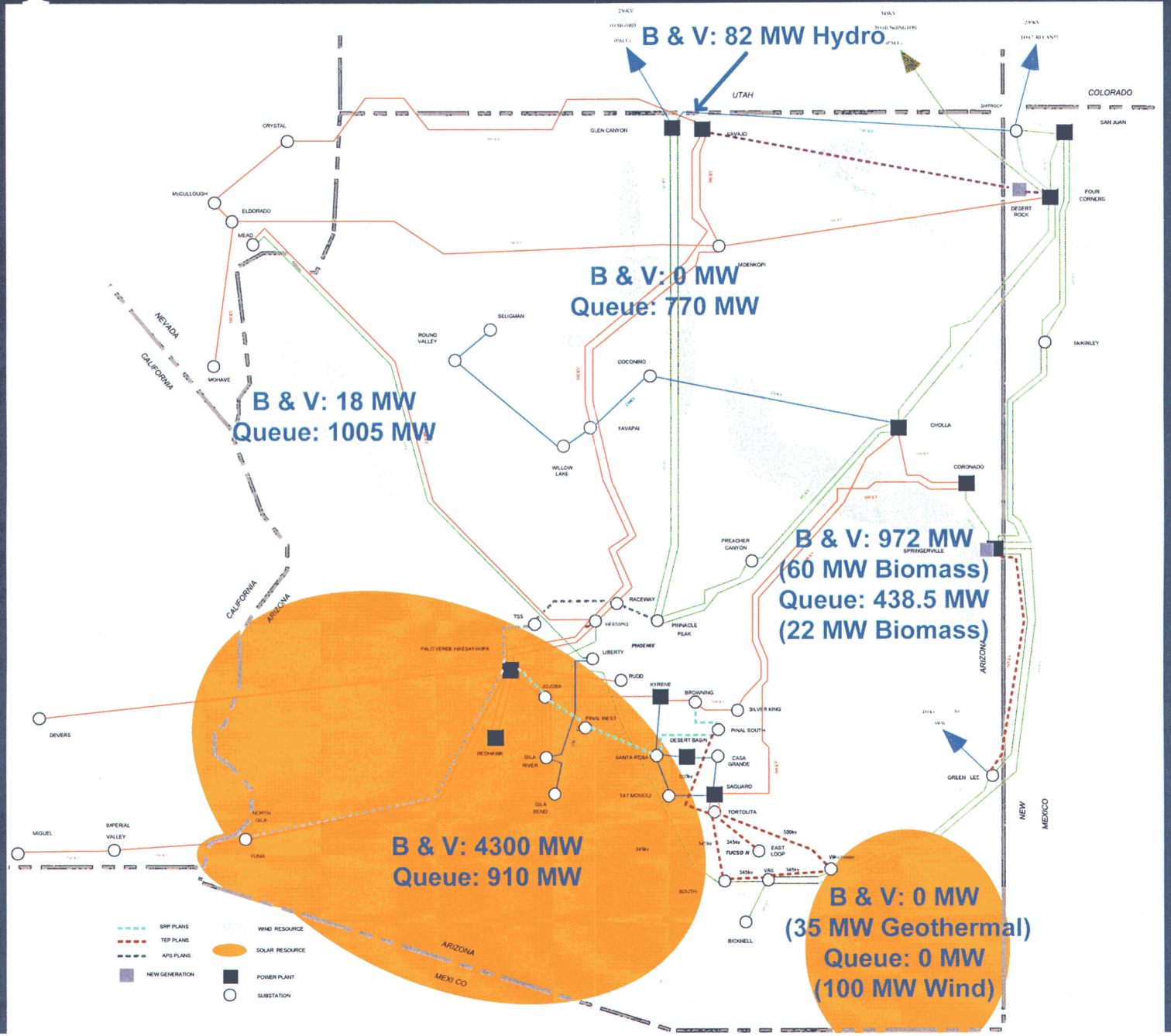
Code	Company	COD	MW Size	POI	County	Type
T1	TEP	2005	80	Dolan Springs Sub	Mohave	Wind
T2	TEP	2008	15	Dolan Springs Sub	Mohave	Wind
T3	TEP	2005	15	Dolan Springs Sub	Mohave	Wind
T4	TEP	2007	95	Co-Spr	St Johns	Wind
A1	APS	2008	60	Cholla - Coconino	Coconino	Wind
A2	APS	2008	128	Cholla Show	Coconino	Wind
A3	APS	2007	22	Cholla zeniff	Coconino	Biomass
A4	APS	2008	270	Ashofork - Pollock	Coconino	Wind
A5	APS	2009	250.5	cholla - show	Coconino	Wind
A6	APS	2010	100	Adams - Mural	Cochise	Wind
A7	APS	2011	110	Harquahala Jnc	Maricopa	Solar
A8	APS	2011	110	Panda Liberty line	Maricopa	Solar
A9	APS	2010	300	Gila Bend	Maricopa	Solar
A10	APS	2010	400	North Gila Sub	Yuma	Solar
W1	WAPA	2008	500	Tap on 345kV Glen Canyon-Pinnacle Peak	Coconino	Wind
W2	WAPA	2008	300	Mead - Davis 230 kV Line	Mohave	Wind
W3	WAPA	2008	65.1	Goldmine Tap Substation	Imperial	Wind
W4	WAPA	2008	500	Peacock Substation	Mohave	Wind
Total			3320.6			

Arizona Renewable Resource Queue

Code	MW Size
T1	80
T2	15
T3	15
T4	95
A1	60
A2	128
A3	22
A4	270
A5	250.5
A6	100
A7	110
A8	110
A9	300
A10	400
W1	500
W2	300
W3	65.1
W4	500

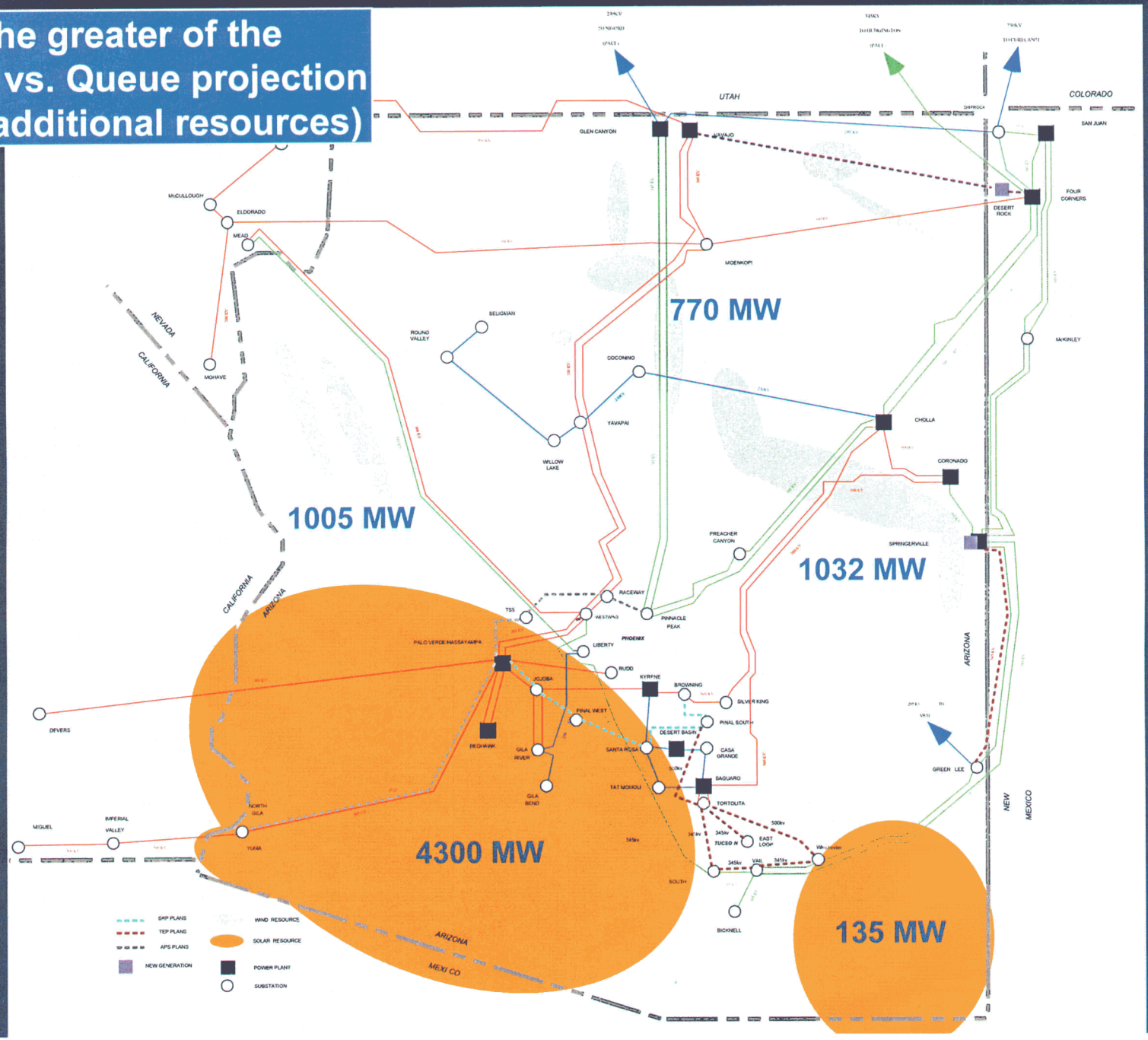


Updated Renewable Resources



Proposed Renewable Resource Projection

The greater of the B & V vs. Queue projection (plus additional resources)



Results From Nov. 16th Meeting

- Renewable resource location and potential are finalized
- Master transmission map was created
- Arizona renewable resource queue is updated to include Navajo Nation projects
- An ATC map is to be developed based on presentations given at a transfer capability stakeholders meeting given in Phoenix on June 27, 2007.

Arizona Renewable Resource Queue

Code	Company	COD	MW Size	POI	County	Type
T1	TEP	2005	80	Dolan Springs Sub	Mohave	Wind
T2	TEP	2008	15	Dolan Springs Sub	Mohave	Wind
T3	TEP	2005	15	Dolan Springs Sub	Mohave	Wind
T4	TEP	2007	95	Co-Spr	St Johns	Wind
A1	APS	2008	60	Cholla - Coconino	Coconino	Wind
A2	APS	2008	128	Cholla Show	Coconino	Wind
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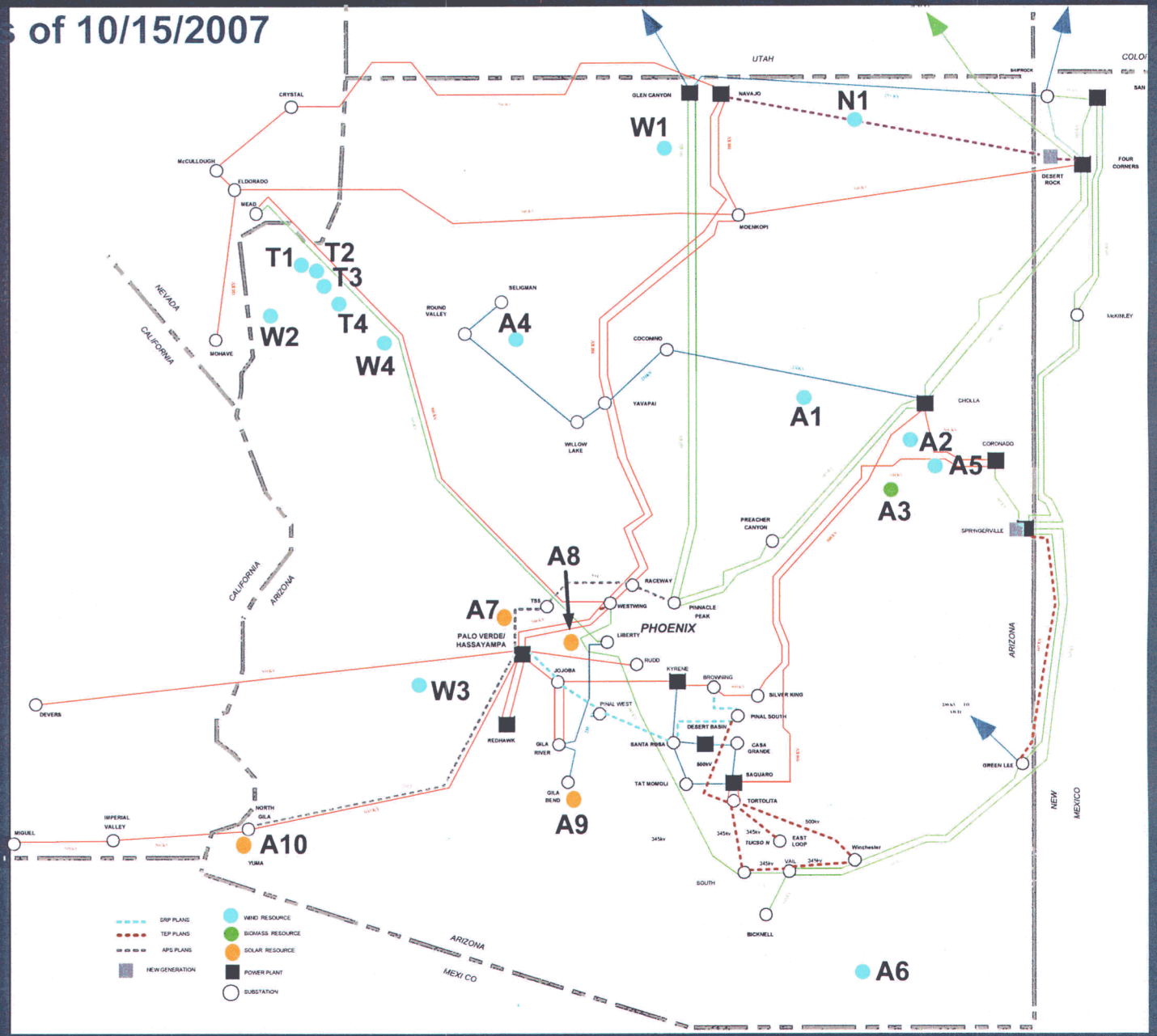
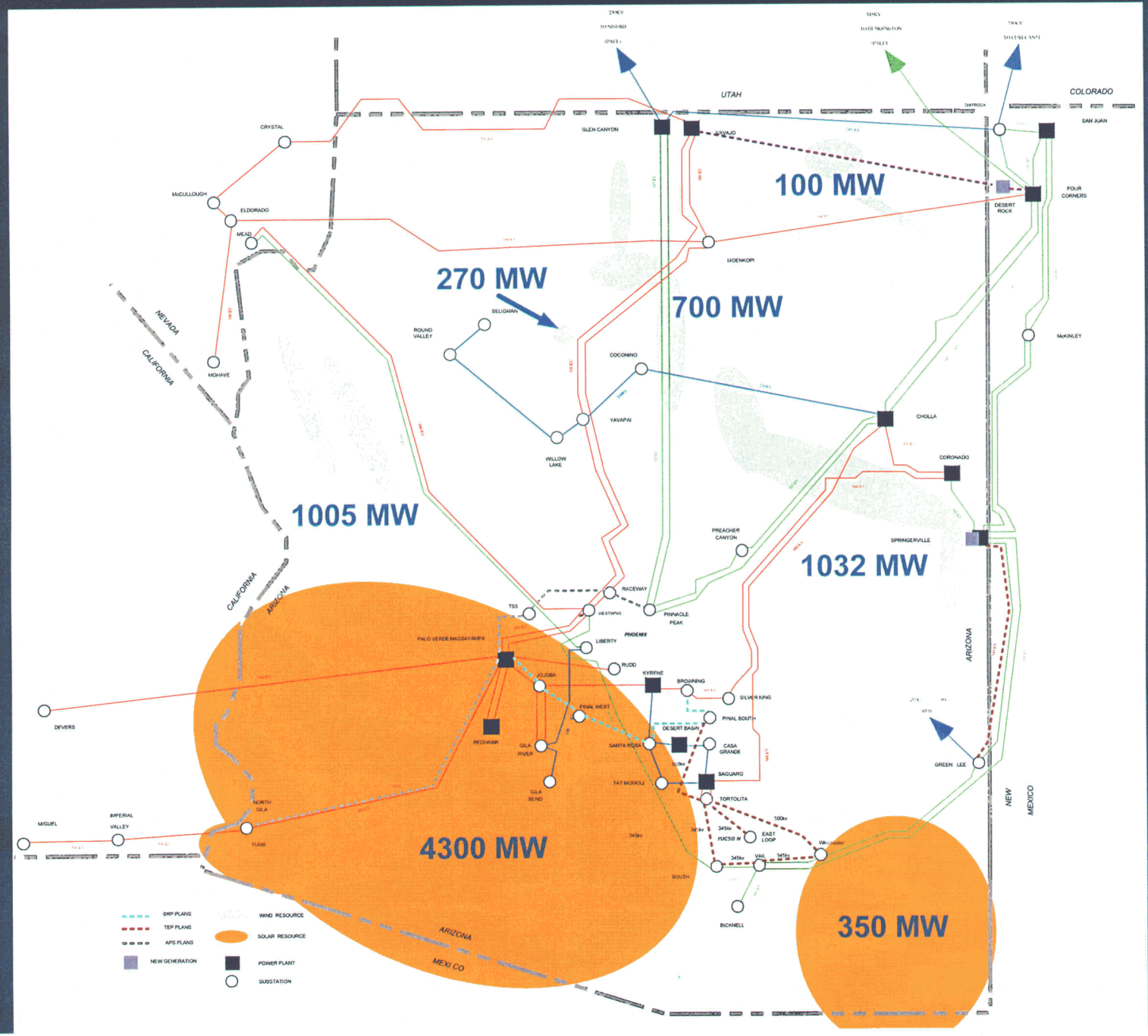
A8	APS	2011	110	Panda Liberty line	Maricopa	Solar
A9	APS	2010	300	Gila Bend	Maricopa	Solar
A10	APS	2010	400	North Gila Sub	Yuma	Solar
W1	WAPA	2008	500	Tap on 345kV Glen Canyon-Pinnacle Peak	Coconino	Wind
W2	WAPA	2008	300	Mead - Davis 230 kV Line	Mohave	Wind
W3	WAPA	2008	65.1	Goldmine Tap Substation	Imperial	Wind
W4	WAPA	2008	500	Peacock Substation	Mohave	Wind
N1	Navajo Nation		100			Wind
Total			3420.6	As of 10/15/2007		

Arizona Renewable Resource Queue

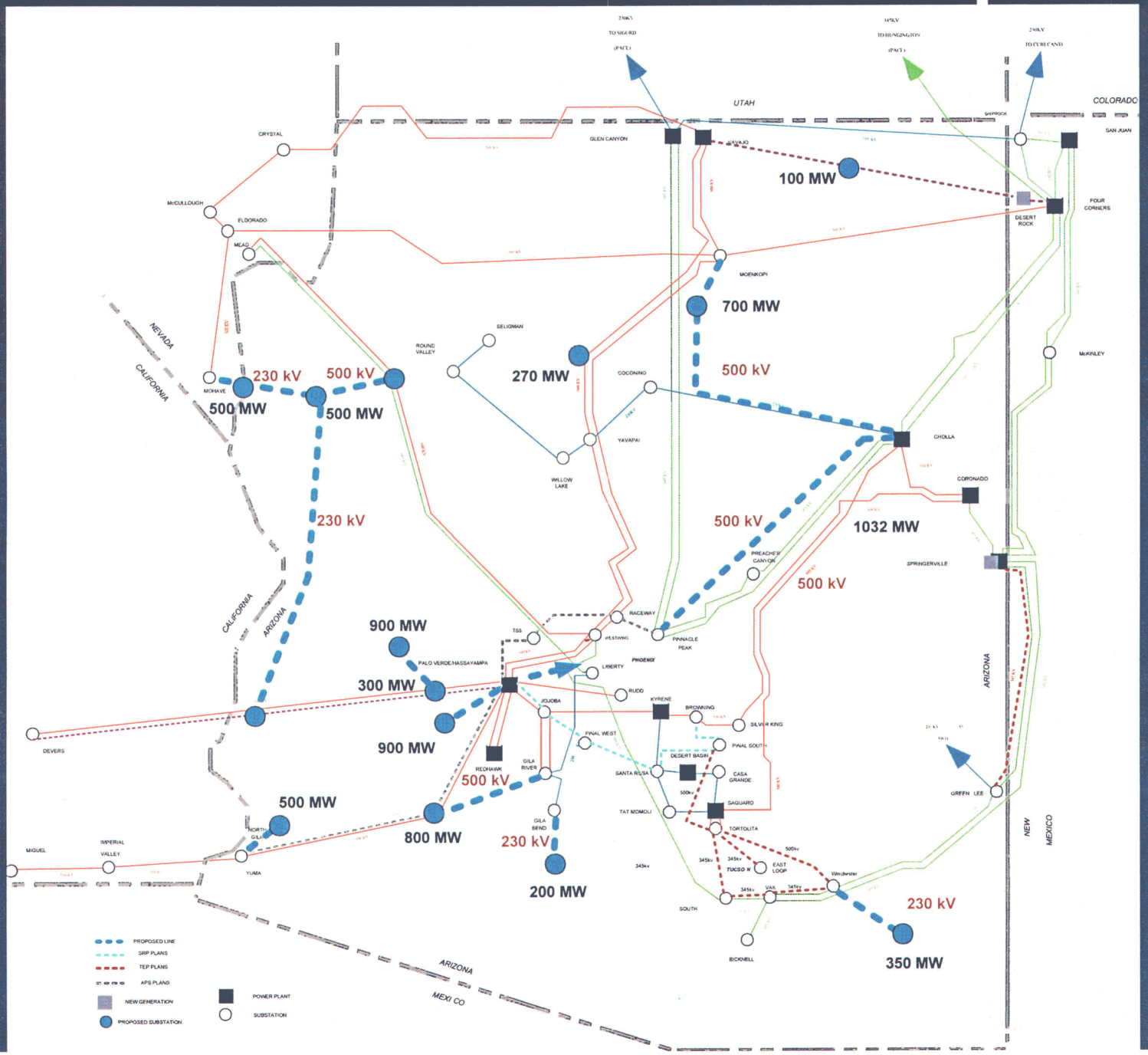
Code	MW Size
T1	80
T2	15
T3	15
T4	95
A1	60
A2	128
A3	22
A4	270
A5	250.5
A6	100
A7	110
A8	110
A9	300
A10	400
W1	500
W2	300
W3	65.1
W4	500
N1	100



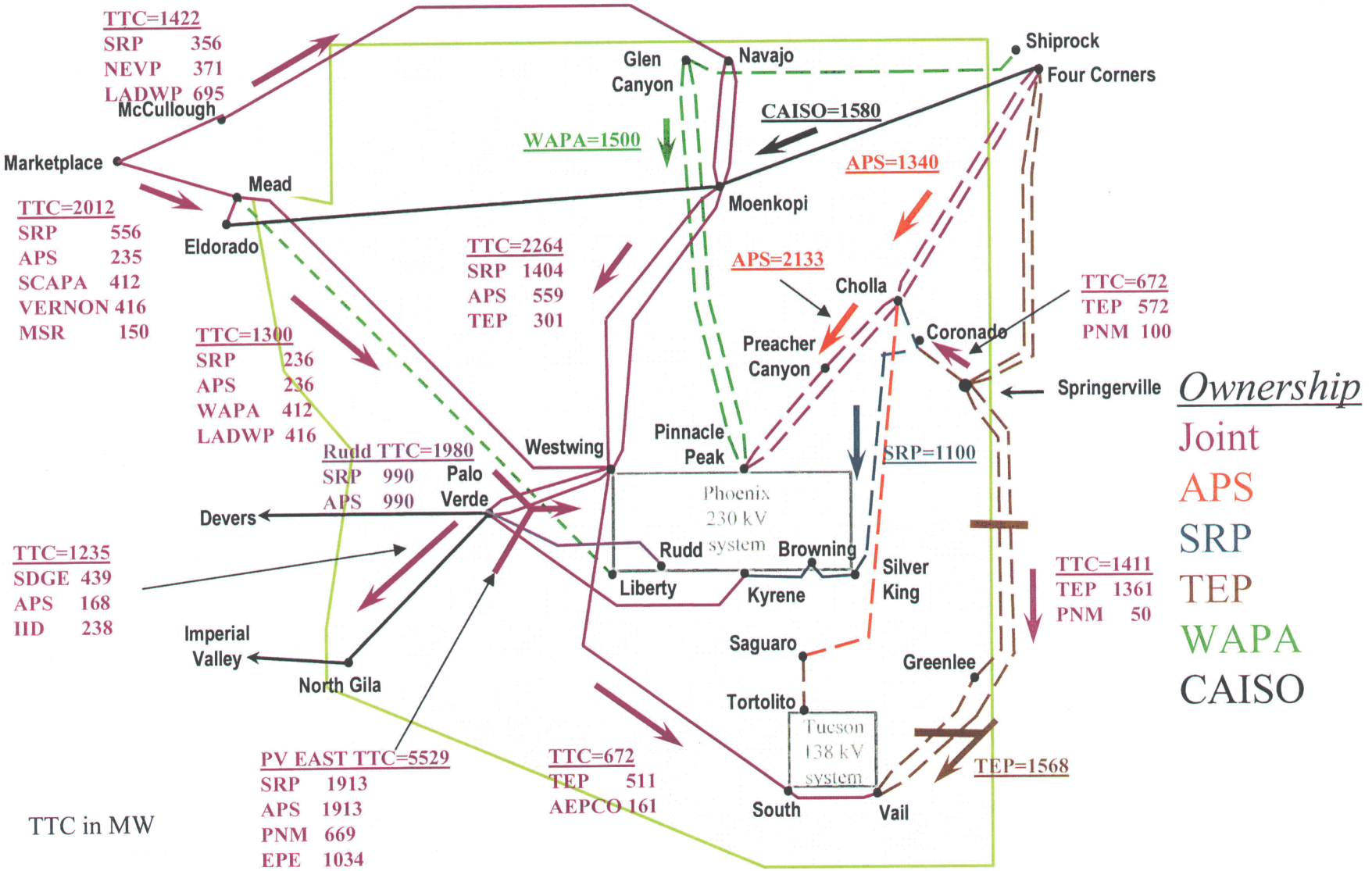
Proposed Renewable Resource Projection



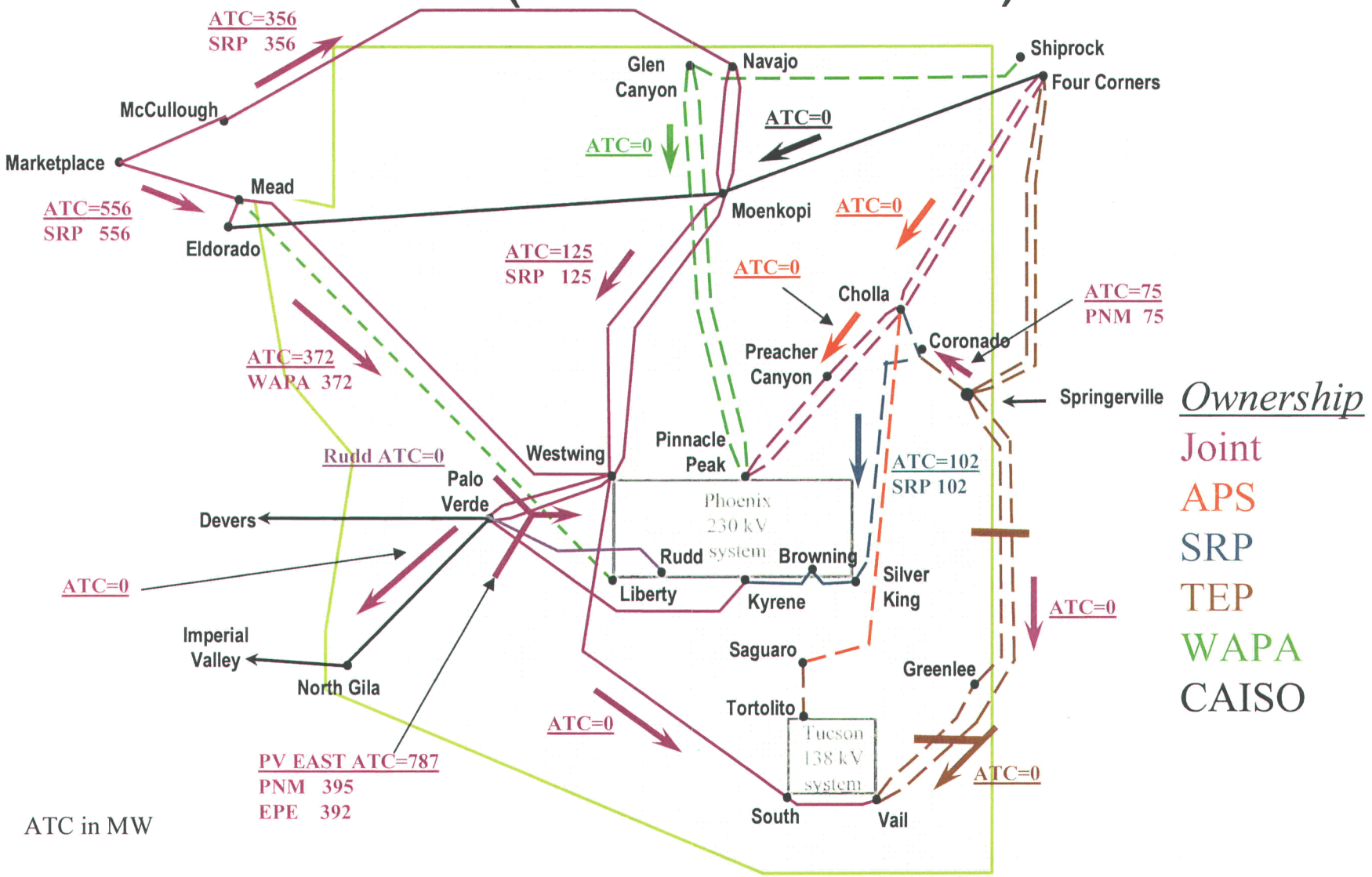
Master Transmission Map



Arizona EHV Transmission TTC



Arizona EHV Transmission
ATC (as of June 2007)



Appendix D
Arizona Renewable Transmission Task Force Stakeholder Meeting
Presentation, November 16, 2007

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Arizona Renewable Transmission Task Force

November 16th 2007

Agenda

- October 8th meeting recap
- Black and Veatch summary
- Renewable energy queue in Arizona
- ATC in Arizona
- Discussion / recommend transmission plans in Arizona

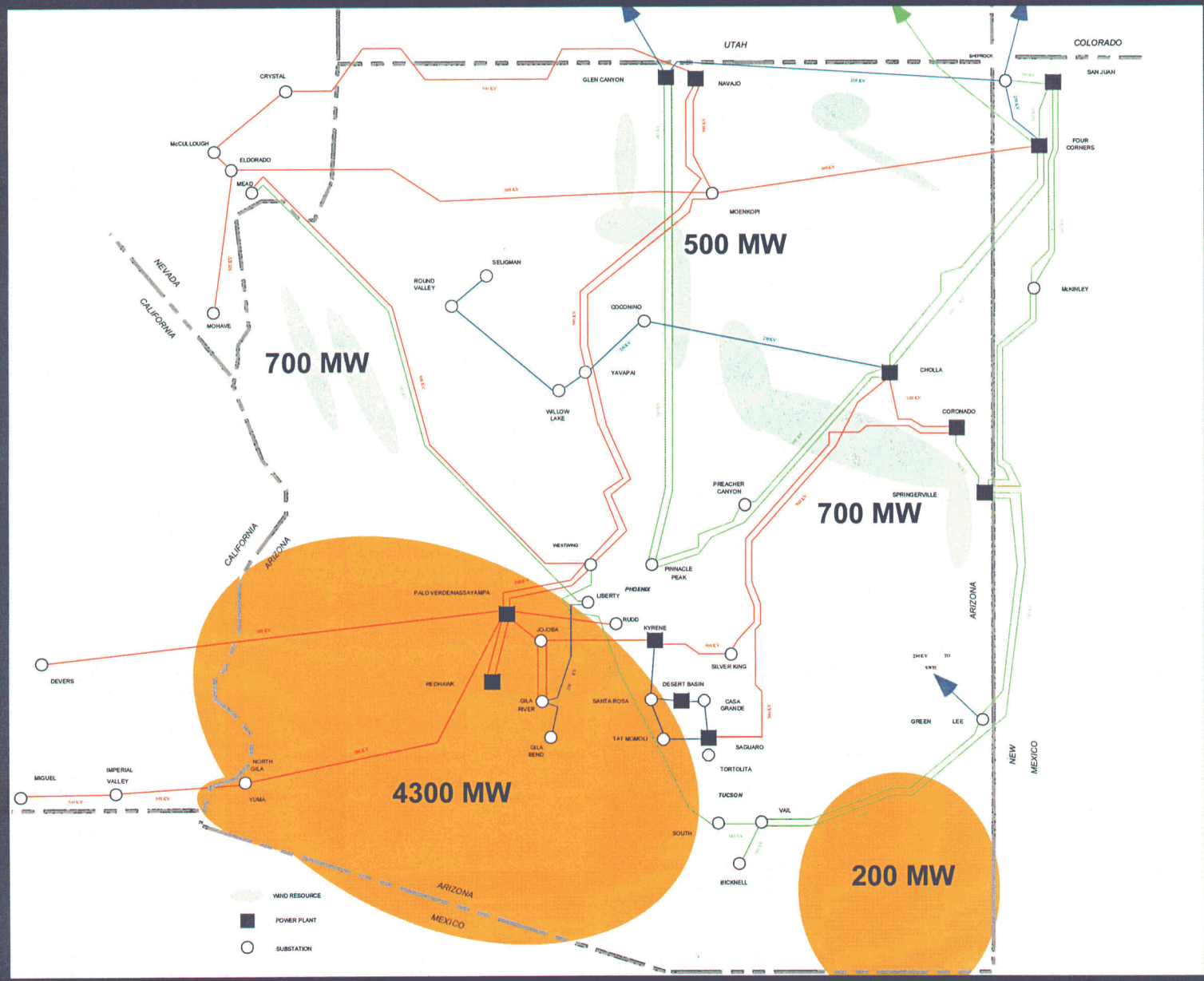
Agenda From Oct. 8th Meeting

- BTA order
- Projected resource projects (non-renewable)
- Existing ATC in Arizona
- SRP, APS, and TEP 10 year plans
- Projected ATC in the next 10 years
- Discussion / recommended transmission plans in Arizona

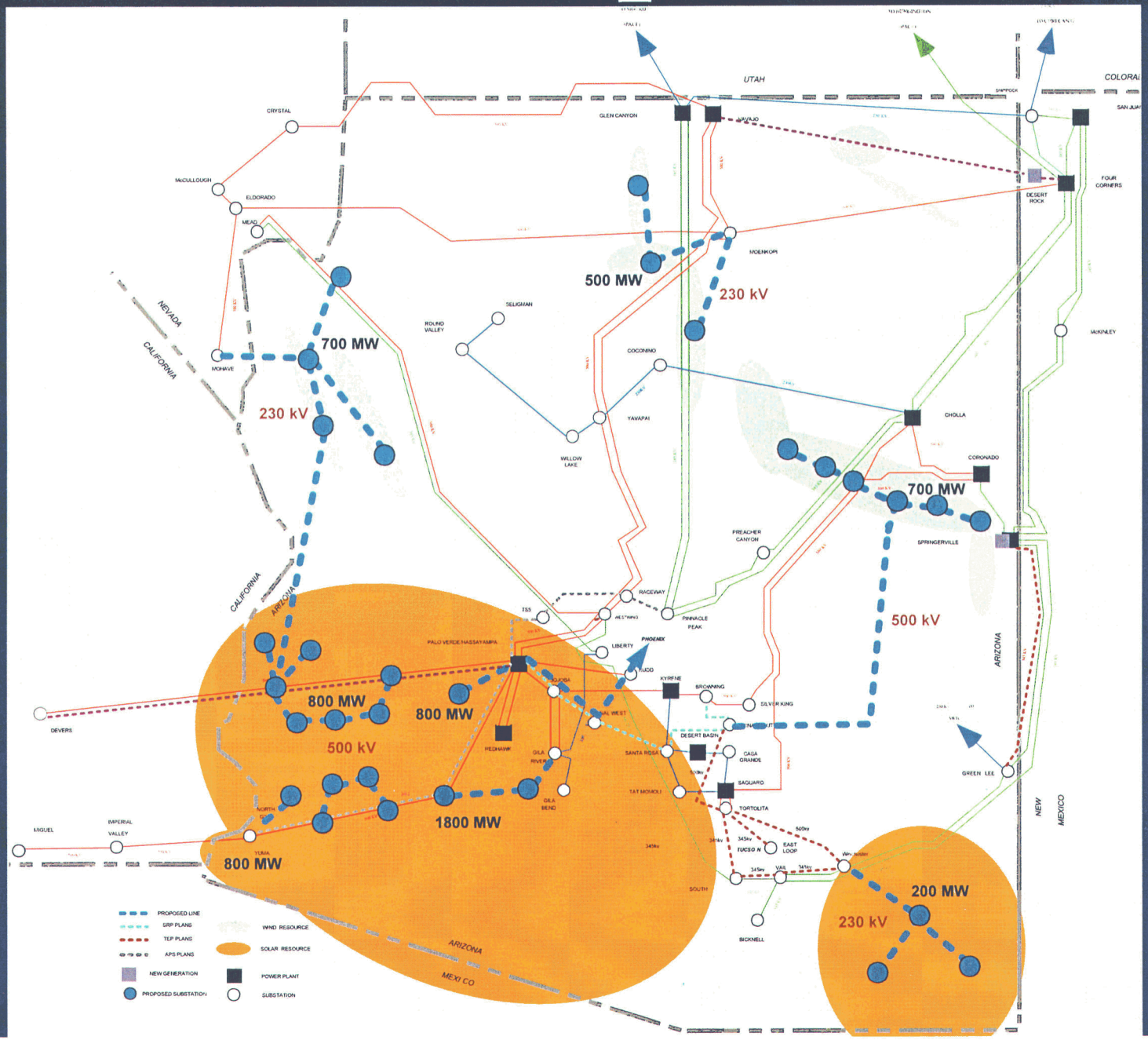
Results From Oct. 8th Meeting

- Initial estimates of renewable resources were augmented
- Three groups were formed to brainstorm possible future transmission scenarios in the Arizona
- Three different Arizona transmission maps were created, and to be merged at a later date
- A comprehensive map is to be decided after renewable energy forecast is more detailed

Changes To Renewable Energy Potential During Oct 8th Meeting



Group A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CRYSTAL
McCULLOUGH
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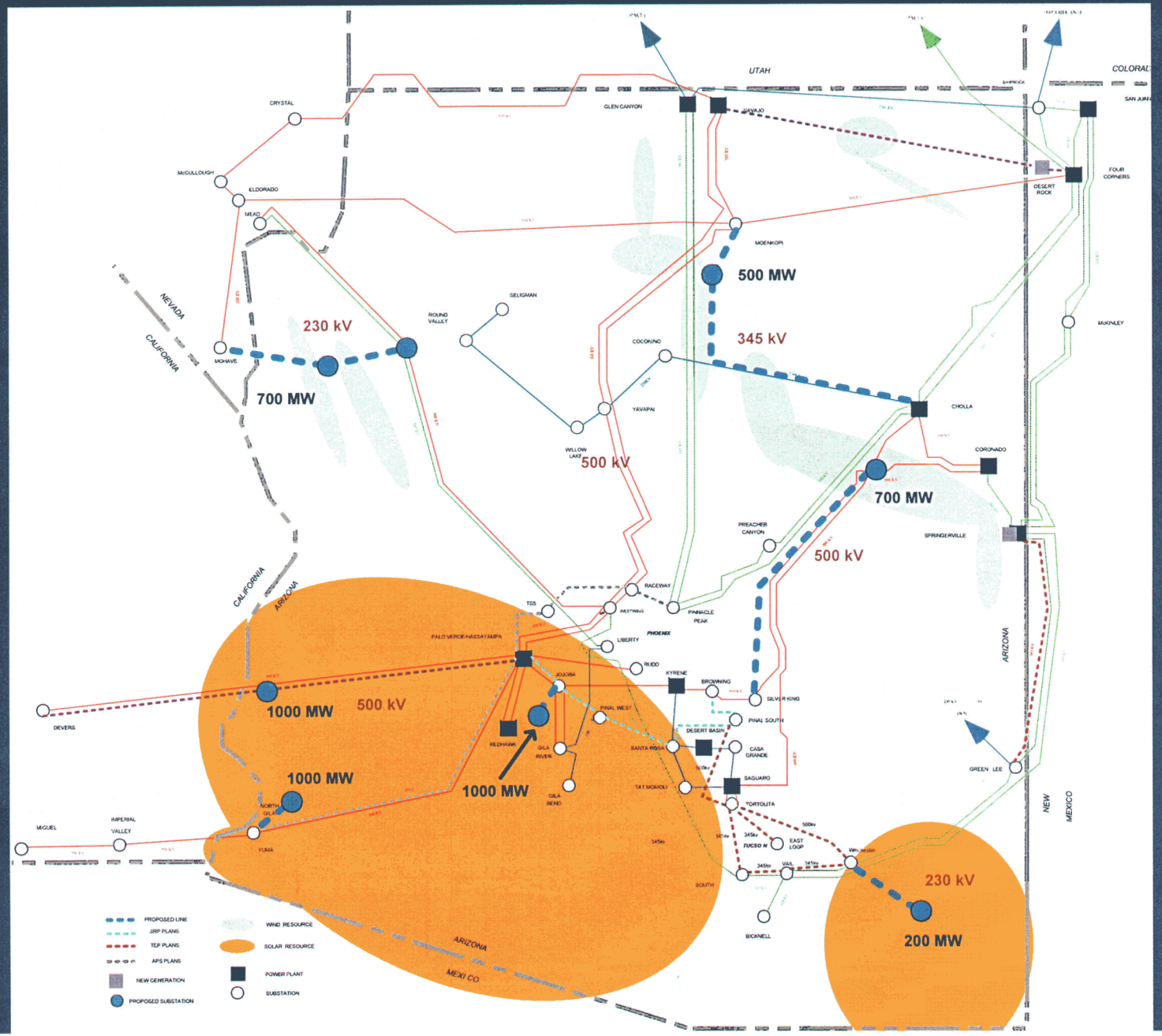
MEAD
MOHAVE
GLEN CANYON
NAVAJO
SHIPROCK
SAN JUAN
FOUR CORNERS
DESERT ROCK
MOENKOPI
SELIGMAN
ROUND VALLEY
COCONINO
YAVAPAI
WILLOW LAKE
McKINLEY
CHOLLA
CORONADO
SPRINGERVILLE
PREACHER CANYON
RAGEWAY
PINNACLE PEAK
PHOENIX
LIBERTY
PALO VERDE/HASSAYAMPA
TSS
JUDD
KYRENE
BROWNING
SILVER KING
DESERT BASIN
CASA GRANDE
SANTA ROSA
SAGUARO
TAT MOMOLI
TORTOLITA
EAST LOOP
FUCSO N
VAIL
BICKNELL
GREEN LEE
DEVERS
MIGUEL
IMPERIAL VALLEY
YUMA
NORTH
SOUTH
GILA RIVER
GILA BEND
HEDGAWK
500 MW
230 kV
700 MW
230 kV
800 MW
800 MW
500 kV
1800 MW
800 MW
700 MW
500 kV
200 MW
230 kV
PROPOSED LINE
SRP PLANS
TEP PLANS
APS PLANS
NEW GENERATION
PROPOSED SUBSTATION
WIND RESOURCE
SOLAR RESOURCE
POWER PLANT
SUBSTATION

Group B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CALIFORNIA
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MEAD
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ROUND VALLEY
GLEN CANYON
SELIGMAN
COCONINO
YAVAPAI
WILLOW LAKE
MOENKOPI
CHOLLA
FOUR CORNERS
DESERT ROCK
McKINLEY
CORONADO
SPRINGERVILLE
PREACHER CANYON
RACEWAY
PINNACLE PEAK
TSS
PALO VERDE-HASSAYAMPA
LIBERTY
RUDD
KYRENE
BROWNING
SILVER KING
PINAL SOUTH
PINAL WEST
DESERT BASIN
CASA GRANDE
SAGUARO
TORTOLITA
EAST LOOP
TUCSO N
SOUTH
BICKNELL
GREEN LEE
JOJOBA
REDHAWK
GILA RIVER
SANTA ROSA
TAT MOMOLI
GILA BEND
NORTH GILA
YUMA
DEVERS
MIGUEL
IMPERIAL VALLEY
230 kV
700 MW
500 MW
345 kV
500 kV
700 MW
500 kV
1000 MW
500 kV
1000 MW
1000 MW
230 kV
200 MW
PROPOSED LINE
JRP PLANS
TEP PLANS
APS PLANS
NEW GENERATION
PROPOSED SUBSTATION
WIND RESOURCE
SOLAR RESOURCE
POWER PLANT
SUBSTATION

Appendix E
Arizona Renewable Transmission Task Force Stakeholder Meeting Sign-In Form, November 16, 2007

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Arizona Renewable Transmission Task Force Meeting
Phoenix AZ
11/16/2007

Name	Representing	Phone #	E-mail Address	Fax
JIM CHARTERS	WSES	623 572 7972	J_CHARTERS@MSN.com	623 572 7972
Ken Bagley	Genesis	623-748-8989	Kabagley@cox.net	
Laurie A Woodall	Az AG	602-542-8864	Laurie.Woodall@azag.gov	
JOHN JOYCE	SWEIA	916-608-5721	John.Kyle@pdsplc.com	
BRUCE EVANS	SWTC	520-586-5336	bevans@swtransco.coop	520-586-5272
Robert Kondziolka	SRP	602-236-0971	robert.Kondziolka@srpnet.com	602-236-3896
John Hernandez	SRP	602-236-0968	Johnny-Hernandez2@srpnet.com	602-236-3896
RAY WILLIAMSON	ACC	602-542-0828	rwilliamson@cc.state.az.us	
Steve Mendoza	WWD	602-809-1810	steve@vendaresources.com	
Gary Ramero	KRSA	430-410-8741	gtr@KRSalive.com	—
ERIC JOHN	SkyFuel	919-656-3495	ERIC.JOHN@SkyFuel.com	
NAM NGUYEN	SCE	626-302-0374	NAM.NGUYEN@SCE.com	
JIM PICKLES	AUSRA	602-343-8257	JIM.PICKLES@AUSRA.com	602 343 8260
ERIK ELLIS	AUSRA	602-343 8258	ERIK@AUSRA.COM	602 343 8260
Jonathan Stahlhut	APS	602 250 1116	jonathan.stahlhut@APS.com	
THOMAS RAMEY	APS	602 250 2070	THOMAS.RAMEY@APS.COM	—
Ben Harrington	DPA	928-871-2260	dpabenh@citlink.net	928-871-4046
LISA SZOT	BP			
Amanda Ormond	IEA			
Peter Krzykos	APS			

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Appendix F
Arizona Renewable Transmission Task Force Stakeholder Meeting
Action Items, November 16, 2007

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Action Items:

- Jon Stahlhut will create a master transmission map and send it out to the group for comments.
- Robert Kondziolka will send ATC slides to Jon Stahlhut. Jon will create an ATC map.
- Queue list is to be updated to include Navajo wind projects.
- Jon Stahlhut will take comments on study plan ideas for the group.

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Appendix G
Arizona Renewable Transmission Task Force Stakeholder Meeting
Presentation, October 8, 2007

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Arizona Renewable Transmission Task Force

October 8th 2007

Agenda

- BTA order
- Projected resource projects (non-renewable)
- Existing ATC in Arizona
- SRP, APS, and TEP 10 year plans
- Projected ATC in the next 10 years
- Discussion / recommended transmission plans in Arizona

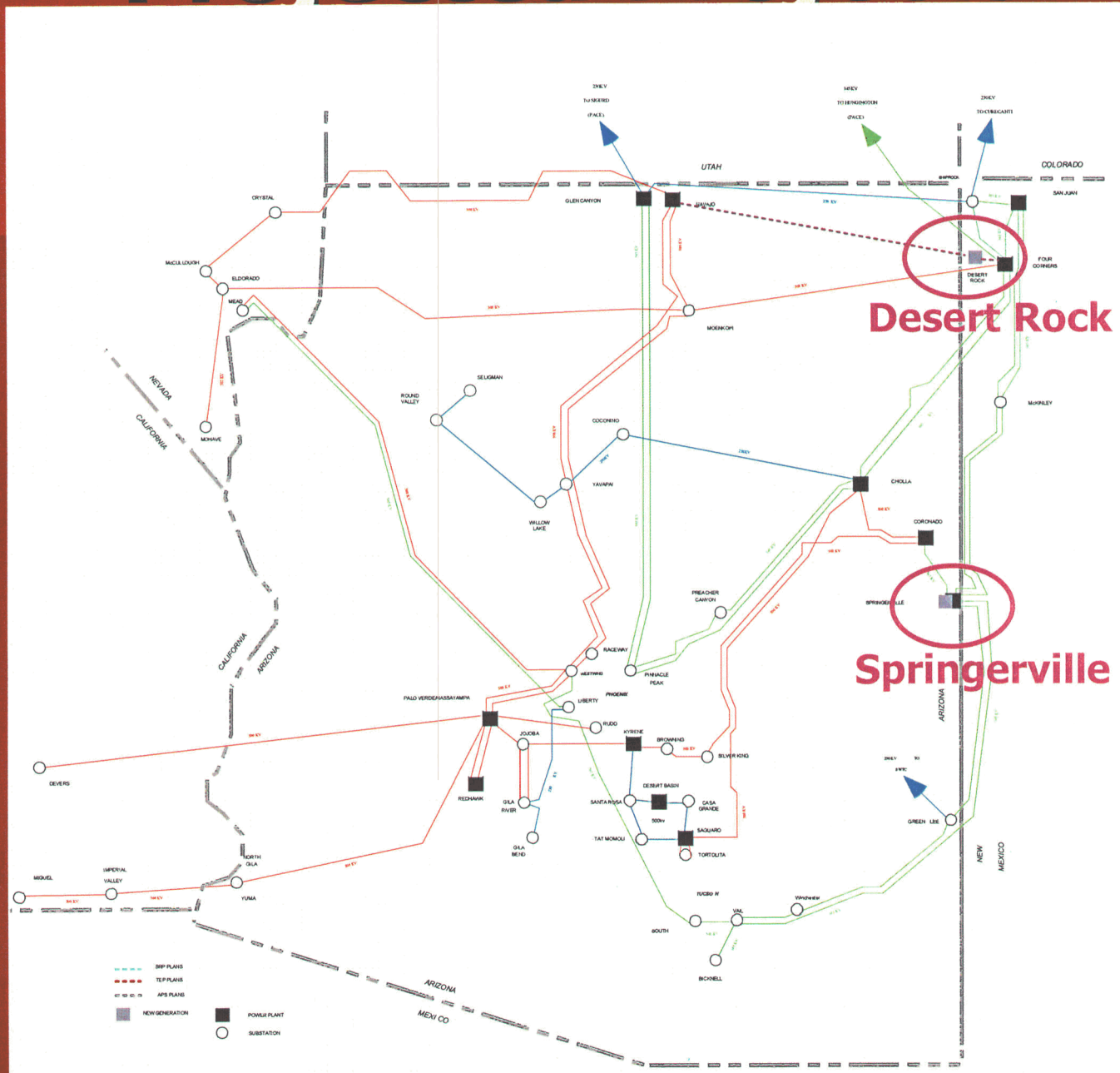
BTA Order

"IT IS FURTHER ORDERED that in the next BTA, Commission regulated electric utilities, in consolation with the stakeholders, should prepare an assessment of ATC for renewable energy and prepare a plan, including a description of the location, amount and transmission needs of renewable resources in Arizona, to bring available renewable resources to load."

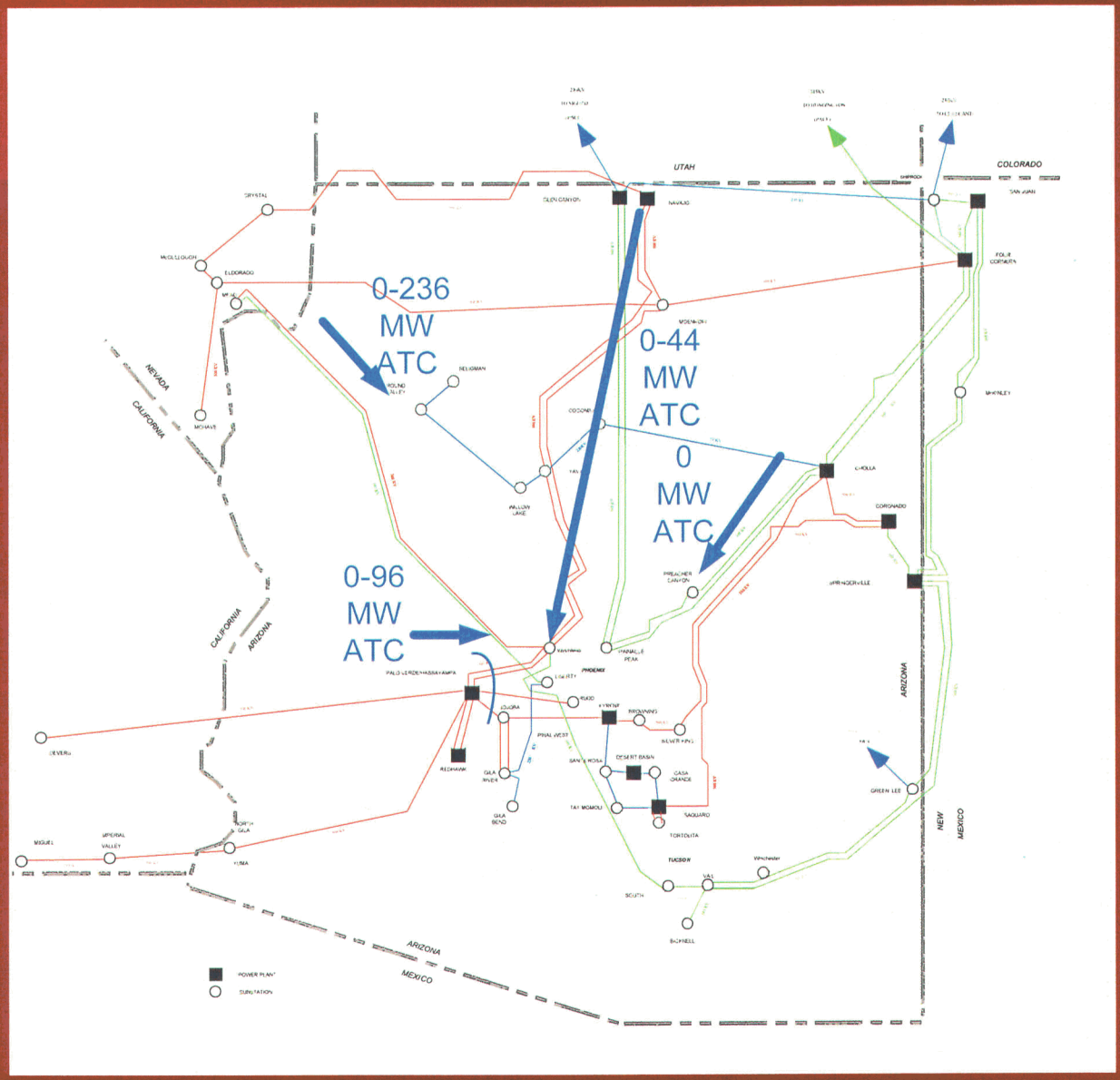
Projected Resource Projects in Arizona (non-renewable)

- Desert Rock (APS)
  - 1400 MW
  - To be implemented in 2012
  - Located in northeast Arizona
- Springerville (SRP)
  - 430 MW
  - To be implemented in 2009

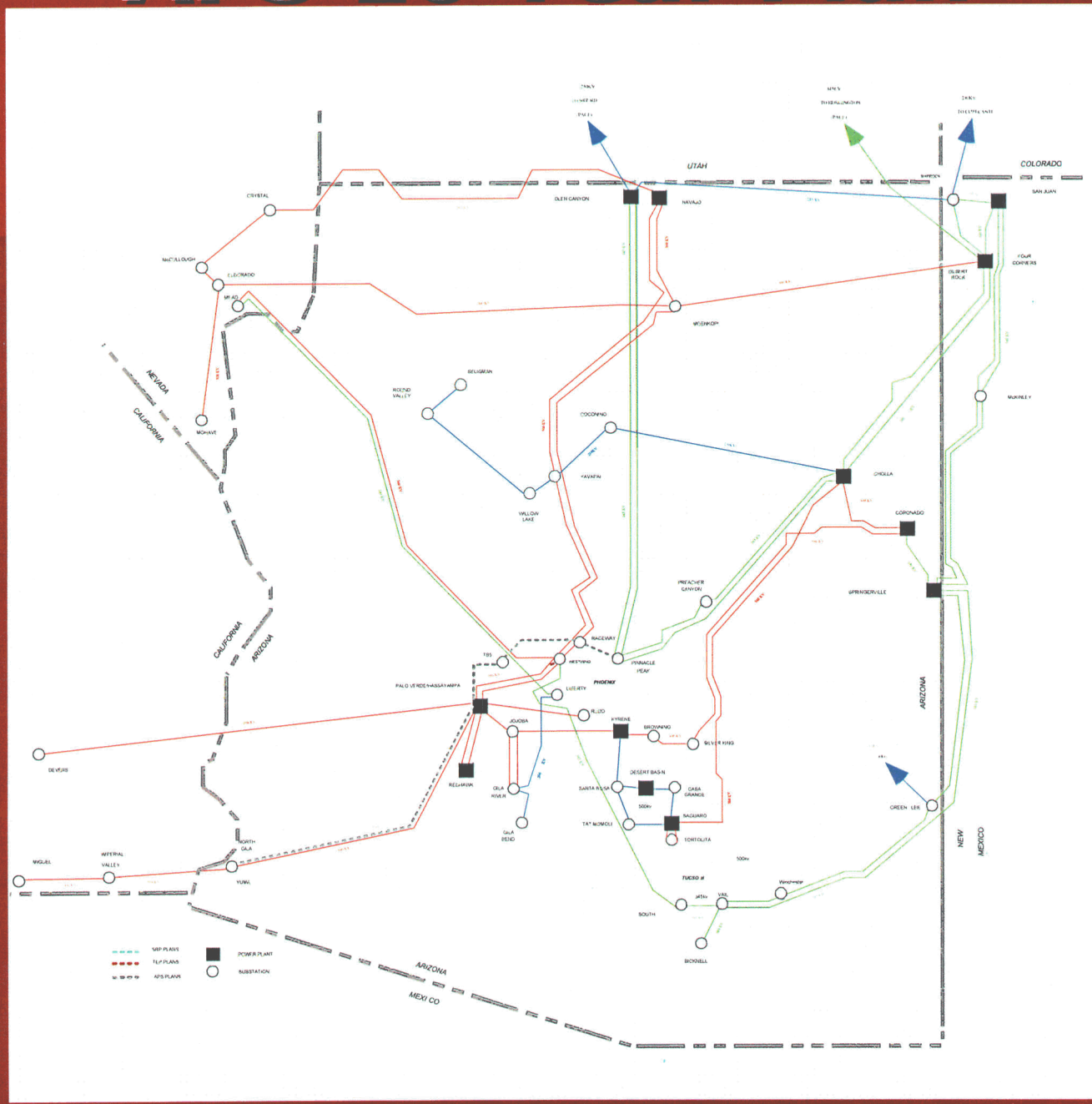
Projected Projects



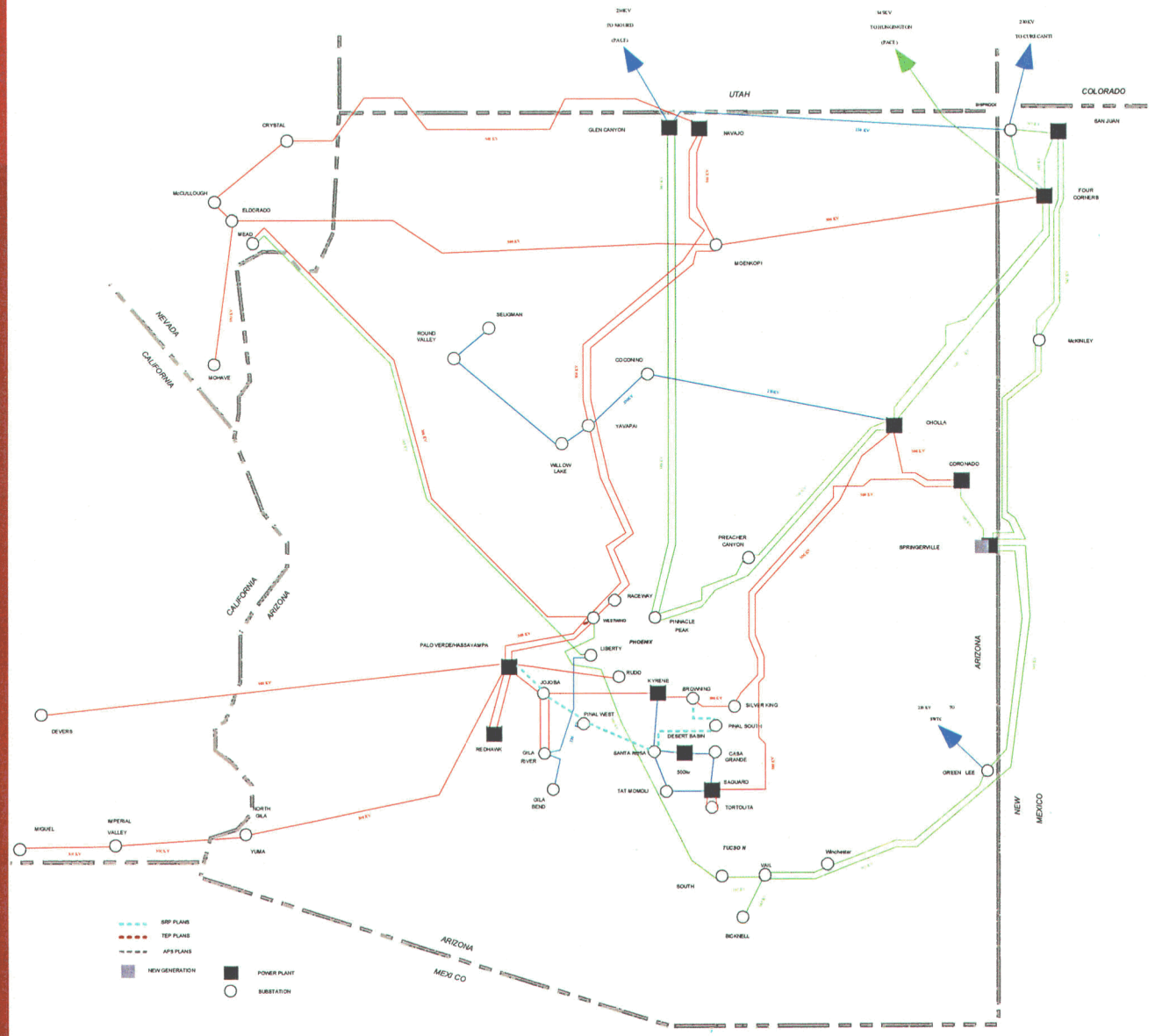
Existing ATC



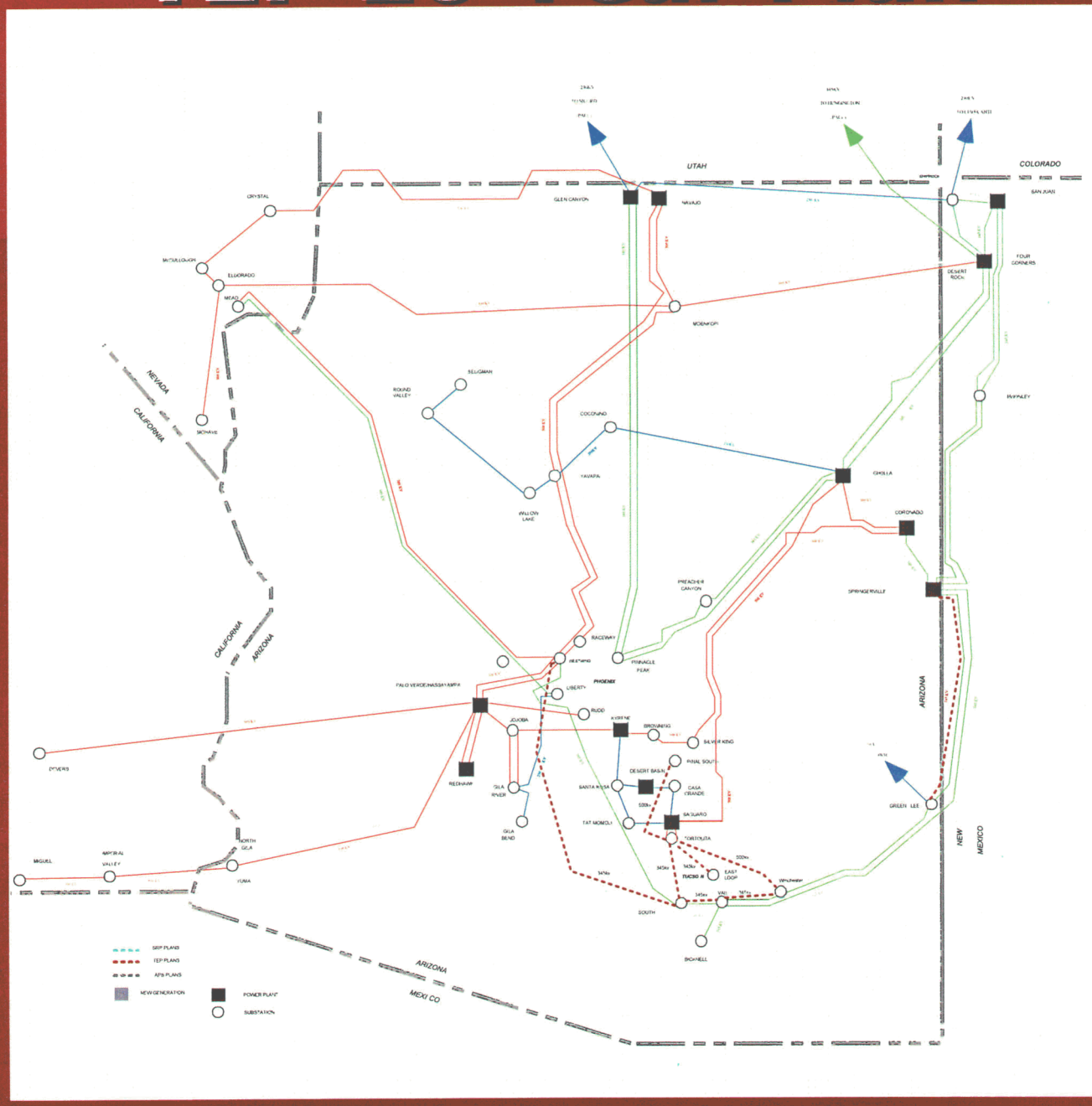
APS 10 Year Plan



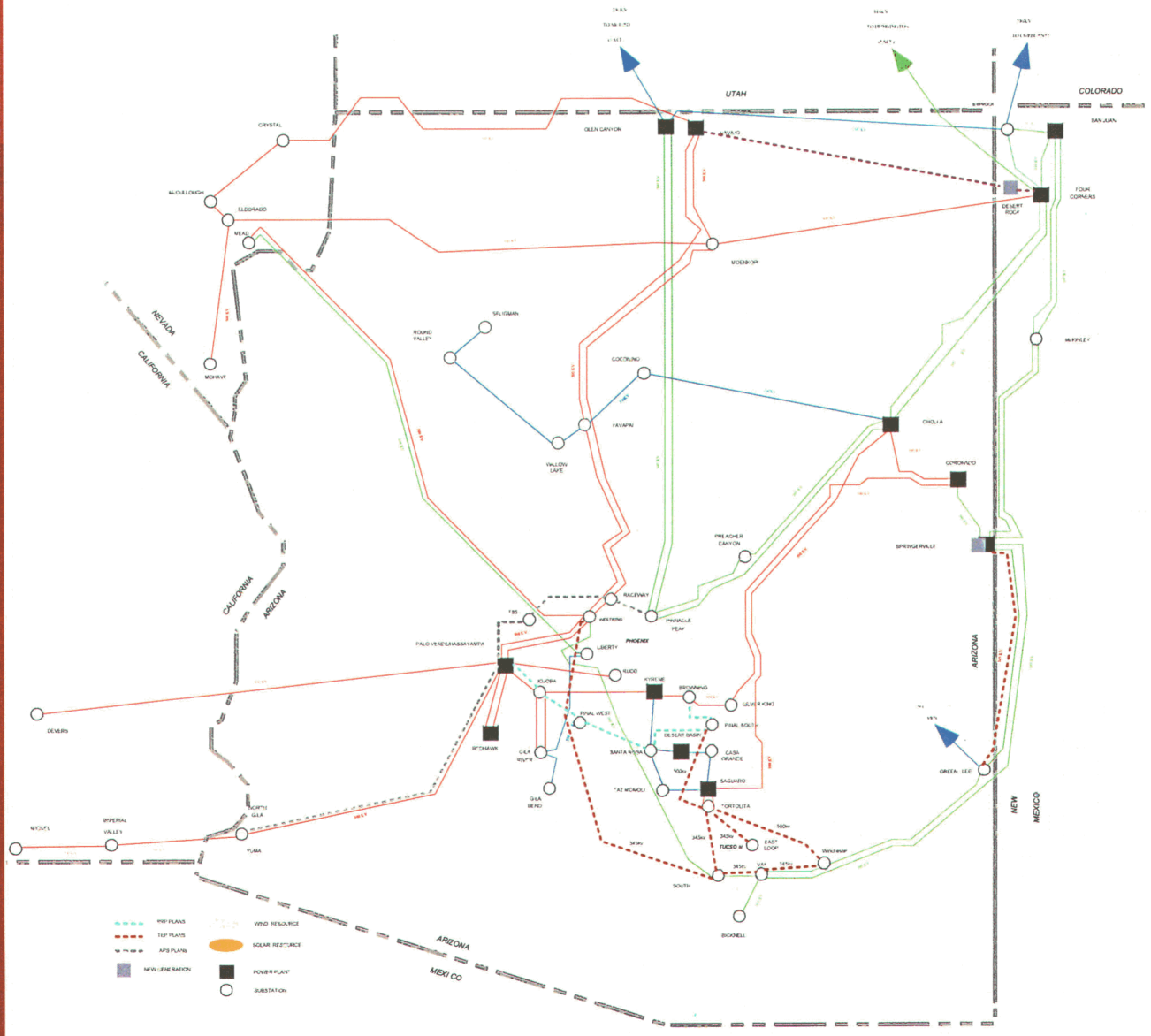
SRP 10 Year Plan



TEP 10 Year Plan



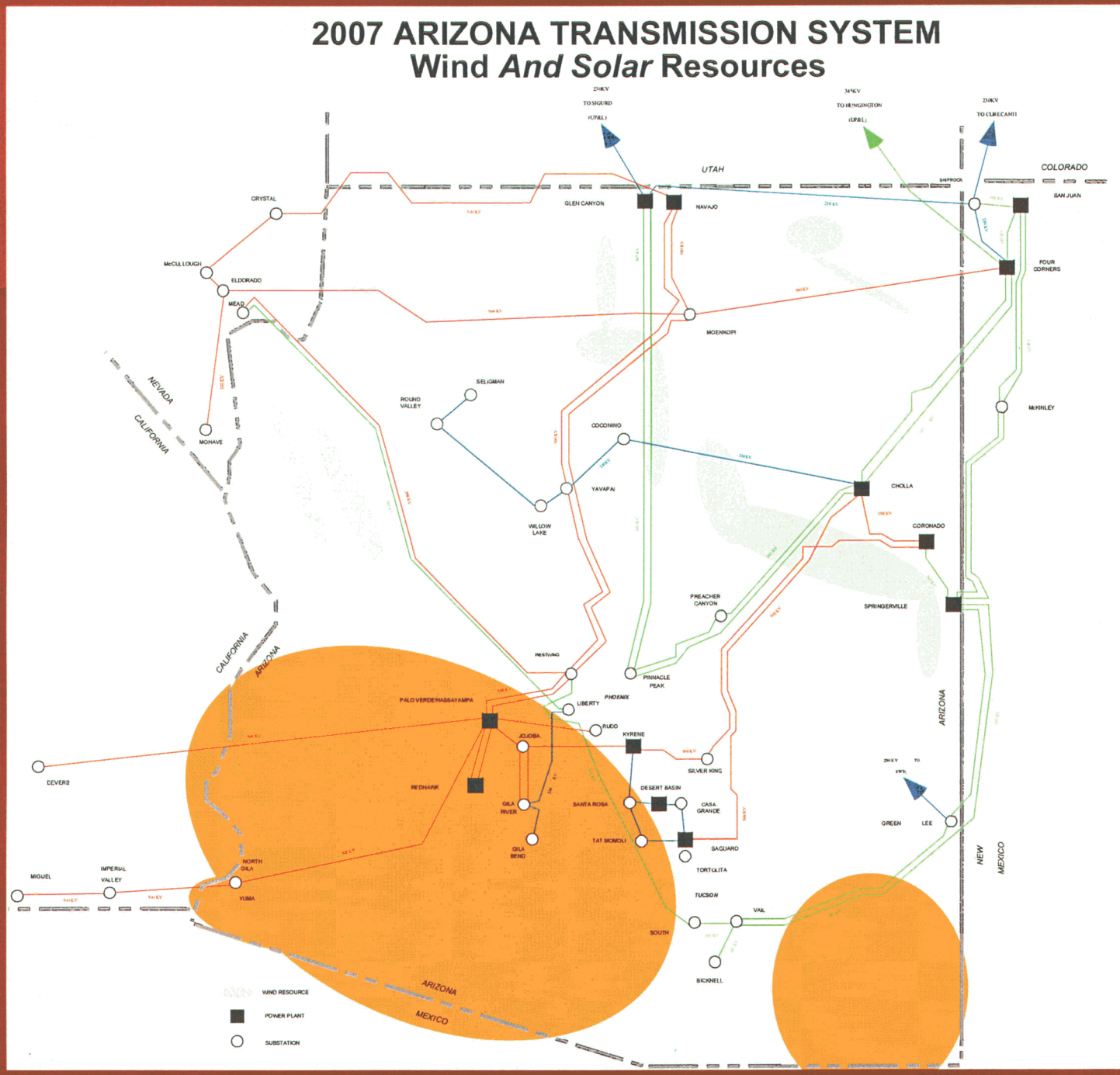
APS, SRP, TEP 10 Year Plans

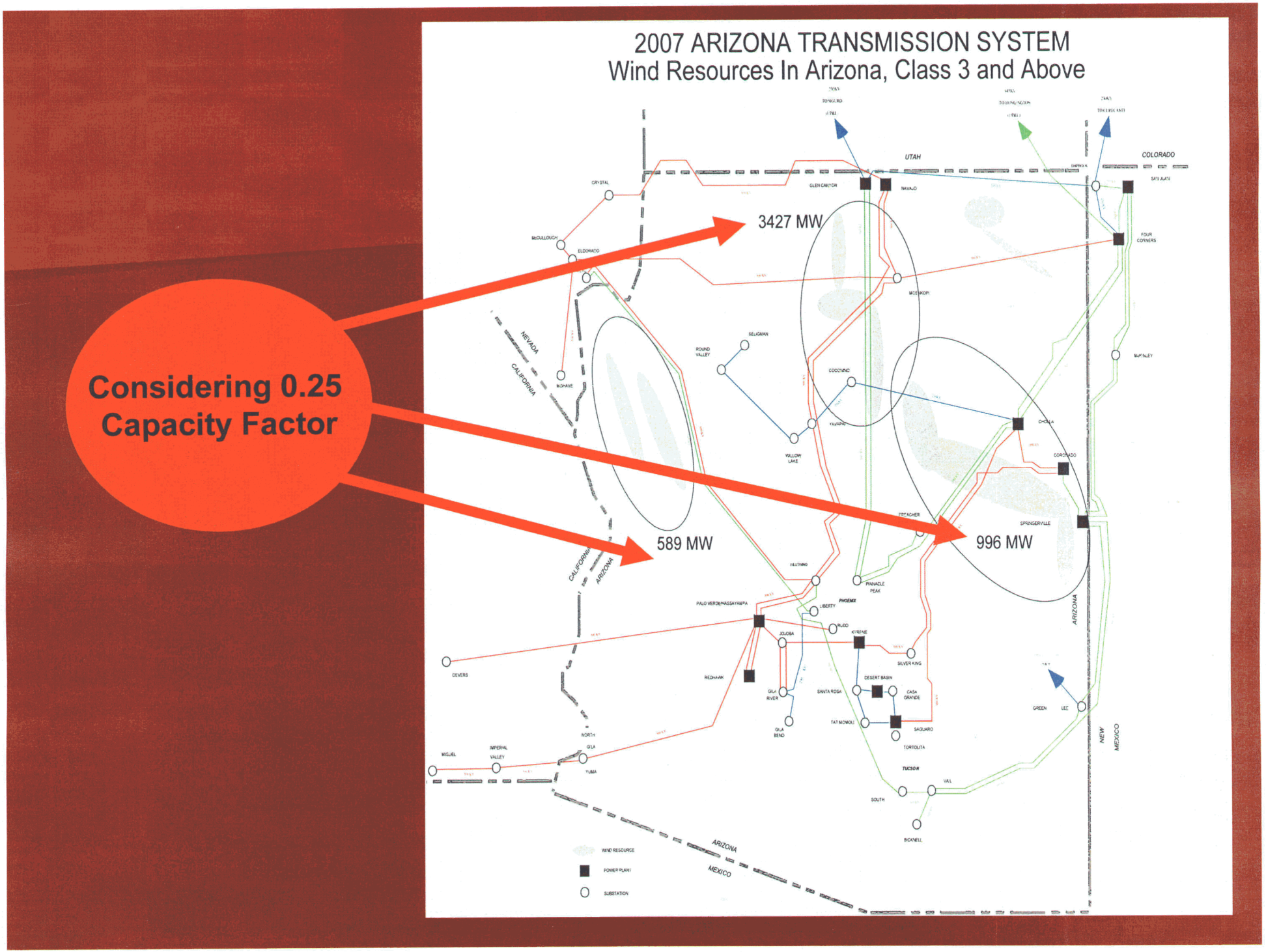


Renewable Resources

- Major resources
  - Wind
    - Primarily in northern Arizona
  - Solar
    - Primarily in southern Arizona
- Other resources
  - Geothermal
  - Biomass
  - Hydro

2007 ARIZONA TRANSMISSION SYSTEM
Wind *And Solar* Resources

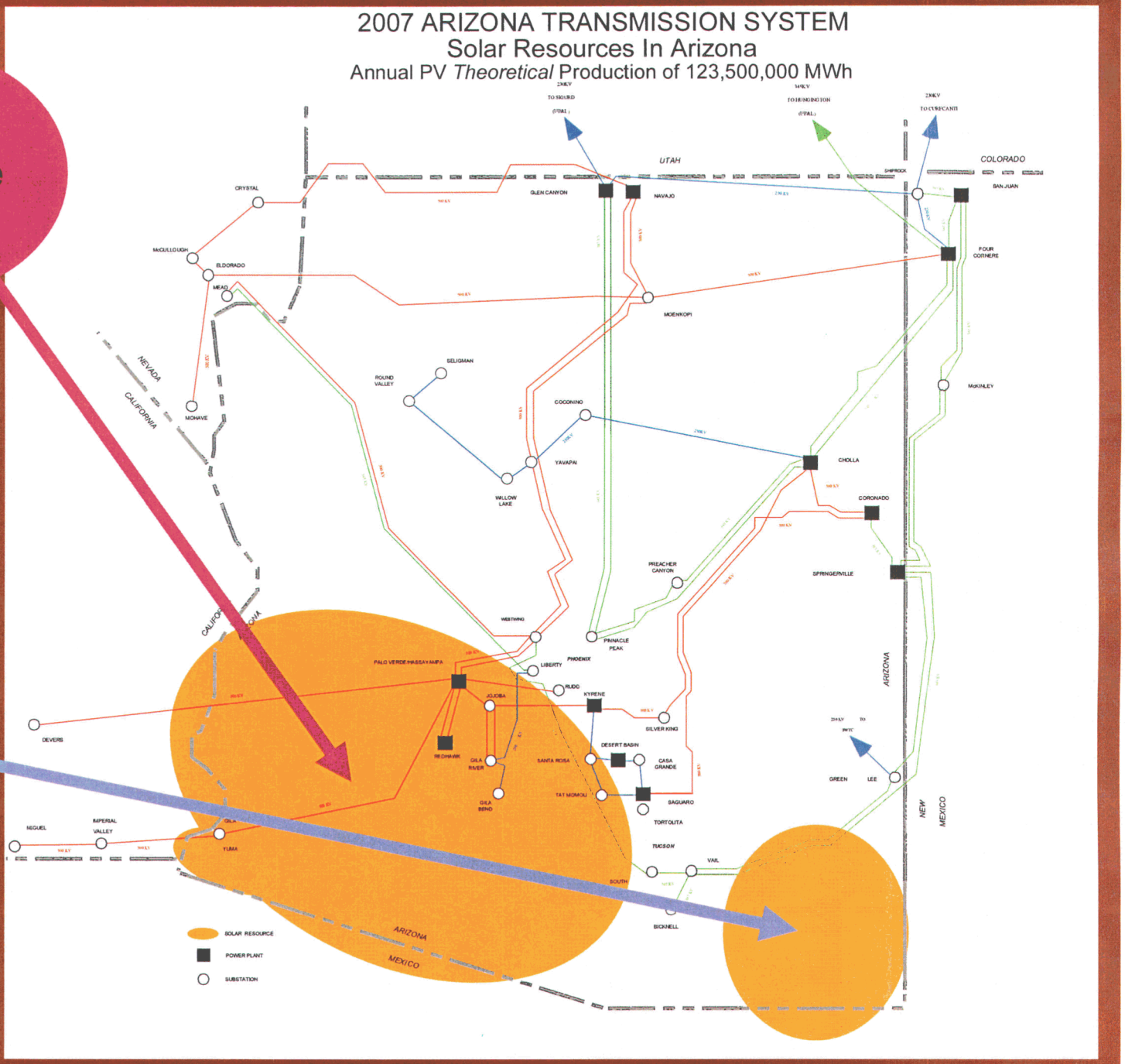


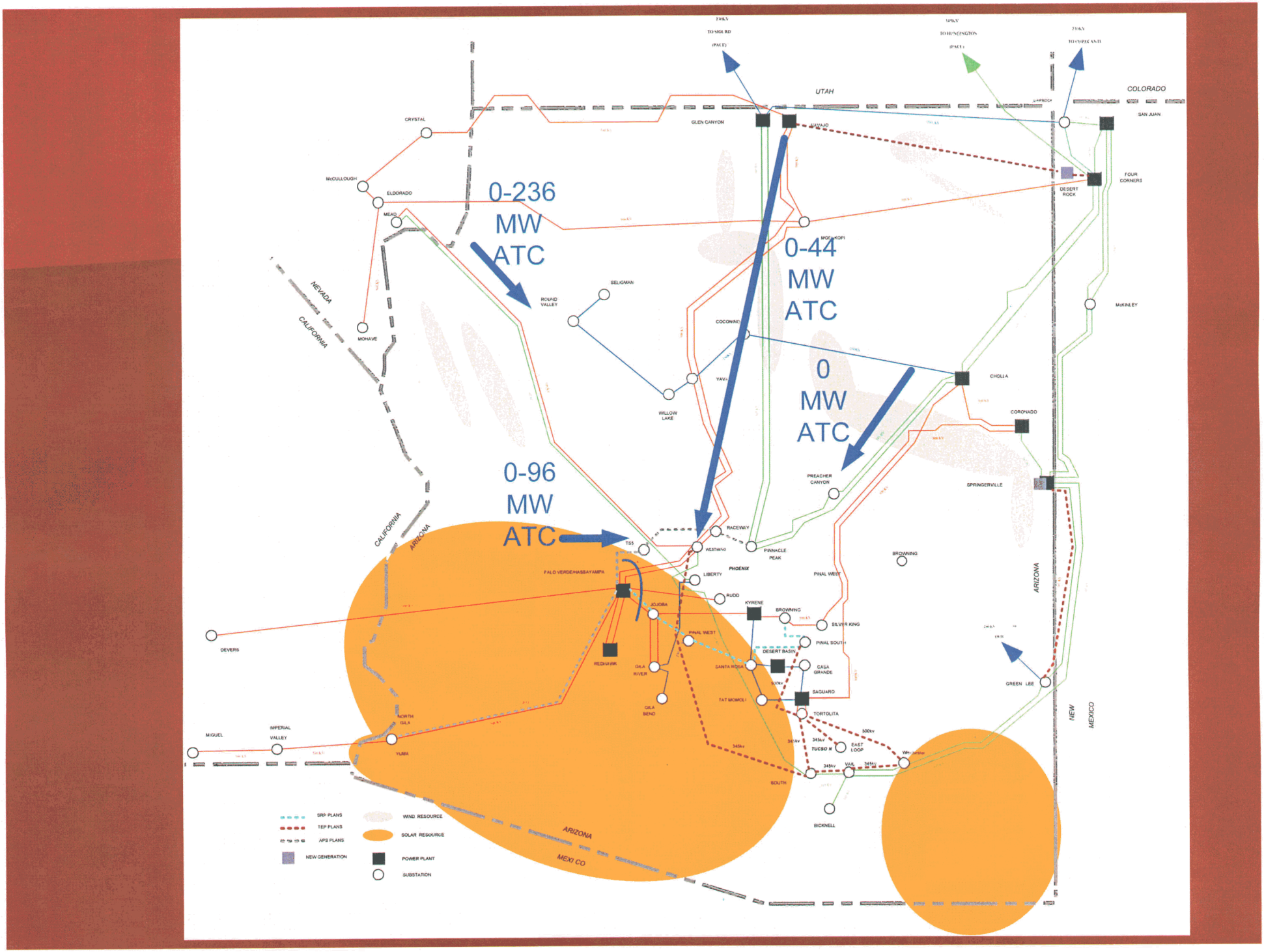

2007 ARIZONA TRANSMISSION SYSTEM
Wind Resources In Arizona, Class 3 and Above
Considering 0.25 Capacity Factor
3427 MW
589 MW
996 MW
UTAH
COLORADO
NEVADA
CALIFORNIA
ARIZONA
NEW MEXICO
MEXICO
CRYSTAL
McCULLOUGH
ELDORADO
GLEN CANYON
NAVAJO
FOUR CORNERS
MOENKOPI
SELIGMAN
ROUND VALLEY
MOHAVE
COCONINO
YAVAPAI
WILLOW LAKE
PINNACLE PEAK
PHOENIX
PALO VERDE/HASSAYAMPA
LIBERTY
RUDD
KYRENE
SILVER KING
JOJOBA
DEVERS
REDHAWK
GILA RIVER
GILA BEND
SANTA ROSA
DESERT BASIN
CASA GRANDE
TAT MOMOLI
SAGUARO
TORTOLITA
TUCSON
SOUTH
VAIL
BICKNELL
NORTH GILA
YUMA
IMPERIAL VALLEY
MIGUEL
WIND RESOURCE
POWER PLANT
SUBSTATION

1732 MW Immediate Potential

0.40 Capacity Factor

92 MW Immediate Potential




0-236
MW
ATC
0-44
MW
ATC
0
MW
ATC
0-96
MW
ATC
UTAH
COLORADO
NEVADA
CALIFORNIA
ARIZONA
NEW MEXICO
CRYSTAL
McCULLOUGH
ELDORADO
MEAD
MOHAVE
GLEN CANYON
NAVAJO
SAN JUAN
DESERT ROCK
FOUR CORNERS
MOENKOPI
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ROUND VALLEY
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WILLOW LAKE
McKINLEY
CHOLLA
CORONADO
SPRINGERVILLE
PREACHER CANYON
RACEWAY
WESTWING
PINNACLE PEAK
PHOENIX
LIBERTY
PALO VERDE/HASSAYAMPA
TS5
RUDD
AGUA FRIA
KYRENE
BROWNING
SILVER KING
PINAL WEST
PINAL SOUTH
DESERT BASIN
SANTA ROSA
CASA GRANDE
SAGUARO
TAT MOMOLI
TORTOLITA
EAST LOOP
TUCSO N
VAIL
SOUTH
BICKNELL
GREEN LEE
REDHAWK
GILA RIVER
GILA BEND
DEVERS
MIGUEL
IMPERIAL VALLEY
NORTH GILA
YUMA
SRP PLANS
TEP PLANS
APS PLANS
NEW GENERATION
WIND RESOURCE
SOLAR RESOURCE
POWER PLANT
SUBSTATION

Arizona Renewable Transmission Task Force

October 8th 2007

Appendix H
Arizona Renewable Transmission Task Force Stakeholder Meeting Sign-In Sheet, October 8, 2007

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Renewable Task Force Meeting
Phoenix, AZ
10/8/2007

Name	Representing	Phone #	E-mail address	FAX
JAMES CHARTERS	WSES	623 572 7972	J_CHARTER@msn.com	623 572 7972
KEN KAGLEY	GENESEE	623-748-2989	kakagley@cox.net	
MARK ETHERTON	PDS/SWPG	602-809-0707	MARK@PDSPLC.com	
LISA A. SZOT	BP ALTERNATIVE ENERGY	713.354.2166	LISA.SZOT@BP.COM	
Jim Rein	SWTC	520.586.5116	jrein@suttransco.com	520.586.5279
BRUCE EVANS	SWTC	520-586-5336	bevans@swtransco.com	520-586-5279
[illegible]	[illegible]	[illegible]	[illegible]	
Bob Anderson	Westwind Wires	775-588-5740	bob-a@sbcglobal.net	
Steve [illegible]	WWA	[illegible]	Steve@[illegible].com	
John Hernandez	SRP	602-236-0568	Johnny.Hernandez@srpnet.com	
Gary Trent	TEP	520-745-3168	gtrent@tep.com	
David Hurlbut	NREL	303-384-7834	david_hurlbut@nrel.gov	
Robert Kondziolka	SRP	602-236-0971	robert.kondziolka@srpnet.com	602-236-3376
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NAM NGUYEN	SCE	626-302-0374	NAM.NGUYEN@sce.com	
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Jon Stahlhut	APS	602 250 1116	jonathan.stahlhut@aps.com	

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Appendix I
Arizona Renewable Transmission Task Force Stakeholder Meeting
Action Items, October 8, 2007

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Action items

- SCE will investigate obtaining ATC data from the ISO in California. This will be subsequently added to the data collected for AZ.
- Peter will also locate information presented at a SWAT conference on AZ ATC and add this to the data already collected.
- Lisa Szot will review the generator interconnection list for utilities in AZ to provide a view into where and how much renewable generation is currently be proposed.
- Barbara Lockwood will summarize the Black & Veatch study results to provide a more concise picture of the report's analysis.
- APS will merge all plans from Oct 8th meeting into a master map.
- Nov. 16th 9:30 meeting.

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Appendix J
Summary Table for Utility Transmission Interconnection Queue – Renewables

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Code	Company	COD	MW Size	POI	County	Type
T1	TEP	2005	80	Dolan Springs Sub	Mohave	Wind
T2	TEP	2008	15	Dolan Springs Sub	Mohave	Wind
T3	TEP	2005	15	Dolan Springs Sub	Mohave	Wind
T4	TEP	2007	95	Co-Spr	St Johns	Wind
A1	APS	2008	60	Cholla - Coconino	Coconino	Wind
A2	APS	2008	128	Cholla Show	Coconino	Wind
A3	APS	2007	22	Cholla zeniff	Coconino	Biomass
A4	APS	2008	270	Ashofork - Pollock	Coconino	Wind
A5	APS	2009	250.5	cholla - show	Coconino	Wind
A6	APS	2010	100	Adams - Mural	Cochise	Wind
A7	APS	2011	110	Harquahala Jnc	Maricopa	Solar
A8	APS	2011	110	Panda Liberty line	Maricopa	Solar
A9	APS	2010	300	Gila Bend	Maricopa	Solar
A10	APS	2010	400	North Gila Sub	Yuma	Solar
W1	WAPA	2008	500	Tap on 345kV Glen Canyon-Pinnacle Peak	Coconino	Wind
W2	WAPA	2008	300	Mead - Davis 230 kV Line	Mohave	Wind
W3	WAPA	2008	65.1	Goldmine Tap Substation	Imperial	Wind
W4	WAPA	2008	500	Peacock Substation	Mohave	Wind
N1	Navajo Nation		100			Wind
			3420.6			

Appendix K
Renewable Resource Assessment – Arizona – B&V Summary

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Renewable Resource Assessment

ARIZONA

B&V Summary

APS

AZ Renewable Resource Assessment

Projected Resource Locations

1. Solar CSP/Yuma – 800MW
2. Solar CSP/Stoval – 1,900MW
3. Solar CSP/Phoenix – 800MW
4. Solar CSP/Tucson – 800MW
5. Wind/Project KS – 18MW
6. Wind/Project RS – 140MW
7. Wind/Project BR – 158MW
8. Wind/Project CV – 597MW
9. Wind/Project BH – 46MW
10. Wind/Project GP – 31MW
11. Biomass/Biogas – 60MW (22 sites)
12. Geothermal/Clifton – 35MW
13. Hydro – 82MW (7 sites, 90% @ GC)

APS

AZ Renewable Resource Assessment

Announced Resource Locations

- **A** Wind/Western - 215MW
- **B** Wind/Foresight - 60WW
- **C** Wind/Hopi Tribe – 100MW
- **D** Wind/PPM – 99MW
- **E** Biomass/Biogas – 10MW (3 sites)

APS

AZ Renewable Resource Assessment

Combined Resource Areas

- 1 Solar CSP/Yuma – 800MW
- 2 Solar CSP/Stoval – 1,900MW
- 3 Solar CSP/Phoenix – 800MW
- 4 Solar CSP/Tucson – 800MW
- 5 Wind/Project KS – 18MW
- 6 Wind/Project RS – 140MW
- 7 Wind/Project BR – 158MW
- 8 Wind/Project CV – 597MW
- 9 Wind/Project BH – 46MW
- 10 Wind/Project GP – 31MW
- 11 Biomass/Biogas – 60MW (22 sites)
- 12 Geothermal/Clifton – 35MW
- 13 Hydro – 82MW (7 sites, 90% @ GC)

- A Wind/Western - 215MW
- B Wind/Foresight - 60WW
- C Wind/Hopi Tribe – 100MW
- D Wind/PPM – 99MW
- E Biomass/Biogas – 10MW (3 sites)

APS

AZ Renewable Resource Assessment

Data Source - Projected

Table 1-1. Arizona Renewable Energy Resources Available in the Near- to Mid-Term.

Technology	Location	Cost (2007$/MWh)	Capacity (MW)	Generation (GWh/yr)
Direct Fired Biomass	Maricopa	143	20	140
Biomass Cofiring	2 potential sites: TEP's Sringerville generating station and APS's Cholla generating station	58 - 63	20	140
Landfill Gas	15 potential small projects identified across the state	82 - 99	10	68
Anaerobic Digestion	Snowflake, Buckeye, Chandler, and Maricopa	62 - 128	10	69
Solar Thermal Electric	100 MW project in 2011. 2–4 200 MW sites per year after 2012	161- 176	4,300[a]	10,940[a]
Hydroelectric	7 potential sites[b]	32 - 215	82	320
Wind	6 potential sites near Kingman and the White Mountains[c]	75 - 141	991	2551
Geothermal	Clifton Hot Springs and Gillard Hot Springs	110 - 122	35	215
Total			**5468**	**14,443**

Notes:

[a] The solar potential is vast, and this only includes projects sufficient for meeting Arizona's forecast renewable energy demands through 2025.

[b] Glen Canyon compromises 90 percent of total potential.

[c] 500 MW of planned wind generation not included.

APS

AZ Renewable Resource Assessment

Data Source - Announced

Table 3-2. Renewable Energy Projects in Arizona.

Technology / Project Name	Owner	MW	COD
Biomass			
Los Reales Landfill Cofiring	TEP	4	1999
Tri Cities Landfill	SRP	5	2001
Eagar Biomass	Western Renewable Energy	3.7 to 4.7*	2008*
Skunk Creek Landfill	Ameresco	3	2008**
27th Ave. Landfill	Cambrian	3	2009**
Snowflake White Mountain Power	NZLegacy Energy LLC	24	2008**
Hydroelectric			
Arizona Falls	SRP	0.8	2003
Solar			
Santan Solar	SRP	0.097	1998
Santan Solar	SRP	0.097	1999
Star	APS	0.2	2000
Flagstaff	APS	0.08	1997
Ocotillo	APS	0.1	1998
Tempe	APS	0.18	1998
Gilbert (AZ)	APS	0.12	1999
Municipal Rooftops	APS	0.1	1999
Ocotillo	APS	0.1	1999
Scottsdale	APS	0.03	1999
Microelectronics Rooftop	APS	0.02	2000
Glendale	APS	0.2	2001
Prescott ERAU Solar	APS	0.2	2001
Agua Fria	SRP	0.2	2001
Yucca	APS	0.1	2001
Prescott Airport Solar Plant	APS	3.4	2002-06
Springerville Generating Station	TEP	5.1	2002-03
Saguaro	APS	1	2005
Wind* **			
Steel Park Wind	Western Wind Energy	15	2007**
Sunshine Wind Energy Park	Foresight Energy Co	60	2007**
Sunset Mountains Wind	Hopi Tribe (The)	100	2007**
Dry Lake Wind	PPM Energy Inc	99	2008**
Steel Park Wind	Western Wind Energy	100	2008**
Steel Park Wind	Western Wind Energy	100	2009**
Total Existing		**24**	
Total Proposed		**504**	

Source: Utilities, GED

Notes:

* Generator is 4.7MW, boiler damaged, was not capable of powering the generator at 4.7MW. May replace with larger boiler.

** Planned / Proposed Projects (COD subject to change).

*** None of the wind projects are currently under contract to sell power.

APS

AZ Renewable Resource Assessment
Project Sensitivities/Filters

- Solar Thermal
  - Equipment availability/supply chain
  - Development timelines/engineering support
  - Project economics
  - Proximity to adequate transmission
  - Land availability/terrain slope/proximity to sensitive areas
- Wind
  - Equipment availability/supply chain
  - Class/Capacity factor
  - Project economics
  - Proximity to adequate transmission
  - Proximity to federal/environmental sensitive areas

APS

AZ Renewable Resource Assessment

Data Source - Solar

Specific site locations were not identified at this stage of analysis. Generic projects have been identified for four areas in Arizona: • Stoval, Yuma, Phoenix, Tucson. The characteristics for these plants are shown below:

Project	Capacity, MW	CF, %	Generation, GWh	First Year Available
Stoval Trough 1	100	30%	261	2011
Stoval Trough 2	200	30%	522	2013
Stoval Trough 3	200	30%	522	2013
Stoval Trough 4	200	30%	522	2014
Stoval Trough 5	200	30%	522	2014
Stoval Trough 6	200	30%	522	2015
Stoval Trough 7	200	30%	522	2015
Stoval Trough 8	200	30%	522	2016
Stoval Trough 9	200	30%	522	2016
Stoval Trough 10	200	30%	522	2016
Phoenix Trough 1	200	27%	478	2019
Phoenix Trough 2	200	27%	478	2019
Phoenix Trough 3	200	27%	478	2019
Phoenix Trough 4	200	27%	478	2019
Tucson Trough 1	200	29%	503	2018
Tucson Trough 2	200	29%	503	2018
Tucson Trough 3	200	29%	503	2018
Tucson Trough 4	200	29%	503	2018
Yuma Trough 1	200	29%	513	2017
Yuma Trough 2	200	29%	513	2017
Yuma Trough 3	200	29%	513	2017
Yuma Trough 4	200	29%	513	2017

The Stoval area, about 80 miles southwest of Phoenix along Interstate 8, has the highest DNI of the potential sites (7.4 kwh/m2/day – per satellite data), with potential areas of low land slope. Because of the improved performance, it has been assumed that initial project deployment would occur at Stoval. A key issue with this area is that a large portion of the land in the region is within the Barry M. Goldwater Air Force Range.

The Yuma site would be southeast of Yuma in the Yuma Desert. The Yuma area has a high satellite DNI of 7.3 kwh/m2/day. Like the Stoval area, the Yuma area could be subject to constraints because of the Barry M. Goldwater Air Force Range.

The Phoenix area would generally be west of Phoenix because of terrain constraints. The area has a satellite DNI of 6.8 kwh/m2/day. The Phoenix TMY2 DNI is 6.9 kWh/m2/day.

The Tucson area could include areas such as the Avra Valley to the west of Tucson and the Sulphur Springs Valley to the east. The area has a satellite DNI of 7.2 kwh/m2/day.

APS

AZ Renewable Resource Assessment

Data Source - Wind

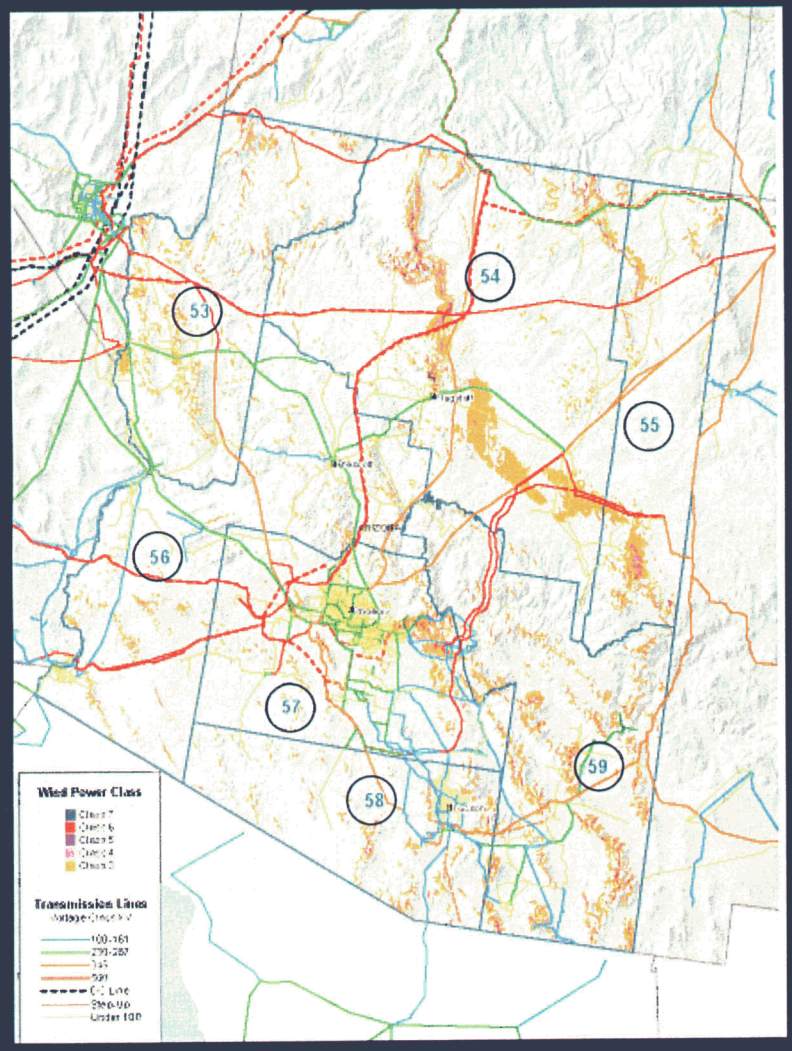

Table 4-21. Arizona Wind Technical Potential

Region	Capacity by Wind Power Class					Total Capacity
	3	4	5	6	7	
53	2,042	255	47	9	1	2,355
54	12,764	586	240	104	12	13,706
55	3,376	407	62	18	1	3,864
56	129	22	2	0	0	152
57	713	115	33	16	2	879
58	194	60	12	2	0	267
59	1,321	370	123	53	4	1,870
Total	20,538	1,814	519	202	20	23,093

Source: Donna Heimiller, NREL, 2006
Note: Total technical potential, assuming 5 MW of capacity per square km.

Table 4-21 The initial screen shows the theoretical potential capacity from wind power class in seven regions in Arizona as estimated by NREL. The regions correspond to the large regions shown in the wind resource map. This theoretical or technical potential is not bound by the constraints of product availability (backordered turbines, for instance), site-specific constraints such as transmission capacity, environmental restrictions, or cost.

To determine near-term developable potential for wind, sites were reviewed in light of proximity to adequate transmission (greater than 69 kV), proximity to federal or environmentally sensitive areas, and constructability. The results developed a much smaller set of resources that could potentially be built and financed in the near term.

APS

Appendix L
Transfer Capability Stakeholders Meeting (WestConnect), Phoenix, AZ,
June 27, 2007

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WEST CONNECT

Enhancing wholesale electricity markets in the southwest

Transfer Capability Stakeholders Meeting

Phoenix, AZ

June 27, 2007

Sierra Pacific - Nevada Power

Existing Paths

Path Name	TTC Determined By	TTC	TRM	CBM	Committed Uses	ATC
	Subregion					
	Subregion					
Path 35 (HA-RE)	WECC	300	0	0	**150**	**150**
Path 77 (Crystal)	WECC	950	116	0	**255**	**579**
Path III-2 (Centennial)	WECC	3000	0	0	**2250**	**750**
Navajo-Crystal (Path 49)	WECC	371	116	0	**255**	**0**
Southern Cut Plane	Nevada Power Company	3350	150	0	**3350**	**0**
	Owner					

Existing Paths

Path Name	TTC Determined By	TTC	TRM	CBM	Committed Uses	ATC
Path 35 (HA-RE)	WECC	300	0	0	150	150
Path 77 (Crystal)	WECC	950	116	0	255	579
Path III-2 (Centennial)	WECC	3000	0	0	2250	750
Navajo-Crystal (Path 49)	WECC	371	116	0	255	0
Southern Cut Plane	Nevada Power Company	3350	150	0	3350	0
Path 32 (Pavant/Gonder – IPP/Gonder)	Sierra Pacific Power	370/343 (Winter-Summer/Spring	0	0	348	22
Path 16 (Midpoint/Humboldt)	Sierra Pacific Power	500	90/50 (Winter/Summer)		352	68
Path 24 (Drum/Summit)	Sierra Pacific Power	100/150 (Summer-Winter/Spring)	0		0	100/150
Path 76 (Hilltop/Bordertown)	Sierra Pacific Power	300	0		300	0
Path 52 (Bishop Control/Silver Peak	Sierra Pacific Power	17	0		0	17

WEST CONNECT

Enhancing wholesale electricity markets in the southwest

Arizona Public Service Co.

WestConnect TTC/ATC Workshop

APS Paths

Phoenix, AZ

6/27/07

Jason Spitzkoff

Existing Paths For APS

Path Name	TTC Determined By	TTC	TRM	CBM	Committed Uses	ATC
Four Corners-Cholla	Owner	1340	0	0	1340	0
Cholla-Pinnacle Peak	Owner	2133	0	0	2133	0
Navajo-Westwing (Path 51)	WECC	559	0	0	559	0
Palo Verde East	Sub-region	1913	0	0	1913	0
Palo Verde-Rudd	Sub-region	990	0	0	990	0
Mead-Perkins (Path 49)	WECC	236	0	0	236	0
Hassayampa-North Gila (Path 49)	WECC	168	0	0	168	0
*Note: The numbers in this table represent annual product values at the end of the 10 year planning horizon						

Other Transmission Paths	
Types	**Numbers**
Transformer	10
230kv paths	18
69kv paths	6

Additions/Changes For APS

Path Name	Venue to Determine TTC Change	Existing TTC	Change	Expect complete	Expect TRM	Expect CBM	Expect Committed Uses	Expect ATC
Mead-Perkins (Path 49)[1]	WECC	236	+113 EOR 9300 Uprate Project	2009	0	0	unknown	unknown
Navajo-Westwing (Path 51)[2]	WECC	559	+207 Series Comp Upgrades	2009	0	0	766	0
Palo Verde-TS5[3]	Sub-region	0	+188/400 New Line	2009/2010	0	0	188/400	0
Palo Verde-TS5[3]	Sub-region	400	+400 TS5-TS9 500kV line	2012	0	0	800	0

1.The allocation of new capacity is not yet determined.
2.Project is still being studied within WECC 3-phase rating process. Preliminary rating is 3100 MW and expected in-service is 2009. Increased capacity expected to be shared, among existing owners, according to ownership percentage of the path.
3.Project is still being studied and the rating, in-service date, and TTC/ATC is firm. 80% of project rating is assumed for APS share. The project may be limited by a single 230/69kV transformer for the first year (dependant upon construction timing).

*Note: The numbers in this table represent annual product values at the end of the 10 year planning horizon

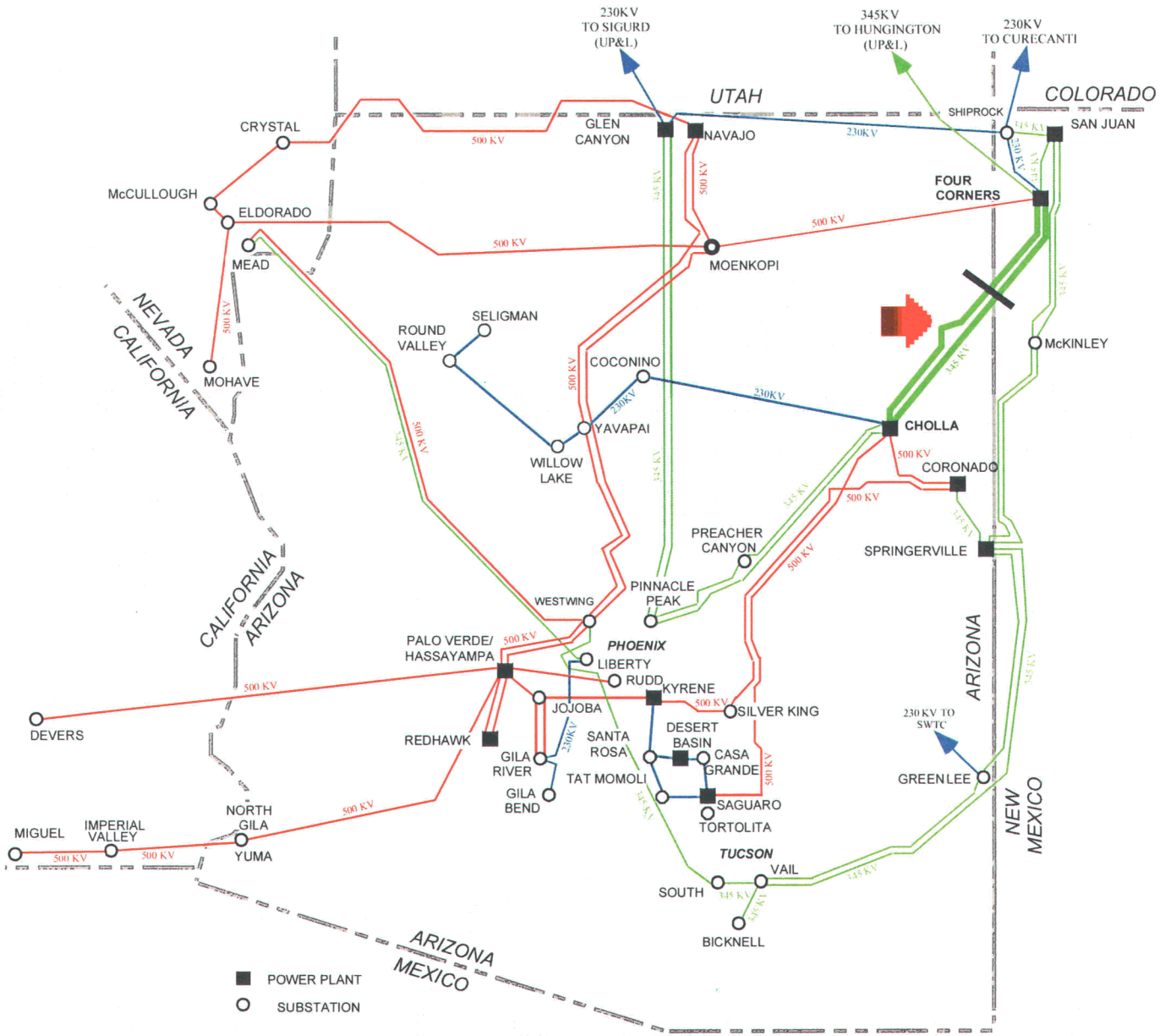
Additions/Changes For APS (cont.)

Path Name	Venue to Determine TTC Change	Existing TTC	Change	Expect complete	Expect TRM	Expect CBM	Expect Committed Uses	Expect ATC
TS9-Pinnacle Peak 500kV[4]	Sub-region	400	+500 New Line	2010	0	0	unknown	unknown
Hassayampa-North Gila #2 (Path 49)[5]	WECC	0	+240-480 Haas-N.Gila #2 500kV line	2012	0	0	unknown	unknown
Sundance-Pinal South 230kV[6]	Owners	0	+800 New Line	2011	0	0	unknown	unknown

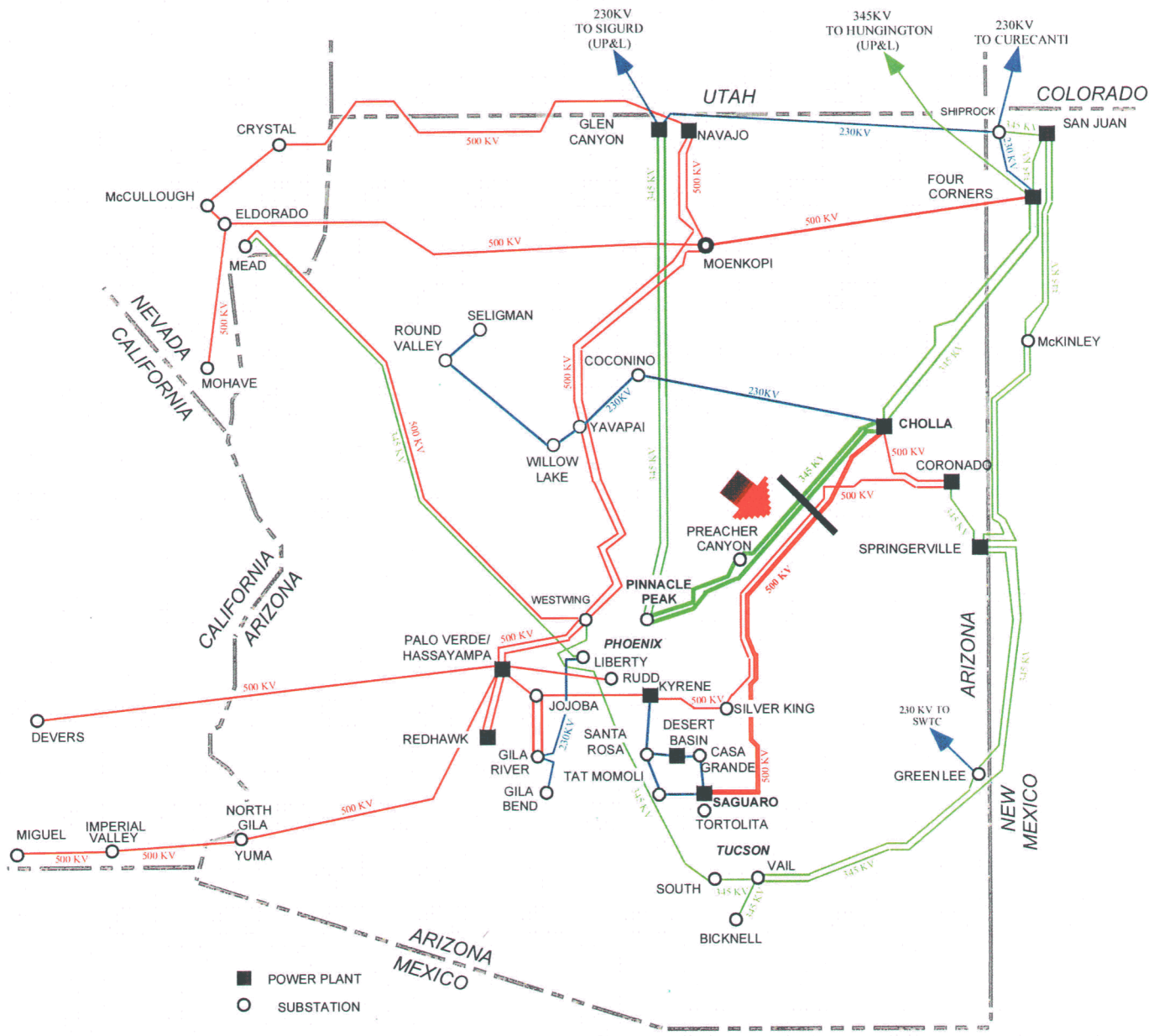
4. Project is currently being studied to determine TTC/ATC. 50% of project assumed for APS share.
5. Project is still being studied and the final rating for this line is still unknown. Depending upon study assumptions it can vary from 600-1200 MW. 40% of project rating is assumed for APS share.
6. Project study has recently begun. No preliminary information yet for expected TTC/ATC.

*Note: The numbers in this table represent annual product values at the end of the 10 year planning horizon

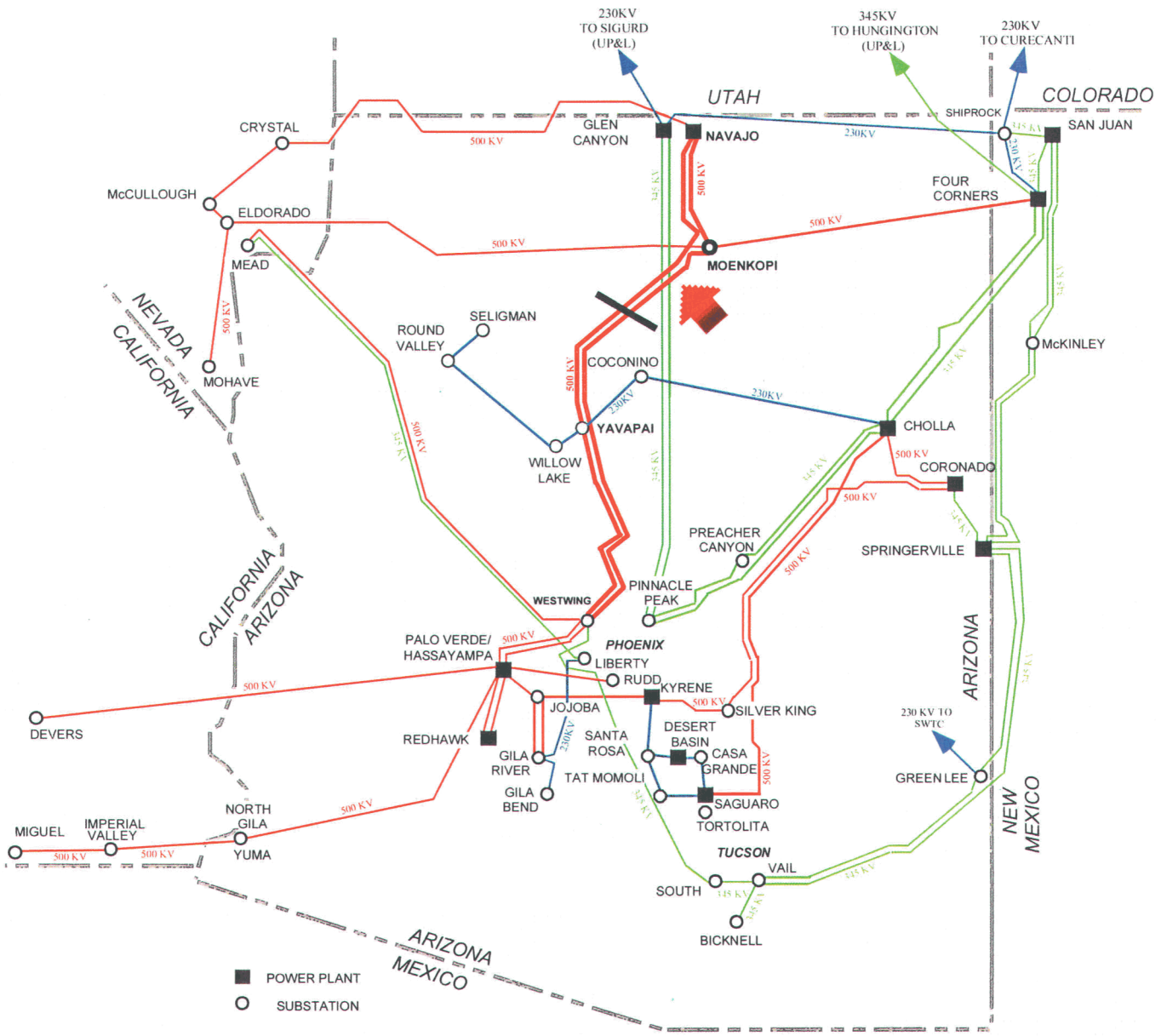
2007 ARIZONA TRANSMISSION SYSTEM



2007 ARIZONA TRANSMISSION SYSTEM



2007 ARIZONA TRANSMISSION SYSTEM



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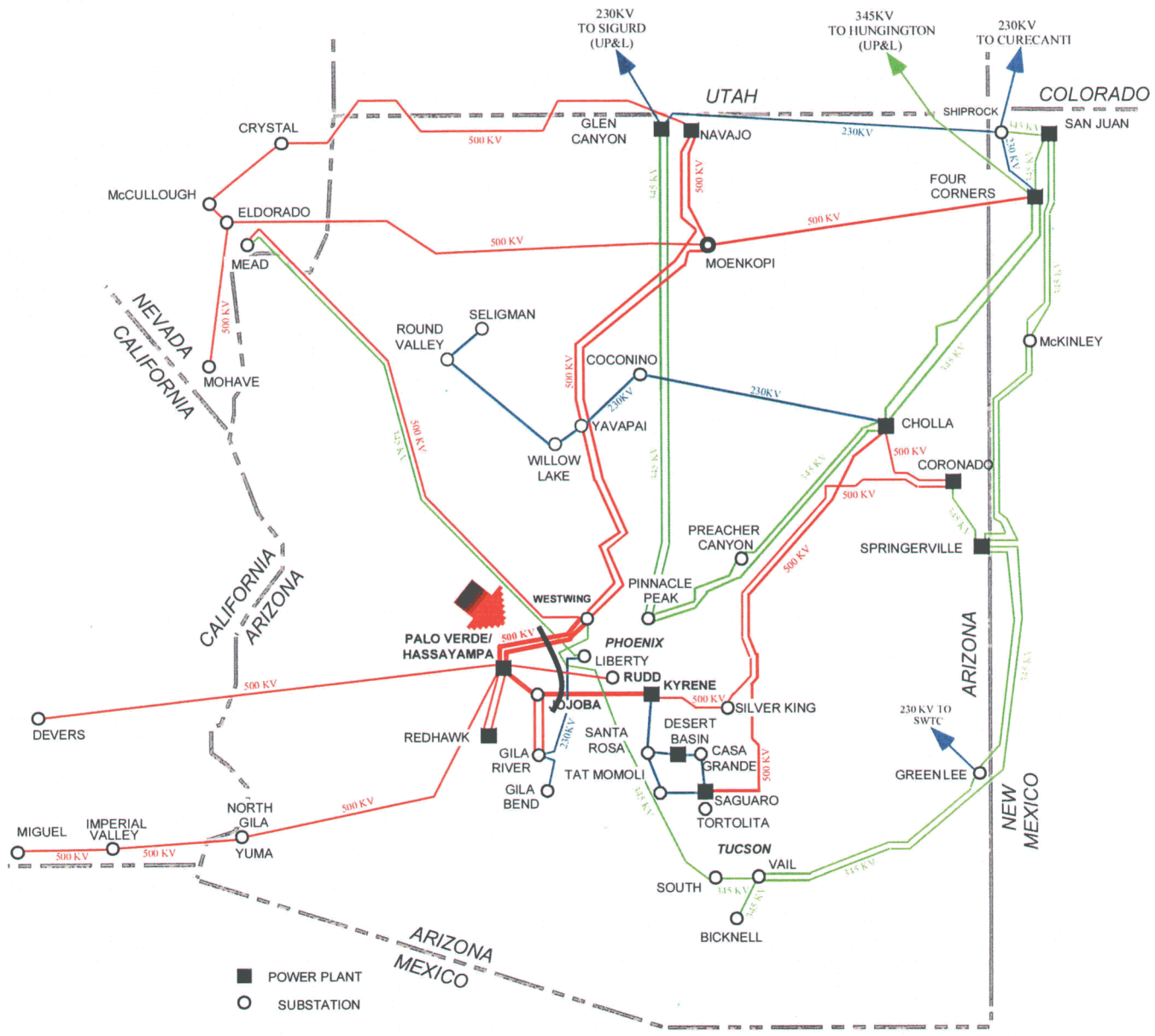
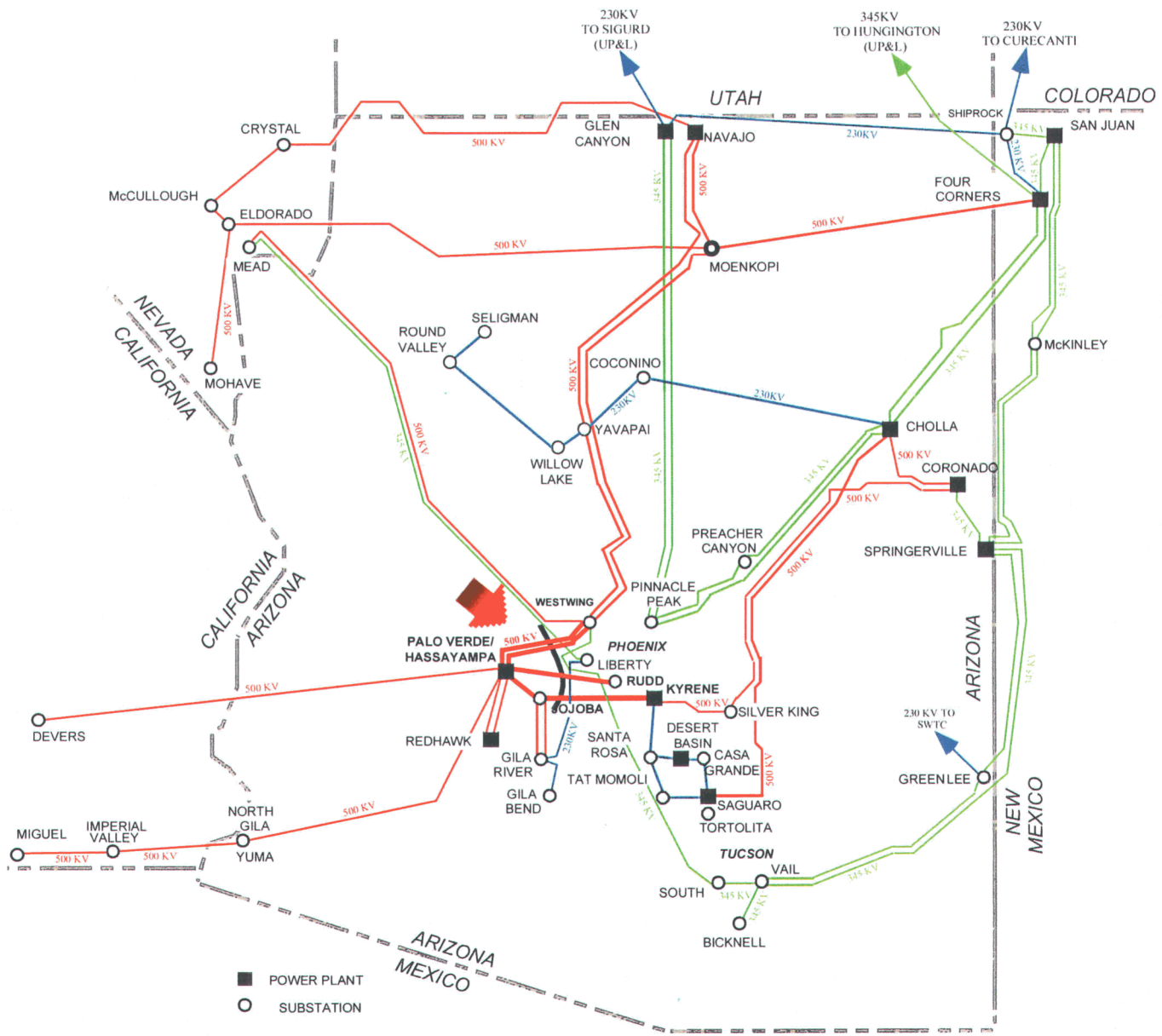
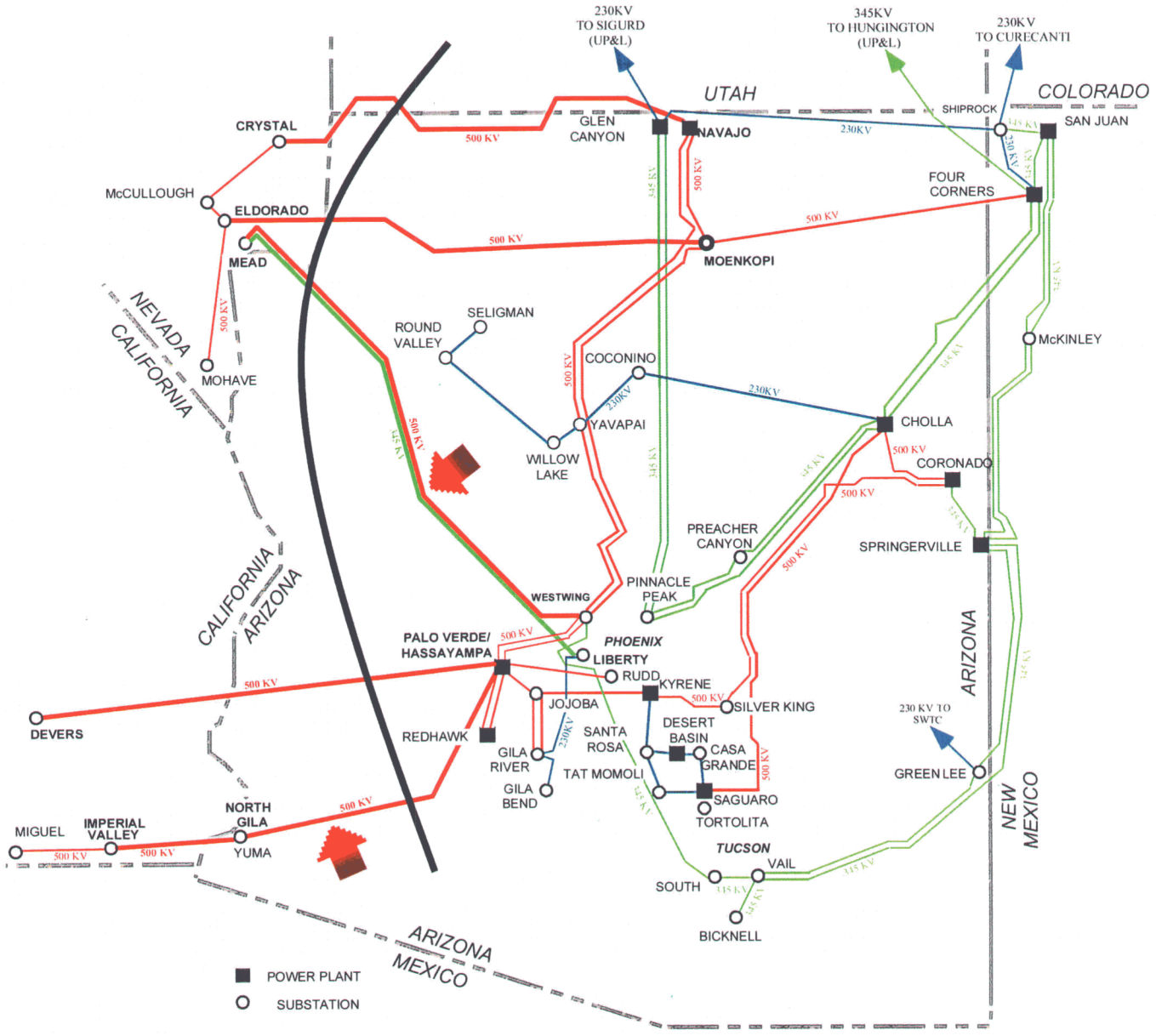


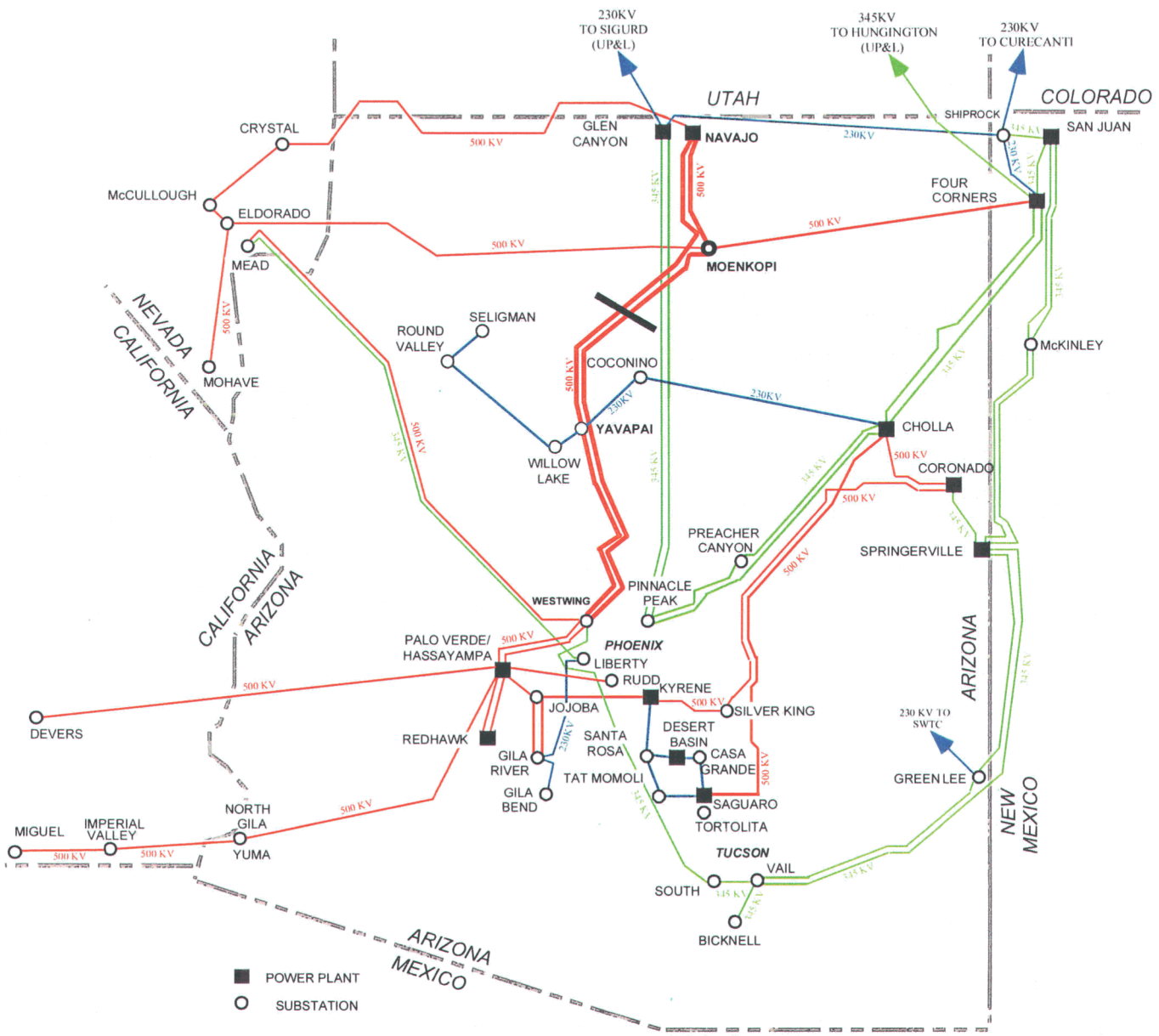
2007 ARIZONA TRANSMISSION SYSTEM



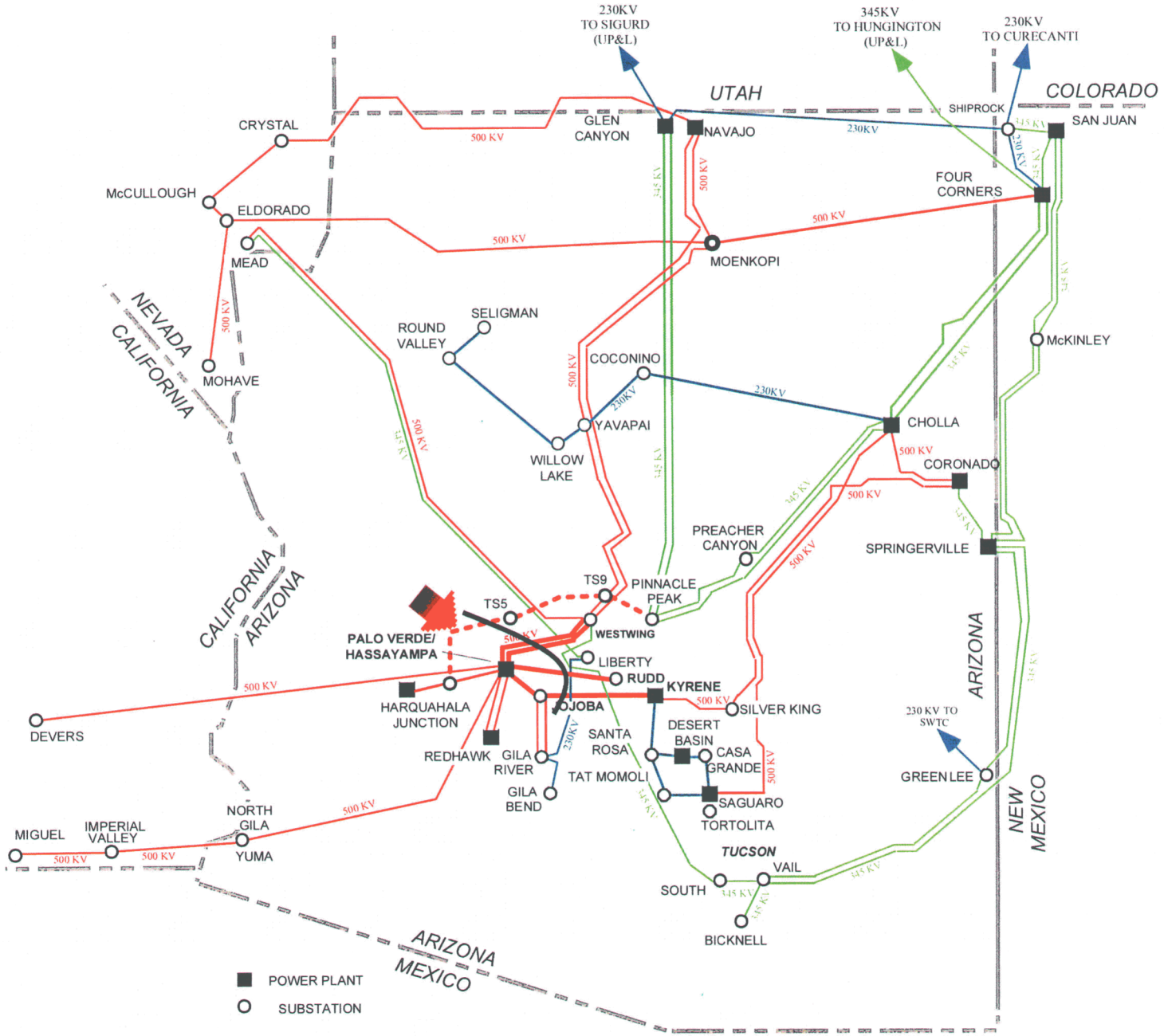
2007 ARIZONA TRANSMISSION SYSTEM



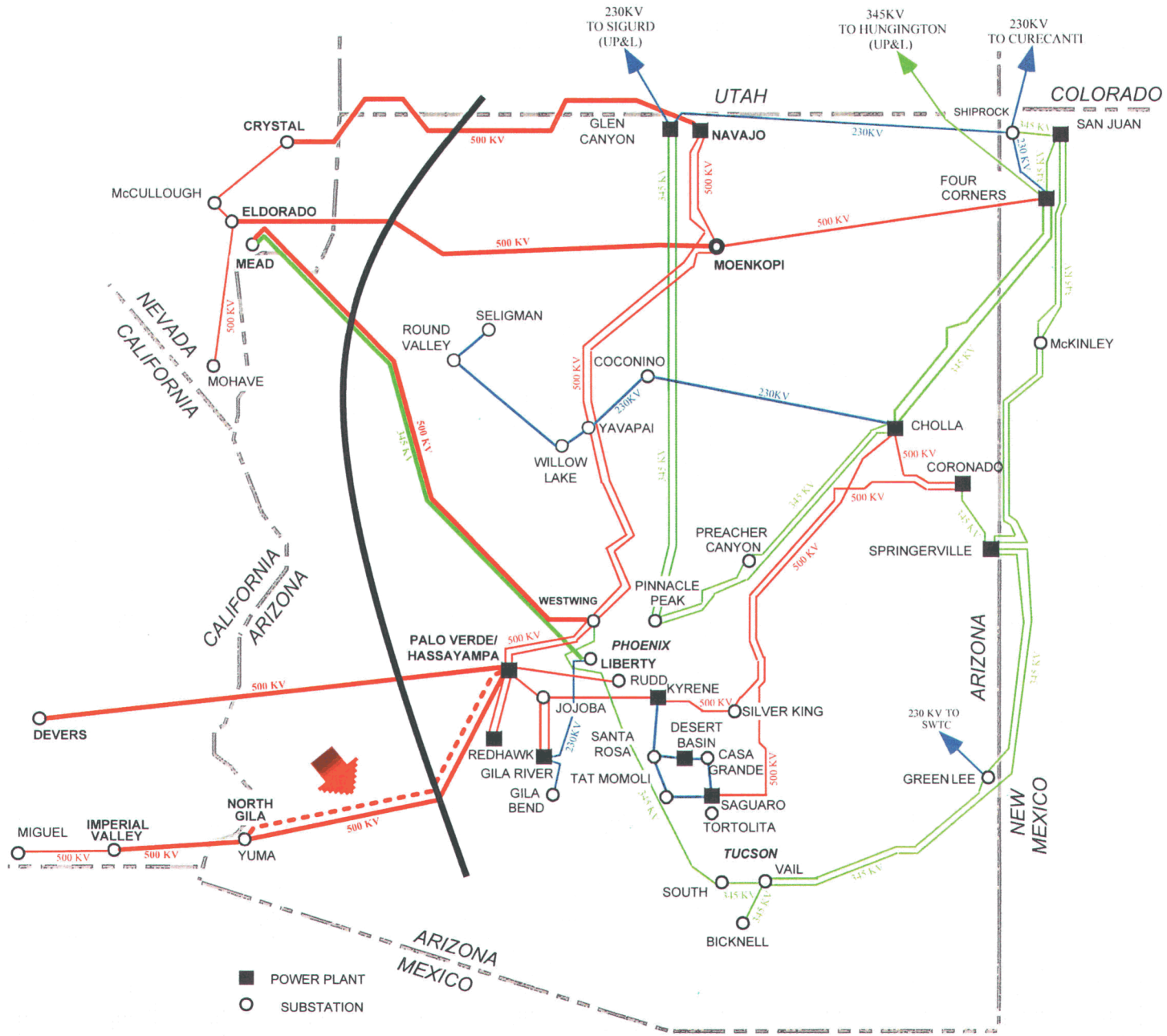
2007 ARIZONA TRANSMISSION SYSTEM



2007 ARIZONA TRANSMISSION SYSTEM

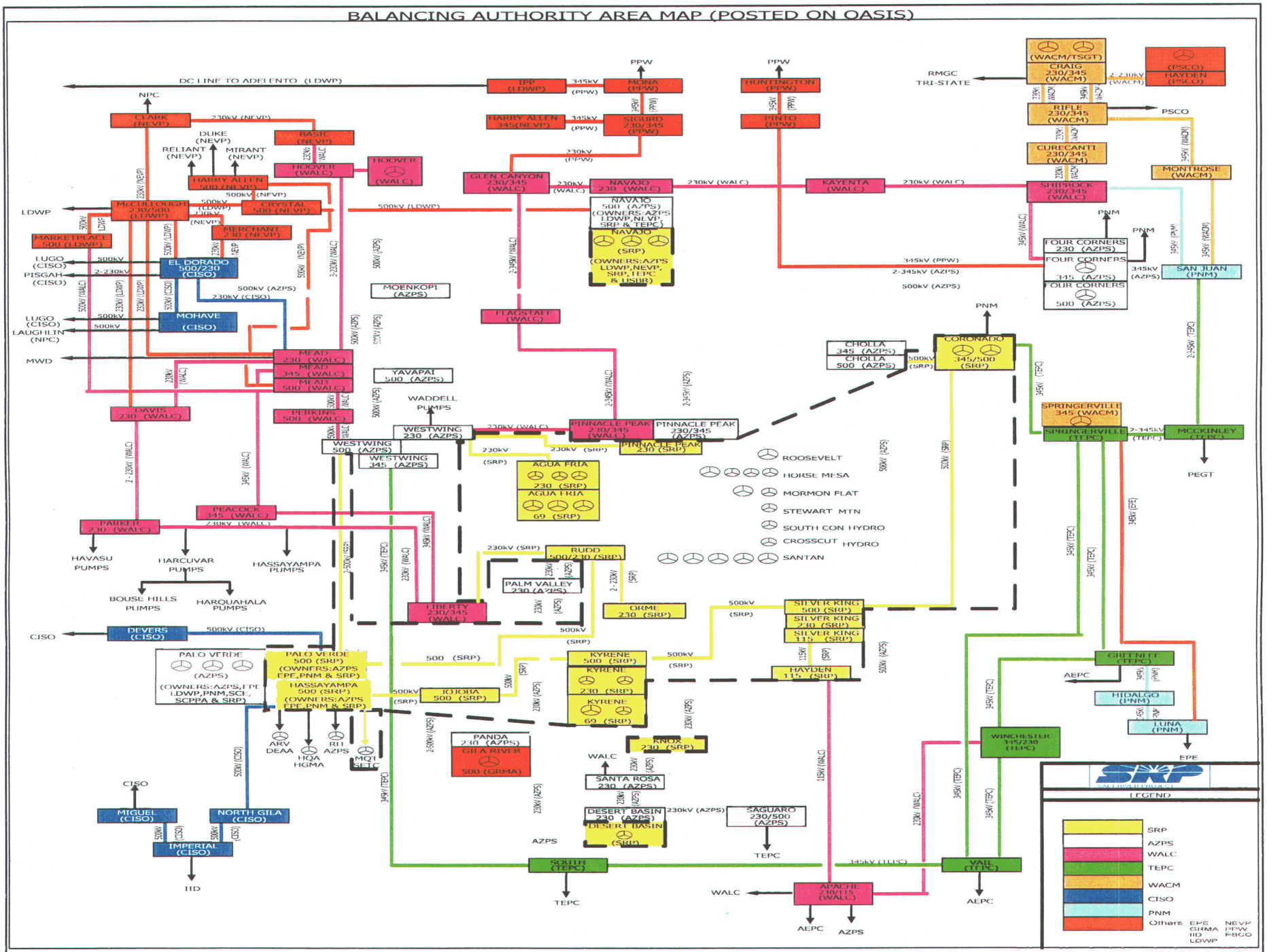


2007 ARIZONA TRANSMISSION SYSTEM



Salt River Project

BALANCING AUTHORITY AREA MAP (POSTED ON OASIS)



EXISTING POSTED PATHS
For
SALT RIVER PROJECT*

Path Name	TTC Determined By	TTC (SRP's Share)	TRM	CBM	Committed Uses	ATC
PaloVerde5-KY5 &WW5	Subregion	1913				
West > East			0	0	1913	0
East > West			0	0	1650	263
PaloVerde5-Rudd2	Subregion	990				
West > East			0	0	990	0
East > West			0	0	0	990
Path 54 (CO-SI-BRG-KY 500kV)	WECC	1100				
North > South			100	0	898	102
South > North			100	0	185	815
Navajo5-Westwing5	WECC	1404				
North > South			210	0	1069	125
South > North			0	0	75	1329

*NOTE: The numbers in this table represent annual product values as of _Jun2007

EXISTING POSTED PATHS
For
SALT RIVER PROJECT*

Path Name	TTC Determined By	TTC (SRP's Share)	TRM	CBM	Committed Uses	ATC
Mead5 – Westwing5	WECC	236				
North > South			0	0	236	0
South > North			0	0	121	115
Marketplace5- Mead5	WECC	556				
North > South			0	0	0	556
South > North			0	0	0	556
Marketplace5- McCullough5	Owner	396				
East > West			0	0	0	396
West > East			0	0	0	396
McCullough 5- Navajo5	WECC	356				
West > East			0	0	0	356
FourCorners 345/230kV	Owner	300				
345 > 230			0	0	0	300
230 > 345			0	0	0	300

*NOTE: The numbers in this table represent annual product values as of _Jun2007

OTHER SRP TRANSMISSION PATHS

Types	Number
Transformer Paths	3
230kV Paths	4
115kV Paths	3
69kV Paths	0

ADDTIONS/CHANGES FOR SRP

Path Name	Venue to Determine TTC Change	Existing TTC SRP (Total)	Change SRP (Total)	Expect Complete	Expect TRM	Expect CBM	Expect Committed Uses	Expect ATC
Palo Verde-Pinal West	Subregion	0 Study To Be Completed	Add PaloVerde-Pinal West +270 (+450)	2008 New Construction	0	0	A	A
Palo Verde-Pinal West-Pinal South-Browning (500kV)	Subregion	0 Study To Be Completed	Add Pinal West-Pinal South-Browning 500kV + 453 (+755)	2011 New Construction	0	0	B	B
DesertBasin - Pinal South 230kV Line	Subregion	0 Study To Be Completed	New Line +600	2011 New Construction	0	0	C	C
Path 54 (Coronado-SilverKing 500kV)	WECC	1100	Redefinition of path and add Springerville Unit 3 +33MW	2007	100	0	873	160 D

ADDITIONS/CHANGES FOR SRP
NOTES

A – This project is still being studied and neither the in-service date nor the TTC/ETC/ATC is firm. Expected SRP TTC for PV-PW line is 270MW. When the project goes into service the expected ETC = 0 MW, ATC = 270 MW. By the end of SRP's 10yr plan (2016) the expected ETC = 270 MW, ATC = 0 MW.

B - This project is still being studied and neither the in-service date nor the TTC/ETC/ATC is firm. Expected SRP TTC for PV-PW-PS-BRG line is 270MW + 453MW = 723MW. When the project goes into service the expected ETC = 600 MW, ATC = 123MW. By the end of SRP's 10yr plan (2016) the expected ETC = 487, TRM = 113MW, ATC = 123 MW.

C - This project is still being studied and neither the in-service date nor the TTC/ETC/ATC is firm. Expected SRP TTC for DB-PW line is 600MW. When the project goes into service the expected ETC = 600 MW, ATC = 0 MW. By the end of SRP's 10yr plan (2016) there is no change in ETC/TRM/ATC.

D – Path 54 is currently in the WECC 3-phase path rating process to determine the increase in rating due to the addition of Springerville Unit 3 and redefinition of the path. When completed it is expected that the path will be redefined such that instead of being composed of two lines (Coronado/Cholla plus Coronado/Silverking) it will be composed of a single line (Coronado/Silverking). Expected SRP TTC for CO-SK line is 1100MW + 33MW = 1133MW. When the project goes into service the expected ETC = 873MW, TRM = 100, ATC = 160MW.

ADDTIONS/CHANGES FOR SRP

Path Name	Venue to Determine TTC Change	Existing TTC SRP (Total)	Change SRP (Total)	Expect Complete	Expect TRM	Expect CBM	Expect Committed Uses	Expect ATC
Path 54 (Coronado-SilverKing 500kV)	WECC	1100	Add Springerville Unit 4 +330	2009	100	0	1283	80 E
Coronado – Cholla 500kV	Subregional	F	Redefinition of Path 54 ?MW	2007	0	0	10	F
Coronado – Cholla 500kV	Subregional	G	Add 2ND Knoll Sub ?MW	2009	0	0	10	G
Path 63 Mead-Perkins 500kV	WECC	236 (1300)	EOR9300 Uprate Project +113 (+623)	2009	0	0	H	H
Path 51 Navajo-Westwing 500kV	WECC	2264	Upgrade Series Comp 518 (836)	2009	210	0	I	I

ADDITIONS/CHANGES FOR SRP
NOTES

E – Path 54 is currently in the WECC 3-phase project rating process to determine the increase in rating due to the addition of Springerville Unit 4. Expected SRP TTC for CO-SK line is 1100MW + 33MW + 330MW = 1463MW. When the project goes into service the expected ETC = 1283MW, TRM = 100MW, ATC = 80MW. By the end of SRP's 10yr plan (2016) there is no change in ETC/TRM/ATC.

F – The redefinition of Path 54 removes the Coronado/Cholla line from the definition of Path 54. A separate study will need to be undertaken to determine a TTC for the Coronado/Cholla path.

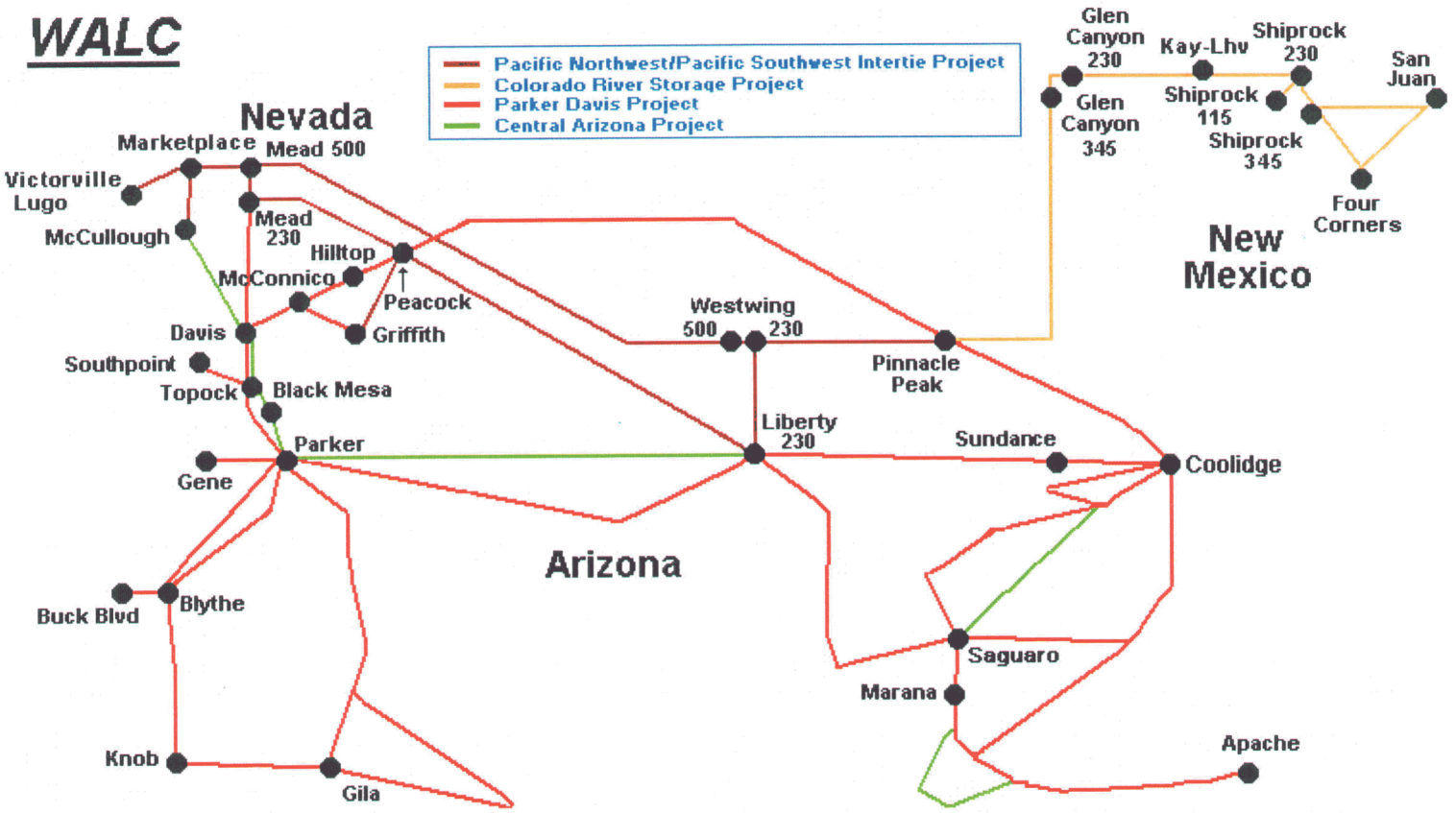
G – The addition of the Second Knoll Substation on the Coronado/Cholla line will alter this path's rating and will require a study which has not been started yet.

H – Expected SRP TTC for Path 63 is 236MW + 113MW = 349MW. When the project goes into service the expected ETC = 349 MW, ATC = 0 MW. By the end of SRP's 10yr plan (2016) there is no change in ETC/TRM/ATC.

I – This project is still being studied and neither the in-service date nor the TTC/ETC/ATC is firm. . Expected SRP TTC for NAV-WW line is 1404MW + 518MW = 1922MW. When the project goes into service the expected ETC = 1071 MW, TRM = 210MW, ATC = 641 MW. By the end of SRP's 10yr plan (2016) the expected ETC = 1123 MW, TRM = 210MW, ATC = 589 MW.

F - APS is developing the Palo Verde to North Gila and Palo Verde to TS5 to TS9 to Pinnacle Peak 500kV projects and SRP is a potential participant in both projects. SRP potential participation ranges from 10% to 50% and participation is dependent upon timing, costs, and ratings. Participation agreements have not been executed. See APS Additions/Changes Table for specific information on the projects.

Western Area Power Administration
DSW


WALC
Pacific Northwest/Pacific Southwest Intertie Project
Colorado River Storage Project
Parker Davis Project
Central Arizona Project
Nevada
Marketplace
Mead 500
Victorville
Lugo
Mead
230
McCullough
Hilltop
McConnico
Peacock
Griffith
Davis
Southpoint
Topock
Black Mesa
Parker
Gene
Buck Blvd
Blythe
Knob
Gila
Arizona
Westwing
500
230
Pinnacle
Peak
Liberty
230
Sundance
Coolidge
Saguaro
Marana
Apache
Glen
Canyon
230
Glen
Canyon
345
Kay-Lhv
Shiprock
230
Shiprock
115
Shiprock
345
San
Juan
Four
Corners
New
Mexico

WALC Paths

WALC Paths

PATH NAME	TTC	CBM	TRM	CU	ATC
W/WALC/DWP-DWP/ADELANTO500-LUGO500/I01	108	0	0	100	8
W/WALC/SYSTRANS/APACHE115-BUCKBLVD161/P01	60	0	0	60	0
W/WALC/SYSTRANS/APACHE115-BLYTHE161/P01	60	0	0	60	0
W/WALC/SYSTRANS/APACHE115-COOLIDGE/P01	60	0	0	60	0
W/WALC/SYSTRANS/APACHE115-COOLIDGE/P02	60	0	0	60	0
W/WALC/SYSTRANS/APACHE115-DAVIS230/P01	60	0	0	60	0
W/WALC/SYSTRANS/APACHE115-GILA161/P01	60	0	0	60	0
W/WALC/SYSTRANS/APACHE115-LIBERTY230/P01	60	0	0	60	0
W/WALC/SYSTRANS/APACHE115-LIBERTY230/P02	60	0	0	60	0
W/WALC/SYSTRANS/APACHE115-MARANA115/P01	60	0	0	60	0
W/WALC/WALC-DWP/APACHE115-MARKETPLACE/Y01	60	40	0	20	0
W/WALC/WALC-DWP/APACHE115-MCCONNICO230/P02	60	0	0	60	0
W/WALC/WALC-DWP/APACHE115-MCCONNICO230/Y01	60	0	0	60	0
W/WALC/SYSTRANS/APACHE115-MEAD230/P01	60	0	0	60	0
W/WALC/SYSTRANS/APACHE115-NOGALES115/P01	60	0	0	60	0
W/WALC/SYSTRANS/APACHE115-PARKER230/P01	60	0	0	60	0
W/WALC/SYSTRANS/APACHE115-PNPKWALC230/P01	60	0	0	60	0
W/WALC/SYSTRANS/APACHE115-PNPKWALC230/P02	60	0	0	60	0
W/WALC/SYSTRANS/APACHE115-SAGUARO115/P01	60	0	0	60	0
W/WALC/WALC-APS/APACHE115-WESTWING500/Y01	60	30	0	30	0
W/WALC/WALC-APS/APACHE115-WESTWING500/Y02	60	0	0	60	0
W/WALC/SYSTRANS/BKB(BUCKBLVD)-APACHE115/P01	60	0	0	57	3

WALC Paths

PATH NAME	TTC	CBM	TRM	CU	ATC
W/WALC/SYSTRANS/BKB(BUCKBLVD)-BLYTHE161/P01	520	0	0	520	0
W/WALC/SYSTRANS/BKB(BUCKBLVD-DAVIS230/P01	279	0	0	279	0
W/WALC/SYSTRANS/BKB(BUCKBLVD)-GILA161/P02	167	0	0	167	0
W/WALC/SYSTRANS/BKB(BUCKBLVD)-GILA161/P01	112	0	0	112	0
W/WALC/SYSTRANS/BKB(BUCKBLVD)-GILA69/P01	112	0	0	112	0
W/WALC/SYSTRANS/BKB(BUCKBLVD)-KNOB161/P01	167	0	0	117	50
W/WALC/SYSTRANS/BKB(BUCKBLVD)-KNOB161/P02	112	0	0	62	50
W/WALC/SYSTRANS/BKB(BUCKBLVD)-LIBERTY230/P01	279	0	0	279	0
W/WALC/WALC-DWP/BKB(BUCKBLVD)-LUGO/Y01	108	40	0	68	0
W/WALC/WALC-DWP/BKB(BUCKBLVD)-LUGO/Y02	108	0	0	108	0
W/WALC/WALC-DWP/BKB(BUCKBLVD)-MCCULLOUG230/P01	240	0	0	240	0
W/WALC/WALC-DWP/BKB(BUCKBLVD)-MCCULLOUG230/P02	240	0	0	240	0
W/WALC/SYSTRANS/BKB(BUCKBLVD)-MEAD230/Y01	279	0	0	279	0
W/WALC/SYSTRANS/BKB(BUCKBLVD)-MEAD230/P01	240	0	0	240	0
W/WALC/SYSTRANS/BKB(BUCKBLVD)-MEAD500/Y01	240	40	0	200	0
W/WALC/SYSTRANS/BKB(BUCKBLVD)-MEAD500/Y02	240	40	0	200	0
W/WALC/SYSTRANS/BKB(BUCKBLVD)-PARKER230/P01	279	0	0	279	0
W/WALC/SYSTRANS/BKB(BUCKBLVD)-PNPKWALC230/P02	279	40	0	239	0
W/WALC/SYSTRANS/BKB(BUCKBLVD)-PNPKWALC230/P01	279	0	0	279	0
W/WALC/SYSTRANS/BKB(BUCKBLVD)-WESTWING230/Y02	279	30	0	249	0
W/WALC/WALC-APS/BKB(BUCKBLVD)-WESTWING230/Y01	279	0	0	279	0
W/WALC/WALC-APS/BKB(BUCKBLVD)-WESTWING500/Y01	279	0	0	279	0

WALC Paths

PATH NAME	TTC	CBM	TRM	CU	ATC
W/WALC/SYSTRANS/BLACKMESA230-PARKER230/P01	438	0	0	438	0
W/WALC/SYSTRANS/BLACKMESA230-TOPOCK230/P01	438	0	0	438	0
W/WALC/SYSTRANS/BLYTHE161-DAVIS230/P01	279	0	0	279	0
W/WALC/SYSTRANS/BLYTHE161-GENE/P01	220	0	0	220	0
W/WALC/SYSTRANS/BLYTHE161-GILA161/P02	167	0	0	167	0
W/WALC/SYSTRANS/BLYTHE161-GLENCANYON2/X01	279	69	20	190	0
W/WALC/SYSTRANS/BLYTHE161-LIBERTY230/P01	279	0	0	279	0
W/WALC/SYSTRANS/BLYTHE161-MEAD230/P01	240	0	0	240	0
W/WALC/SYSTRANS/BLYTHE161-PARKER230/P01	279	0	0	279	0
W/WALC/SYSTRANS/BLYTHE161-PNPKWALC230/P01	279	0	0	279	0
W/WALC/SYSTRANS/BLYTHE161-TOPOCK230/P01	279	0	0	279	0
W/WALC/SYSTRANS/COOLIDGE-APACHE115/P01	60	0	0	60	0
W/WALC/SYSTRANS/COOLIDGE-APACHE115/P02	60	0	0	60	0
W/WALC/SYSTRANS/COOLIDGE-APACHE115/P03	60	0	0	60	0
W/WALC/SYSTRANS/COOLIDGE-DAVIS230/P02	---	---	---	---	---
W/WALC/SYSTRANS/COOLIDGE-DAVIS230/P01	450	0	0	450	0
W/WALC/WALC-APS/COOLIDGE-FOURCORNE345/X01	300	69	20	211	0
W/WALC/SYSTRANS/COOLIDGE-GLENCANYON2/X01	359	69	20	270	0
W/WALC/SYSTRANS/COOLIDGE-LIBERTY230/P01	451	0	0	451	0
W/WALC/SYSTRANS/COOLIDGE-LIBERTY230/Y01	359	30	0	329	0
W/WALC/WALC-DWP/COOLIDGE-MARKETPLACE/Y01	398	0	0	398	0
W/WALC/WALC-DWP/COOLIDGE-MARKETPLACE/Y02	240	40	0	200	0

WALC Paths

PATH NAME	TTC	CBM	TRM	CU	ATC
W/WALC/SYSTRANS/COOLIDGE-MEAD230/Y01	450	0	0	450	0
W/WALC/SYSTRANS/COOLIDGE-MEAD230/P01	240	0	0	240	0
W/WALC/SYSTRANS/COOLIDGE-PNPKWALC230/Y01	398	40	0	358	0
W/WALC/SYSTRANS/COOLIDGE-PNPKWALC230/P01	359	0	0	359	0
W/WALC/SYSTRANS/COOLIDGE-SAGUARO115/P01	240	0	0	205	35
W/WALC/SYSTRANS/COOLIDGE-SHR2(SHIPROCK230)/X01	350	69	20	261	0
W/WALC/SYSTRANS/COOLIDGE-SUNDANCE/P01	451	0	0	451	0
W/WALC/SYSTRANS/COOLIDGE-WESTWING230/Y01	398	0	0	258	140
W/WALC/SYSTRANS/COOLIDGE-WESTWING230/Y02	359	30	0	189	140
W/WALC/SYSTRANS/DAVIS230-COOLIDGE/P01	---	---	---	---	---
W/WALC/SYSTRANS/DAVIS230-COOLIDGE/Y01	240	0	40	200	0
W/WALC/SYSTRANS/DAVIS230-HILLTOP230/P01	239	0	0	239	0
W/WALC/WALC-DWP/DAVIS230-MARKETPLACE/P01	240	0	0	240	0
W/WALC/WALC-DWP/DAVIS230-MCCULLOUG230/A01	240	0	0	240	0
W/WALC/SYSTRANS/DAVIS230-MEAD230/P01	240	0	0	240	0
W/WALC/SYSTRANS/DAVIS230-PNPKWALC230/P02	---	---	---	---	---
W/WALC/SYSTRANS/DAVIS230-PNPKWALC230/P01	359	0	0	359	0
W/WALC/SYSTRANS/DAVIS230-TOPOCK230/P01	638	0	0	638	0
W/WALC/SYSTRANS/DAVIS230-WESTWING230/Y01	240	80	0	160	0
W/WALC/APS-WALC/FOURCORNE345-BLYTHE161/X01	230	39	20	171	0
W/WALC/APS-WALC/FOURCORNE345-GLENCANYON2/C01	300	0	0	300	0
W/WALC/APS-WALC/FOURCORNE345-MEAD230/X01	---	---	---	---	---

WALC Paths

PATH NAME	TTC	CBM	TRM	CU	ATC
W/WALC/APS-WALC/FOURCORNE345-MEAD230/W01	300	39	20	241	0
W/WALC/APS-WALC/FOURCORNE345-MEAD230/X02	240	39	20	181	0
W/WALC/APS-WALC/FOURCORNE345-PARKER230/X01	300	39	20	241	0
W/WALC/APS-WALC/FOURCORNE345-PNPKWALC230/C01	300	39	20	241	0
W/WALC/APS-WALC/FOURCORNE345-SAGUARO115/X01	240	39	20	181	0
W/WALC/APS-WALC/FOURCORNE345-SHIPROCK345/C01	300	0	0	300	0
W/WALC/APS-WALC/FOURCORNE345-SHIPROCK230/C01	300	0	0	300	0
W/WALC/APS-PNM/FOURCORNE345-SANJUAN345/C01	299	0	0	299	0
W/WALC/APS-WALC/FOURCORNE345-TOPOCK230/X01	---	---	---	---	---
W/WALC/APS-APS/FOURCORNE345-WESTWING500/W01	300	39	20	241	0
W/WALC/SYSTRANS/GENE-BLACKMESA230/V01	250	0	0	190	60
W/WALC/SYSTRANS/GENE-BLYTHE161/P01	230	0	0	170	60
W/WALC/SYSTRANS/GENE-NORTH_HAVASU/P01	250	0	0	190	60
W/WALC/SYSTRANS/GILA161-BUCKBLVD161/P01	112	0	0	112	0
W/WALC/SYSTRANS/GILA161-BLYTHE161/P01	112	0	0	112	0
W/WALC/SYSTRANS/GILA161-GILA69/P01	150	0	0	150	0
W/WALC/SYSTRANS/GILA161-KNOB161/P01	112	0	0	0	112
W/WALC/SYSTRANS/GILA161-MEAD230/P01	167	0	0	167	0
W/WALC/SYSTRANS/GILA161-MEAD230/Y01	167	0	0	167	0
W/WALC/SYSTRANS/GILA161-PNPKWALC230/P01	167	0	0	167	0
W/WALC/SYSTRANS/GILA161-WESTWING230/Y01	167	0	0	167	0
W/WALC/SYSTRANS/GILA69-NRTHGILA69/P01	75	0	0	75	0

WALC Paths

PATH NAME	TTC	CBM	TRM	CU	ATC
W/WALC/WALC-APS/GLENCANYON2-FOURCORNE345/C01	300	69	0	231	0
W/WALC/SYSTRANS/GLENCANYON2-MEAD230/X01	---	---	---	---	---
W/WALC/SYSTRANS/GLENCANYON2-MEAD500/W01	412	39	20	353	0
W/WALC/SYSTRANS/GLENCANYON2-PNPKWALC230/C01	600	39	20	541	0
W/WALC/SYSTRANS/GLENCANYON2-SAGUARO115/X01	240	39	20	181	0
W/WALC/SYSTRANS/GLENCANYON2-SHR2(SHIPROCK230)/C01	350	69	0	281	0
W/WALC/SYSTRANS/GLENCANYON2-SJ345(SANJUAN345)/C01	269	69	0	200	0
W/WALC/SYSTRANS/GLENCANYON2-WESTWING230/W01	600	39	20	541	0
W/WALC/WALC-APS/GLENCANYON2-WESTWING500/W01	412	39	20	353	0
W/WALC/SYSTRANS/GLENCANYON3-PNPKWALC230/C01	1494	39	20	1435	0
W/WALC/SYSTRANS/GRIFFITH230-GILA161/P01	167	0	0	167	0
W/WALC/SYSTRANS/GRIFFITH230-GLENCANYON2/X01	---	---	---	---	---
W/WALC/SYSTRANS/GRIFFITH230-HILLTOP230/P01	239	0	0	239	0
W/WALC/SYSTRANS/GRIFFITH230-LIBERTY230/I01	450	0	0	445	5
W/WALC/WALC-DWP/GRIFFITH230-MARKETPLACE/I01	500	40	0	460	0
W/WALC/WALC-DWP/GRIFFITH230-MARKETPLACE/Y01	239	40	0	199	0
W/WALC/WALC-DWP/GRIFFITH230-MCCONNICO230/P01	797	0	0	797	0
W/WALC/SYSTRANS/GRIFFITH230-MEAD230/I01	600	0	0	600	0
W/WALC/SYSTRANS/GRIFFITH230-MEAD230/Y01	359	30	0	329	0
W/WALC/SYSTRANS/GRIFFITH230-MEAD230/P01	239	0	0	239	0
W/WALC/SYSTRANS/GRIFFITH230-NRTHGILA69/P01	75	0	0	75	0
W/WALC/SYSTRANS/GRIFFITH230-PNPKWALC230/P01	---	---	---	---	---

WALC Paths

PATH NAME	TTC	CBM	TRM	CU	ATC
W/WALC/SYSTRANS/GRIFFITH230-PRESCOTT230/P01	---	---	---	---	---
W/WALC/SYSTRANS/GRIFFITH230-SAGUARO115/P01	239	0	0	204	35
W/WALC/SYSTRANS/GRIFFITH230-STHPOINT230/P01	239	0	0	239	0
W/WALC/SYSTRANS/GRIFFITH230-SUNDANCE/P01	239	0	0	204	35
W/WALC/WALC-APS/GRIFFITH230-WESTWING230/I01	398	0	0	398	0
W/WALC/SYSTRANS/HEADGATEROCK-COOLIDGE/P01	167	0	0	167	0
W/WALC/SYSTRANS/HEADGATEROCK-DAVIS230/P01	167	0	0	167	0
W/WALC/SYSTRANS/HEADGATEROCK-LIBERTY230/P01	167	0	0	167	0
W/WALC/SYSTRANS/HEADGATEROCK-MEAD230/P01	167	0	0	167	0
W/WALC/SYSTRANS/HEADGATEROCK-PNPKWALC230/P01	167	0	0	167	0
W/WALC/WALC-APS/HEADGATEROCK-WESTWING500/Y01	167	0	0	167	0
W/WALC/WALC-DWP/HILLTOP230-MCCONNICO230/P01	450	0	0	450	0
W/WALC/SYSTRANS/KAYENTA230-SHR2(SHIPROCK230)/C01	350	40	0	310	0
W/WALC/SYSTRANS/KNOB161-BLYTHE161/P01	167	0	0	167	0
W/WALC/SYSTRANS/KNOB161-GILA161/P01	112	0	0	55	57
W/WALC/SYSTRANS/KNOB161-MEAD230/P01	167	0	0	167	0
W/WALC/SYSTRANS/LIBERTY230-APACHE115/P01	60	0	0	60	0
W/WALC/SYSTRANS/LIBERTY230-BKB(BUCKBLVD)/P01	230	0	0	230	0
W/WALC/SYSTRANS/LIBERTY230-BKB(BUCKBLVD)/P02	112	0	0	112	0
W/WALC/SYSTRANS/LIBERTY230-BLYTHE161/P01	230	0	0	230	0
W/WALC/SYSTRANS/LIBERTY230-COOLIDGE/P01	451	0	0	291	160
W/WALC/SYSTRANS/LIBERTY230-DAVIS230/P01	450	0	0	450	0

WALC Paths

PATH NAME	TTC	CBM	TRM	CU	ATC
W/WALC/SYSTRANS/LIBERTY230-GENE/P01	220	0	0	220	0
W/WALC/SYSTRANS/LIBERTY230-GILA161/P01	167	0	0	167	0
W/WALC/SYSTRANS/LIBERTY230-GLENCANYON2/W01	398	69	20	309	0
W/WALC/SYSTRANS/LIBERTY230-GRIFFITH230/I01	450	0	0	450	0
W/WALC/SYSTRANS/LIBERTY230-HEADGATEROCK/P01	96	0	0	96	0
W/WALC/SYSTRANS/LIBERTY230-KNOB161/P01	167	0	0	132	35
W/WALC/WALC-DWP/LIBERTY230-LUGO/I01	108	0	0	108	0
W/WALC/SYSTRANS/LIBERTY230-MARANA115/P01	80	0	0	30	50
W/WALC/WALC-DWP/LIBERTY230-MARKETPLACE/Y01	450	40	0	410	0
W/WALC/SYSTRANS/LIBERTY230-MCCONNICO230/Y01	239	0	0	239	0
W/WALC/SYSTRANS/LIBERTY230-MEAD230/I01	450	0	0	450	0
W/WALC/SYSTRANS/LIBERTY230-MEAD230/I02	398	0	0	398	0
W/WALC/SYSTRANS/LIBERTY230-MEAD230/P01	240	0	0	240	0
W/WALC/SYSTRANS/LIBERTY230-MEAD500/I01	450	40	0	410	0
W/WALC/SYSTRANS/LIBERTY230-PARKER230/P01	558	0	0	558	0
W/WALC/SYSTRANS/LIBERTY230-PEACOCK230/I01	450	0	0	270	180
W/WALC/SYSTRANS/LIBERTY230-PNPKWALC230/I01	398	40	0	218	140
W/WALC/SYSTRANS/LIBERTY230-SAGUARO115/P01	320	0	0	285	35
W/WALC/SYSTRANS/LIBERTY230-SJ345(SANJUAN345)/W01	269	69	20	180	0
W/WALC/SYSTRANS/LIBERTY230-SUNDANCE/P01	451	0	0	251	200
W/WALC/SYSTRANS/LIBERTY230-TOPOCK230/P01	450	0	0	450	0
W/WALC/WALC-APS/LIBERTY230-WESTWING230/I01	398	0	0	258	140

WALC Paths

PATH NAME	TTC	CBM	TRM	CU	ATC
W/WALC/WALC-APS/LIBERTY230-WESTWING500/I01	398	0	0	246	152
W/WALC/DWP-WALC/LUGO-LIBERTY230/I01	---	---	---	---	---
W/WALC/DWP-DWP/LUGO-MARKETPLACE/I01	108	0	0	0	108
W/WALC/DWP-WALC/LUGO-MEAD230/I01	108	0	0	0	108
W/WALC/DWP-WALC/LUGO-MEAD500/I01	108	0	0	0	108
W/WALC/DWP-APS/LUGO-WESTWING230/I01	---	---	---	---	---
W/WALC/DWP-APS/LUGO-WESTWING500/I01	---	---	---	---	---
W/WALC/SYSTRANS/MARANA115-LIBERTY230/P01	80	0	0	75	5
W/WALC/SYSTRANS/MARANA115-MCCONNICO230/P01	80	0	0	80	0
W/WALC/SYSTRANS/MARANA115-ORACLE115/P01	80	0	0	80	0
W/WALC/SYSTRANS/MARANA115-PNPKWALC230/P01	80	0	0	80	0
W/WALC/SYSTRANS/MARANA115-SAGUARO115/P01	80	0	0	40	40
W/WALC/WALC-APS/MARANA115-WESTWING500/Y01	80	0	0	80	0
W/WALC/DWP-DWP/MARKETPLACE-LUGO/I01	108	0	0	100	8
W/WALC/DWP-DWP/MARKETPLACE-MCCULLOUG230/I01	400	0	0	400	0
W/WALC/DWP-WALC/MARKETPLACE-MEAD230/I01	500	0	0	408	92
W/WALC/DWP-WALC/MARKETPLACE-MEAD500/I01	814	0	0	0	814
W/WALC/DWP-WALC/MARKETPLACE-SAGUARO115/Y01	---	---	---	---	---
W/WALC/DWP-APS/MARKETPLACE-WESTWING500/I01	412	40	0	0	372
W/WALC/SYSTRANS/MCCONNICO230-DAVIS230/P01	239	0	0	239	0
W/WALC/SYSTRANS/MCCONNICO230-GRIFFITH230/P01	797	0	0	797	0
W/WALC/SYSTRANS/MCCONNICO230-HILLTOP230/P01	239	0	0	239	0
W/WALC/DWP-WALC/MCCULLOUG230-DAVIS230/P01	319	0	0	319	0
W/WALC/DWP-DWP/MCCULLOUG230-MARKETPLACE/I01	319	0	0	319	0

WALC Paths

PATH NAME	TTC	CBM	TRM	CU	ATC
W/WALC/DWP-WALC/MCCULLOUG230-MEAD230/P01	240	0	0	240	0
W/WALC/DWP-WALC/MCCULLOUG230-MEAD500/Y01	240	40	0	200	0
W/WALC/SYSTRANS/MEAD230-APACHE115/P01	60	0	0	60	0
W/WALC/SYSTRANS/MEAD230-BKB(BUCKBLVD)/Y02	230	80	0	150	0
W/WALC/SYSTRANS/MEAD230-BKB(BUCKBLVD)/Y01	230	0	40	190	0
W/WALC/SYSTRANS/MEAD230-BKB(BUCKBLVD)/P01	230	0	0	230	0
W/WALC/SYSTRANS/MEAD230-BLYTHE161/P01	230	0	0	230	0
W/WALC/SYSTRANS/MEAD230-COOLIDGE/P01	---	---	---	---	---
W/WALC/SYSTRANS/MEAD230-DAVIS230/P01	319	0	0	319	0
W/WALC/WALC-APS/MEAD230-FOURCORNE345/X01	---	---	---	---	---
W/WALC/SYSTRANS/MEAD230-GENE/Y01	220	0	40	180	0
W/WALC/SYSTRANS/MEAD230-GENE/P01	220	0	0	220	0
W/WALC/SYSTRANS/MEAD230-GILA161/P01	167	0	0	167	0
W/WALC/SYSTRANS/MEAD230-GILA69/P01	112	0	0	112	0
W/WALC/SYSTRANS/MEAD230-GLENCANYON2/X01	---	---	---	---	---
W/WALC/SYSTRANS/MEAD230-GLENCANYON2/W01	398	69	40	289	0
W/WALC/SYSTRANS/MEAD230-GRIFFITH230/I01	600	0	40	560	0
W/WALC/SYSTRANS/MEAD230-GRIFFITH230/P01	239	0	0	239	0
W/WALC/SYSTRANS/MEAD230-HEADGATEROCK/P01	96	0	0	96	0
W/WALC/SYSTRANS/MEAD230-HILLTOP230/P01	239	0	0	239	0
W/WALC/SYSTRANS/MEAD230-LIBERTY230/I01	450	0	40	400	10
W/WALC/SYSTRANS/MEAD230-LIBERTY230/I02	412	80	0	282	50
W/WALC/SYSTRANS/MEAD230-LIBERTY230/P01	319	0	0	319	0
W/WALC/WALC-DWP/MEAD230-LUGO/I01	108	40	0	60	8

WALC Paths

PATH NAME	TTC	CBM	TRM	CU	ATC
W/WALC/SYSTRANS/MEAD230-MCCONNICO230/P01	239	0	0	239	0
W/WALC/WALC-DWP/MEAD230-MCCULLOUG230/I01	400	40	0	360	0
W/WALC/WALC-DWP/MEAD230-MCCULLOUG500/I01	500	40	0	460	0
W/WALC/SYSTRANS/MEAD230-MEAD500/I01	500	40	0	0	460
W/WALC/SYSTRANS/MEAD230-NRTHGILA69/P01	75	0	0	75	0
W/WALC/SYSTRANS/MEAD230-PARKER230/P01	319	0	0	319	0
W/WALC/SYSTRANS/MEAD230-PNPKWALC230/I01	412	80	0	282	50
W/WALC/SYSTRANS/MEAD230-PNPKWALC230/P01	319	0	0	319	0
W/WALC/SYSTRANS/MEAD230-PNPKWALC230/P02	319	0	0	319	0
W/WALC/SYSTRANS/MEAD230-SAGUARO115/P01	319	0	0	319	0
W/WALC/SYSTRANS/MEAD230-SHR2(SHIPROCK230)/X01	---	---	---	---	---
W/WALC/SYSTRANS/MEAD230-SJ345(SANJUAN345)/X01	---	---	---	---	---
W/WALC/SYSTRANS/MEAD230-TOPOCK230/P01	319	0	0	319	0
W/WALC/WALC-APS/MEAD230-WESTWING230/I01	412	80	0	282	50
W/WALC/WALC-APS/MEAD230-WESTWING500/I01	412	40	0	0	372
W/WALC/WALC-APS/MEAD500-FOURCORNE345/W01	300	80	20	200	0
W/WALC/SYSTRANS/MEAD500-GLENCANYON2/W01	600	80	20	500	0
W/WALC/WALC-DWP/MEAD500-LUGO/I01	108	0	0	100	8
W/WALC/WALC-DWP/MEAD500-MARKETPLACE/I01	814	0	0	100	714
W/WALC/SYSTRANS/MEAD500-MEAD230/I01	500	0	0	408	92
W/WALC/SYSTRANS/MEAD500-SHR2(SHIPROCK230)/W01	350	80	20	250	0
W/WALC/WALC-APS/MEAD500-WESTWING230/I01	412	80	0	282	50
W/WALC/WALC-APS/MEAD500-WESTWING500/I01	412	40	0	0	372
W/WALC/SYSTRANS/NOGALES115-SAGUARO115/P01	60	0	0	55	5
W/WALC/SYSTRANS/NRTHGILA69-GILA161/P01	70	0	0	70	0

WALC Paths

PATH NAME	TTC	CBM	TRM	CU	ATC
W/WALC/SYSTRANS/NRTHGILA69-GILA69/P01	75	0	0	75	0
W/WALC/SYSTRANS/PARKER230-APACHE115/P01	60	0	0	60	0
W/WALC/SYSTRANS/PARKER230-BLACKMESA230/P01	438	0	0	438	0
W/WALC/SYSTRANS/PARKER230-BLYTHE161/P01	230	0	0	230	0
W/WALC/SYSTRANS/PARKER230-COOLIDGE/P01	451	0	0	416	35
W/WALC/SYSTRANS/PARKER230-DAVIS230/P01	450	0	0	450	0
W/WALC/SYSTRANS/PARKER230-GENE/P01	220	0	0	220	0
W/WALC/SYSTRANS/PARKER230-GILA161/P01	167	0	0	110	57
W/WALC/SYSTRANS/PARKER230-HILLTOP230/P01	239	0	0	239	0
W/WALC/SYSTRANS/PARKER230-LIBERTY230/P01	501	0	0	466	35
W/WALC/WALC-DWP/PARKER230-MARKETPLACE/Y02	450	40	0	410	0
W/WALC/WALC-DWP/PARKER230-MARKETPLACE/Y01	240	40	0	200	0
W/WALC/SYSTRANS/PARKER230-MEAD230/P01	240	0	0	240	0
W/WALC/SYSTRANS/PARKER230-PNPKWALC230/P01	359	0	0	359	0
W/WALC/SYSTRANS/PARKER230-SAGUARO115/P01	320	0	0	285	35
W/WALC/WALC-APS/PEACOCK230-GAVILANPK230/P01	400	0	0	400	0
W/WALC/SYSTRANS/PNPKWALC230-APACHE115/P01	60	0	0	60	0
W/WALC/SYSTRANS/PNPKWALC230-APACHE115/P02	60	0	0	60	0
W/WALC/SYSTRANS/PNPKWALC230-BKB(BUCKBLVD)/P01	230	0	0	230	0
W/WALC/SYSTRANS/PNPKWALC230-BLACKMESA230/P01	359	0	0	359	0
W/WALC/SYSTRANS/PNPKWALC230-BLACKMESA230/V01	239	0	0	239	0
W/WALC/SYSTRANS/PNPKWALC230-BLYTHE161/P01	---	---	---	---	---
W/WALC/SYSTRANS/PNPKWALC230-BLYTHE161/P02	230	0	0	230	0
W/WALC/SYSTRANS/PNPKWALC230-COOLIDGE/P01	359	0	0	259	100
W/WALC/SYSTRANS/PNPKWALC230-DAVIS230/P01	---	---	---	---	---

WALC Paths

PATH NAME	TTC	CBM	TRM	CU	ATC
W/WALC/WALC-APS/PNPKWALC230-FOURCORNE345/C01	300	69	20	211	0
W/WALC/WALC-APS/PNPKWALC230-GAVILANPK230/P01	400	0	0	285	115
W/WALC/SYSTRANS/PNPKWALC230-GENE/P01	220	0	0	220	0
W/WALC/SYSTRANS/PNPKWALC230-GILA161/P01	167	0	0	167	0
W/WALC/SYSTRANS/PNPKWALC230-GLENCANYON2/C01	600	69	20	511	0
W/WALC/SYSTRANS/PNPKWALC230-GRIFFITH230/P01	---	---	---	---	---
W/WALC/SYSTRANS/PNPKWALC230-GRIFFITH230/I01	450	30	0	240	180
W/WALC/SYSTRANS/PNPKWALC230-GRIFFITH230/I02	412	30	40	342	0
W/WALC/SYSTRANS/PNPKWALC230-HEADGATEROCK/P01	96	0	0	96	0
W/WALC/SYSTRANS/PNPKWALC230-HILLTOP230/P01	239	0	0	239	0
W/WALC/SYSTRANS/PNPKWALC230-HILLTOP230/P02	239	0	0	239	0
W/WALC/SYSTRANS/PNPKWALC230-KAY-LHV/C01	350	69	20	261	0
W/WALC/SYSTRANS/PNPKWALC230-LIBERTY230/I01	637	30	0	377	230
W/WALC/WALC-DWP/PNPKWALC230-LUGO/I01	108	30	0	78	0
W/WALC/SYSTRANS/PNPKWALC230-MARANA115/P01	80	0	0	80	0
W/WALC/WALC-DWP/PNPKWALC230-MARKETPLACE/I01	412	30	0	382	0
W/WALC/WALC-DWP/PNPKWALC230-MCCULLOUG230/I01	400	30	0	370	0
W/WALC/SYSTRANS/PNPKWALC230-MEAD230/P01	---	---	---	---	---
W/WALC/SYSTRANS/PNPKWALC230-MEAD230/I01	412	30	0	382	0
W/WALC/SYSTRANS/PNPKWALC230-NAVAJO230/C01	350	69	20	261	0
W/WALC/SYSTRANS/PNPKWALC230-PARKER230/P02	---	---	---	---	---
W/WALC/SYSTRANS/PNPKWALC230-PARKER230/P01	359	0	0	359	0
W/WALC/SYSTRANS/PNPKWALC230-PEACOCK230/P01	---	---	---	---	---
W/WALC/SYSTRANS/PNPKWALC230-SAGUARO115/P01	240	0	0	240	0
W/WALC/SYSTRANS/PNPKWALC230-SHR2(SANJUAN230)/C01	350	69	20	261	0

WALC Paths

PATH NAME	TTC	CBM	TRM	CU	ATC
W/WALC/WALC-PNM/PNPKWALC230-SJ345(SANJUAN345)/C01	269	69	20	180	0
W/WALC/SYSTRANS/PNPKWALC230-SUNDANCE/P01	359	0	0	359	0
W/WALC/SYSTRANS/PNPKWALC230-TOPOCK230/P01	359	0	0	359	0
W/WALC/WALC-APS/PNPKWALC230-WESTWING500/I01	412	30	0	230	152
W/WALC/SYSTRANS/SAGUARO115-APACHE115/P01	60	0	0	60	0
W/WALC/SYSTRANS/SAGUARO115-BLYTHE161/P01	80	0	0	80	0
W/WALC/SYSTRANS/SAGUARO115-COOLIDGE/P01	80	0	0	55	25
W/WALC/SYSTRANS/SAGUARO115-GENE/P01	80	0	0	80	0
W/WALC/SYSTRANS/SAGUARO115-GILA161/P01	80	0	0	80	0
W/WALC/SYSTRANS/SAGUARO115-GILA161/P02	80	0	0	80	0
W/WALC/SYSTRANS/SAGUARO115-HEADGATEROCK/P01	80	0	0	80	0
W/WALC/SYSTRANS/SAGUARO115-LIBERTY230/P01	80	0	0	40	40
W/WALC/SYSTRANS/SAGUARO115-MARANA115/P01	80	0	0	30	50
W/WALC/SYSTRANS/SAGUARO115-NOGALES115/P01	80	0	0	80	0
W/WALC/SYSTRANS/SAGUARO115-ORACLE115/P01	80	0	0	80	0
W/WALC/SYSTRANS/SAGUARO115-PARKER230/P01	80	0	0	80	0
W/WALC/SYSTRANS/SAGUARO115-SUNDANCE/P01	80	0	0	40	40
W/WALC/SYSTRANS/SHIPROCK115-SHIPROCK345/C01	167	0	0	167	0
W/WALC/SYSTRANS/SHIPROCK115-SHR2(SANJUAN230)/C01	167	0	0	167	0
W/WALC/WALC-APS/SHIPROCK345-FOURCORNE345/C01	300	0	0	300	0
W/WALC/SYSTRANS/SHIPROCK345-GLENCANYON2/C01	300	0	0	300	0
W/WALC/SYSTRANS/SHIPROCK345-SHIPROCK115/C01	300	0	0	300	0
W/WALC/SYSTRANS/SHIPROCK345-SHR2(SANJUAN230)/C01	300	0	0	300	0
W/WALC/WALC-PNM/SHIPROCK345-SJ345(SANJUAN345)/C01	269	0	0	269	0
W/WALC/SYSTRANS/SHR2(SHIPROCK230)-GLENCANYON2/C01	400	0	0	400	0

WALC Paths

PATH NAME	TTC	CBM	TRM	CU	ATC
W/WALC/SYSTRANS/SHR2(SHIPROCK230)-KAYENTA230/C01	400	0	0	400	0
W/WALC/SYSTRANS/SHR2(SHIPROCK230)-MEAD230/X01	---	---	---	---	---
W/WALC/SYSTRANS/SHR2(SHIPROCK230)-PNPKWALC230/C01	400	39	20	341	0
W/WALC/SYSTRANS/SHR2(SHIPROCK230)-SHIPROCK115/C01	330	0	0	330	0
W/WALC/SYSTRANS/SHR2(SHIPROCK230)-SHIPROCK345/C01	300	0	0	300	0
W/WALC/SYSTRANS/SHR2(SHIPROCK230)-SJ345(SANJUAN345)/C01	269	0	0	269	0
W/WALC/SYSTRANS/SHR2(SHIPROCK230)-WESTWING230/W01	400	39	20	341	0
W/WALC/WALC-APS/SHR2(SHIPROCK230)-WESTWING500/W01	400	39	20	341	0
W/WALC/PNM-APS/SJ345(SANJUAN345)-FOURCORNE345/C01	299	0	0	299	0
W/WALC/PNM-WALC/SJ345(SANJUAN345)-GLENCANYON2/C01	269	0	0	269	0
W/WALC/PNM-WALC/SJ345(SANJUAN345)-MEAD230/X01	---	---	---	---	---
W/WALC/PNM-WALC/SJ345(SANJUAN345)-MEAD230/X02	240	39	20	181	0
W/WALC/PNM-WALC/SJ345(SANJUAN345)-PARKER230/X01	269	39	20	210	0
W/WALC/PNM-WALC/SJ345(SANJUAN345)-PNPKWALC230/C01	269	39	20	210	0
W/WALC/PNM-WALC/SJ345(SANJUAN345)-SHIPROCK115/C01	269	0	0	269	0
W/WALC/PNM-WALC/SJ345(SANJUAN345)-SHIPROCK345/C01	269	0	0	269	0
W/WALC/PNM-WALC/SJ345(SANJUAN345)-WESTWING230/W01	269	39	20	210	0
W/WALC/SYSTRANS/STHPOINT230-DAVIS230/P01	319	0	0	319	0
W/WALC/SYSTRANS/STHPOINT230-MEAD230/P01	240	0	0	240	0
W/WALC/SYSTRANS/STHPOINT230-PNPKWALC230/P01	239	0	0	239	0
W/WALC/SYSTRANS/STHPOINT230-TOPOCK230/P01	319	80	40	199	0
W/WALC/SYSTRANS/SUNDANCE-APACHE115/P01	60	0	0	60	0
W/WALC/SYSTRANS/SUNDANCE-BKB(BUCKBLVD)/P01	230	0	0	230	0
W/WALC/SYSTRANS/SUNDANCE-BLACKMESA230/P01	438	0	0	438	0
W/WALC/SYSTRANS/SUNDANCE-BLYTHE161/P01	230	0	0	230	0

WALC Paths

PATH NAME	TTC	CBM	TRM	CU	ATC
W/WALC/SYSTRANS/SUNDANCE-COOLIDGE/P01	734	0	0	734	0
W/WALC/SYSTRANS/SUNDANCE-DAVIS230/P01	450	0	0	450	0
W/WALC/WALC-APS/SUNDANCE-FOURCORNE345/X01	300	69	20	211	0
W/WALC/SYSTRANS/SUNDANCE-GENE/P01	220	0	0	220	0
W/WALC/SYSTRANS/SUNDANCE-GILA161/P01	167	0	0	167	0
W/WALC/SYSTRANS/SUNDANCE-GLENCANYON2/X01	359	69	20	270	0
W/WALC/SYSTRANS/SUNDANCE-GLENCANYON3/X01	359	0	0	359	0
W/WALC/SYSTRANS/SUNDANCE-GRIFFITH230/P01	239	0	0	239	0
W/WALC/SYSTRANS/SUNDANCE-HILLTOP230/P01	239	0	0	239	0
W/WALC/SYSTRANS/SUNDANCE-KNOB161/P01	112	0	0	112	0
W/WALC/SYSTRANS/SUNDANCE-LIBERTY230/P01	451	0	0	451	0
W/WALC/WALC-DWP/SUNDANCE-LUGO/Y01	108	40	0	68	0
W/WALC/SYSTRANS/SUNDANCE-MARANA115/P01	80	0	0	30	50
W/WALC/WALC-DWP/SUNDANCE-MARKETPLACE/Y01	450	40	0	410	0
W/WALC/SYSTRANS/SUNDANCE-MCCONNICO230/P01	239	0	0	239	0
W/WALC/WALC-DWP/SUNDANCE-MCCULLOUG230/P01	240	0	0	240	0
W/WALC/SYSTRANS/SUNDANCE-MEAD230/P01	240	0	0	240	0
W/WALC/SYSTRANS/SUNDANCE-NRTHGILA69/P01	75	0	0	75	0
W/WALC/SYSTRANS/SUNDANCE-PARKER230/P01	451	0	0	451	0
W/WALC/SYSTRANS/SUNDANCE-PEACOCK230/P01	450	0	0	270	180
W/WALC/SYSTRANS/SUNDANCE-PNPKWALC230/P01	359	0	0	359	0
W/WALC/SYSTRANS/SUNDANCE-SAGUARO115/P01	240	0	0	205	35
W/WALC/SYSTRANS/SUNDANCE-SHIPROCK115/X01	330	69	20	241	0
W/WALC/SYSTRANS/SUNDANCE-SHR2(SHIPROCK230)/X01	350	69	20	261	0
W/WALC/WALC-PNM/SUNDANCE-SJ345(SANJUAN345)/X01	269	69	20	180	0

WALC Paths

PATH NAME	TTC	CBM	TRM	CU	ATC
W/WALC/SYSTRANS/SUNDANCE-STHPOINT230/P01	450	0	0	450	0
W/WALC/SYSTRANS/SUNDANCE-TOPOCK230/P01	450	0	0	450	0
W/WALC/SYSTRANS/SUNDANCE-WESTWING230/Y01	398	0	0	258	140
W/WALC/WALC-APS/SUNDANCE-WESTWING500/Y01	398	0	0	246	152
W/WALC/SYSTRANS/TOPOCK230-BKB(BUCKBLVD)/P01	230	0	0	230	0
W/WALC/SYSTRANS/TOPOCK230-BLACKMESA230/P01	438	0	0	438	0
W/WALC/SYSTRANS/TOPOCK230-BLYTHE161/P01	230	0	0	230	0
W/WALC/SYSTRANS/TOPOCK230-DAVIS230/P01	638	0	0	638	0
W/WALC/SYSTRANS/TOPOCK230-GENE/P01	220	0	0	220	0
W/WALC/SYSTRANS/TOPOCK230-LIBERTY230/P01	450	0	0	450	0
W/WALC/WALC-DWP/TOPOCK230-MARKETPLACE/Y01	240	0	0	240	0
W/WALC/WALC-DWP/TOPOCK230-MCCULLOUG230/A01	240	0	0	240	0
W/WALC/SYSTRANS/TOPOCK230-MEAD230/P01	240	0	0	240	0
W/WALC/SYSTRANS/TOPOCK230-PARKER230/P01	450	0	0	450	0
W/WALC/SYSTRANS/TOPOCK230-PNPKWALC230/P01	---	---	---	---	---
W/WALC/SYSTRANS/TOPOCK230-PNPKWALC230/P02	359	0	0	359	0
W/WALC/SYSTRANS/TOPOCK230-WESTWING230/Y01	398	0	0	398	0
W/WALC/WALC-APS/TOPOCK230-WESTWING500/Y01	398	0	0	398	0
W/WALC/SYSTRANS/WESTWING230-BLYTHE161/Y01	230	0	0	230	0
W/WALC/SYSTRANS/WESTWING230-DAVIS230/Y01	319	0	0	319	0
W/WALC/APS-WALC/WESTWING230-GRIFFITH230/I01	450	0	0	270	180
W/WALC/SYSTRANS/WESTWING230-LIBERTY230/I01	637	0	0	339	298
W/WALC/SYSTRANS/WESTWING230-MEAD500/I01	412	0	0	412	0
W/WALC/APS-WALC/WESTWING230-PNPKWALC230/I01	600	40	0	263	297
W/WALC/APS-APS/WESTWING230-RACEWAY230/I01	366	0	0	266	100

WALC Paths

PATH NAME	TTC	CBM	TRM	CU	ATC
W/WALC/APS-PNM/WESTWING230-SJ345(SANJUAN345)/W01	269	69	20	180	0
W/WALC/APS-APS/WESTWING230-WESTWING500/I01	412	0	0	260	152
W/WALC/APS-WALC/WESTWING500-APACHE115/Y01	60	0	0	60	0
W/WALC/APS-WALC/WESTWING500-BKB(BUCKBLVD)/Y01	230	0	0	230	0
W/WALC/APS-WALC/WESTWING500-BLYTHE161/Y01	230	80	0	150	0
W/WALC/APS-WALC/WESTWING500-BLYTHE161/Y02	230	0	0	230	0
W/WALC/APS-APS/WESTWING500-FOURCORNE345/W01	300	80	20	200	0
W/WALC/APS-WALC/WESTWING500-GILA161/Y01	112	0	0	112	0
W/WALC/APS-WALC/WESTWING500-GLENCANYON2/W01	600	80	20	500	0
W/WALC/APS-WALC/WESTWING500-GRIFFITH230/I01	450	80	0	320	50
W/WALC/APS-WALC/WESTWING500-HEADGATEROCK/Y01	96	80	0	16	0
W/WALC/APS-WALC/WESTWING500-LIBERTY230/I01	637	80	0	507	50
W/WALC/APS-DWP/WESTWING500-LUGO/I01	108	0	0	108	0
W/WALC/APS-DWP/WESTWING500-MARKETPLACE/I01	412	0	0	412	0
W/WALC/APS-WALC/WESTWING500-MCCONNICO230/Y01	239	80	0	159	0
W/WALC/APS-DWP/WESTWING500-MCCULLOUG230/I01	400	0	0	400	0
W/WALC/APS-DWP/WESTWING500-MCCULLOUG500/I01	412	0	0	412	0
W/WALC/APS-WALC/WESTWING500-MEAD230/I02	450	80	0	370	0
W/WALC/APS-WALC/WESTWING500-MEAD230/I01	412	0	0	412	0
W/WALC/APS-WALC/WESTWING500-MEAD230/Y01	240	80	0	160	0
W/WALC/APS-WALC/WESTWING500-MEAD500/I01	412	0	0	412	0
W/WALC/APS-WALC/WESTWING500-PARKER230/Y01	558	80	0	478	0
W/WALC/APS-WALC/WESTWING500-PEACOCK230/I01	450	80	0	370	0
W/WALC/APS-WALC/WESTWING500-PNPKWALC230/I01	412	80	0	282	50
W/WALC/APS-WALC/WESTWING500-SAGUARO115/Y01	320	80	0	240	0

WALC Paths

PATH NAME	TTC	CBM	TRM	CU	ATC
W/WALC/APS-WALC/WESTWING500-SHR2(SHIPROCK230)/W01	350	80	20	250	0
W/WALC/APS-WALC/WESTWING500-TOPOCK230/Y01	319	0	0	319	0
W/WALC/APS-APS/WESTWING500-WESTWING230/I01	797	80	0	667	50

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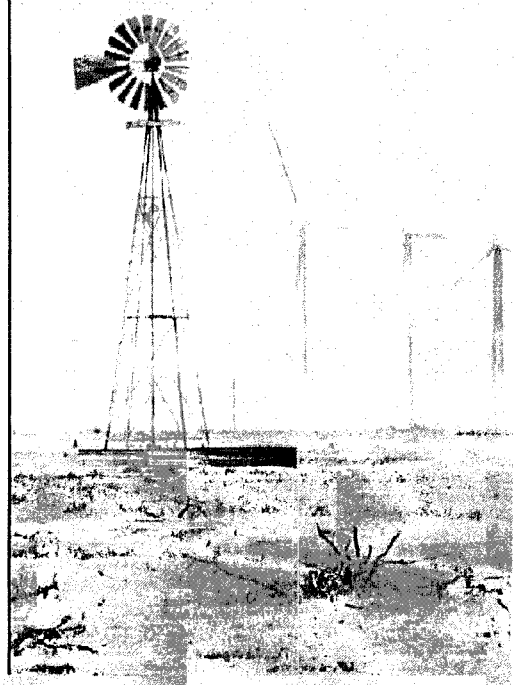
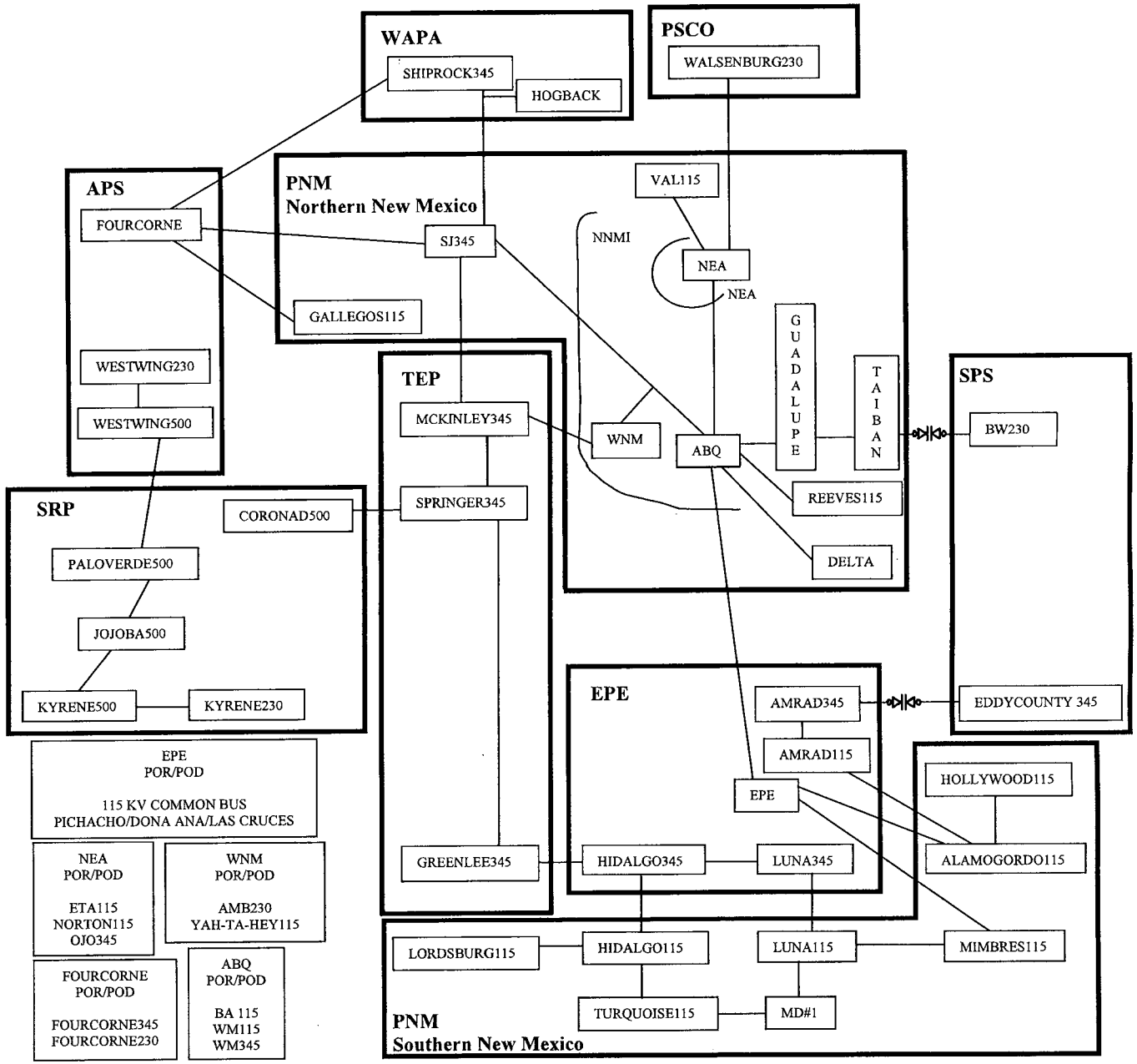
PNM®

A personal commitment to New Mexico



Transmission Paths



2007 Updates

- 1/1/07 -- Acquisition of TNMP resulted in PNM posting 9 new paths and modifying 5 paths for Southern New Mexico

- Tri-State energized the Colorado-New Mexico 230 kV Interconnection Project (CNMIP) on 2/1/07 resulting in Path 48 being increased ~20 MW to ~60 MW

Significant Transmission Path Determinations for 2007

Path Name	TTC Determined	TTC	TRM	CBM	Committed Uses	ATC
FOURCORNE/SJ345 – WNM/ABQ	WECC	1852*	127		**1823**	**0**
WNM/ABQ – FOURCORNE/SJ345	Owner	1233	0		**90**	**1143**
NEA – SJ345/WNM/ABQ	Subregion	64	0		**0**	**64**
TAIBAN – BW230	Owner	200	0		**1**	**199**
BW230 – TAIBAN	Owner	200	0		**200**	**0**
ABQ – GUAD	Owner	200	0		**1**	**199**
GUAD – ABQ	Owner	600	0		**490**	**110**
GUAD – TAIBAN	Owner	200	0		**1**	**199**
TAIBAN – GUAD	Owner	400	0		**0**	**400**
SJ345 – FOURCORNE345	Subregion	299	0		**116**	**183**
FOURCORNE345 – SJ345	Subregion	299	0		**0**	**299**
FOURCORNE – GAL	Owner	100	0		**75**	**25**
GAL - FOURCORNE	Owner	100	0		**0**	**100**
SJ345 – SPRINGER345	Subregion	100	0		**100**	**0**
SPRINGER345 – SJ345	Subregion	100	0		**0**	**100**
SPRINGER345 – CORONADO500	Subregion	100	0		**100**	**0**
CORONADO500 – SPRINGER345	Subregion	100	0		**25**	**75**
SJ345 – GREENLEE345	Subregion	63	3		**60**	**0**
GREENLEE345 – SJ345	Subregion	50	0		**50**	**0**
SHIPROCK345 – FOURCORNE345	Subregion	300	0		**0**	**300**
FOURCORNE345 – SHIPROCK345	Subregion	300	0		**0**	**300**
SJ345 – SHIPROCK345	Subregion	269	0		**50**	**219**

Significant Transmission Path Determinations for 2007

Path Name	TTC Determined	TTC	TRM	CBM	Committed Uses	ATC
SHIPROCK345 – SJ345	Subregion	269	0		**0**	**269**
GREENLEE345 – HIDALGO345	Subregion	160	3		**157**	**0**
HIDALGO345 – GREENLEE345	Subregion	300	0		**130**	**170**
PALOVERDE500 – EAST(WESTWING500, KYREN500 & JOJOBA500)	Subregion	669	0		**274**	**395**
EAST(WESTWING500, KYREN500 & JOJOBA500) – PALOVERDE500	Subregion	106	0		**0**	**106**
WESTWING500 – WESTWING230	Subregion	181	0		**134**	**47**
WESTWING230 –WESTWING500	Subregion	181	0		**0**	**181**
KYREN500 –KYRENE230	Subregion	298	0		**0**	**298**
KYREN230 – KYRENE500	Subregion	298	0		**0**	**298**
WESTWING – FOURCORNE	Subregion	264	0		**264**	**0**
FOURCORNE345 – FOURCORNE230	Subregion	156	0		**8**	**148**
FOURCORNE230 – FOURCORNE345	Subregion	156	0		**30**	**126**
HIDALGO345 – LUNA345	Subregion	214	3		**149**	**62**
LUNA345 – HIDALGO345	Subregion	214	0		**0**	**214**
LUNA345 – LUNA115	Subregion	200	3		**157**	**40**
LUNA115 – LUNA345	Subregion	200	0		**0**	**200**
HIDALGO345 – HIDALGO115	Subregion	400	0		**110**	**290**
HIDALGO115 – HIDALGO345	Subregion	400	0		**182**	**218**
EDDY230-AMRAD345	Owner	67	0		**67**	**0**
AMRAD345-EDDY230	Owner	67	0		**0**	**67**

Significant Transmission Path Determinations for 2007

Other Transmission Paths	
Types	**Numbers**
Transformer	2
115kv paths	10

Hourly ATC on FOURCORNE_SJ345-WNM/ABQ (Path 48) for June 13, 2007

	June 13, 2007 Hourly Posting For Path 48																							
Segment	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**
FOURCORNE_SJ345-WNM/ABQ																								
TTC	1764	1764	1765	1764	1764	1763	1760	1757	1754	1752	1751	1747	1748	1747	1743	1747	1747	1748	1747	1747	1750	1754	1757	1759
Firm Transmission Reservations	341	341	341	341	341	341	341	441	466	366	391	341	341	341	341	341	341	341	341	341	341	341	341	341
Non-Firm Transmission Reservations	186	183	183	184	184	192	144	302	363	267	293	243	281	245	244	243	243	238	233	233	233	231	191	184
TRM	127	127	127	127	127	127	127	127	127	127	127	127	127	127	127	127	127	127	127	127	127	127	127	127
CU Firm	807	778	756	765	841	830	1030	1089	1086	1080	1077	1044	1021	1004	980	974	999	1203	1246	1216	1217	1175	1038	895
Firm ATC	489	518	541	531	455	465	262	100	75	179	156	235	259	275	295	305	280	77	33	63	65	111	251	396
Non Firm ATC	771	803	826	815	739	741	586	366	305	405	381	460	446	498	519	530	505	307	268	298	300	348	528	680

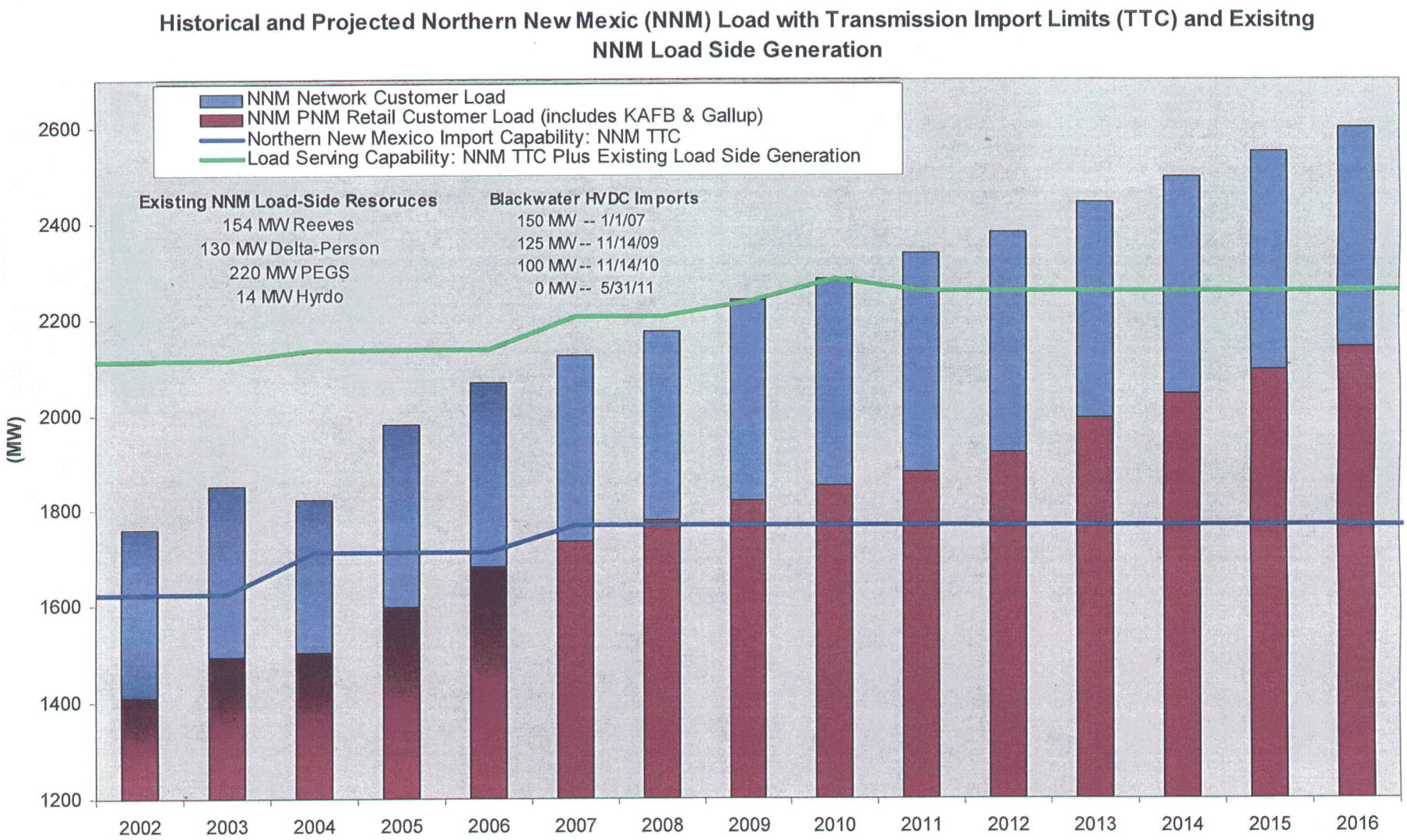
Path 48 - Total Transfer Capability (TTC)

- The TTC toggles between a voltage stability limit and a thermal limit, depending on the amount of var support in-service.
- PNM has developed independent real-time nomogram equations that are incorporated in the Energy Management Systems to ensure system can meet reliability criteria under n-1 conditions.
- These nomogram equations utilize metered real-time system conditions and real/reactive power flows to determine Path 48 limits on a one-minute basis.
- Affected by many factors such as:
  - Shunt Capacitors/Reactors
  - Power Factor Levels
  - Load-Side generation
  - Series Capacitors

Path 48 - Committed Uses

- Existing Committed Uses Are:
  - Retail Loads
  - Network Customers
  - Transmission Service Provided To Others
  - Losses
  - Transmission Reliability Margin (TRM)

Projected Path 48 Yearly Summer Transmission Requirements



Questions?

Western Area Power Administration WACM

WACM ATC - 2007

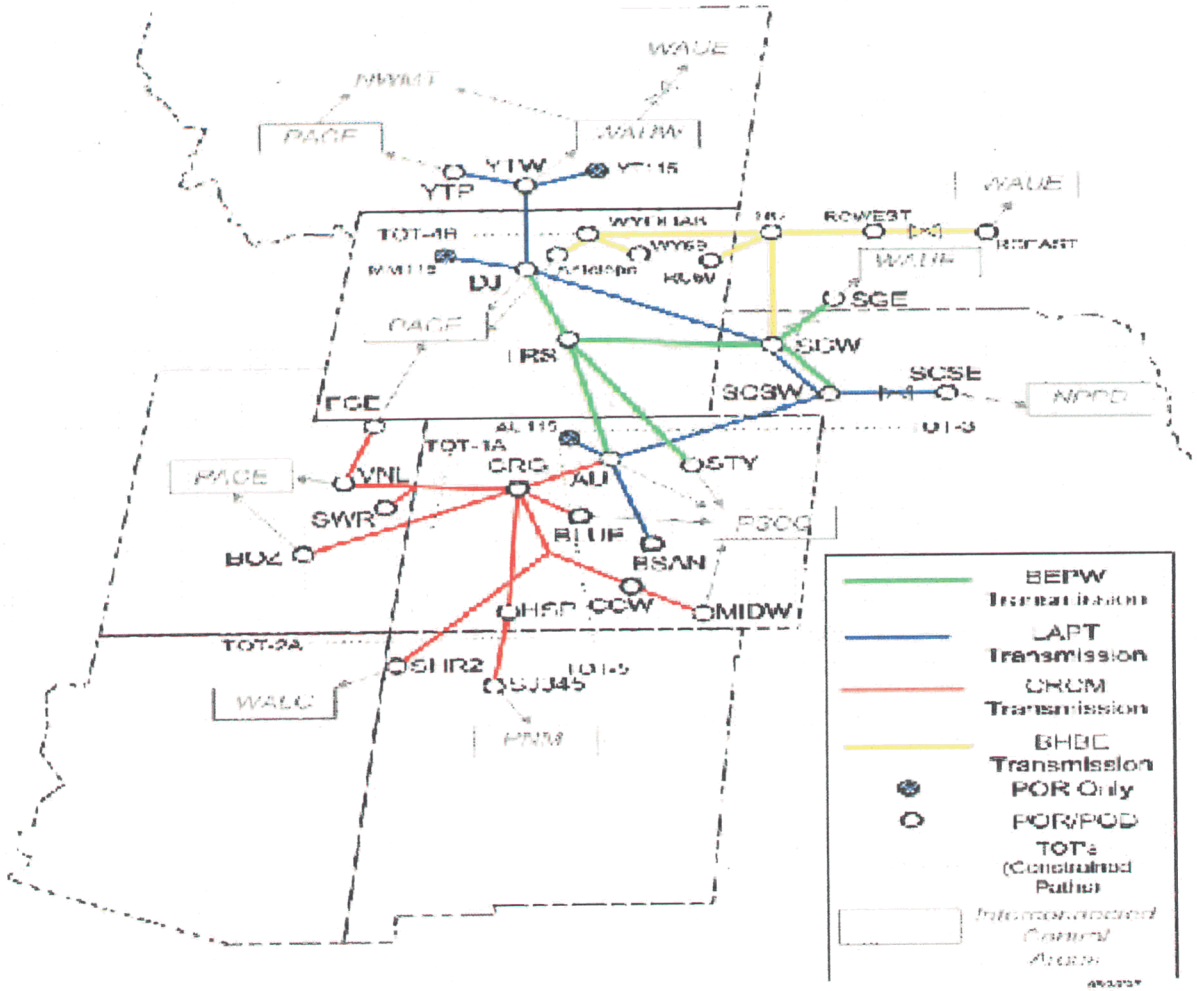
Presented to WestConnect Stakeholders

June 27, 2007

Phoenix Airport Marriott

Bob Easton

WACM CONTROL AREA
OASIS MAP V-2
TRANSMISSION PROVIDERS, PATHS & INTERCONNECTIONS



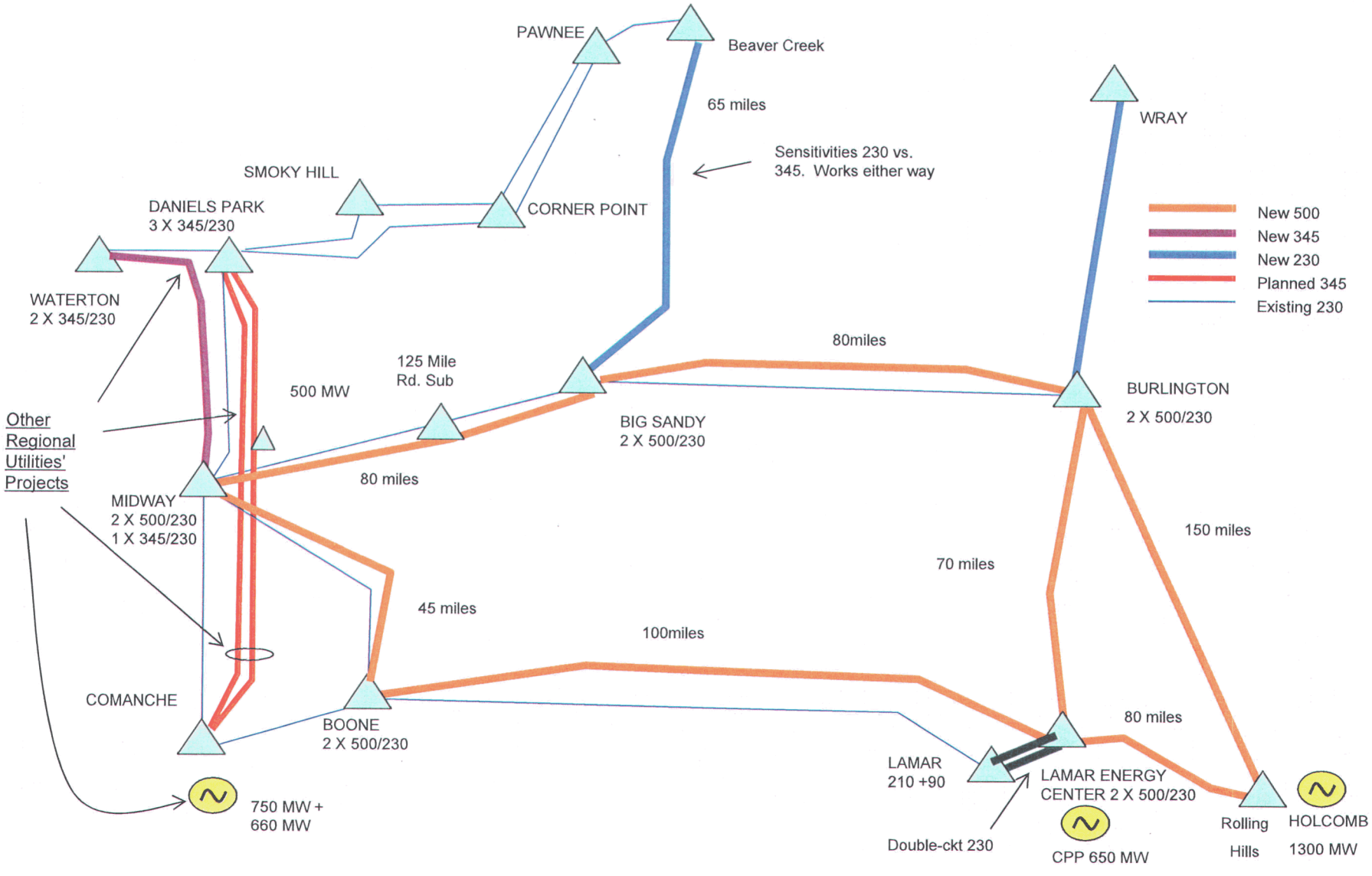
Existing Paths

Path Name	TTC Determined By	TTC	TRM	CBM	Committed Uses	ATC
SCSW – AU	WECC	400	54	0	**348**	**-2**
AU – SCSW	WECC	400	54	0	**200**	**146**
DJ – SGW	Owner	447	54	0	**264**	**129**
SGW – DJ	Owner	447	54	0	**51**	**342**
SGW - SCSW	Owner	173	54	0	**85**	**34**
SCSW – SGW	Owner	173	54	0	**35**	**84**
DJ – YTW	Owner	170	83	0	**87**	**0**
SCSE - SCSW	Owner	200	0	0	**200**	**0**
SCSW – SCSE	Owner	200	0	0	**200**	**0**
YTW – DJ	Owner	225	54	0	**171**	**0**
YTP – YTW	Subregion	298	100	0	**0**	**198**
YTW – YTP	Subregion	298	100	0	**48**	**150**
SGW – ARH	Owner	214	54	0	**160**	**0**
HDN – BRU	Subregion	25	0	0	**0**	**25**
SCSW – ARH	Owner	98	0	0	**51**	**47**

ADDITIONS/CHANGES

Path Name	Venue to Determine TTC Change	Existing TTC	Change	Expect complete	Expect TRM	Expect CBM	Expect Committed Uses	Expect ATC
SCSW - AU	WECC	400	75	2010	54	0	75	0

500 kV Minimum for 1800 MW (net)



WEST CONNECT

Enhancing wholesale electricity markets in the southwest

Public Service Company of Colorado

Public Service Company of Colorado/Xcel Energy

Robert K. Johnson
Lookout Control Center
303-273-4893
robert.k.johnson@xcelenergy.com

TRM And CBM

- No use of CBM by Xcel/PSCo
- Use TRM per WECC guidelines– for generation loss and transmission outages
- Set aside TRM for Rocky Mountain Reserve Group deliveries (gen. loss) to and from PSCo
- WECC allows TRM to be used for emergency deliveries for unplanned loss of generation or transmission

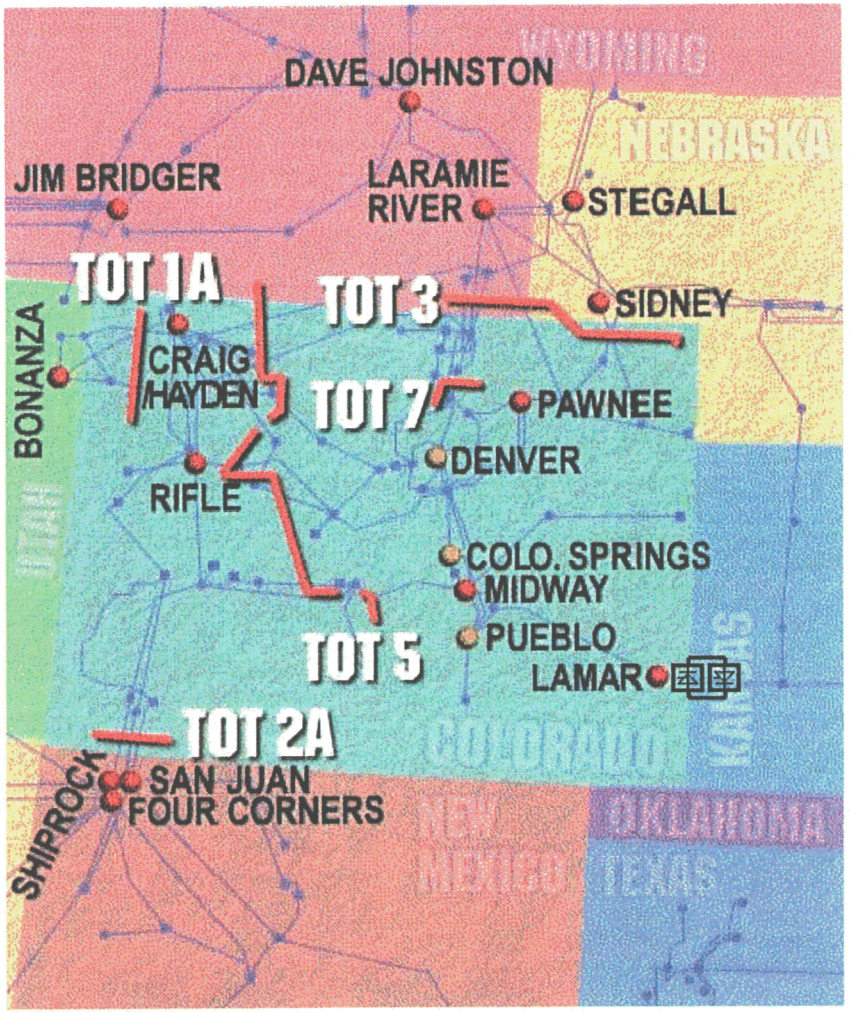
TTC-Total Transfer Capability

- Joint Studies run by the path owners to find TTC (path ratings or OTCs)
- TTC developed internally for wholly owned transmission paths
- TTC based on WECC Criteria
- Results presented to Colorado Coordinated Planning Group
- Seasonal TTCs Approved –WECC OTC PC

File Edit View Favorites Tools Help Back Address https://www.rmao.com/documents/PSCO/map.html Go Links

Transmission Path Map

Click on any part of a TOT path on the map to go to specific information for that path
or **select one of the text links below.**



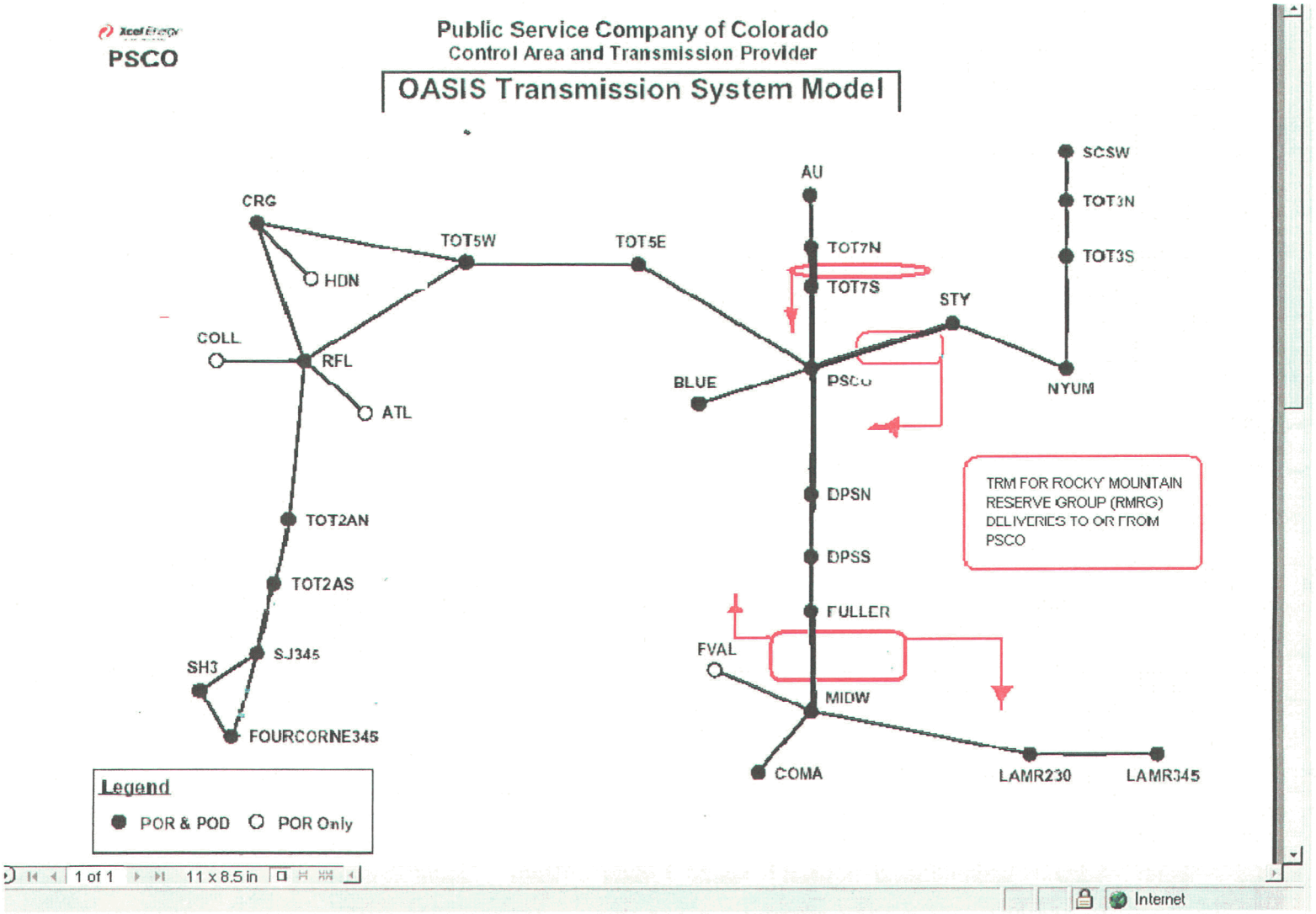
TOT 1A | TOT 2A | TOT 3 | TOT 5 | TOT 7

Other Links:

PSCO

Public Service Company of Colorado
Control Area and Transmission Provider

OASIS Transmission System Model



Path	TTC	LT Firm ATC	TRM	Committed Use	TTC studies
TOT 2 A –north to south	60	0	0	60	Subregion&WECC OTC PC
TOT 2 A –south to north	200	0	0	200	Subregion&WECC OTC PC
TOT 3 – north to south	57	0	0	57	Subregion&WECC OTC PC
TOT 3 – so to north	57	57	0	0	Subregion&WECC OTC

PSCo- As of June 25, 2007 – 2/4

Path	TTC	LT Firm ATC	TRM	Committed Use	TTC studies
TOT 5 – West to East	**480**	**0**	**0**	480	Subregion&WECC OTC PC
TOT 5 – East to West	**480**	**149**	**0**	331	Subregion&WECC OTC PC
FC to San Juan 345	**149**	**27**	**0**	122	PSCo and other owners

PSCo- As of June 25, 2007 – 3/4

Path	TTC	LT Firm ATC	TRM	Committed Use	TTC studies
TOT 7 – no to south	516 MW dynamic	0	59	457	PRPA, PSCo-CCPG
TOT 7 – south to north	516 MW dynamic	0	0	516	PRPA, PSCo-CCPG
Story to PSCo	576	0	47	529	PSCo

PSCo- As of June 25, 2007 – 4/4

Path	TTC	LT Firm ATC	TRM	Committed Use	TTC studies
PSC Central Sys to Midway(N to S)	**1280**	**281**	**321**	**678**	PSCo
PSC Central Sys to Midway(S to N)	**1280**	**0**	**74**	**1206**	PSCo

Questions?

Please Contact

Bob Johnson

Xcel Energy/PSColorado

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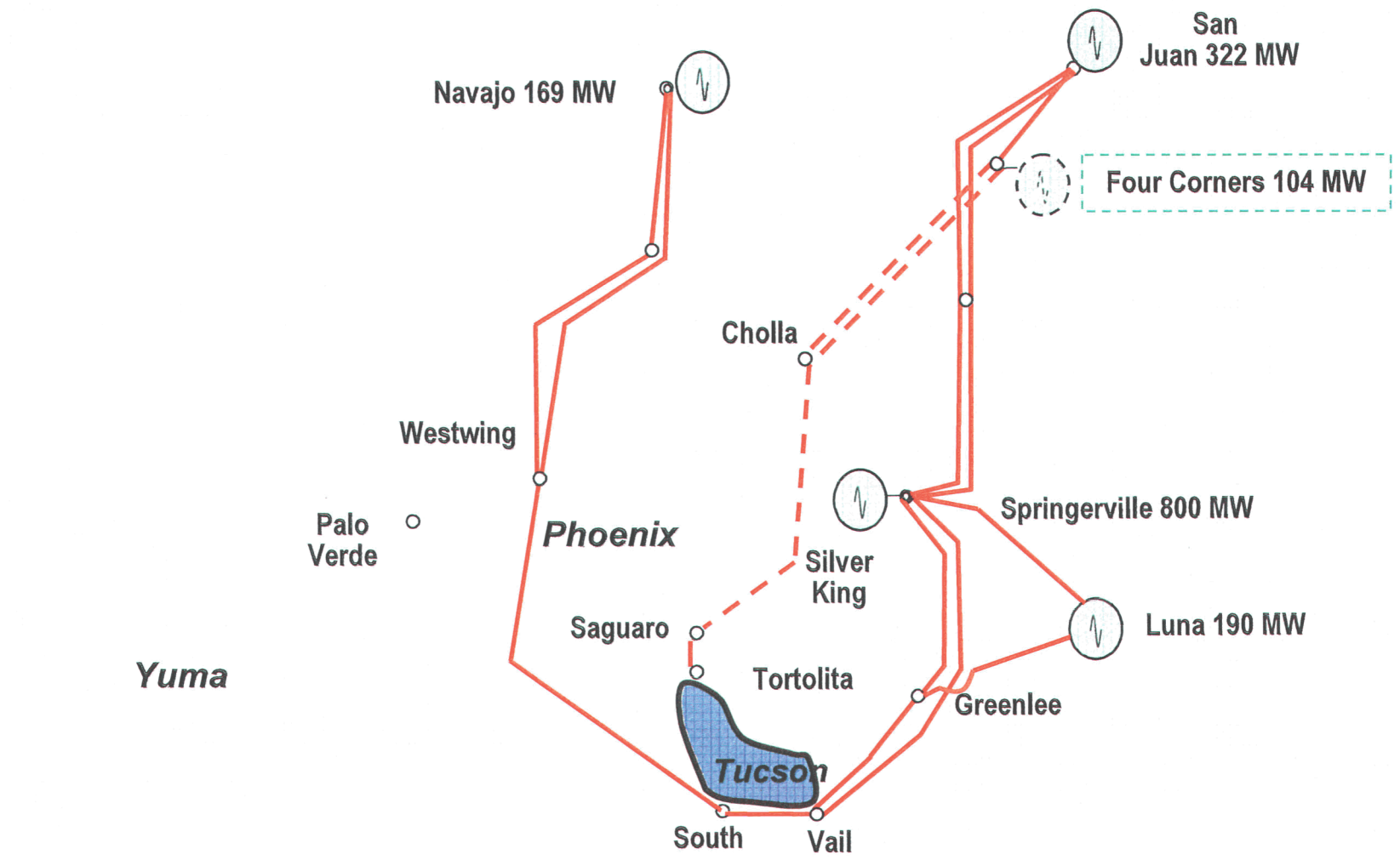
robert.k.johnson@xcelenergy.com

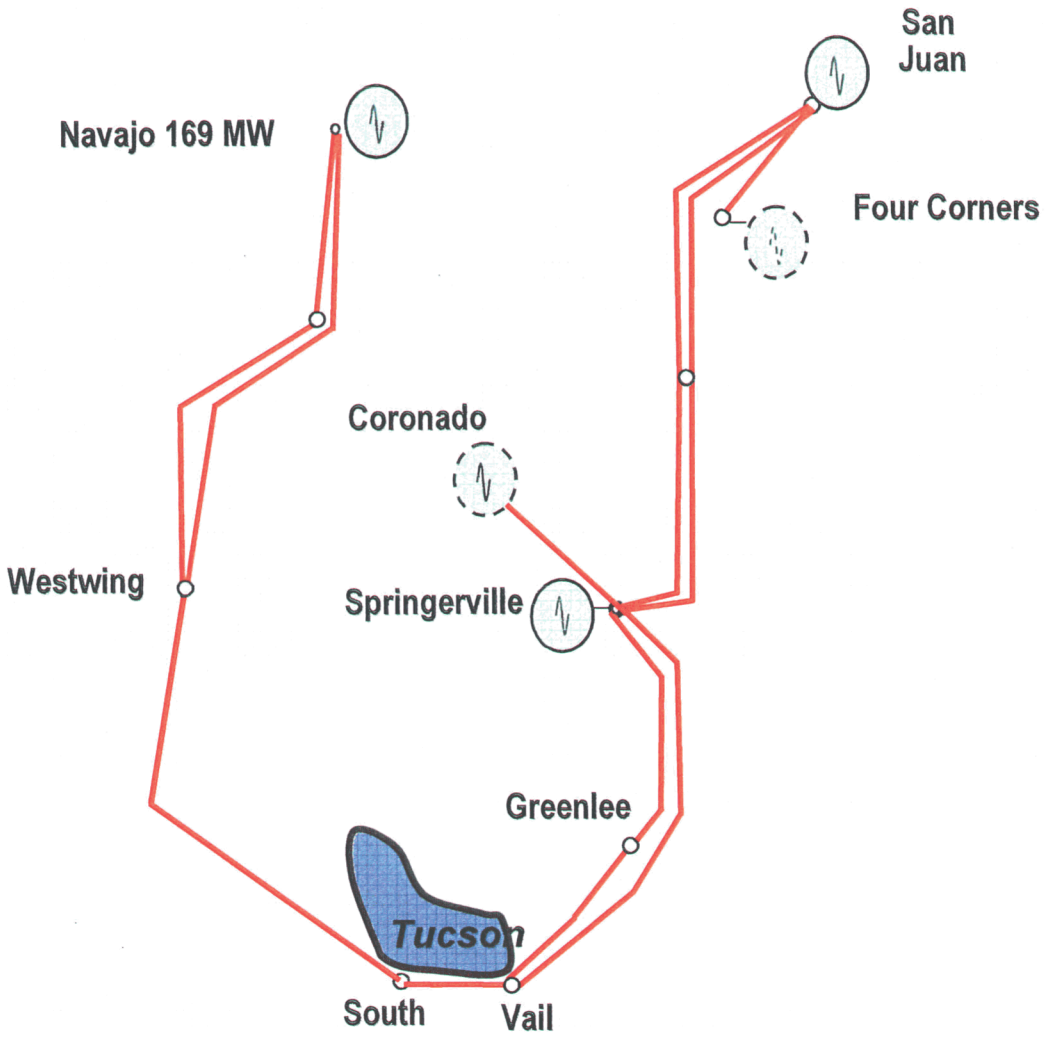
Tucson Electric Power Company

WestConnect TTC/ATC Open Stakeholder Meeting

TEP Generation resources



TEP Transmission Resources



TEP Path Values

Path Name	TTC	TTC determined by	TRM	CBM	Committed Uses (Long-Term Reservations)		ATC
					Contract Obligations	Network resource	
WW - VL	511	Sub region	0	0	342	169	0
VL - WW	511	Sub region	0	0	391	0	120
SJ - SP	1770	Sub region	95	0	804	332	539
SP - SJ	1770	Sub region	0	0	992	0	773
SP - VL	1568	Sub region	40	0	302	1226	0
VL - SP	1568	Sub region	0	0	529	0	1039

Other TEP Transmission Information

Types	Numbers
Transformers: 500/345kV 500/138kV 345/138kV	(1) Westwing (3 Single Phase + Spare) (2) Tortolita (5) South (3) and Vail (2)
138kv Paths:	Total = 36 (353 Miles)

2007 Studies

- TEP EHV System
  - Ratings Grandfathered under WECC Process
  - No Seasonal Rating Adjustments per WECC Operating Transfer Capability Policy Committee (OTCPC)
- TEP Annual Operating Study
  - Assess impacts to local area transmission
  - Determine System Operating Limits (SOLs)

WEST CONNECT

Enhancing wholesale electricity markets in the southwest

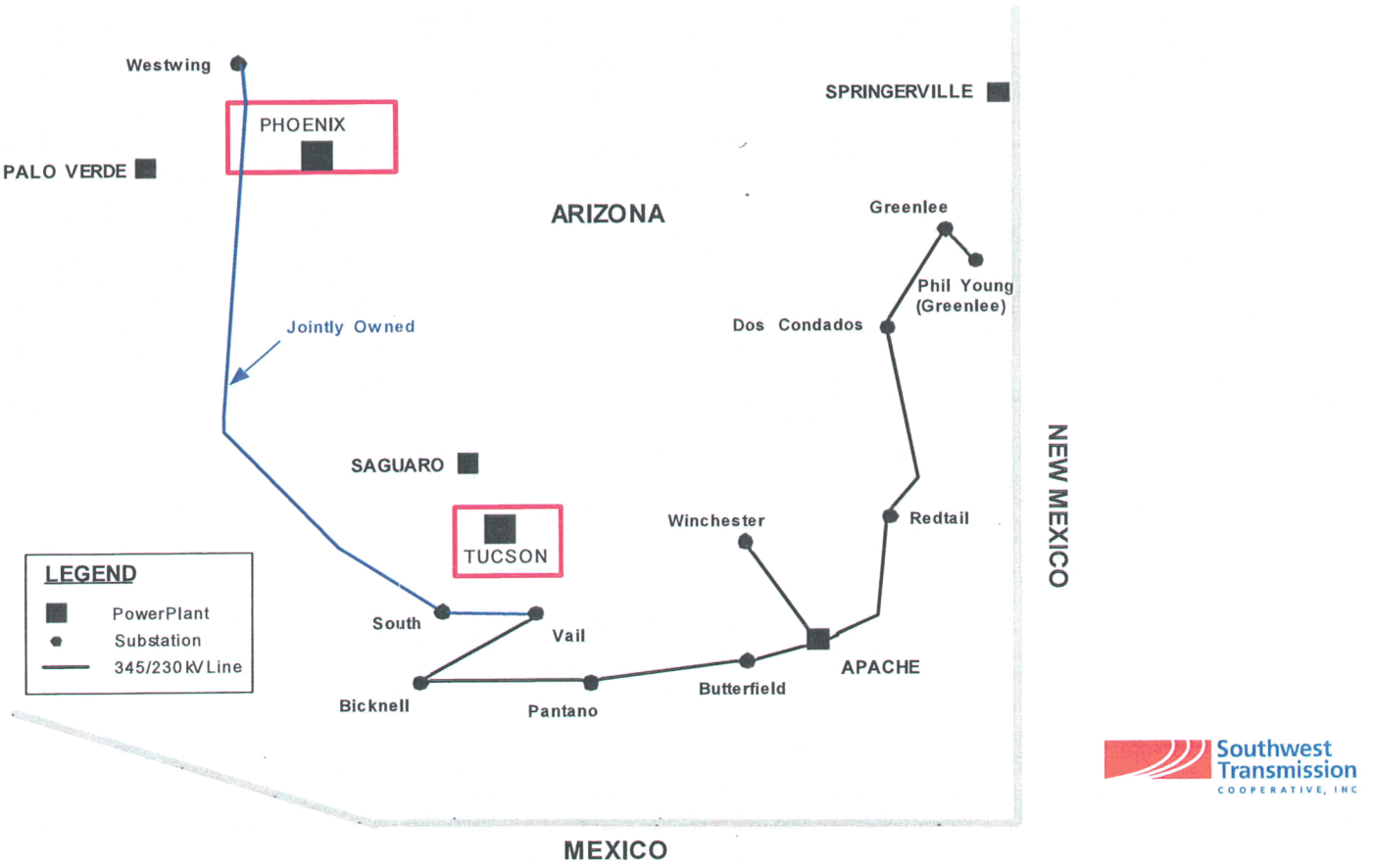
Southwest Transmission Cooperative Inc.

WestConnect Stakeholders Transfer Capability Meeting
Southwest Transmission Cooperative, Inc.

Presented by James Rein
June 27, 2007

Southwest Transmission
COOPERATIVE, INC

SWTC EHV Transmission Map



Southwest Transmission COOPERATIVE, INC

Existing Paths

Path Name	TTC Determined By	TTC	TRM	CBM	Committed Uses	ATC
Westwing - Vail	Subregion	161	0	0	161	0
Vail - Westwing	Subregion	161	0	0	116	45
Vail - Apache	Owner	193	0	0	193	0
Apache - Vail	Owner	193	0	0	186	7
Winchester - Apache	Owner	420	0	0	250	170
Apache - Winchester	Owner	420	0	0	100	320
Greenlee - Apache	Owner	193	0	0	125	68
Apache - Greenlee	Owner	193	0	0	85	108

Other Transmission Paths	
Types	**Numbers**
345 kV paths	6
230kV paths	12
115kV paths	6

Southwest Transmission COOPERATIVE, INC

Additions/Changes

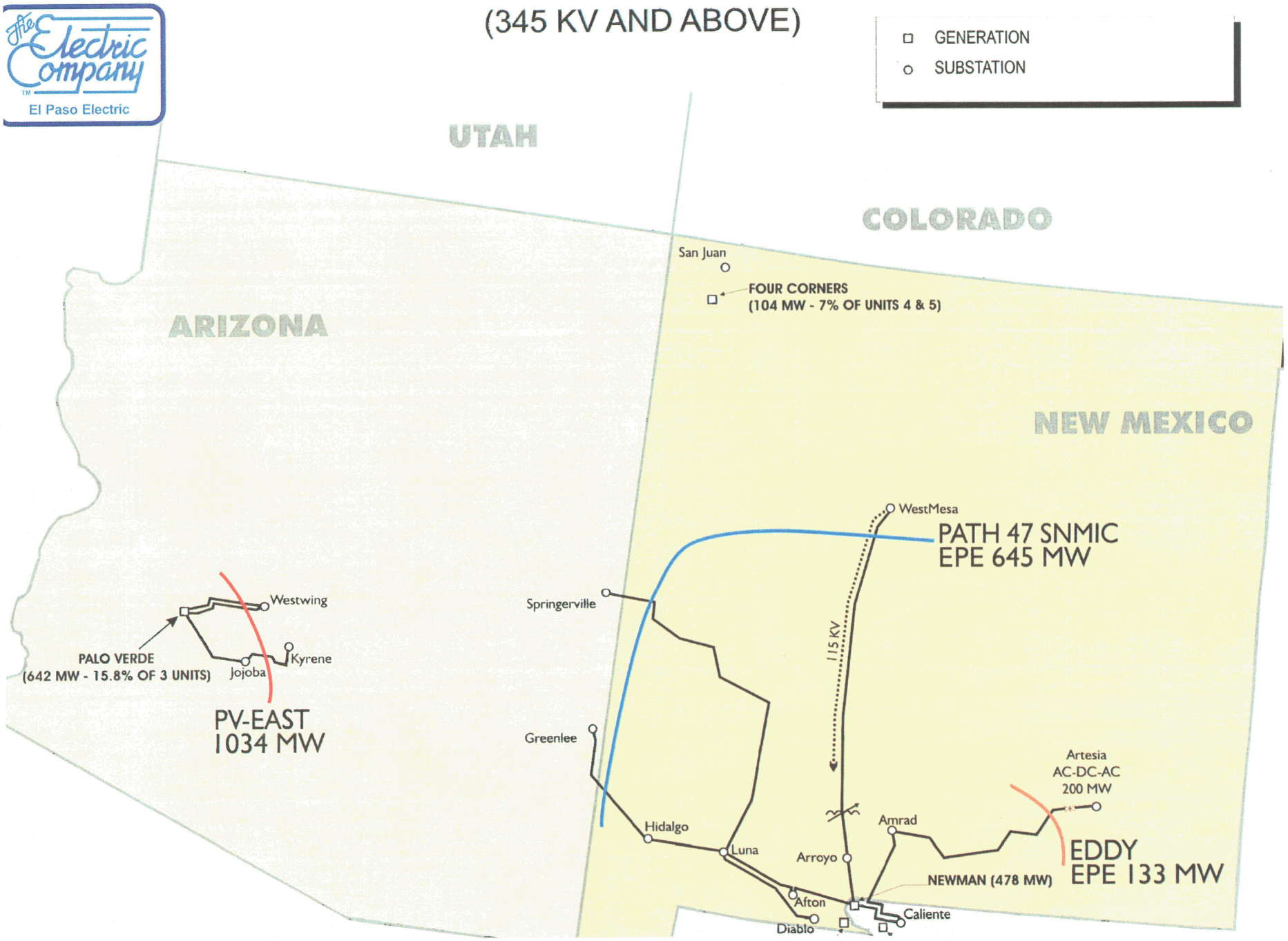
Path Name	Venue to Determine TTC Change	Existing TTC	Change	Expected Complete	Expected TRM	Expected CBM	Expected Committed Uses	Expected ATC
Palo Verde-Pinal West (1)	Subregion	40	40	2008	0	0	40	0
Pinal West-Palo Verde (1)	Subregion	40	40	2008	0	0	40	0
Greenlee-Apache (2)	Owner	193	413	2009	0	0	200	213
Apache-Greenlee (2)	Owner	193	413	2009	0	0	85	328

Notes:
(1) Joint participation project, final study work not yet completed or approved, data reflects preliminary study information for SWTC participation share only
(2) Greenlee Transformer Upgrade Project, final study work not yet completed or approved, data reflects preliminary study information

Additional Information:
- Potential SWTC participation in joint project from Pinal West to Pinal South to Tortolita, preliminary planning study work underway, but do not as yet have TTC data estimate
- SWTC also has a number of 115 kV projects, which we expect will provide import/export, final study work not yet completed or approved

El Paso Electric Company

(345 KV AND ABOVE)



El Paso Electric Company

Existing Paths

Path Name	TTC Determined By	TTC	TRM	CBM	Committed Uses	ATC
WECC Path 47	WECC (EPE/PNM/Tri-State)	Nomogram/Firm= **645 MW**	0	0	**645 MW**	**0 MW**
Palo Verde East	APS/SRP/PNM/EPE	**1034 MW**	0	0	**642 MW**	**392 MW**
Eddy County HVDC	HVDC Terminal (EPE & PNM)	**133 MW**	0	0	**133 MW**	**0 MW**

Other Transmission Paths	
Types	**Numbers**
El Paso Internal System Transformers (345/115 kV)	740 MW

ADDITIONS/CHANGES

Path Name	Venue to Determine TTC Change	Existing TTC	Change	Expect complete	Expect TRM	Expect CBM	Expect Committed Uses	Expect ATC
Transformers (345/115 kV)	EPE	740 MW	160 MW	2Q 2008	0	0	900 MW	0

Next Steps

- Input from attendees
- Wrap up

Contacts and Information

•WestConnect (www.westconnect.com)
- Charles Reinhold – Project Manager
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208-253-6916
- Jerry Smith – Arizona Public Service
Jerry.Smith@aps.com
602-250-1135

Appendix M
APS Transmission Update, March 14, 2007

APS Transmission Update

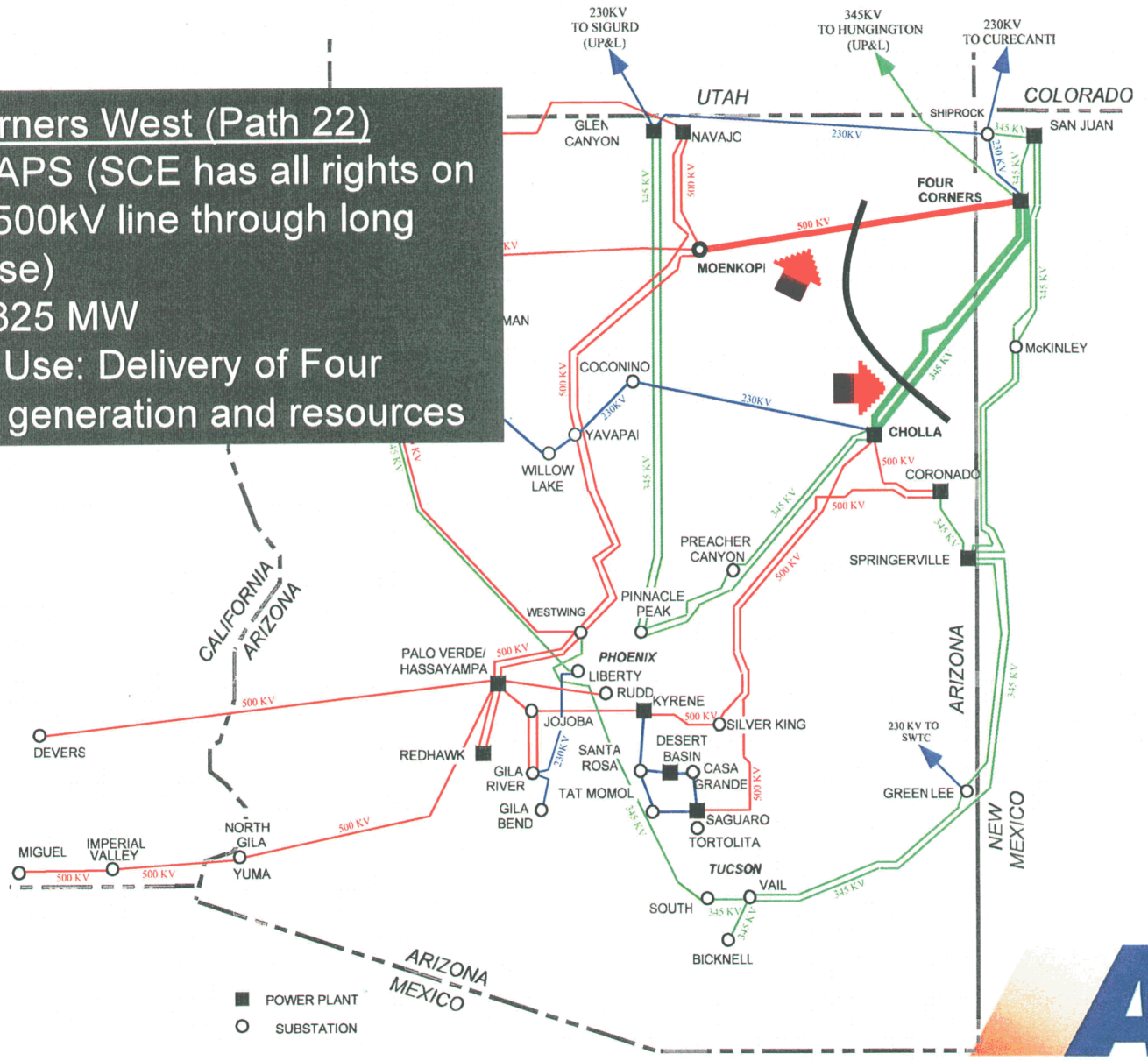
Jason Spitzkoff
Transmission Planning
March 14, 2007

Agenda

- Introduction
- The Arizona Transmission System - Total Transfer Capability (TTC) for 5 Significant Paths
- The APS Transmission System TTCs
- The APS Transmission System Available Transfer Capability (ATC)
- Cost Estimates of Interconnection
- Question and Answer Period

2007 ARIZONA TRANSMISSION SYSTEM

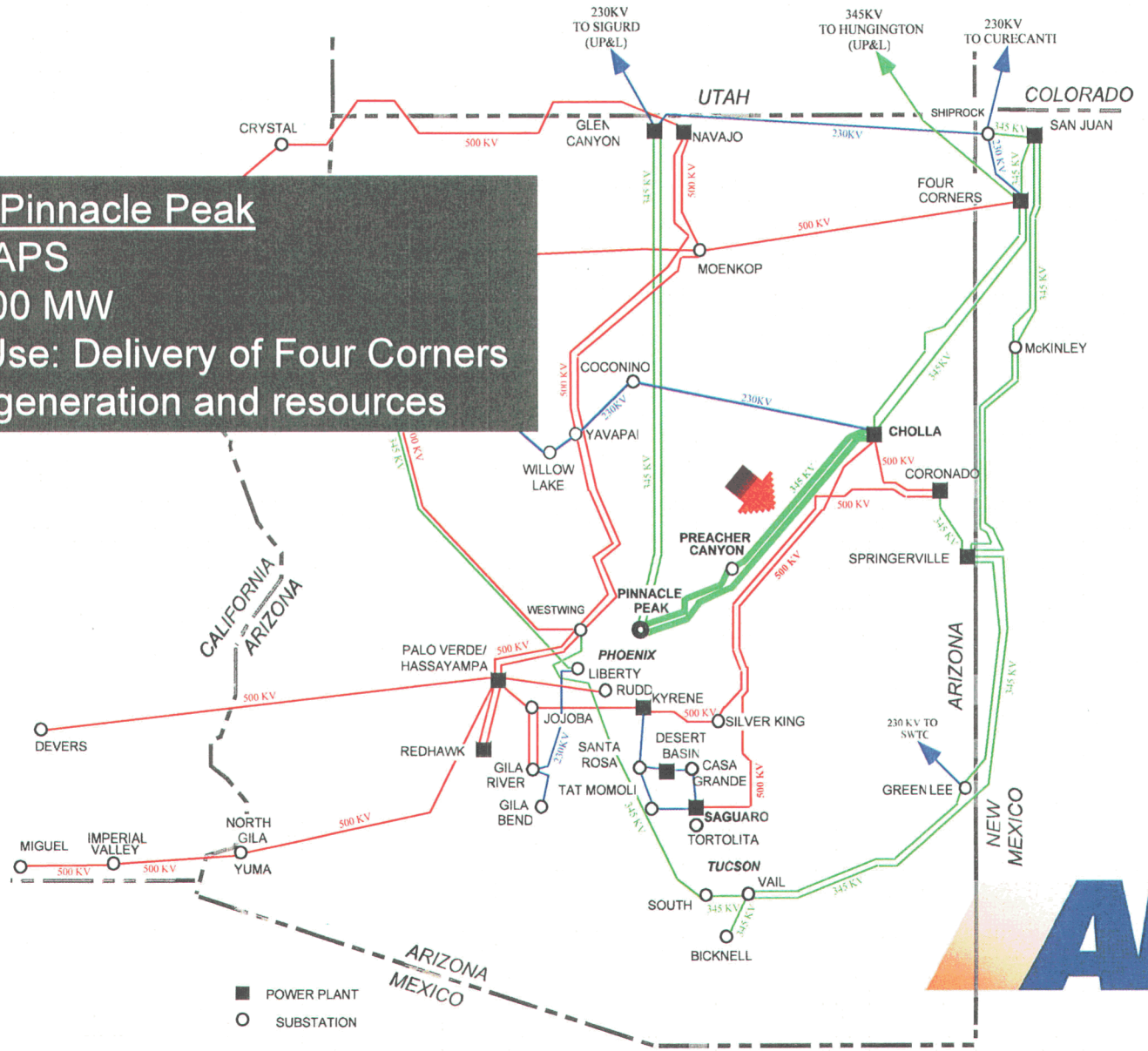
Four Corners West (Path 22)
Owner: APS (SCE has all rights on FC-MK 500kV line through long term lease)
TTC= 2325 MW
Primary Use: Delivery of Four Corners generation and resources



3/13/2007

2007 ARIZONA TRANSMISSION SYSTEM

Cholla to Pinnacle Peak
Owners: APS
TTC= 1200 MW
Primary Use: Delivery of Four Corners & Cholla generation and resources



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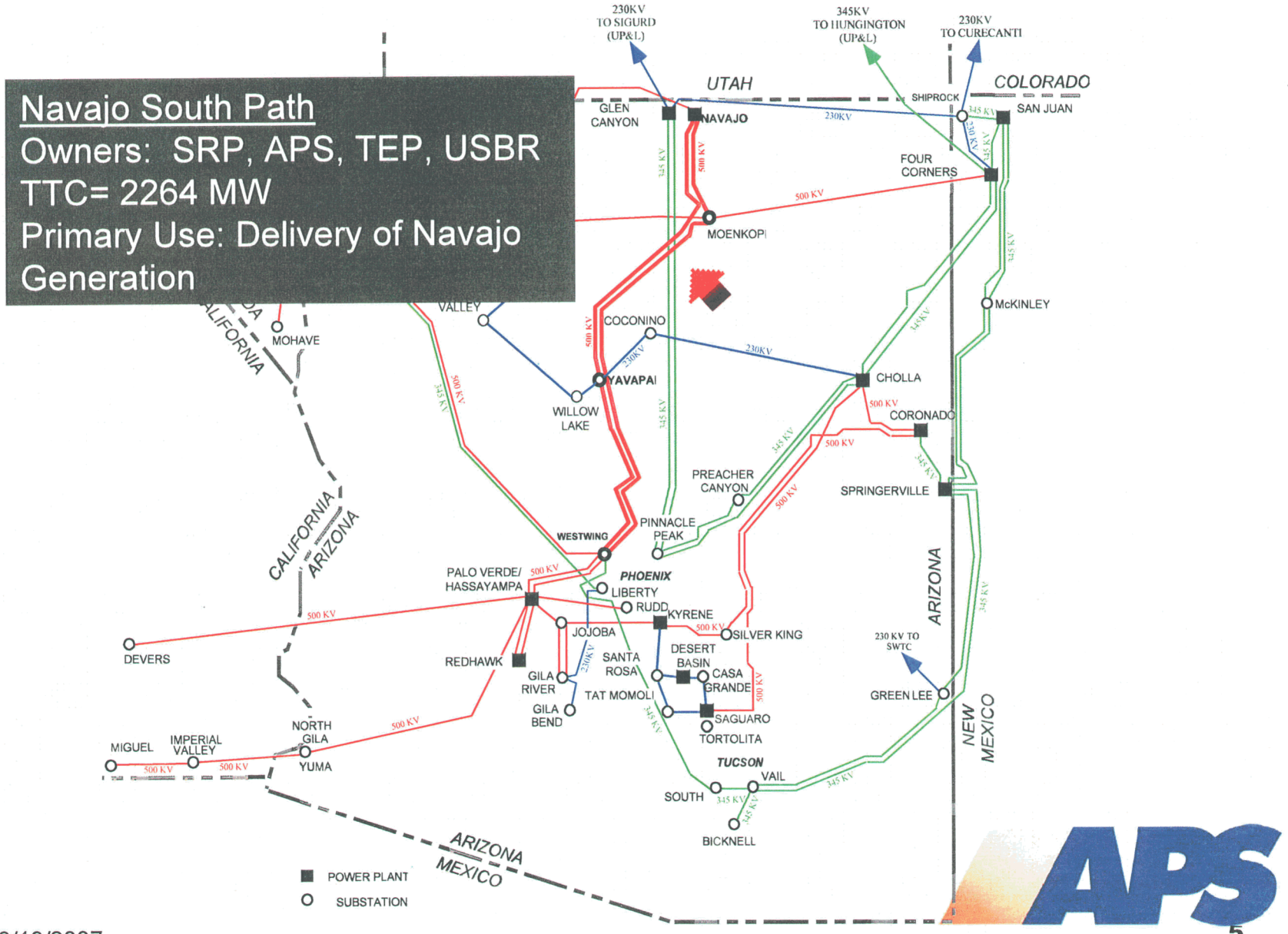

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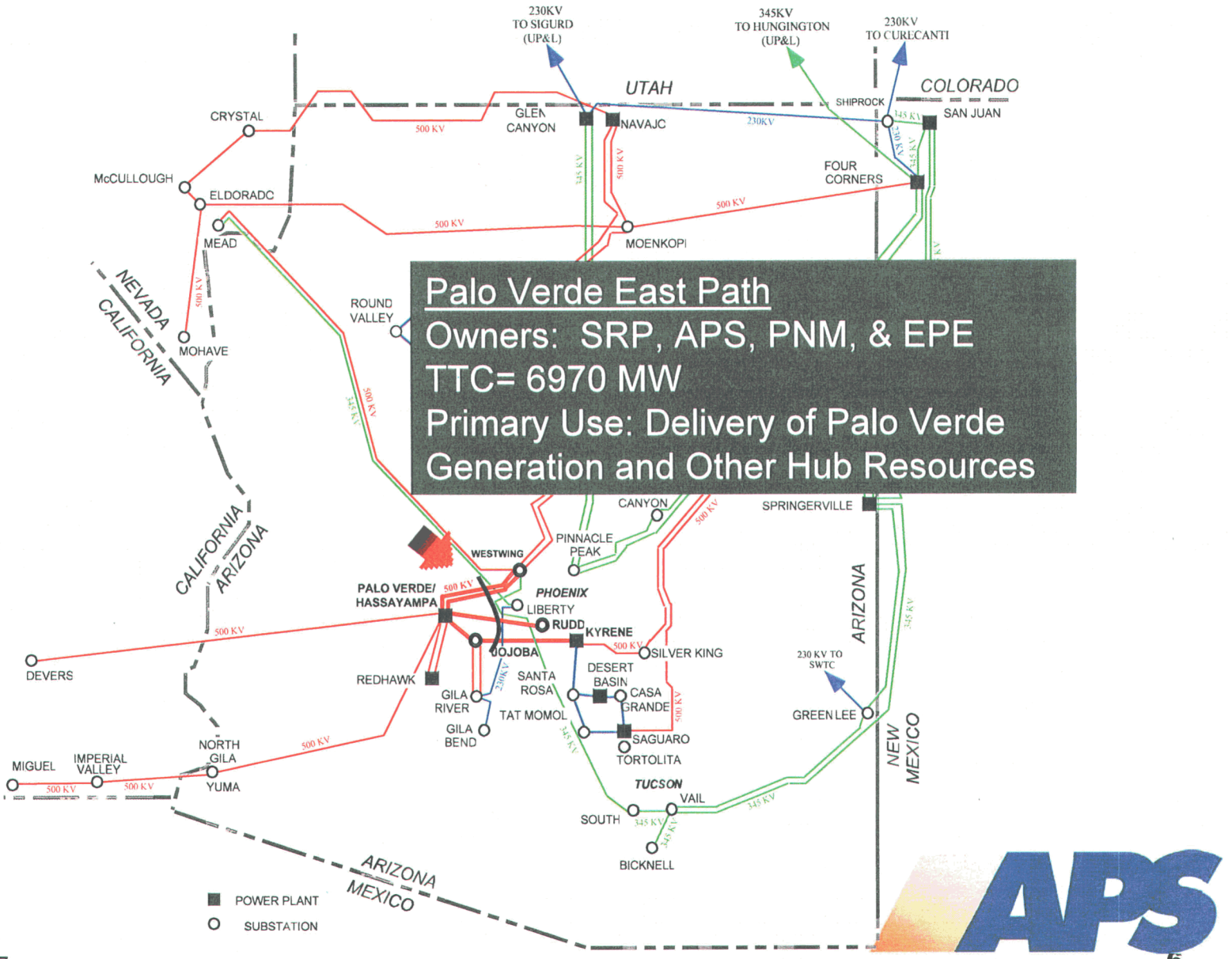
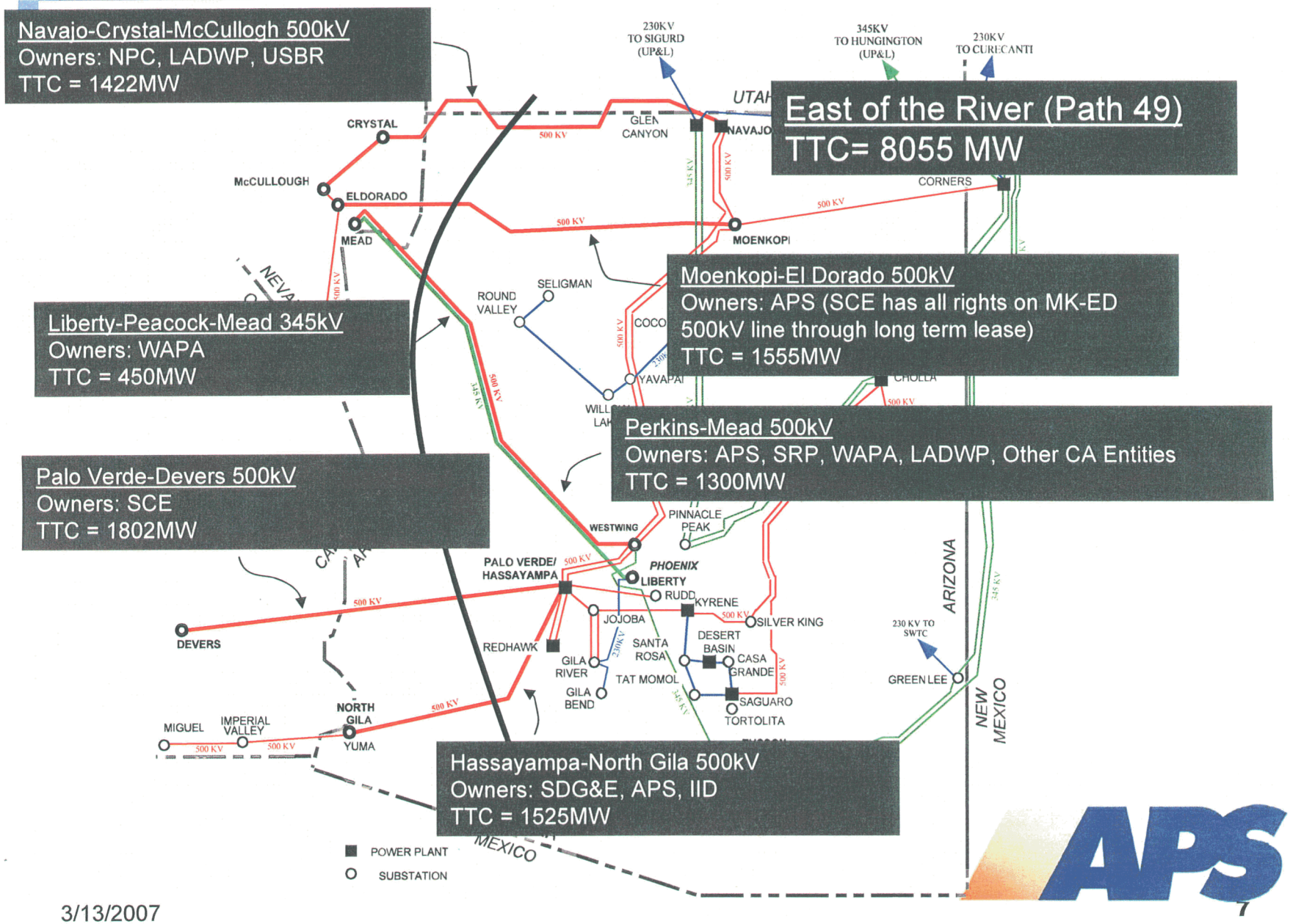


Palo Verde East Path
Owners: SRP, APS, PNM, & EPE
TTC= 6970 MW
Primary Use: Delivery of Palo Verde Generation and Other Hub Resources

2007 ARIZONA TRANSMISSION SYSTEM



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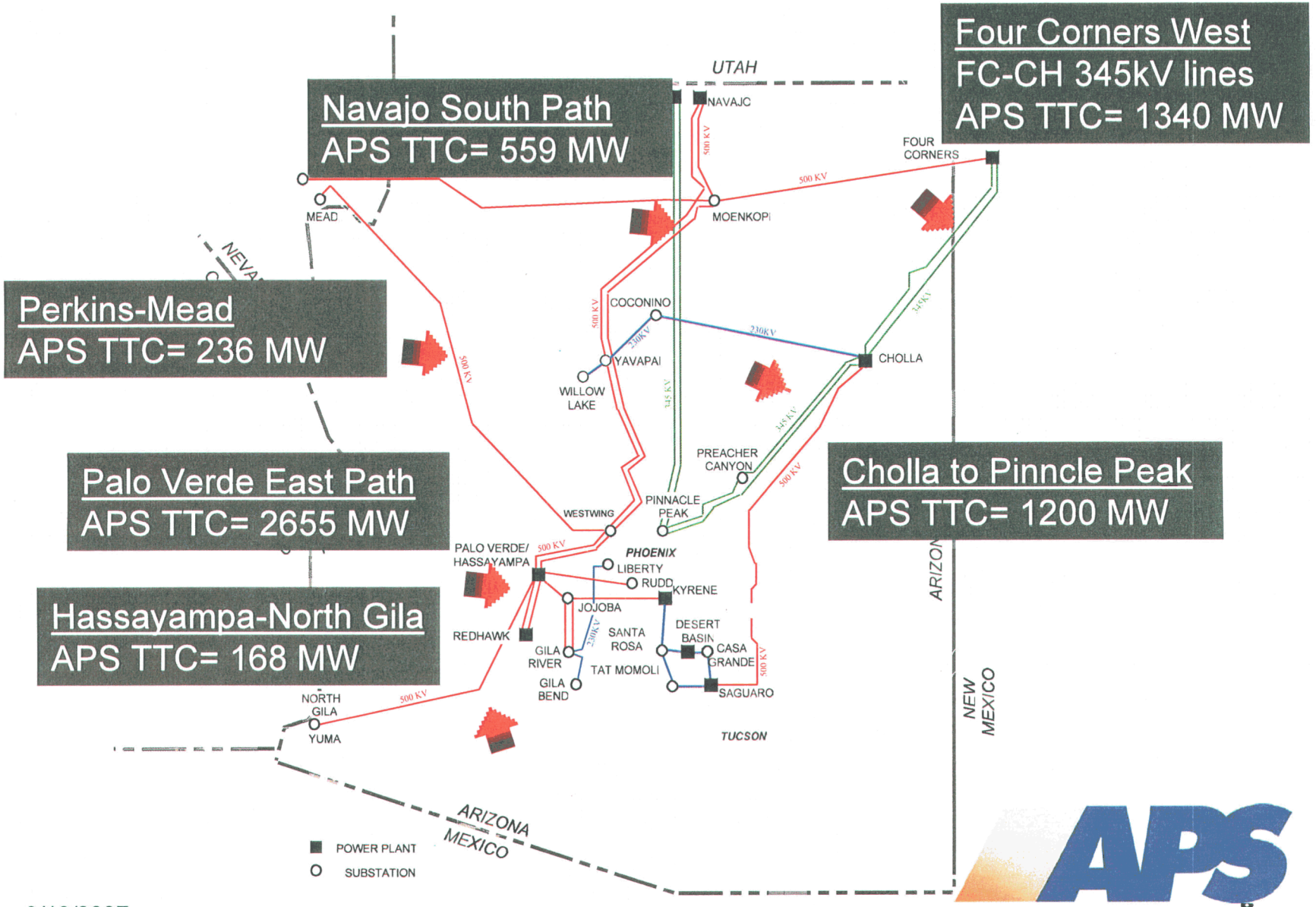
2007 ARIZONA TRANSMISSION SYSTEM
Paths with APS Participation



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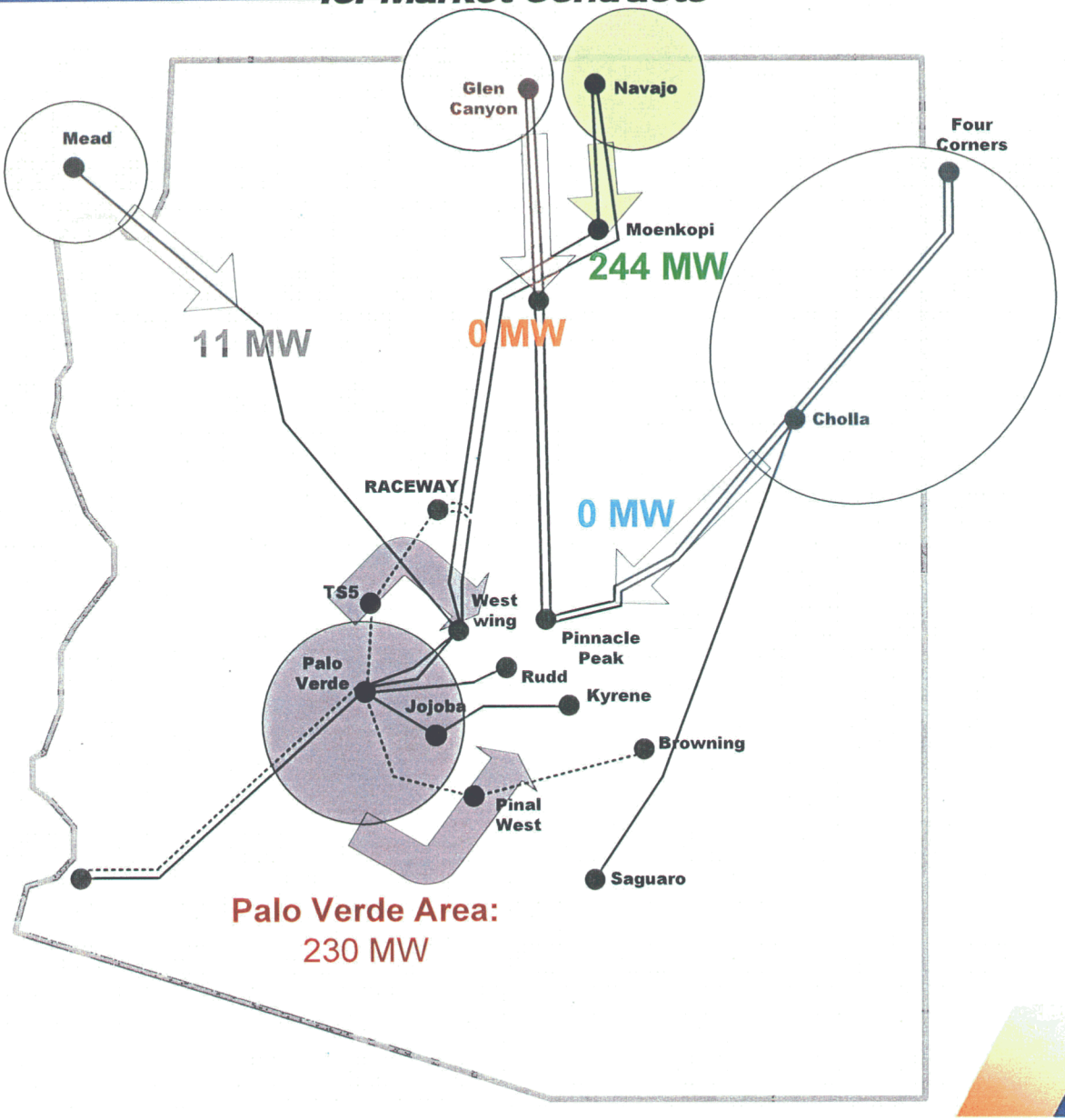
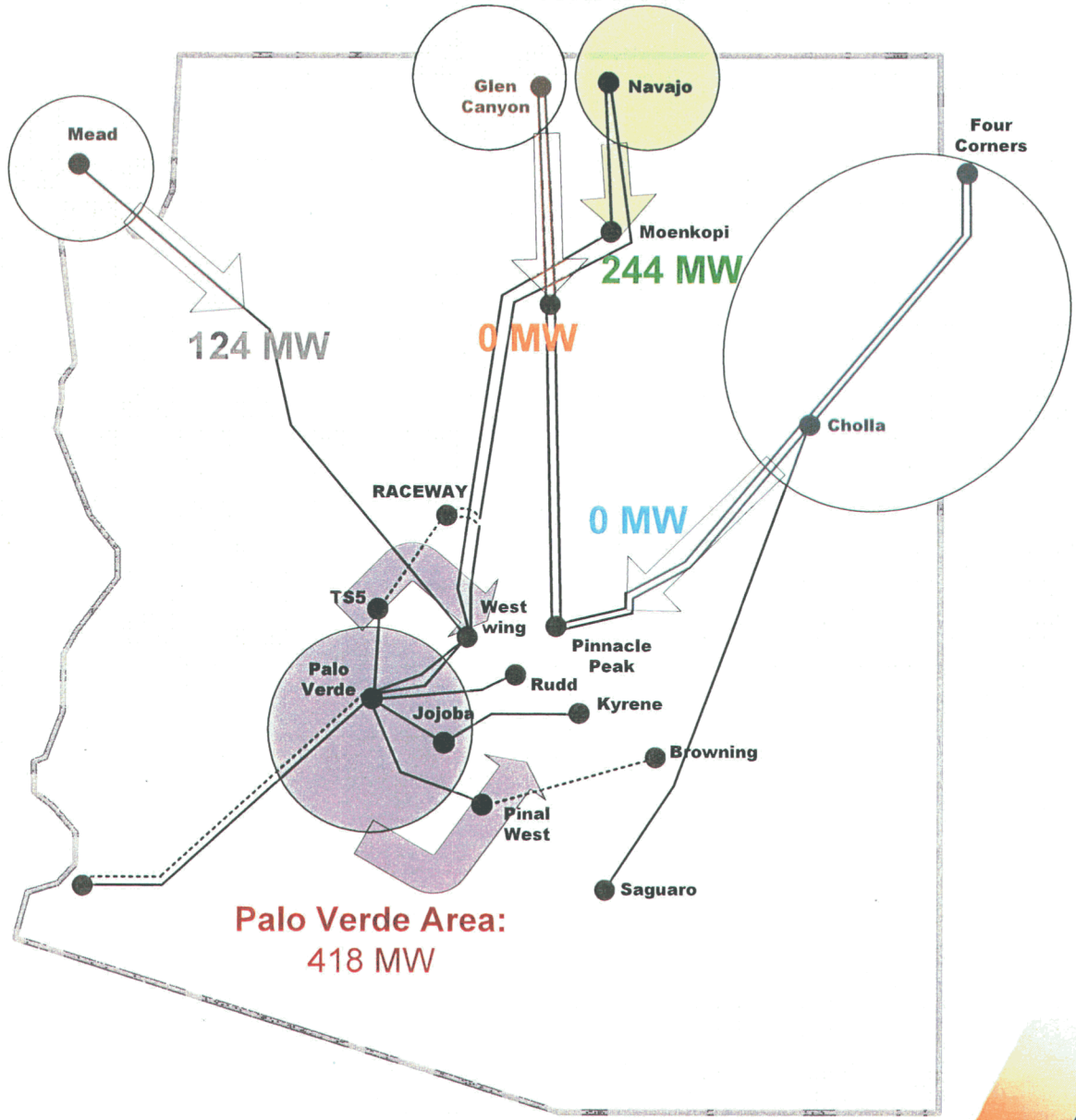
2007-2008 APS Transmission Available for Market Contracts



2009 APS Transmission Available for Market Contracts

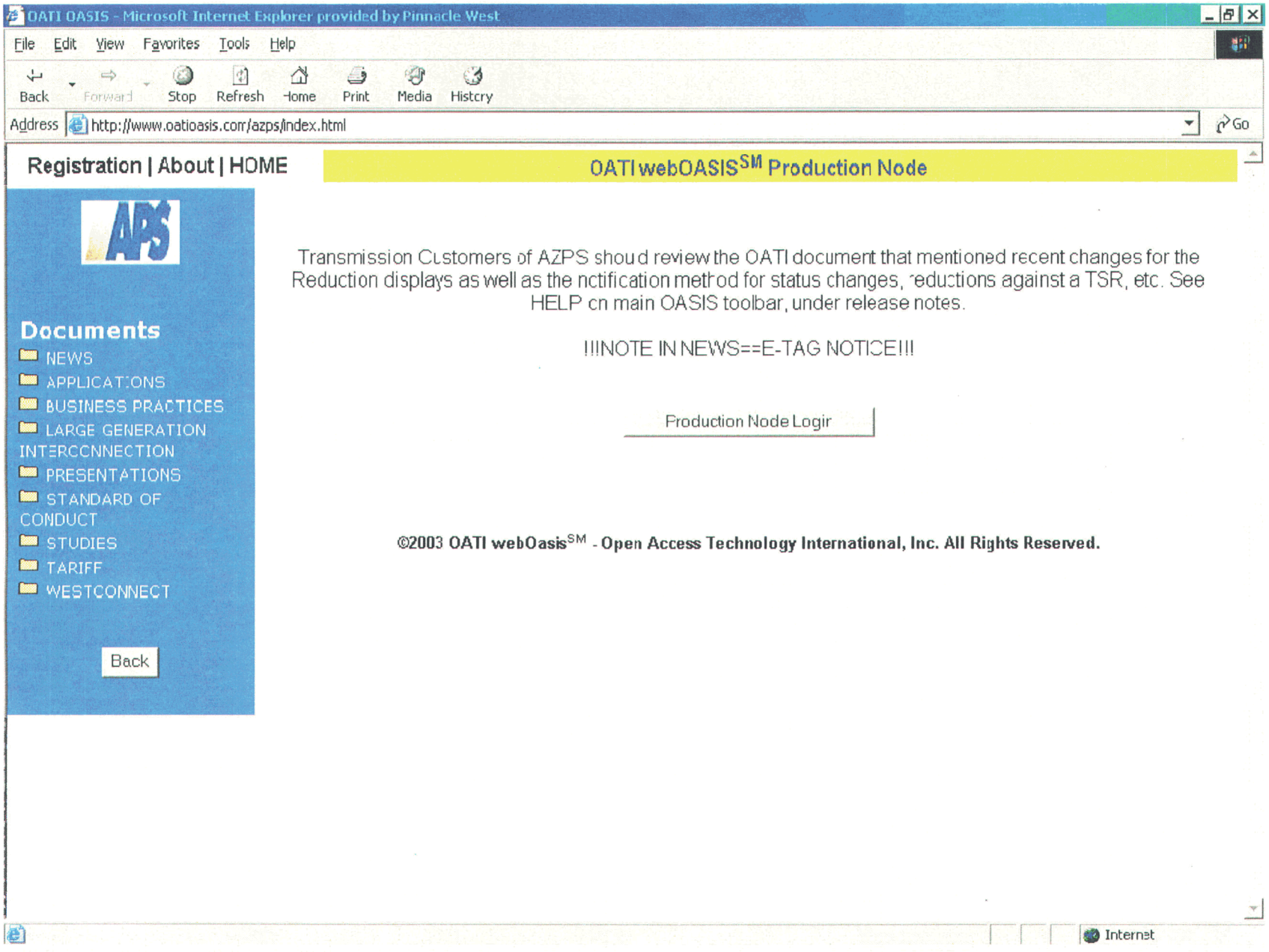


Cost Estimate (2007 dollars)

	$M/mile of transmission line* (single circuit)	Cost of substation to interconnect into existing line** ($M)
500kV	$2.6	$10.5
345kV	$1.7	$5.7
230kV	$1.6	$4.1
69kV	$0.4	$2.4

* Line Siting and Right-of-way acquisition costs are not included in cost per mile. It is assumed that the Interconnect Party would acquire their own CEC and Right-of-way. Quoted cost is for a single circuit line.

** Substation siting and land cost is not included. It is assumed that the Interconnect Party would acquire the land. Substation assumption is for a 3 breaker ring. The cost of transformers in not included.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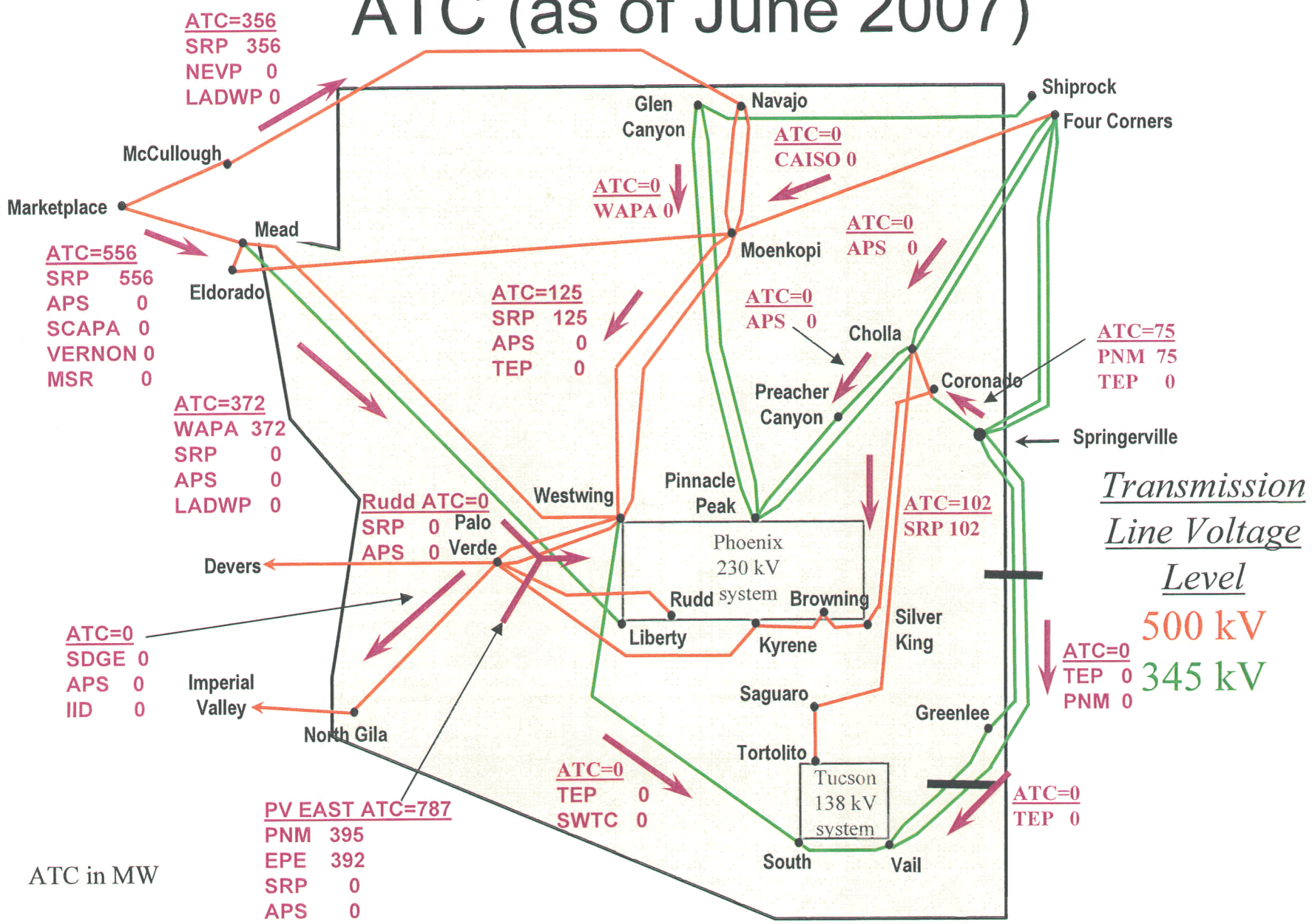
Questions ?

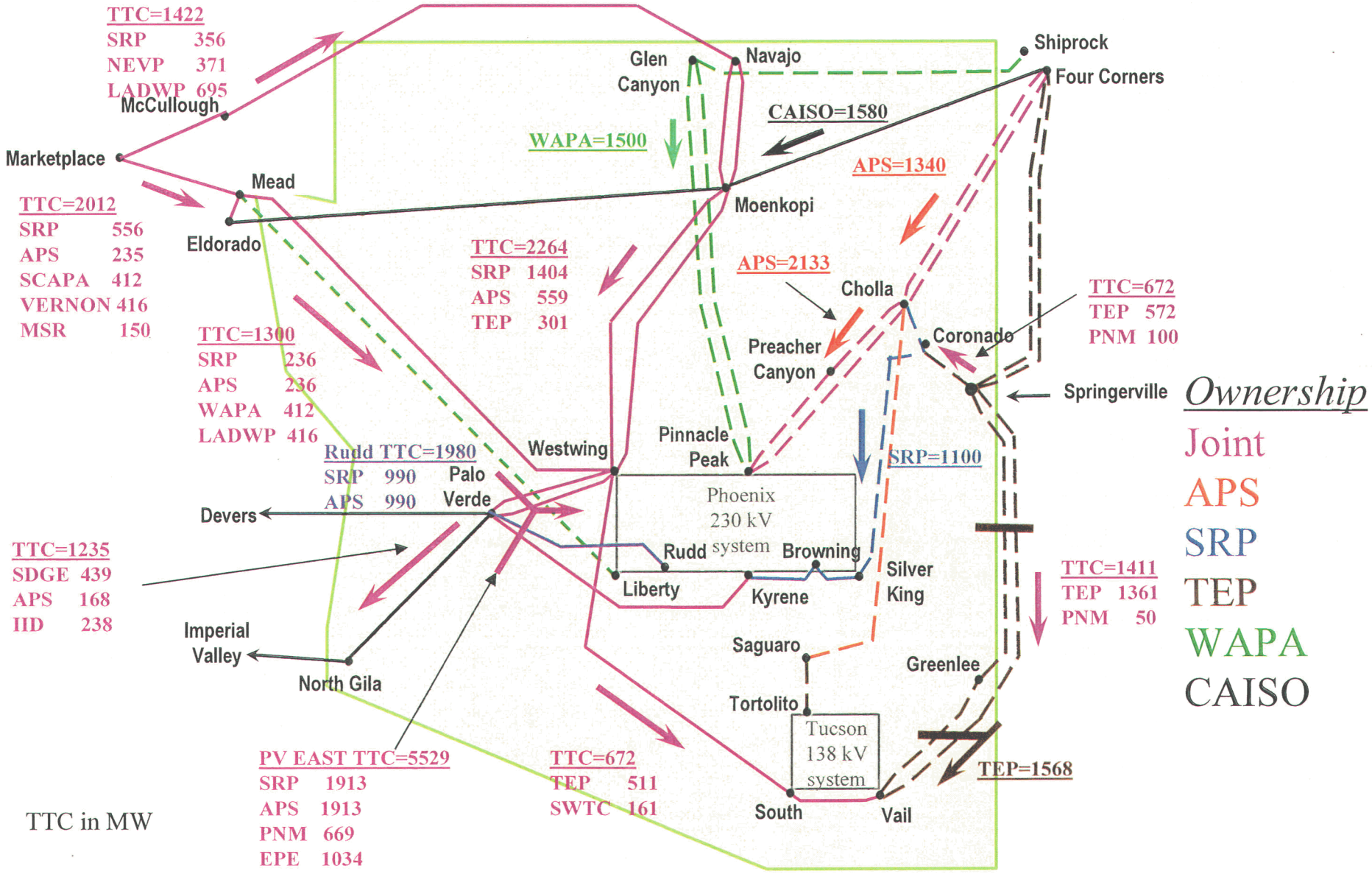
APS

Appendix N
Arizona EHV Transmission ATC and TTC as of June, 2007

Arizona EHV Transmission ATC (as of June 2007)



Arizona EHV Transmission TTC



Appendix O
Email Invitations to the October 8, 2007 and November 16, 2007 BTA Workshops

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Smithers, Phil (Z88940)

Subject: RE: Arizona Renewable Transmission Task Force

From: Barrie.Kokanos@aps.com [mailto:Barrie.Kokanos@aps.com]
Sent: Wednesday, September 26, 2007 11:01 AM
To: asormond@msn.com; Barrie.Kokanos@aps.com; bevans@swtransco.coop; dana.cabbell@sce.com; deubank@pnm.com; dlee@caiso.com; debra_lew@nrel.gov; dmalone@epelectric.com; dtovar@epelectric.com; Thomas.Duane@pnm.com; erik@ausra.com; frank@wecc.biz; gtromero@srpnet.com; gtrent@tep.com; gnail@pnm.com; jds@krsaline.com; j_charters@msn.com; joanna.prukop@state.nm.us; greenlaw@wapa.gov; jxhernan@srpnet.com; john.kyei@pdsplc.com; karbeit@optisolar.com; keisch@tristategt.org; kabagley@cox.net; laurie.woodall@azag.gov; lvt@krsaline.com; lisa.shot@bp.com; mark@pdsplc.com; njjack@srpnet.com; pjohnson@swtransco.coop; pat.d.risner@bhpbilliton.com; paul.andrae@verizon.net; pzhang@epri.com; rmitchell@trans-elect.com; rbelval@tep.com; saber@wapa.gov; shelton@wapa.gov; dpasteve@citlink.net; steve@verderesources.com; biggst@lac.losalamos.nm.us; johns@sitheglobal.com; tcarr@westgov.org; twray@southwesternpower.com
Cc: Jonathan.Stahlhut@aps.com; Peter.Krzykos@aps.com
Subject: Arizona Renewable Transmission Task Force

Based on the responses we've collected, the transmission meeting for the Arizona Renewable Transmission Task Force will meet on 10/8 at APS's 502 building from 9:30 to 3:00. If you have any questions please forward your requests to Jon Stahlhut. Attached is a map on the location of the building. The call-in number is 877-857-7026 and the conf code is 602-250-1652. We'll be serving lunch so please indicate if you plan on attending.
Tentative Agenda -
-4th BTA Order
-Outline projected renewable locations in AZ -Determine existing ATC -Outline other projected resource projects -Overlay SRP, APS, and TEP 10 yr plans -Determine ATC for the next 10 yrs -Recommend additional transmission plans to accommodate renewable resources.

<<Map to 502 and surrounding area.doc>> Email Firewall made the following annotations
---
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Smithers, Phil (Z88940)

From: Stahlhut, Jonathan W(Z06487)
Sent: Wednesday, June 25, 2008 10:17 AM
To: Smithers, Phil (Z88940)
Subject: FW: Arizona Renewable Transmission Task Force

Attachments: Map to 502 and surrounding area.doc

Nov 16th invite

From: Stahlhut, Jonathan W(Z06487)
Sent: Friday, November 02, 2007 1:23 PM
To: 'Amanda Ormond (asormond@msn.com)'; 'Amy LeGere'; Kokanos, Barrie L(Z03062); 'Bob Anderson'; 'Bruce Evans (bevans@swtransco.coop)'; 'Dana Cabbell'; 'Dave Eubank'; 'Dave Hurlbut'; 'David Lee (dlee@caiso.com)'; 'Debra Lew (debra_lew@nrel.gov)'; 'Dennis Malone'; 'dtovar@epelectric.com'; 'Duane, Thomas'; 'Eric John'; 'Erik Ellis (erik@ausra.com)'; 'Frank (frank@wecc.biz)'; 'Gary Romero (gtromero@srpnet.com)'; 'Gary Trent'; 'George Nail (gnail@pnm.com)'; Hammond, Bryan L(Z41182); 'J. Brian Cain'; 'Jerry Smith (jds@krsaline.com)'; 'Jim Charters (j_charters@msn.com)'; 'Jim Rein'; 'Joanna Prukop (joanna.prukop@state.nm.us)'; 'John Greenlaw (greenlaw@wapa.gov)'; 'John Hernandez'; 'John Hernandez'; 'John Kyei (john.kyei@pdsplc.com)'; 'Kathryn Arbeit (karbeit@optisolar.com)'; 'Keith Schwertfeger (keisch@tristategt.org)'; 'Ken Bagley (kabagley@cox.net)'; Krzykos, Peter P(R57883); 'Laurie Woodall (laurie.woodall@azag.gov)'; 'Lee Ann V. Torkelson (lvt@krsaline.com)'; 'Lisa Szot'; Lockwood, Barbara (Z31204); 'Mark Etherton (mark@pdsplc.com)'; 'Nam Nguyen'; 'Nevida Jack (njjack@srpnet.com)'; 'Pam Johnson (pjohnson@swtransco.coop)'; 'Pat Risner (pat.d.risner@bhpbilliton.com)'; 'Paul Andrae (paul.andrae@verizon.net)'; 'Pei Zhang (pzhang@epri.com)'; 'Prem Bahl'; Ramey, Thomas H(Z77077); 'Ray Williamson'; 'Robert Kondziolka'; 'Robert Mitchell (rmitchell@trans-elect.com)'; 'Ron Belval (rbelval@tep.com)'; 'saber@wapa.gov'; 'shelton@wapa.gov'; Stahlhut, Jonathan W(Z06487); 'Steve Begay'; 'Steve Mendoza (steve@verderesources.com)'; 'Susan Williams'; 'Tom Biggs (biggst@lac.losalamos.nm.us)'; 'Tom Darin '; 'Tom Johns'; 'Tom Karr (tcarr@westgov.org)'; 'Tom Wray (twray@southwesternpower.com)'
Subject: Arizona Renewable Transmission Task Force

The next meeting for the Arizona Renewable Transmission Task Force will meet on Friday November 16th at APS's 502 building from 9:30 to 3:00. Attached is a map on the location of the building.

We'll be serving lunch so please indicate if you plan on attending.

Tentative Agenda -

- October 8th meeting recap
- Black and Veatch summary
- Renewable energy queue in Arizona
- ATC in Arizona
- Discussion / recommended transmission plans in Arizona

If there are any questions please let me know.

Jon

Jonathan Stahlhut, Ph.D.
Transmission Planning
Arizona Public Service Co.
(602) 250-1116
81-1116
jonathan.stahlhut@aps.com

Map to 502 and
surrounding are...

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Appendix P
Arizona Renewable Energy Assessment Final Report, Black and Veatch, September 2007

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A UniSource Energy Company

Arizona Public Service Company
Salt River Project
Tucson Electric Power Corporation

Arizona Renewable Energy Assessment

FINAL REPORT
B&V Project Number 145888

September 2007

Black & Veatch Corporation
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Overland Park, Kansas 66211
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ENERGY WATER INFORMATION GOVERNMENT

Principal Investigators:

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Steve Block
Keith Cummer
Kevin Gilton
Ric O'Connell
Bill Roush
Larry Stoddard
Sean Tilley
Dave Woodward
Matt Hunsaker

GeothermEx – Subcontractor for geothermal sections

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1.0 Executive Summary

Black & Veatch Corporation has prepared this report for Arizona Public Service Company, Salt River Project, and Tucson Electric Power Company (APS/SRP/TEP). The purpose of this report is to assess the prospects for significant renewable energy development in Arizona. The scope of the study is limited to Arizona projects that would export power to the grid (that is, not distributed energy projects). This study includes a review of the current status of renewable energy in Arizona, characterization of renewable power generation technologies, assessment of Arizona's renewable resources, and an assessment of key risk factors. This section summarizes the key findings in these areas.

1.1 Background and Objective

Electricity produced in Arizona is mostly from traditional natural gas, coal, and nuclear resources. Hydroelectric contributes about 6 percent, while non-hydro renewable resources are currently very small (0.07 percent). To stimulate further development of renewable energy, the Arizona Corporation Commission adopted final rules in 2006 to substantially increase Arizona's Renewable Energy Standard (RES). The new RES mandates that impacted utilities (including TEP and APS) obtain 15 percent of their energy from renewable resources by 2025. SRP has also adopted a renewable energy goal similar to the RES.

The objective of this report is to assess the full potential of Arizona renewable energy resources while accounting for the economics of developing those resources. Large scale renewable energy development will be necessary to meet the renewable mandates set forth in the Southwest. Although Arizona is well known for its solar resources, solar is currently the most expensive renewable energy resource. By comparison, Arizona is thought by many to have relatively limited opportunities for comparatively lower cost renewables, such as wind, biomass, geothermal and hydroelectric. This study assesses the relative potential of all resources and forecasts which are most likely to be developed over the next 20 years. It is important to note that this report concentrates on the potential of the renewable energy resources themselves. It does not, beyond the inclusion of transmission interconnection costs, address the potential cost or availability of transmission capacity needed to deliver these resources to load. Further, out-of-state resources and their impact on the Arizona renewable energy market are not included in the scope of this review.

This study was undertaken in two phases. The Interim Report (Section 3, 4 and 6 of this Final Report) reviewed a broad range of renewable energy technologies and

concluded with recommendations for further study in Phase 2. Phase 2 of the project (the remainder of this Final Report) characterizes the most promising options in greater detail and identifies potential projects for possible implementation.

1.2 Renewable Energy Technology Options

Nineteen renewable and advanced energy technologies were assessed in Phase 1. The technologies were split into eight categories as shown below. Each technology was described with respect to its principles of operation, applications, resource characteristics, cost and performance, environmental impacts, and outlook for Arizona applications.

Technologies that are **bold and underlined** in the list below were recommended for further study in Phase 2 due to their large potential and/or low cost.

1. Solid biomass
   - **1.1 Direct fired**
   - 1.2 Biomass Gasification and IGCC
   - **1.3 Cofiring**
   - 1.4 Plasma Arc Gasification
2. Biogas
   - **2.1 Anaerobic digestion**
   - **2.2 Landfill gas**
3. Solar Electric
   - 3.1 Solar thermal electric
     - **3.1.1 Parabolic Trough**
     - **3.1.2 Parabolic dish engine**
     - 3.1.3 Power Tower
     - 3.1.4 Compact Lens Fresnel Reflector
   - 3.2 Solar photovoltaic
     - 3.2.1 Residential
     - **3.2.2 Commercial**
     - **3.2.3 Utility-scale**
4. Hydroelectric
   - **4.1 Conventional Hydroelectric**
   - **4.2 Pumped Storage**
5. **Wind**
6. **Geothermal**
7. Fuel Cells Using Renewable Fuels
8. Compressed Air Energy Storage

1.3 Renewable Resource Assessment

Additional research was performed for technologies that were recommended in the first phase of the project. The objective was to assess the renewable energy resources that are suitable for development in the near- to mid-term (next 20 years). Potential development prospects were identified, levelized generation costs were calculated, and supply curves were developed for each resource. An end result of this process was the identification of a list of over 100 hypothetical renewable energy projects that might be developed to meet demands for renewable energy in Arizona (Appendix A and B contain lists of these projects). Table 1-1 and Figure 1-1 summarize the renewable energy

resources in Arizona potentially developable over the near- to mid-term (through 2025). The table and figure do not include existing (24 MW) or planned projects (504 MW), which are shown in Table 3-2.

General findings from the resource assessment are described in the following sections.

Table 1-1. Arizona Renewable Energy Resources Available in the Near- to Mid-Term.

Technology	Location	Cost (2007$/ MWh)	Capacity (MW)	Generation (GWh/yr)
Direct Fired Biomass	Maricopa	143	20	140
Biomass Cofiring	2 potential sites: TEP's Sringerville generating station and APS's Cholla generating station	58 - 63	20	140
Landfill Gas	15 potential small projects identified across the state	82 - 99	10	68
Anaerobic Digestion	Snowflake, Buckeye, Chandler, and Maricopa	62 - 128	10	69
Solar Thermal Electric	100 MW project in 2011. 2–4 200 MW sites per year after 2012	161- 176	4,300[a]	10,940[a]
Hydroelectric	7 potential sites[b]	32 - 215	82	320
Wind	6 potential sites near Kingman and the White Mountains[c]	75 - 141	991	2551
Geothermal	Clifton Hot Springs and Gillard Hot Springs	110 - 122	35	215
Total			**5468**	**14,443**

Notes:

[a] The solar potential is vast, and this only includes projects sufficient for meeting Arizona's forecast renewable energy demands through 2025.

[b] Glen Canyon compromises 90 percent of total potential.

[c] 500 MW of planned wind generation not included.

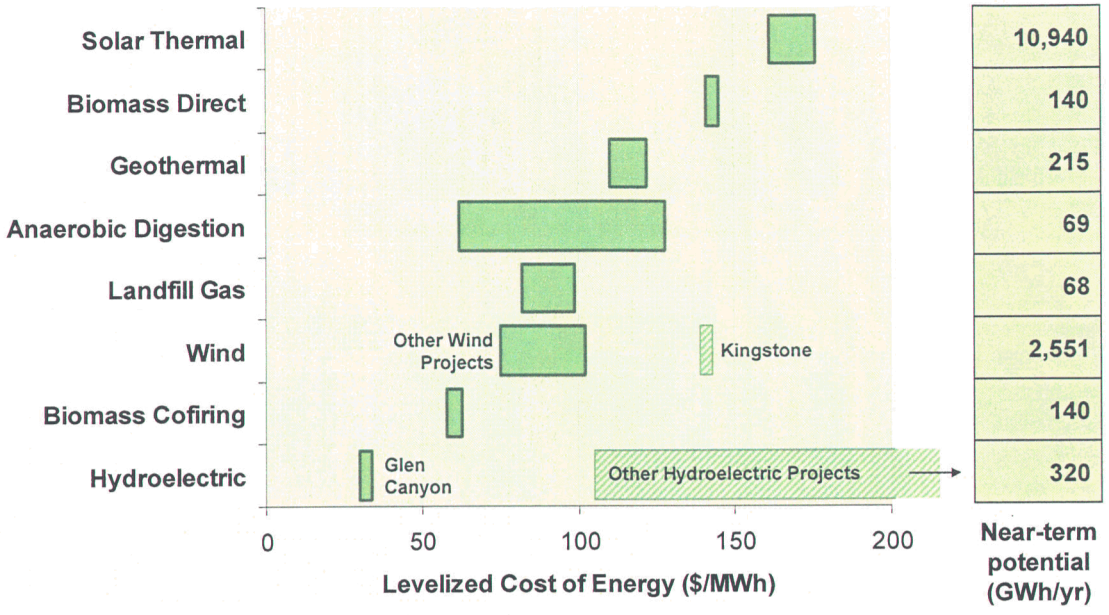


Figure 1-1. Summary Cost and Potential of Arizona Renewable Resources.

1.3.1 Direct Fired and Cofired Biomass

Although biomass resources are limited, direct-fired biomass and cofired biomass technologies were identified as promising technologies in the first stage of the analysis. Sufficient resource was identified in central Arizona to support a 20 MW direct-fired combustion plant in the vicinity of Maricopa. This facility would be a low emission, fuel-flexible fluidized bed that would burn a variety of biomass fuels, including mill residues, urban wood waste from Phoenix and Tucson, and agricultural residues. The two potential cofiring projects are a 10 MW facility located at TEP's Springerville Generating Station and a 10 MW facility located at APS's Cholla Generating Station. To counter potential negative impacts on the boilers, the cofiring projects were assumed to use a gasification system close-coupled to the existing boiler. The cofiring projects would utilize forest and mill residues.

Considering the other renewable energy options evaluated in this study, the costs of the two cofiring projects are relatively low (about $60/MWh in 2010), and the costs of cofiring are certainly lower than the direct fired project (about $162/MWh in 2012). In general, the costs of biomass in Arizona are high compared to other states due to limited available low cost biomass and the small scale of the potential projects.

While cofiring is lower cost than direct fired biomass plants, there are a couple of significant barriers to its implementation. Initiating a biomass cofiring project may require the host coal plant to reopen existing air permits, even though cofiring generally

reduces emissions. The risk and cost of reopening existing permits is not included in the cofiring cost estimate, but it may be a significant deterrent to cofiring projects. Further, electricity demand in Arizona is increasing faster than any other state (600 MW increase per year). Biomass cofiring converts capacity to a renewable source rather than adds capacity, and thus may be less attractive than new capacity additions.

If the cofiring projects face too many obstacles, an additional direct fired biomass facility could be developed in Northern Arizona in lieu of the cofiring projects.

1.3.2 Landfill Gas

Black & Veatch utilized the Environmental Protection Agency Landfill Methane Outreach Program (LMOP) database of landfills in Arizona to assess 25 potential sites. Black & Veatch attempted to contact each of the landfills to verify data and assess the suitability for power development. Based on this review, fifteen potential projects were identified, totaling 9.7 MW of capacity and 68 GWh of annual generation. This capacity is much smaller than what would be expected for similar sized landfills in other states due to Arizona's dry climate. Most of these projects could be available by 2010 if development were prioritized. Projects costs vary, but most projects are projected to generate power for around $90/MWh.

The overall prospects for landfill gas generation are small. Landfill gas projects can take less time to develop than large solar or wind projects, so landfill gas may play a more significant role in the near term.

1.3.3 Anaerobic Digestion

The utilization of biogas generated from anaerobic digestion of animal manure was identified as a technically feasible option in the first stage of the analysis. Potential anaerobic digestion projects were identified based on large concentrations of livestock (swine, dairy, and poultry) operations within an area. Four anaerobic digestion projects were identified, ranging from 1.5 to 3.5 MW. The projects total 9.9 MW of capacity and 69 GWh of annual generation. The costs for the anaerobic digestion projects range from $70/MWh to $140/MWh (in 2010), largely dependent on project scale.

While this resource has a relatively limited generation potential, anaerobic digestion projects could be executed relatively quickly and with low levels of risk.

1.3.4 Solar Thermal Electric

There is large potential for solar thermal development in Arizona. The review focused on the only commercially proven technology: parabolic trough. Parabolic dish

Stirling systems are promising, but unproven; their costs were assessed in a side scenario study (section 8).

The potential for solar thermal was characterized in a different manner than other technologies. Rather than being limited by resource availability, the technology is limited by equipment availability, development timelines, and ultimately economics. Due to supplier constraints, it was assumed that the first 100 MW trough plant in Arizona would not be completed until 2011. It is assumed that the near term supply chain constraints in the industry will be alleviated by 2013, and two to four 200 MW plants could be constructed per year thereafter. Generic projects were characterized in four areas of the state: Phoenix, Yuma, Stoval, and Tucson.

Unlike most other technologies evaluated for this study, it is expected that significant technical and cost advances will be realized for solar thermal trough plants. In addition, parabolic dish engine technology may also be deployed on a commercial level, and this technology could become competitive over the term of this study (through 2025).

The supply curve for solar thermal trough plants is relatively flat with the lowest cost projects generating power for about $160/MWh (hypothetical 2007 project, includes 30 percent investment tax credit). The flat supply curve means that a lot of solar thermal can be developed for about the same cost. This cost is substantially higher than non-solar resources profiled in this study. The potential supply of solar thermal potential is vast, and exceeds the near-term demands for renewable energy in Arizona.

1.3.5 Solar Photovoltaic

As with solar thermal technologies, constraints on the deployment of solar photovoltaic projects are not related to resource; the constraints are mainly capital costs and equipment availability. The review focused on deployment of larger photovoltaic systems (5-10 MW). Concentrating photovoltaic technology was also addressed as a possible future technology.

Even with significant cost reductions, costs for solar photovoltaic and concentrating photovoltaic projects are too high (greater than $240/MWh) to compete with the other renewable energy technologies surveyed. However, an advantage of solar photovoltaics is that smaller projects may be able to come online in the very near-term (2008 and 2009). As such, they are one of the few in-state technologies available to meet near-term renewable energy demand.

Alternative project and cost structures for solar PV projects are currently being refined, and they have the potential to substantially lower the "all-in" cost of energy from solar PV. Given the high capital costs for PV, any improvement in capital structure or

financing costs has a relatively strong impact on the final levelized cost. These structures have not been modeled in this report.

1.3.6 Hydroelectric

Seven hydroelectric projects were identified as potentially promising. The total combined capacity of the seven projects identified is 81.8 MW, with an energy generation potential of 320 GWh/yr. A single project, adding generation at Glen Canyon dam, makes up about 90 percent of this total. The projects were identified based on government information, and details were difficult to verify. Of the seven projects, Glen Canyon, Tucson and Waddell are the only projects that could be reasonably located. Glen Canyon and Waddell have the most head and flow available compared to other sites. They also have existing hydropower installed and therefore show the most potential for further study. The Glen Canyon project is the lowest cost project of all the renewable energy projects surveyed for this study. It is forecast to cost about $50/MWh in 2015, the year it is projected to be available. The other hydroelectric projects are all projected to be much more expensive, at costs over $150/MWh in 2013, the first year they are projected to be available.

Drought conditions of recent years have reduced water resources throughout the Western US in recent years, including Lake Powell. Continued drought conditions may decrease the actual statewide hydroelectric potential.

1.3.7 Wind Power

While the wind resource is generally less attractive in Arizona compared to surrounding states, wind was identified as one of the more promising resources in the first phase of the study. To identify specific areas conducive to the development of a utility-scale wind energy projects, information was gathered on Arizona's estimated wind resource, transmission infrastructure, environmental restrictions, and federal land areas. After reviewing many potential sites for constructability, transmission proximity, wind resource, and other constraints, six sites were chosen as the most promising for near-term development. While it is possible that other wind sites could be developed in Arizona, these sites are less attractive based on this analysis.

The total combined capacity of the six sites identified is 990 MW, with an energy generation potential of 2,550 GWh/yr. (The 500 MW of already planned wind projects are not included in this total). Costs for most projects are estimated to be about $75 to $100/MWh in 2010, which is the year when wind is first expected to be available. While the wind resources in Arizona are modest when judged against many other states, compared to other renewable energy options in Arizona, prospects for wind are good due

to the relatively low cost. Arizona wind resources, however, are stronger in the winter when electricity demand is low, and weaker in the summer when demand is higher. Assessment of the seasonal value of energy (or avoided cost, more generally) was not included in the scope of this study.

1.3.8 Geothermal

Geothermal was identified as a relatively unknown, but potentially promising resource in the first phase of this study. The two known geothermal resources with the highest temperatures are located in the eastern part of the state: the Clifton Hot Springs and the Gillard Hot Springs projects. Interpretation of preliminary data suggests that resource temperatures may enable binary power generation.

Because the projects are still in their early exploratory state, there is not enough data available to accurately characterize the geothermal projects with a high degree of precision. Even identifying the potential project size is still speculative. For this reason, generic 20 and 15 MW projects were assumed. At best, these assumptions identify "place-holder" projects that must be further defined as more information about the true potential of each site is discovered. Because of their small-scale and long lead time (which places them after the assumed expiration of the production tax credit), costs for the two projects are relatively high ($149/MWh and $163/MWh in 2014). Nevertheless, this cost is still competitive with solar resources that are expected to be developed in the same timeframe.

1.4 Forecasted Renewable Energy Development

Black & Veatch has developed a model to help utilities, states, and other entities develop renewable energy plans. For the utilities represented in this study, Black & Veatch evaluated Arizona's renewable energy development potential in light of increased demand for renewable energy stimulated, in part, by the Renewable Energy Standard. The model was then used to forecast renewable energy development in the state through 2025.

The model evaluates the total lifecycle cost of renewable energy projects, including capital and operating costs, performance, and transmission system interconnection. Projections are made for future changes in technology cost and performance based on Black & Veatch's experience. By allowing the model to consider all possible renewable energy resources in Arizona, the study assesses the full potential of all renewable energy resources while accounting for the economics of developing those resources. The model does not include transmission system upgrades (other than interconnection costs) or system integration costs for intermittent resources (e.g. wind).

The model also does not assess value (i.e., avoided cost) of the resource as determined by its degree of firmness or time of delivery (e.g. on-peak vs. off-peak). In selecting projects, utilities may consider these factors, which may result in a different order of resource/project development. Further, although long term transmission constraints have not been reviewed, a long term analysis should include a transmission development plan.

Figure 1-2 shows the total renewable energy supply curve for Arizona in the year 2025. Costs are in nominal dollars (that is, 2025 costs) without tax credits. This curve shows all new projects identified in the study. The curve also shows a demand line indicating the projected 2025 renewable energy demand of 11,210 GWh (this already accounts for planned projects). If development of renewables in Arizona were economically optimum (again, not considering transmission upgrades and avoided costs), then all of the projects to the left side of the demand line would be built by 2025. It should be noted that there are additional higher cost resources that would extend the potential supply of renewables further to the right than indicated on this chart. However, once sufficient projects were identified to meet demand, Black & Veatch did not continue to identify higher cost projects.

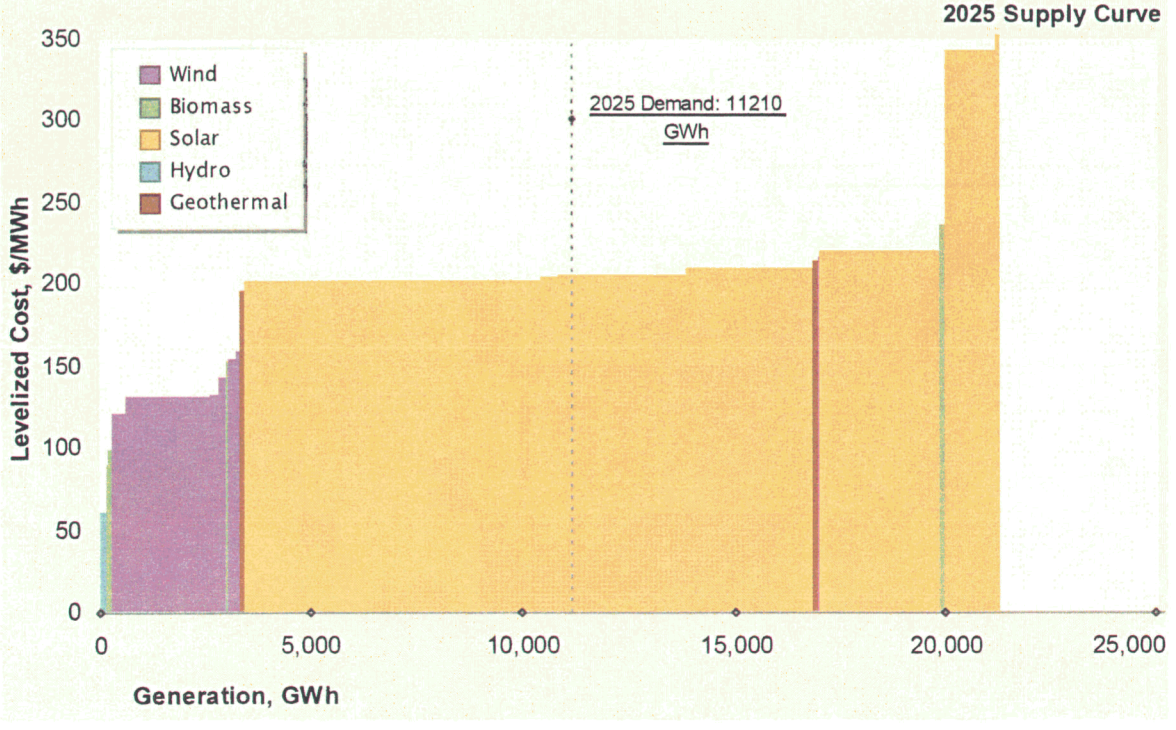


Figure 1-2. Total Arizona Renewable Supply Potential in 2025.

The supply curve shows that a portion of Arizona's renewable energy demands can be met with lower cost non-solar resources, especially wind. However, by 2017, it is

projected that lower cost non-solar resources will be exhausted and large-scale solar thermal plants will then be built at a rate of 200 to 400 MW per year through 2025. Other insights from the model include:

- **Non-solar resources limited** – Arizona has a variety of renewable energy resources that could be developed; however, other than solar, these resources appear relatively limited. In the mid to near-term, developable potential for new biomass, geothermal, and hydroelectric projects combined could contribute about 952 GWh/yr, or 1 percent of the electricity that was generated in Arizona in 2005. Wind could contribute about 2.5 percent. With energy storage, solar could theoretically supply the entire electricity needs of the state. (Note that these totals exclude 825 GWh/yr of additional existing and already planned projects, most of which is wind).
- **Non-solar resources important** – Despite the relatively limited potential of wind, biomass, geothermal and hydroelectric resources, they serve an important role in forestalling the need to install expensive solar. However, the relatively limited potential of these resources compared to surrounding states may serve as a deterrent for large, out-of-state renewable energy project developers.
- **Regional renewable energy markets** – This study did not include an assessment of regional renewable energy supply and demand. Neighboring states, namely California, New Mexico, and Nevada, also have aggressive renewable energy standards. These states may have more economical renewable energy sources than Arizona (for example, Salton Sea geothermal resources and New Mexico wind); however, given their own aggressive in-state demands and transmission limitations, they may not be a dependable source for Arizona. While the importation of renewable energy may help to defer Arizona's needs, it is not likely to fully satisfy them.
- **Lowest cost resources** – The most promising project opportunities from an economic perspective involve enhancements to existing facilities: adding a unit at the existing Glen Canyon hydroelectric project and biomass cofiring at the Cholla and Springerville coal plants. These projects are around $60/MWh or less.
- **Solar about twice cost of other resources** – Solar is the most expensive of the renewable resources profiled in this study. The lower cost solar resources (about $161-176/MWh in 2007) are about twice as expensive as the bulk of the non-solar resources (about $70-110/MWh in 2007). The base case model included only proven, fully commercial solar technologies such as solar

photovoltaics and solar thermal trough. If forecasted technology improvements are realized, dish engine technologies have the potential to be cost competitive with conventional parabolic trough systems.

- **Arizona's reliance on solar is unique** – Arizona appears unique in the U.S. in its dependence on in-state solar energy to meet its renewable energy demands. It is estimated that 65 percent of the Arizona renewable demand in 2025 will be met by solar. Generally speaking, other states in the Southwest U.S. will likely be less reliant on solar to meet their renewable energy requirements. This is because other states generally have a larger base of non-solar renewables that they can rely on for near-term needs. By comparison, Arizona's non-solar resources are relatively limited. Solar technologies will play a key part of renewable's future in Arizona.
- **Consideration of avoided costs is important and necessary** – This project did not assess the differential value (i.e., avoided cost) of renewable resources. Avoided cost is typically determined by assessing a resource's capacity value (based on degree of "firmness" at the time of a utility's system peak demand) and its energy value (based on time of delivery). In selecting projects to develop or procure, utilities may consider these factors, which may result in a different order of resource/project development than shown in the supply curves in this report. This is important when comparing resources such as wind and solar. For example, wind energy projects only provide fractional capacity value (often estimated at 20 percent of the nameplate capacity) and are more likely to offset low cost energy resources during the winter and spring. Solar resources can readily provide firm capacity with gas hybridization or thermal storage. Further, solar is generally coincident with times of higher capacity needs. There are numerous methods to calculate avoided cost, and costs are specific to individual utility systems.

1.5 Assessment of Key Risk Factors

Black & Veatch analyzed some of the risk factors of interest to utilities in Arizona to determine how sensitive the supply curve results would be to changing situations. These factors include tax credit changes, implementation of advanced solar technologies, delayed technical advances, escalating construction costs, manufacturing/supply chain constraints, near term performance learning curve, and competition for limited resources.

1.5.1 Tax Credit Changes

Most renewable resources benefit from either production tax credits (PTCs) or investment tax credits (ITCs). The base case model assumed tax credits expire in 2012. In the long term, whether tax credits expire in 2008 or 2012 has little impact on the cumulative average cost of meeting renewable energy demand in Arizona (less than 1 percent by 2025). This is because many of the most expensive, large solar projects would likely be built after 2012. If tax credits never expire, the impact is a significant reduction in cumulative portfolio costs (25 percent reduction).

1.5.2 Advanced Solar Technologies

There are pre-commercial advanced solar technologies that may reduce the cost of solar energy. Two of these technologies include concentrating solar photovoltaic (CPV) and parabolic dish engine. These technologies were not included in the base case model, but were modeled in a sensitivity analysis. Based on Black & Veatch's assumptions, technology advancements in CPV will not make that technology competitive with conventional solar parabolic trough technologies for utility scale applications. However, there does appear to be potential for dish engine technologies to become competitive with solar trough technology.

1.5.3 Delayed Technical Advances

Advances are expected in wind and solar technologies, resulting in lower costs and higher capacity factors. However, there is a risk that such advancement may be delayed or not realized, and this was investigated in a sensitivity analysis. When technology advances were delayed, wind and solar thermal projects had lower capacity factors compared to the base case, which required development of more projects to meet the same demand. Because of lack of advancement, solar projects, particularly in the later years, are higher cost than the base case. The reduced technical advances will make levelized costs for wind and solar higher, which will make other technologies (biomass and geothermal) comparatively more attractive in early years. The cumulative effect on the total renewable energy cost will likely be an increase of 15 to 20 percent by 2025.

1.5.4 Escalating Construction Costs

The model base case has a capital cost escalation of 2.5 percent per year, which is meant to track close to general inflation. There is a risk that construction costs will escalate at a higher rate, depending on future markets for materials and labor. A sensitivity analysis was performed assuming 5 percent escalation. The results are pronounced. At year 2025, levelized costs are about 37 percent higher than the base case.

1.5.5 Manufacturing and Supply Chain Constraints

Manufacturing and supply chain constraints were assumed in the model. The projects most likely to be impacted by such constraints are solar and wind. For wind projects, there is currently a delay of up to two years between turbine order and turbine delivery because demand is greater than manufacturing capability. The wind projects identified for this project are assumed to be available to come online between 2010 and 2013. If there are additional constraints in the turbine supply chain, then it is likely that renewable energy demand would not be met in some years with in-state resources.

Solar projects were also modeled with manufacturing constraints in mind. Due to these constraints, it has been assumed that the first 100 MW trough plant in Arizona could not be completed until 2011. It is assumed that the near-term supply chain constraints in the industry will be alleviated by 2013, and two to four 200 MW plants could be constructed per year thereafter if deemed economical

1.5.6 Near-Term Performance Learning Curve / Project Failure

In the near-term, projects may under-deliver renewable energy as they gain experience during the initial operational and development learning period. Projects may also fail outright, and not supply any renewable energy. From a supply curve standpoint, contract failure shifts the supply curve to the left. When a project fails, its generation is removed from the supply curve, while all projects to the right (more expensive projects) shift left to fill in the space. As lower-priced projects fail, utilities will be forced to contract with more expensive renewable projects to procure the necessary amount of energy.

1.5.7 Competition for Limited Renewable Resources

As more and more renewable energy projects are developed, there will be fewer renewable resources to utilize in the future. There is a risk that utility competition for limited renewable resources will increase prices. This is particularly true in supply-constrained markets. For Arizona utilities, it is possible that renewable energy developers may set energy prices as high as possible while still beating the marginal cost of competing energy supplies. This would increase the total renewable energy cost, but it is uncertain to what extent.

2.0 Introduction

Black & Veatch Corporation has prepared this study of renewable energy for the three largest utilities in Arizona: Arizona Public Service Company, Salt River Project, and Tucson Electric Power Company (APS/SRP/TEP). The purpose of this report is to assess the prospects for significant renewable energy development in Arizona. The scope of the study is limited to Arizona projects that would export power to the grid (that is, not distributed generation projects).

This study includes a review of the current status of renewable energy in Arizona, characterization of renewable power generation technologies, assessment of Arizona's renewable resources, and an assessment of key risk factors.

2.1 Background

In response to increasing public interest in clean energy sources, concerns about energy security, and the environmental impacts of fossil fuels, numerous states have encouraged development of renewable energy sources. Renewable energy standards have been a popular mechanism used by other states and countries to mandate a certain percentage of electricity be generated from renewable energy resources.

Electricity in Arizona is largely produced from traditional natural gas, coal, and nuclear resources. Hydroelectric contributes about 6 percent, while non-hydro renewable resources are currently very small (0.07 percent). To stimulate development of renewables, Arizona was one of the earlier states to adopt a renewable energy standard. Arizona enacted its original Environmental Portfolio Standard (EPS) in March of 2001. The EPS required that investor owned utilities provide 1.1 percent of their power from renewables by 2007.

In November 2006, the Arizona Corporation Commission adopted final rules to substantially increase Arizona's Renewable Energy Standard (RES) such that some utilities would be required to obtain 15 percent of their energy from renewable resources by 2025. Such a standard places Arizona among the most aggressive in the nation. In addition, Arizona is surrounded by other states in the Southwest (California, Nevada, and New Mexico) that also have strong renewable energy standards. The combined effect of these standards is to substantially increase the demand for renewable energy in the region.

2.2 Objective

The objective of this report is to assess the full potential of all Arizona renewable energy resources while accounting for the economic variables of developing those

resources. Large scale renewable energy development will be necessary to meet the renewable mandates set forth in the Southwest. Although Arizona is well known for its solar resources, solar is the most expensive renewable energy resource. By comparison, Arizona is thought by many to have relatively limited opportunities for lower cost renewables, including wind, biomass, geothermal and hydroelectric. This study assesses the relative potential of all resources and forecasts which are most likely to be developed over the next 20 years.

2.3 Approach

Black & Veatch has developed an objective methodology to assess renewable energy potential based on sound utility generation planning fundamentals and the specific challenges inherent to analyzing renewable energy generation technologies. This study was undertaken in two phases. This final report is a comprehensive account of both. An Interim Report covered Phase 1. It described the current status of renewable energy in Arizona, characterized renewable power generation technologies and the general potential of the different resources, and reviewed available financial incentives for renewable energy. The Interim Report (Section 3, 4 and 6 of this Final Report) reviewed a broad range of renewable energy technologies and concluded with recommendations for further study in Phase 2. Phase 2 of the project (the remainder of this Final Report) characterizes the most promising options in greater detail and identifies potential projects for possible implementation.

This study began with an assessment of renewable energy generation technologies to identify the most promising technologies for Arizona. The following technologies were initially identified as potentially promising:

- Wind
- Solar Thermal (trough)
- Solar Thermal (dish)
- Solar Photovoltaics
- Direct Biomass Combustion
- Cofired Biomass
- Anaerobic Digestion
- Landfill Gas
- Hydroelectric
- Geothermal

Following identification of the most promising technologies, a resource assessment was performed to quantify the near-term developable potential of the promising renewable resources. In some cases, the assessment included new primary

research and initial siting activities to collect renewable energy resource data. This information was used to determine the size of the resources, geographic distribution, and technical feasibility of utilization. An end result of this process was the identification of a list of over 100 hypothetical renewable energy projects that might be developed to meet demands for renewable energy.

Following the resource assessment, the total lifecycle costs were calculated for each renewable energy project. Costs included capital and operating costs, performance, transmission system interconnection, and financial incentives. Transmission costs, which can be significant, have not been included at this stage of the analysis. Projections were also made for future changes in technology cost and performance based on Black & Veatch's experience in the field. Resource estimates were combined with technology characteristics to develop a set of economic supply curves showing the renewable energy available (MWh) at different levelized costs ($/MWh). The supply curves for the individual renewable energy technologies were then combined to generate statewide renewable energy supply curves. The supply curves can be used to identify a hypothetical least-cost set of renewable energy projects through 2025.

Once the base model was established, it was used to test the model results against various key risk factors.

2.4 Report Organization

Following this Introduction, this report is organized into the following sections:

- **Section 3 – Renewable Energy Overview:** This section provides an overview of renewable energy including the historical development of renewables in the US followed by the status of renewable energy in Arizona.
- **Section 4 – Assessment of Renewable Energy Technology Options:** This section reviews the general characteristics and costs of renewable energy technology options for Arizona. The section concludes with a short list of technologies recommended for further study.
- **Section 5 – Renewable Resource Assessment:** This section summarizes the renewable energy resources of Arizona that are suitable for development in the near- to mid-term (next 20 years). Potential development prospects are identified, levelized generation costs are calculated, and a set of supply curves is developed.
- **Section 6 – Renewable Energy Financial Incentives:** This section describes the existing and proposed incentives that are available to new renewable energy facilities.

- **Section 7 – Renewable Energy Development Model:** This section summarizes the supply curve model. The model is described, assumptions are outlined, and key results are presented.
- **Section 8 – Assessment of Key Risk Factors:** Black & Veatch analyzed some of the risk factors of interest to utilities in Arizona to determine how sensitive the supply curve results would be to changing situations. These factors include changes in tax law, delayed technical advances, escalating construction costs, manufacturing/supply chain constraints, near term performance learning curve, and competition for limited resources.

3.0 Renewable Energy Overview

This section provides an overview of renewable energy including the historical development of renewables in the US followed by the status of renewable energy in Arizona.

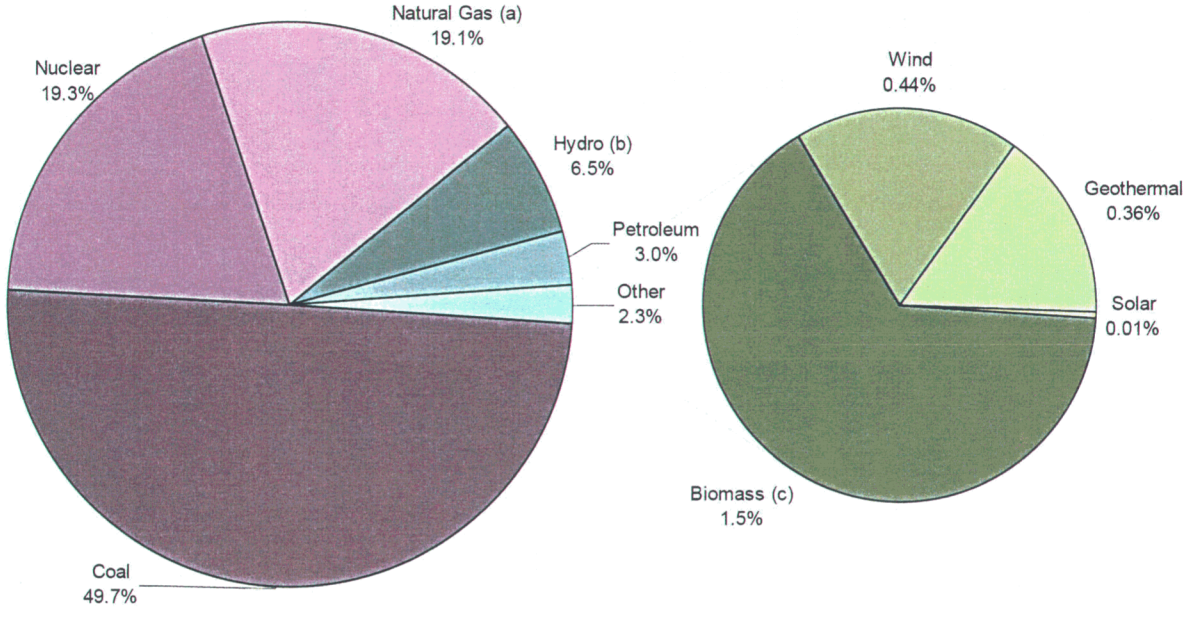
Renewable energy generation technologies are based on energy sources that are practically inexhaustible in that most are solar derivatives. Such technologies are often favored by the public over conventional fossil fuel technologies because of the perception that renewable technologies are more environmentally benign. Renewable energy options include wind, solar, biomass, biogas, geothermal, hydroelectric, and ocean energy. Table 3-1 shows the power conversion technologies that have been developed to harness these energy sources.

Table 3-1. Renewable Energy Conversion Technologies

Renewable Resource	Energy Conversion Technology
Solar	Photovoltaic Thermal electric (trough, dish, etc.) Thermal water heating Absorption chilling
Wind	Wind Turbines
Water	Hydroelectric Turbines Pumped Hydro Storage (also Compressed Air Storage)
Ocean	Wave Energy Devices Tidal/Current Energy Turbines Thermal Energy Conversion
Geothermal	Steam Turbines Direct Use Geothermal Heat Pumps
Biomass	Combustion (direct fired, cofiring with coal) Gasification / Pyrolysis
Biogas, Biodiesel, Ethanol	Engine generators Combustion turbines Microturbines Fuel cells

Renewable technologies have been developed to harvest energy from wind, solar radiation, biomass, water, and the earth's thermal energy. Although the potential resources are very large, non-hydro renewable energy currently only supplies about 2

percent of the electricity demand in the United States. Figure 3-1 is a summary of electricity generation for the United States in 2005, including a breakdown of the renewable energy portion of generation. The figure shows that renewable sources represent only a few percent of total electricity generation. The largest sources of renewable generation are hydroelectric followed by biomass, such as wood waste. Although increasing in popularity, other renewable energy sources, including wind and solar, make up much smaller portions of the total.



[a] Includes a small amount of other gases (propane, refinery gas, etc.)
[b] Includes pumped storage hydro
[c] Includes wood, waste-to-energy, landfill gas, agricultural byproducts, etc.

Figure 3-1. U.S. Electricity Generation by Source, 2005 (Source: EIA).

Recent natural disasters coupled with increased global demand and political instability led to sharp increases in oil and natural gas prices. Energy supply and security has become a topic of concern among policy makers and the public at large. In addition to their price volatility, fossil fuels emit pollutants and are often imported from other states or countries. Policy makers have historically looked to renewable energy to address these issues, and interest is resurging again.

3.1 Historical Development of Renewable Energy

Modern forms of non-hydro renewable energy technology have largely developed over the last thirty years. Industry growth has been uneven in response to abruptly shifting market forces, changing government policies, and evolving technology.

3.1.1 1978-1991: PURPA and Standard Offer Contracts

The modern era of renewable energy arose from the initial oil shortages of the 1970s. In 1978, the federal government passed the Public Utilities Regulatory Policy Act, which stimulated widespread development of renewable energy projects. Under PURPA, many biomass, wind, and geothermal plants came online and were allowed to sell excess power to the utility at an avoided cost or other negotiated rate. Some of these costs/rates, particularly in California, were tied to high forecasts of future fossil prices. The generous PURPA contracts combined with other financial incentives allowed California to lead the world in development of biomass, geothermal, wind and solar technologies. Ultimately, PURPA spurred the development of the independent power producer (IPP) industry. IPPs currently dominate ownership of renewable energy plants.

As shown in Figure 3-2 and Figure 3-3, growth of the renewable energy industry was faster during the 1980s than at any other time in recent history – with the possible exception of the current renewables "boom." During this period the predominant technologies implemented were biomass, waste to energy, and geothermal. In fact, up until 1999, biomass and waste accounted for approximately two-thirds of renewable generation capability installed in the US (nameplate basis). However, wind energy technology, which had matured in Europe, was to soon take over leadership.

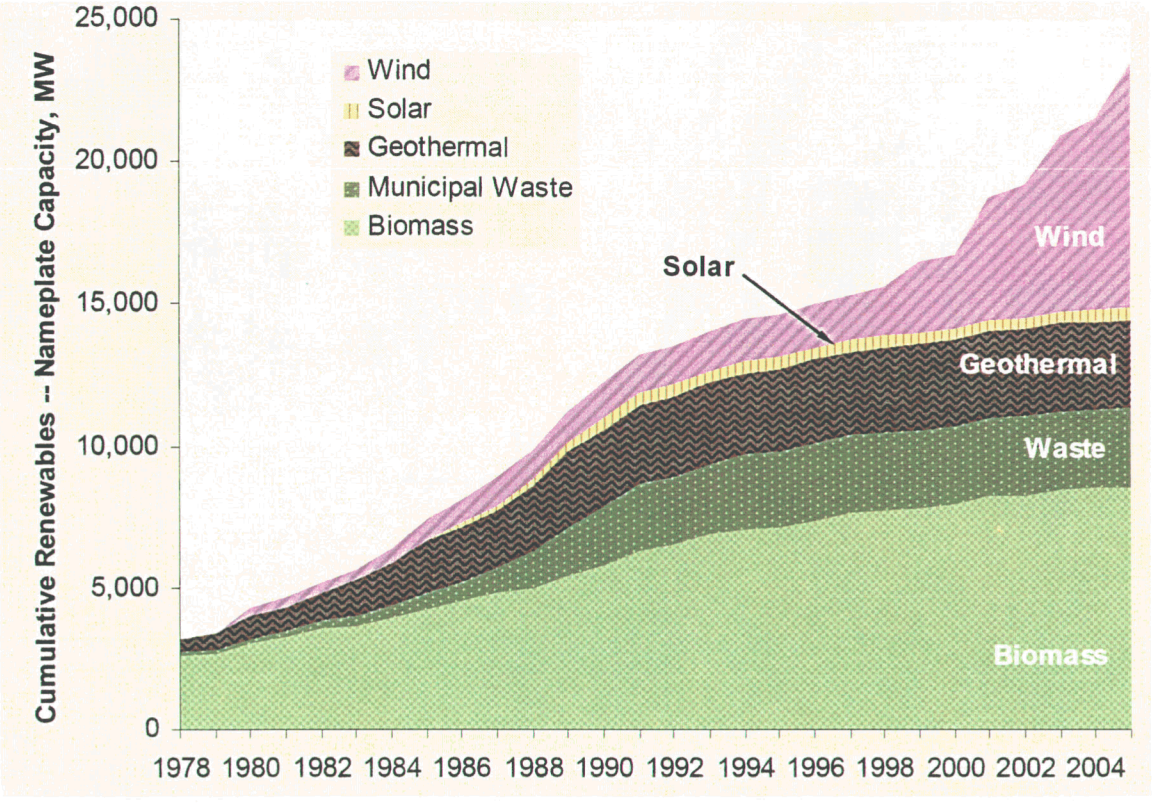


Figure 3-2. Cumulative Renewable Generation Capacity, MW (Data from GED[1]).

[1] Black & Veatch analysis of data from Global Energy Decisions' proprietary "Energy Velocity" database, May 2006.

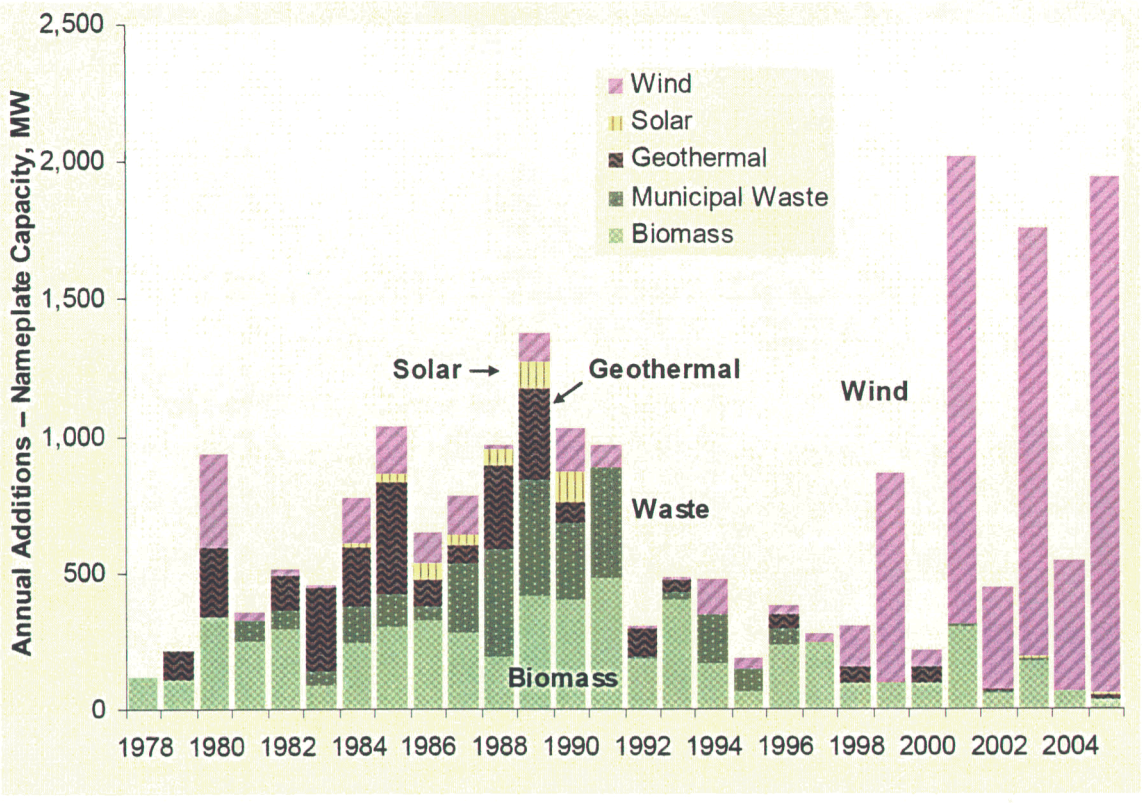


Figure 3-3. U.S. Annual Capacity Additions, MW (Data from GED).

3.1.2 1992-2004: The PTC and RPS Era

As the influence of PURPA waned with lower electricity costs in the 1990s, a new round of renewable energy development, mostly wind, was spurred by the Production Tax Credit (PTC) enacted in 1992. Despite the new incentive, development in the early 1990s was at a much slower pace than during the 1980s.

Near the latter half of the last decade, states began to implement Renewable Portfolio Standards (RPS) mandating that a certain percentage of electricity supply come from renewable sources. RPS programs accelerated the development of renewables (see Figure 3-2). To date, 22 states have implemented RPS policies mandating that a portion of power supplied to retail customers come from renewable energy sources. RPS goals vary greatly by state, as does the specific consideration for biomass energy. Notable state RPS programs include California (20 percent renewables by 2010), New York (24 percent by 2013), Massachusetts (4 percent by 2009), and Pennsylvania (18 percent by 2020). Figure 3-4 shows the various state renewable portfolio standards.

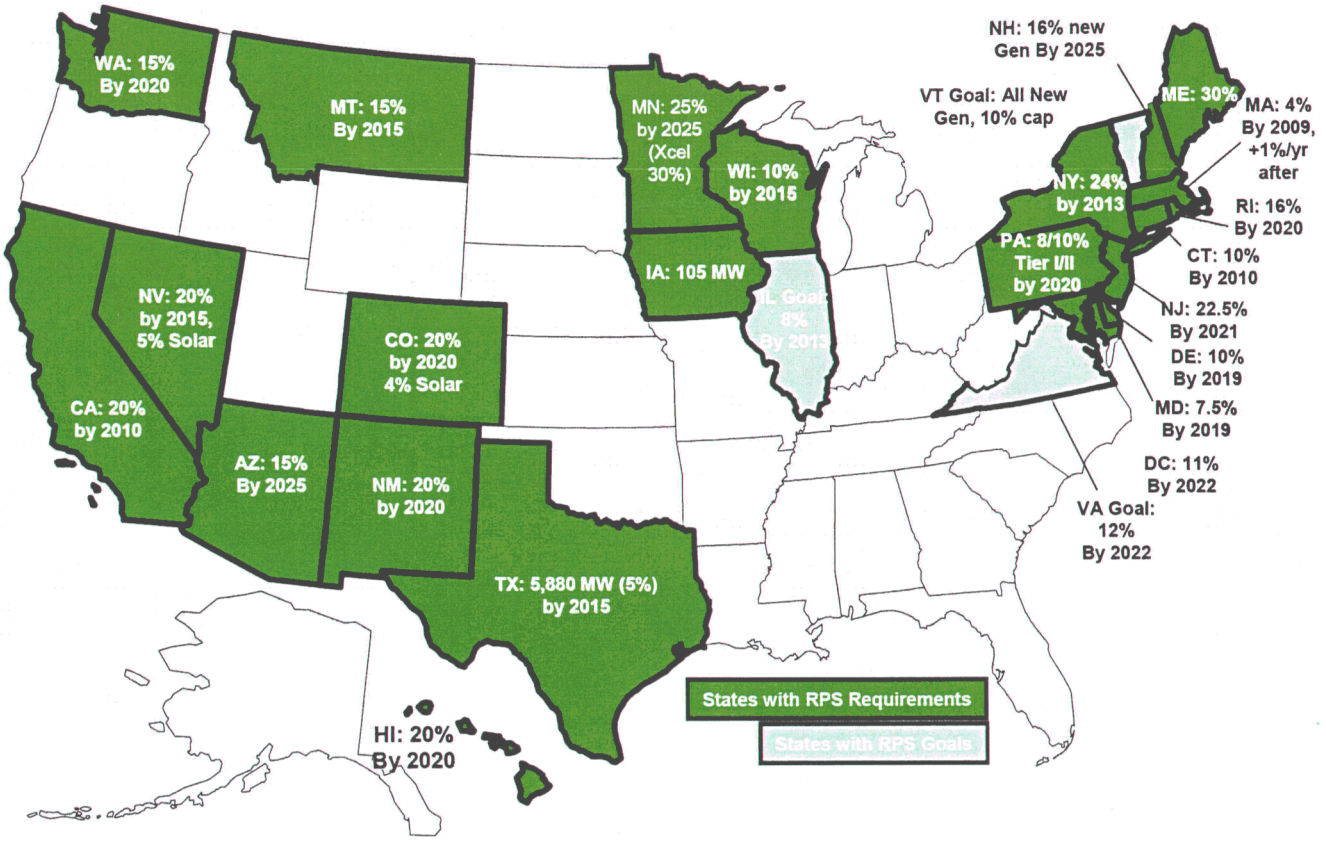


Figure 3-4. State Renewable Portfolio Standards (as of May 2007).

Based on developments in Europe, wind energy technology had also greatly improved from the designs of the 1980s. Wind benefited greatly from the combination of preferential PTC treatment, RPS programs, and improved technology. Since 1999, about 90 percent of all new renewable energy development has been wind (nameplate capacity basis). Prior to 1999, wind comprised about 10 percent of total renewables additions.

3.1.3 2005: Energy Policy Act

In the past year, changes in federal tax policy and a surge in demand for renewable energy have caused a new era in renewable energy development.

Federal involvement in the energy industry has traditionally been limited due to strong state regulation; however, the federal government is increasing its role, especially with respect to renewable energy. Recently, the government has significantly expanded tax and other incentives for renewable energy developers through the Energy Policy Act of 2005 (EPAct). The federal government has traditionally funded renewable research and development through the Department of Energy, and President Bush's recent state of the Union address called for more investment and spending on renewables.

The Energy Policy Act of 2005 included significant changes to renewable energy incentives, particularly related to the tax code. The changes in the tax code from the EPAct are significant: the PTC was extended to many new technologies and the Investment Tax Credit (ITC) was increased from 10 percent to 30 percent for solar.

The PTC provides a tax credit of 1.5 cents per kWh of eligible renewable generation for the first ten years of the project's life. The full credit is adjusted for inflation, and is worth $20/MWh as of 2007. Some resources receive half the PTC amount, currently $10/MWh. The PTC has gone through an "up and down" cycle of expiration and renewal over the past few years (see Figure 3-5). Originally enacted as part of the Energy Policy Act of 1992, the credit has expired numerous times before being renewed by Congress. The gaps in the PTC record have caused the wind market to cycle through boom and bust periods of development. Prior to October 2004, the PTC applied only to the production of electricity from wind and "closed-loop" biomass (and poultry waste for a brief period). Wind is the only technology that benefited significantly from the PTC during this timeframe.

Additional information on the ITC, PTC, and other renewable energy incentives is provided in Section 6 of this report.

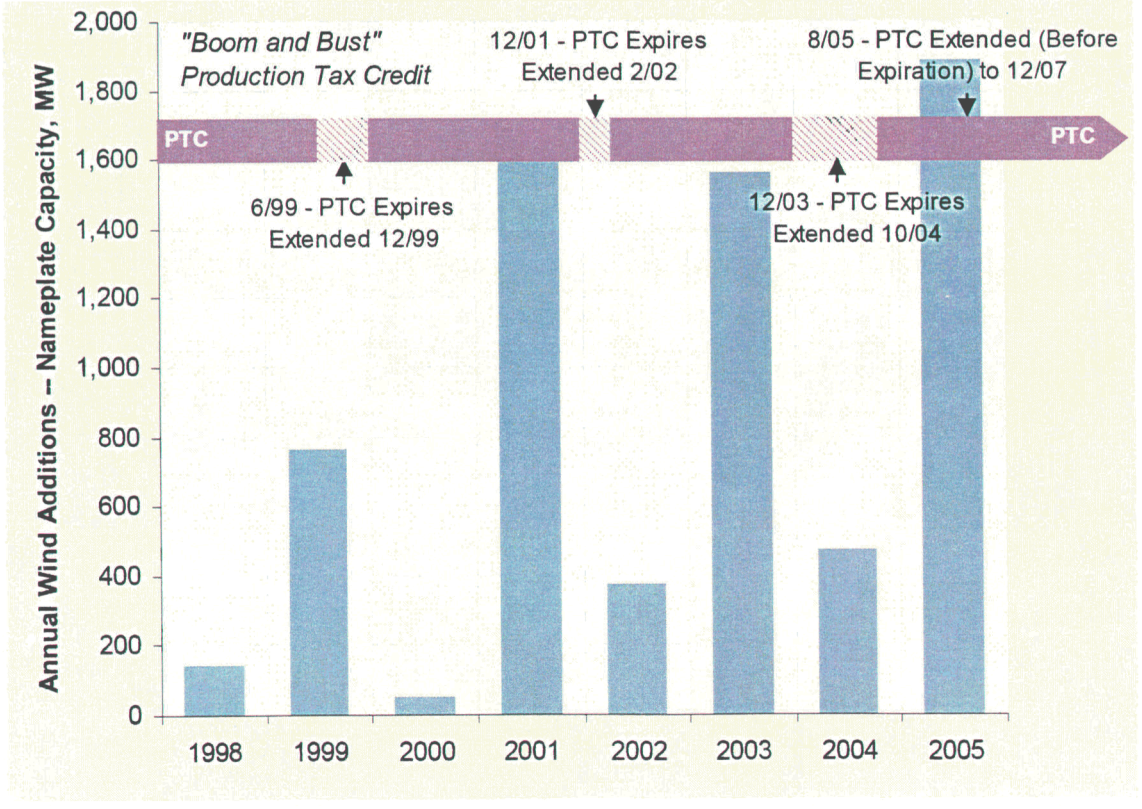


Figure 3-5. Production Tax Credit Cycle and Impact on Wind Installations (Data from GED).

The PTC again expired at the end of 2003 and was not renewed until October 4, 2004,[2] as part of the Working Families Tax Relief Act of 2004 (H.R. 1308). This Act extended the credit through December 31, 2005 and expanded it to include additional resources. The timing of this extension did little to spur new development of non-wind projects. The Energy Policy Act of 2005 modified the PTC and extended it through December 31, 2007. Another one year extension (Through December 31, 2008) was recently granted through the Tax Relief and Health Care Act of 2006. Due to the expanded timeframe and eligibility, the latest revisions have accelerated development of many different types of renewable energy. The PTC is now available for all the major renewable resources, with some receiving the "full" PTC and others the "half" credit (see Section 6 for details).

In the past, the PTC has been successful in encouraging development of wind energy but not other technologies. Closed-loop biomass (including poultry waste for a short time) was the only other technology eligible prior to 2004. Biomass was not developed due to restrictive definitions placed on fuel eligibility. However, the recent expansions and extensions of the PTC are now stimulating widespread development of all types of renewable energy technologies.

3.2 Renewable Energy Status in Arizona

Figure 3-6 shows the electricity generation data for Arizona in 2005. Current energy sources are comprised largely of traditional natural gas, coal, and nuclear resources. Hydroelectric contributes about 6 percent, while non-hydro renewable resources are currently very small (0.07 percent).

Figure 3-7 shows the historical generation data for Arizona from 1990 to 2005. Reviewing this information shows two key facts: (1) electricity generation in Arizona is increasing rapidly (over 60 percent growth from 1990 to 2005) and (2) the proportion of natural gas in Arizona's electricity supply has increased rapidly, from about 3 percent in 1997, to over 28 percent in 2005.

[2] Though when it was renewed, it applied retroactively so any project that went into operation received the PTC.

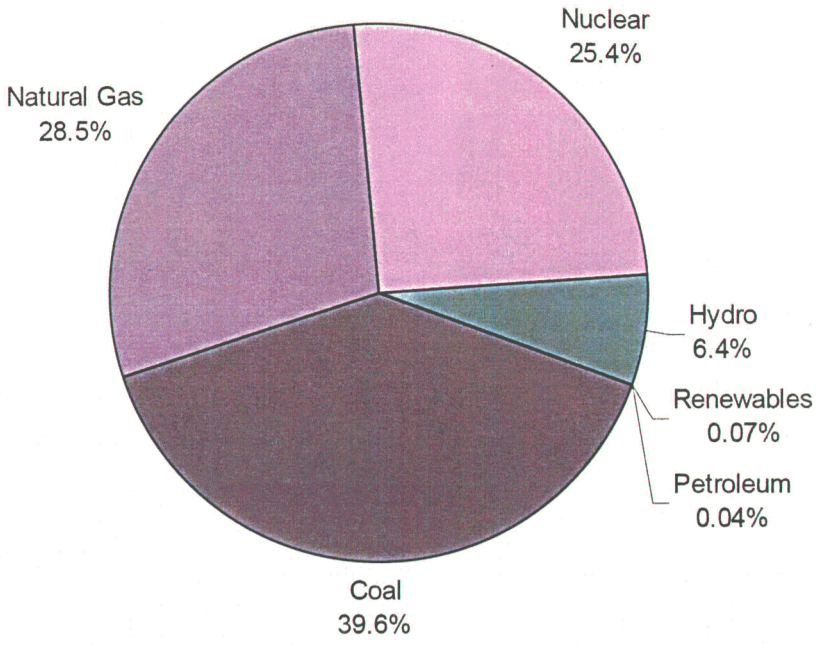


Figure 3-6. Electricity Generation in Arizona by Source, 2005 (Source: EIA).

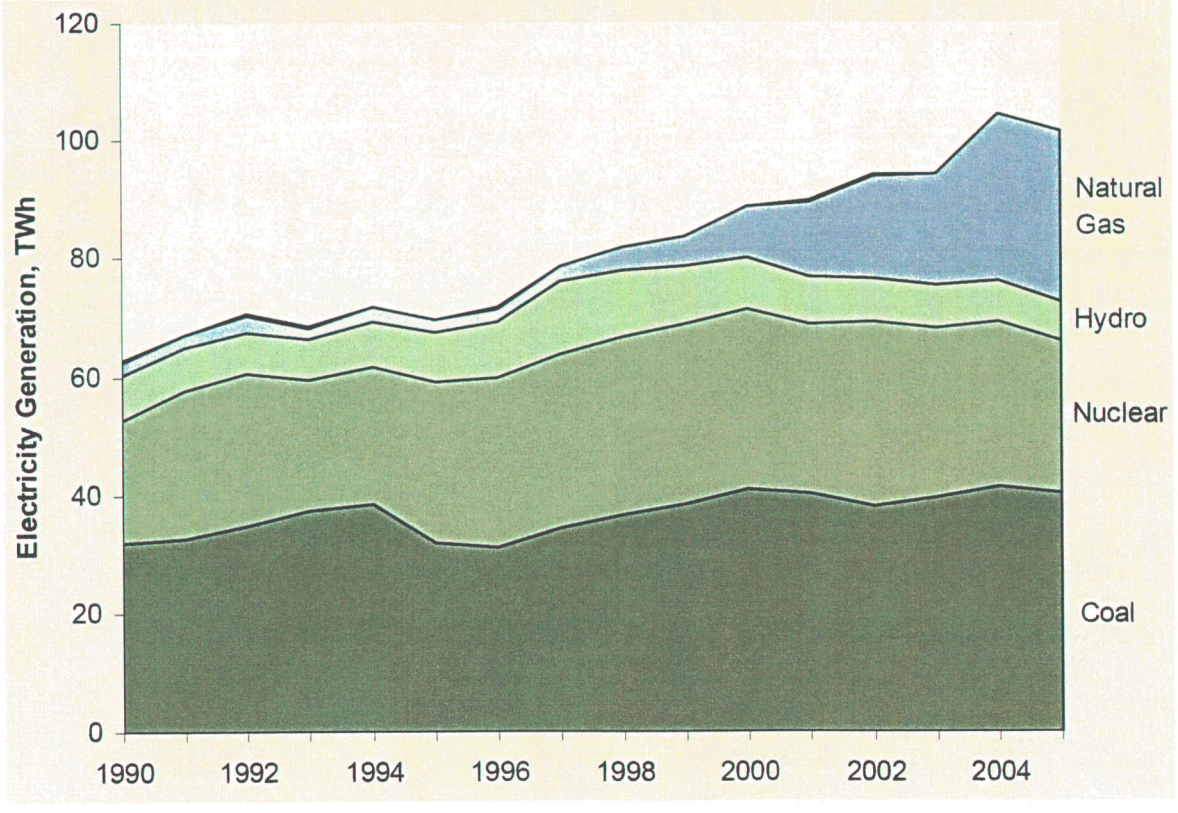


Figure 3-7. Electricity Generation in Arizona 1990-2005 (Source: EIA).

3.2.1 Existing and Announced Renewable Energy Projects

Although renewables currently only comprise a small fraction of the electricity in Arizona, this will likely change in the near future. Table 3-2 shows existing and announced renewable energy projects (excluding large hydroelectric projects). There are about 24 MW of renewable energy projects currently operating in Arizona, including 12 MW of biomass, 0.8 MW hydroelectric, and the remainder solar (11 MW). In addition, there are over 500 MW of projects in various stages of development throughout the state. The vast majority of these projects are based on wind resources, although there is a 20 MW biomass project under construction in eastern Arizona.

3.2.2 Arizona Renewable Energy Standard[3]

Arizona was one of the earlier states to adopt a renewable portfolio standard mandating that utilities source a portion of their energy from renewable energy sources. Arizona enacted its original Environmental Portfolio Standard (EPS) in March of 2001. The EPS required that investor owned utilities provide 1.1 percent of their power from renewables by 2007. The standard began with a requirement of 0.2 percent in 2002, increasing by 0.2 percent annually. Solar electric was to make up 50 percent of the standard in 2001, increasing to 60 percent for 2004 through 2012. Although the EPS was largely responsible for several of the projects identified in the previous section, many felt that the mandate needed to be revised.

After much deliberation, on November 14th, 2006 the Arizona Corporation Commission (ACC) adopted a new Renewable Energy Standard (RES) that requires utilities to meet higher targets for renewable energy sources. The requirement begins at 1.25 percent renewables in 2006 and stair-steps up to 15 percent renewable energy production by 2025 (see Table 3-3). A certain portion of the RES must be met with distributed renewable energy generation sources, such as small solar and wind. This is also known as a set-aside. The set-asides begin at 5 percent of the standard in 2007 and rise to 30 percent of the renewable standard percentage in 2012 and thereafter. At the full 15 percent standard in 2025, the set-aside would be 30 percent of total renewable requirement of 15 percent, or 4.5 percent of total electricity generation (10.5 is non-distributed resources). One half of the distributed resource requirement must come from residential installations, the other half must be from non-residential, non-utility applications. The purpose of the set-aside is to encourage renewable energy production from distributed sources such as small solar or wind equipment located on or near ratepayer property instead of larger, centralized renewable power plants.

[3] Source: ACC Decision No. 69127 (AAC R14-2-1801 et seq.), available at: http://www.cc.state.az.us/utility/electric/res.pdf, accessed January 2007.

Table 3-2. Renewable Energy Projects in Arizona.

Technology / Project Name	Owner	MW	COD
Biomass			
Los Reales Landfill Cofiring	TEP	4	1999
Tri Cities Landfill	SRP	5	2001
Eagar Biomass	Western Renewable Energy	3.7 to 4.7*	2008*
Skunk Creek Landfill	Ameresco	3	2008**
27th Ave. Landfill	Cambrian	3	2009**
Snowflake White Mountain Power	NZLegacy Energy LLC	24	2008**
Hydroelectric			
Arizona Falls	SRP	0.8	2003
Solar			
Santan Solar	SRP	0.097	1998
Santan Solar	SRP	0.097	1999
Star	APS	0.2	2000
Flagstaff	APS	0.08	1997
Ocotillo	APS	0.1	1998
Tempe	APS	0.18	1998
Gilbert (AZ)	APS	0.12	1999
Municipal Rooftops	APS	0.1	1999
Ocotillo	APS	0.1	1999
Scottsdale	APS	0.03	1999
Microelectronics Rooftop	APS	0.02	2000
Glendale	APS	0.2	2001
Prescott ERAU Solar	APS	0.2	2001
Agua Fria	SRP	0.2	2001
Yucca	APS	0.1	2001
Prescott Airport Solar Plant	APS	3.4	2002-06
Springerville Generating Station	TEP	5.1	2002-03
Saguaro	APS	1	2005
Wind* **			
Steel Park Wind	Western Wind Energy	15	2007**
Sunshine Wind Energy Park	Foresight Energy Co	60	2007**
Sunset Mountains Wind	Hopi Tribe (The)	100	2007**
Dry Lake Wind	PPM Energy Inc	99	2008**
Steel Park Wind	Western Wind Energy	100	2008**
Steel Park Wind	Western Wind Energy	100	2009**
Total Existing		**24**	
Total Proposed		**504**	

Source: Utilities, GED

Notes:

* Generator is 4.7MW, boiler damaged, was not capable of powering the generator at 4.7MW. May replace with larger boiler.

** Planned / Proposed Projects (COD subject to change).

*** None of the wind projects are currently under contract to sell power.

Table 3-3. Arizona Renewable Energy Standard Requirements.

Year	RES Total Requirement	Distributed Share of RES	Distributed Share of Total	Non-Distributed Share of Total
2006	1.25%	0.0%	0.0%	1.3%
2007	1.50%	5.0%	0.1%	1.4%
2008	1.75%	10.0%	0.2%	1.6%
2009	2.0%	15.0%	0.3%	1.7%
2010	2.5%	20.0%	0.5%	2.0%
2011	3.0%	25.0%	0.8%	2.3%
2012	3.5%	30.0%	1.1%	2.5%
2013	4.0%	30.0%	1.2%	2.8%
2014	4.5%	30.0%	1.4%	3.2%
2015	5.0%	30.0%	1.5%	3.5%
2016	6.0%	30.0%	1.8%	4.2%
2017	7.0%	30.0%	2.1%	4.9%
2018	8.0%	30.0%	2.4%	5.6%
2019	9.0%	30.0%	2.7%	6.3%
2020	10.0%	30.0%	3.0%	7.0%
2021	11.0%	30.0%	3.3%	7.7%
2022	12.0%	30.0%	3.6%	8.4%
2023	13.0%	30.0%	3.9%	9.1%
2024	14.0%	30.0%	4.2%	9.8%
2025	15.0%	30.0%	4.5%	10.5%

Eligible renewable resources include:

- Biogas electricity generator
- Biomass electricity generator
- Hydroelectric
  - Existing hydroelectric upgrades
  - Existing hydroelectric used to "firm" other eligible resources
  - New small hydroelectric (10 MW or less)
- Fuel cells that use only renewable fuels
- Geothermal generator
- Landfill gas generator
- Solar electricity resources

- Wind generator
- Hybrid wind and solar

In addition, various distributed generation technologies qualify for the distributed resource set-aside. These include solar daylighting, solar pool water heaters, solar HVAC, combined heat and power (CHP) and other on-site technologies. However, these technologies were not investigated in this report, since the focus is on the non-distributed share of the RES.

It should be noted that only the regulated utilities are covered by the ruling. This includes investor owned utilities (Arizona Public Service and Tucson Electric Power) and cooperatives. Salt River Project is not required to comply with the RES; however, SRP has adopted its own renewable energy goals. In 2004, SRP established a voluntary goal of achieving 15 percent of its energy from renewable energy and energy efficiency by 2025. Currently SRP has obtained 5 percent of its 15 percent goal (4 percent renewables, and 1 percent energy efficiency). The majority of the renewables share is from large hydroelectric.

4.0 Assessment of Renewable Energy Technology Options

This section reviews the general characteristics and costs of renewable energy technology options for Arizona.

The first step in the development of generation alternatives involves the identification of generic generation technologies whose technical and cost characteristics cause them to be worthwhile candidates for inclusion in portfolio plans. The objective of this section is to characterize the various renewable energy technologies suitable for application in Arizona. The information contained in this section will be used to screen technologies for further investigation later in the project.

4.1 Introduction

Technologies to harness renewable energy are diverse and include wind, solar, biomass, biogas, geothermal, hydroelectric, and ocean energy. Steady advances in equipment and operating experience spurred by government incentives have lead to many mature renewable technologies. The technical feasibility and cost of energy from nearly every form of renewable energy have improved since the early 1980s. However, most renewable energy technologies struggle to compete economically with conventional fossil fuel technologies, and in most countries the renewable fraction of total electricity generation remains small. This is true despite a huge resource base that has potential to provide many multiples of current electricity demand. Nevertheless, the field is rapidly expanding from niche markets to making meaningful contributions to the world's electricity supply.

4.1.1 Technologies Evaluated

This section provides an overview of the following renewable energy options:

1. Solid biomass
   - 1.1 Direct fired
   - 1.2 Cofiring
   - 1.3 Biomass gasification and IGCC
   - 1.4 Plasma arc gasification
2. Biogas
   - 2.1 Anaerobic digestion
   - 2.2 Landfill gas
3. Solar
   - 3.1 Solar photovoltaic
   - 3.2 Solar thermal electric

4. Hydroelectric
5. Wind
6. Geothermal
7. Fuel cells using renewable fuels

In addition, although it is not a renewable energy technology, compressed air energy storage can potentially help enable development of intermittent renewable energy sources, such as wind. The technology is briefly introduced at the end of this chapter.

4.1.2 General Approach to Characterization

Generally, each technology is described with respect to its principles of operation, applications, resource characteristics, cost and performance, environmental impacts, and a high level assessment (non-quantitative) of its development prospects for Arizona. The alternatives have been presented with a typical range for performance and cost, and the generic data provided should not be considered definitive estimates. A more detailed treatment of cost for promising technologies (including supply curves) is provided later in this report. The performance and costs are based on a representative size and installation in Arizona. Estimates are based on Black & Veatch project experience, vendor inquiries, and a literature review. In addition, an overall levelized cost range for the general technology type is provided. This levelized cost of energy accounts for capital cost (including direct and indirect costs), fuel, operations, maintenance, and other costs over the typical life expectancy of the unit. (See further description below.) A range of levelized costs is typically provided. In such cases, the low end of the levelized cost is based on the higher capacity factors and the lower capital and O&M costs. This approach is simple from a calculation perspective; however it must be noted that the low end of the costs represents and ideal "best case scenario", which is likely difficult to achieve in practice. The high end of the levelized cost is based on the lower capacity factors and the higher capital and O&M costs. Applicable financial incentives have been included in the levelized cost calculations, as indicated for each technology. These incentives are generally described in Section 6.

It should be noted that the characteristics provided in this section are general, and have been developed for the purposes of providing high-level screening information to identify the most promising technologies. Section 5 of this report provides estimates which are project-specific. These estimates are more accurate and representative of actual projects that could potentially be developed.

Although a few of the technologies are not commercially viable at this time, cost and performance data were assembled as available to provide a complete screening-level resource planning evaluation.

4.1.3 Levelized Cost of Energy Calculation Example

A levelized busbar cost model was constructed to evaluate the cost of each generating option. A levelized busbar analysis converts both fixed and variable costs to a single, all-inclusive cost per kilowatt-hour, assuming a given capacity factor[4].

Table 4-1 illustrates the calculation of a busbar cost at a 90 percent capacity factor for a 35 MW biomass plant based on the capital and operating characteristics developed in this section and the fixed charge rate assumptions described in Section 7. The columns of the table present the year-by-year costs in four categories (capital, fixed O&M, variable O&M, fuel) based on the input assumptions shown at the top of the table. Any applicable tax credits are also accounted for on a pre-tax basis. The total annual cost is determined by applying the levelized fixed charge rate to the initial capital cost. The fixed O&M is equal to the initial cost plus escalation; variable O&M is based on the escalated cost and unit production, fuel cost is based on the escalated fuel cost, output and the net plant heat rate. Busbar costs are equal to the total cost divided by output, and the present worth cost is based on a 10.1 percent discount rate. At a capacity factor of 90 percent, the table indicates that the busbar cost of the unit is $66/MWh over a 20 year period. This is a levelization of a 20 year nominal cost and has the following interpretation: if the busbar costs of the facility were $66/MWh every year of the 2007-2026 period, the present value of these costs would be the same as the present value of the variable, year-by-year costs listed in the "Busbar Cost" column of Table 4-1.

[4] Capacity factor is a significant assumption in the busbar cost calculation as it is the basis for determining the number of kilowatt hours a generating unit will produce, and the unit's all inclusive cost will be spread over, in a given time period.

Table 4-1. Biomass Levelized Cost of Energy Calculation.

Biomass Direct Combustion

Low Cost Case

Plant Input Data		Economic Input Data	Rate	Escalation
Capital Cost ($1,000)	96,250	First Year Fixed O&M ($1,000)	2,905.00	2.5%
Total Net Capacity (MW)	35.00	First Year Variable O&M ($1,000)	3,118.12	2.5%
Capacity Factor	90%	Fuel Rate ($/MBtu)	1.00	2.5%
Full Load Heat Rate, Btu/kWh (HHV)	13,500.00	Tax Credit ($/MWh)	16.56	2.5%
Debt Term	15			
Project Life	20			
		Present Worth Discount Rate	10.1%	
Hours per Year	8,760	Levelized Fixed Charge Rate	12.00%	

Year	Annual Capital Cost ($1,000)	Fixed O&M ($1,000)	Variable O&M ($1,000)	Tax Credit ($1,000)	Fuel Rate ($/MBtu)	Fuel Cost ($1,000)	Total Cost ($1,000)	PW Total Cost ($1,000)	Busbar Cost ($/MWh)	PW Cost ($/MWh)	Avoided Capacity Cost ($/kW)	Avoided Energy Cost ($/MWh)
2007	11,550	2,905	3,118	(4,570)	1.00	3,725	16,729	15,194	60.62	55.06	0.00	111.89
2008	11,550	2,978	3,196	(4,684)	1.03	3,818	16,858	13,907	61.09	50.40	0.00	121.46
2009	11,550	3,052	3,276	(4,801)	1.05	3,914	16,991	12,731	61.57	46.14	0.00	131.10
2010	11,550	3,128	3,358	(4,921)	1.08	4,012	17,127	11,655	62.07	42.24	0.00	133.40
2011	11,550	3,207	3,442	(5,044)	1.10	4,112	17,266	10,672	62.57	38.68	0.00	139.93
2012	11,550	3,287	3,528	(5,170)	1.13	4,215	17,409	9,774	63.09	35.42	160.34	146.48
2013	11,550	3,369	3,616	(5,299)	1.16	4,320	17,556	8,952	63.62	32.44	162.00	155.09
2014	11,550	3,453	3,706	(5,432)	1.19	4,428	17,706	8,200	64.17	29.72	160.15	159.54
2015	11,550	3,539	3,799	(5,568)	1.22	4,539	17,860	7,513	64.72	27.23	192.08	155.25
2016	11,550	3,628	3,894	(5,707)	1.25	4,652	18,018	6,884	65.30	24.95	192.80	164.57
2017	11,550	3,719	3,991		1.28	4,769	24,029	8,338	87.08	30.22	192.35	168.47
2018	11,550	3,812	4,091		1.31	4,888	24,341	7,672	88.21	27.80	183.14	166.80
2019	11,550	3,907	4,194		1.34	5,010	24,660	7,059	89.37	25.58	203.74	163.22
2020	11,550	4,005	4,298		1.38	5,135	24,988	6,497	90.56	23.54	200.11	168.86
2021	11,550	4,105	4,406		1.41	5,264	25,324	5,980	91.77	21.67	196.32	159.73
2022	-	4,207	4,516		1.45	5,395	14,118	3,028	51.16	10.97	214.88	164.41
2023	-	4,312	4,629		1.48	5,530	14,471	2,819	52.44	10.22	202.03	166.83
2024	-	4,420	4,745		1.52	5,668	14,833	2,625	53.76	9.51	206.07	170.16
2025	-	4,531	4,863		1.56	5,810	15,204	2,443	55.10	8.85	210.19	173.57
2026	-	4,644	4,985		1.60	5,955	15,584	2,275	56.48	8.24	214.40	177.04
2027	-	-	-		-	-	-	-	0.00	0.00	0.00	0.00
2028	-	-	-		-	-	-	-	0.00	0.00	0.00	0.00
2029	-	-	-		-	-	-	-	0.00	0.00	0.00	0.00
2030	-	-	-		-	-	-	-	0.00	0.00	0.00	0.00
2031	-	-	-		-	-	-	-	0.00	0.00	0.00	0.00
2032	-	-	-		-	-	-	-	0.00	0.00	0.00	0.00
2033	-	-	-		-	-	-	-	0.00	0.00	0.00	0.00
2034	-	-	-		-	-	-	-	0.00	0.00	0.00	0.00
2035	-	-	-		-	-	-	-	0.00	0.00	0.00	0.00
2036	-	-	-		-	-	-	-	0.00	0.00	0.00	0.00
2037	-	-	-		-	-	-	-	0.00	0.00	0.00	0.00
2038	-	-	-		-	-	-	-	0.00	0.00	0.00	0.00
2039	-	-	-		-	-	-	-	0.00	0.00	0.00	0.00
2040	-	-	-		-	-	-	-	0.00	0.00	0.00	0.00
2041	-	-	-		-	-	-	-	0.00	0.00	0.00	0.00
2042	-	-	-		-	-	-	-	0.00	0.00	0.00	0.00
2043	-	-	-		-	-	-	-	0.00	0.00	0.00	0.00
2044	-	-	-		-	-	-	-	0.00	0.00	0.00	0.00
2045	-	-	-		-	-	-	-	0.00	0.00	0.00	0.00
2046	-	-	-		-	-	-	-	0.00	0.00	0.00	0.00
2047	-	-	-		-	-	-	-	0.00	0.00	0.00	0.00
2048	-	-	-		-	-	-	-	0.00	0.00	0.00	0.00
2049	-	-	-		-	-	-	-	0.00	0.00	0.00	0.00
2050	-	-	-		-	-	-	-	0.00	0.00	0.00	0.00
2051	-	-	-		-	-	-	-	0.00	0.00	0.00	0.00
2052	-	-	-		-	-	-	-	0.00	0.00	0.00	0.00
2053	-	-	-		-	-	-	-	0.00	0.00	0.00	0.00
2054	-	-	-		-	-	-	-	0.00	0.00	0.00	0.00
2055	-	-	-		-	-	-	-	0.00	0.00	0.00	0.00
2056	-	-	-		-	-	-	-	0.00	0.00	0.00	0.00

Levelized Bus-bar Cost, $/MWh	66.09
Net Levelized Cost ($1,000)	18,238.23

Calculating the levelized cost of energy allows various technologies to be compared on an economic basis. However, it is important to note that busbar costs may not always be comparable between all options. For example, it is not appropriate to directly compare the levelized cost of an intermittent wind plant with dispatchable output from a peaking plant. This is because the economic value of the peaking plant is higher

than the time variant output from the wind plant. Additionally, transmission costs have not been included in the generalized levelized cost of energy calculations and these should be considered when comparing specific projects against one another.

4.2 Solid Biomass

Biomass is any material of recent biological origin; the most common form is wood. Electricity generation from biomass is the second most prolific source of renewable electric generation after hydroelectric power. Solid biomass power generation options include direct-fired biomass, biomass gasification, and cofired biomass, as described in the following subsections. This section concludes with a summary of development prospects for biomass in Arizona.

4.2.1 Direct-Fired Biomass

According to the US Department of Energy, there is about 35,000 MW of installed biomass combustion capacity worldwide. Combined heat and power applications in the pulp and paper industry comprise the majority of this capacity (Figure 4-1).

Figure 4-1. 35 MW Biomass Combustion Plant.

Operating Principles

Direct biomass combustion power plants in operation today use the same steam Rankine cycle that was introduced commercially 100 years ago. In many respects, biomass power plants are similar to coal plants. When burning biomass, pressurized steam is produced in a boiler and then expanded through a turbine to produce electricity. Prior to its combustion in the boiler, the biomass fuel may require processing to improve the physical and chemical properties of the feedstock. Furnaces used in biomass combustion include spreader stoker fired, suspension fired, fluidized bed, cyclone, and pile burners. Advanced technologies, such as integrated biomass gasification combined cycle (IGCC), Plasma Gasification and biomass pyrolysis, are currently under development.

Applications

Although wood is the most common biomass fuel, other biomass fuels include agricultural residues such as bagasse (sugar cane residues), dried manure and sewage sludge, black liquor from pulp mills, and dedicated fuel crops such as fast growing grasses and eucalyptus.

Biomass plants usually have a capacity of less than 50 MW because of the dispersed nature of the feedstock and the large quantities of fuel required. As a result of the smaller scale of the plants and lower heating values of the fuels, biomass plants are commonly less efficient than modern fossil fuel plants. In addition to being less efficient, biomass is generally more expensive than conventional fossil fuels on a $/MBtu basis because of added transportation costs. These factors usually limit the use of direct-fired biomass technology to inexpensive or waste biomass sources.

Resource Availability

To be economically feasible, dedicated biomass plants are located either at the source of a fuel supply (such as at a sawmill) or within 50 miles of numerous suppliers (up to 200 miles for a very high quantity, low cost supplier). Wood and wood waste are the primary biomass resources and are typically concentrated in areas of high forest-product industry activity. In rural areas, agricultural production can often yield significant fuel resources that can be collected and burned in biomass plants. These agricultural resources include bagasse, corn stover, rice hulls, wheat straw, and other residues. Energy crops, such as switchgrass and short rotation woody crops, have also been identified as potential biomass sources. In urban areas, biomass is typically composed of wood wastes such as construction debris, pallets, yard and tree trimmings, and railroad ties. Locally grown and collected biomass fuels are relatively labor intensive

and can provide substantial employment benefits to rural economies. In general, the availability of sufficient quantities of biomass is less of a feasibility concern than the high costs associated with transportation and delivery of the fuel.

Based on recent biomass resource assessments that Black & Veatch is familiar with, the expected cost of clean wood residues can vary as much as 100 percent depending on the type of residue, quantity, and hauling distance.

Cost and Performance Characteristics

Table 4-2 presents the typical characteristics of a 35 MW stoker boiler biomass plant with Rankine cycle using wood as fuel. Two fuel costs scenarios were evaluated: (1) a relatively lower cost ($1.00/MBtu) scenario which would be based primarily on urban wood waste sources in the major metropolitan areas, and (2) a moderate cost ($2.50/MBtu) scenario which would be more representative of a project using forest thinnings and forestry residues. Actual fuel cost could vary significantly from the values characterized here based on local supply and demand, and transportation distance. For example, Black & Veatch has previously estimated costs for biomass resources at greater than $3/MBtu in some parts of Arizona. In this case, transport distances were up to 200 miles. (Additional discussion is provided in Section 5.) Another possible biomass fuel is dedicated energy crops, which are grown specifically to provide feedstock for biomass plants. However, experience with energy crops is very limited in Arizona; further, costs for these fuels would likely approach $4.00/MBtu or greater. For these reasons, electricity costs for energy crops are not provided.

Table 4-2. Direct-Fired Biomass Combustion Technology Characteristics.

Performance	
Typical Duty Cycle	Baseload
Net Plant Capacity (MW)	35
Net Plant Heat Rate (HHV, Btu/kWh)	13,500
Capacity Factor (percent)	70 to 90
Economics (2007$)	
Total Project Cost ($/kW)	2,750 to 3,500
Fixed O&M ($/kW-yr)	83
Variable O&M ($/MWh)	11.3
Levelized Cost, $1.00/MBtu ($/MWh)	66 to 94
Levelized Cost, $2.50/MBtu ($/MWh)	90 to 118
Applicable Incentives	Open loop: $10/MWh PTC, 5-yr MACRS Close loop: $20/MWh PTC, 5-yr MACRS
Technology Status	
Commercial Status	Commercial
Installed US Capacity (MW)	7,000

Environmental Impacts

Biomass power projects must maintain a careful balance to ensure long-term sustainability with minimal environmental impact. Most biomass projects target utilization of biomass waste material for energy production, saving valuable landfill space. Biomass projects that burn forestry or agricultural products must ensure that fuel harvesting and collection practices are both sustainable and do not adversely affect the environment. On the positive side, biomass projects that collect thin forests to reduce the risk of forest fires are increasingly seen as a way to restore a positive balance to forest ecosystems while avoiding catastrophic and polluting uncontrolled forest fires.

Unlike fossil fuels, biomass is viewed as a carbon-neutral power generation fuel. While carbon dioxide (CO_2) is emitted during biomass combustion, a nearly equal amount of carbon dioxide is absorbed from the atmosphere during the biomass growth phase. Further, biomass fuels contain little sulfur compared to coal and therefore produce less sulfur dioxide (SO_2). Finally, unlike coal, biomass fuels typically contain only trace amounts of toxic metals, such as cadmium and lead. However, biomass combustion still must include technologies to control emissions of nitrogen oxides (NO_x), particulate matter (PM), and carbon monoxide (CO) to maintain Best Available Control Technology (BACT) standards.

Arizona Biomass Combustion Outlook

The outlook for biomass combustion technologies is provided in Section 4.2.5 Biomass Technologies Development Prospects.

4.2.2 Biomass Gasification and IGCC

Biomass gasification is an emerging technology that converts solid biomass into a gaseous fuel which can then be combusted or otherwise utilized. There are numerous uses for the gas and many different gasifier technologies. Integrated gasification combined cycle (IGCC) is a developing application that combines a gasifier with a conventional combined cycle power plant (combustion turbine followed by a steam cycle). All of the 19 demonstration scale of IGCC plants constructed worldwide have been fossil-fueled. There are no integrated gasification combined cycle plants currently operating with biomass as a primary fuel.

Operating Principles

Biomass gasification is a process to convert solid biomass into a gaseous fuel. This is accomplished by heating the biomass in an environment low in oxygen ("fuel rich"). Gasification is a promising process for biomass conversion. By converting solid fuel to a combustible gas, gasification enables the use of more advanced, efficient and environmentally benign energy conversion processes such as gas turbines and fuel cells to produce power, and chemical synthesis to produce ethanol and other value added products. There is a huge variety of gasification technologies including updraft, downdraft, fixed grate, entrained flow, fluidized bed, and molten metal baths. The technology choice depends primarily on the fuel characteristics and the desired capacity of the plant.

Most biomass gasification systems are air blown. The primary product of air-blown gasification is a low heating value fuel gas, typically 15 to 20 percent (150-200 Btu/ft^3) of the heating value of natural gas (1,000 Btu/ft^3). Using oxygen, steam, or indirect heating results in a higher quality gas, although at higher costs.

Applications

The primary advantage of gasification over direct combustion is the versatility of the gasification product. Gasification expands the use of solid fuel to include practically all the uses of natural gas and petroleum, including close-coupled boilers, combustion engines and turbines, fuel cells, and chemical synthesis, and Stirling engines. The various fuel gas conversion options are illustrated in Figure 4-2.

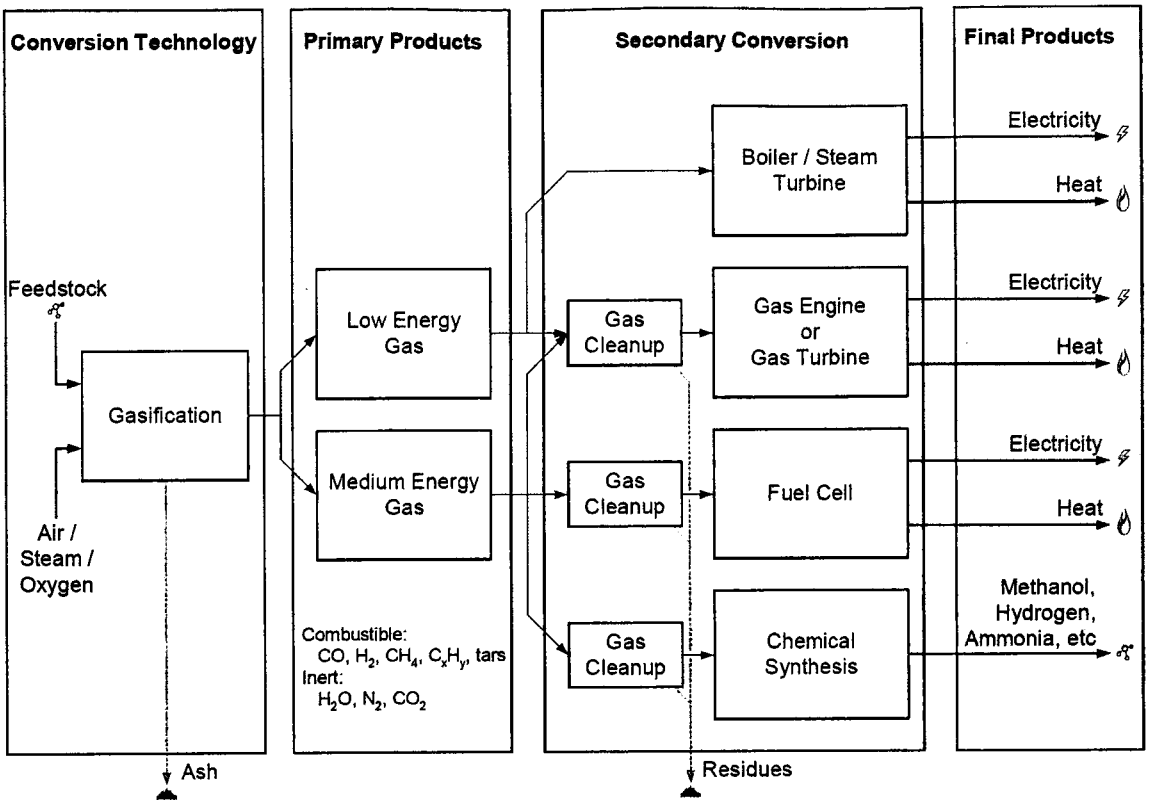


Figure 4-2. General Gasification Flow.

One of the principal focus areas for biomass gasification technology developers has been biomass IGCC. In an IGCC plant, the syngas exiting the gasifier is cleaned and combusted in a combustion turbine, generating power. Waste heat from the gas turbine is used to generate steam for use in a Rankine steam cycle. Net conversion to electricity for biomass IGCC plants is projected to be approximately 35 percent, compared to 20 to 25 percent for direct fired biomass plants. The potentially significant increase in efficiency makes biomass IGCC attractive; however, problems experienced with technology demonstration will need to be overcome. Although there are many gasifiers installed that produce fuel gas for close-coupled combustion in a boiler (essentially staged combustion), recent attempts to demonstrate more advanced processes, such as IGCC, have not been successful. Issues have been related partially to the gasification process itself, but also to supporting ancillary equipment, such as fuel handling and gas cleanup. Regardless, there are several biomass gasification equipment suppliers, including Foster Wheeler, Energy Products of Idaho, and Primenergy, which continue to develop biomass gasification technology for other applications.

Resource Availability

A biomass gasification or biomass IGCC plant would have similar resource availability issues as a direct-fired biomass plant. To be economically feasible it should be located either at the source of a fuel supply or within 50 to 75 miles of numerous suppliers. Wood, wood byproducts, agricultural residues, energy crops, and urban wood wastes are all suitable fuels for a biomass IGCC plant.

Like other biomass conversion technologies, an IGCC biomass plant would be limited in capacity by the amount of resource which could feasibly be delivered. A reasonable estimate for this limit is 30 MW to 75 MW, depending on location. Conversely, coal IGCC power plants are typically limited by the gas turbine capacity, not by fuel availability, and can be designed for much larger capacities similar to other fossil fuel power plants.

Cost and Performance Characteristics

Given the lack of commercial experience, cost and performance estimates for an IGCC biomass plant are uncertain. Since it would be limited to a size much smaller than an IGCC coal plant, an IGCC biomass plant would not benefit from the economies of scale of such plants. Table 4-3 presents projected characteristics for a biomass IGCC combustion plant for urban wood waste and forest residues.

Environmental Impacts

A biomass IGCC biomass project would have the same long-term sustainability concerns as other biomass conversion technologies. Biomass is viewed as a carbon-neutral power generation fuel. While CO_2 is emitted during biomass conversion, a nearly equal amount of CO_2 is absorbed from the atmosphere during the biomass growth phase. Further, biomass fuels contain little sulfur compared to coal and therefore produce less SO_2. Finally, unlike coal, biomass fuels typically contain only trace amounts of toxic metals, such as cadmium, and lead. Biomass gasification technologies will require equipment to control emissions of NO_x, PM, and CO to maintain air emission standards. It is important to note that given that biomass IGCC is expected to have higher efficiency than biomass combustion-based power plants, the pounds of pollution per MWh generated are substantially less.

Table 4-3. Biomass IGCC Technology Characteristics.	
Performance	
Typical Duty Cycle	Baseload
Net Plant Capacity (MW)	35
Net Plant Heat Rate (Btu/kWh)	10,000 to 11,500
Capacity Factor (percent)	70 to 90
Economics ($2007)	
Total Project Cost ($/kW)	3,000 to 4,000
Fixed O&M ($/kW-yr)	83
Variable O&M ($/MWh)	10.7
Levelized Cost, $1.00/MBtu ($/MWh)	65 to 99
Levelized Cost, $2.50/MBtu ($/MWh)	82 to 120
Applicable Incentives	Open loop: $10/MWh PTC, 5-yr MACRS Closed loop: $20/MWh PTC, 5-yr MACRS
Technology Status	
Commercial Status	Demonstration
Installed US Capacity (MW)	0

4.2.3 Biomass Cofiring

One of the most economical methods to burn biomass is to cofire it with coal in existing plants. Cofired projects are usually implemented by retrofitting a biomass fuel feed system to an existing coal plant, although greenfield facilities can also be designed to accept a variety of fuels.

As discussed in the previous section, a major challenge to biomass power is that the dispersed nature of the feedstock and high transportation costs generally preclude plants larger than 50 MW. By comparison, coal power plants rely on the same fundamental power conversion technology but can have much higher unit capacities, exceeding 1,000 MW. As a result of this larger capacity, modern coal plants are able to obtain higher efficiency at lower cost. Through cofiring, biomass benefits from this higher efficiency through a more competitive cost than a stand-alone, direct-fired biomass plant.

It should be noted that electricity demand in Arizona is increasing faster than any other state. Biomass cofiring converts capacity to a renewable source rather than adds capacity, and thus may be less attractive than alternatives to add capacity.

Applications

There are several methods of biomass cofiring that can be used to produce energy on a commercial scale. Provided that they were initially designed with some fuel flexibility, stoker and fluidized bed boilers generally require minimal modifications to accept biomass. For these types of boilers, simply mixing the fuel into the coal pile may be sufficient to cofire biomass.

Figure 4-3. Coal and Wood Mix.

Cyclone boilers and pulverized coal (PC) boilers (the most common in the utility industry) require smaller fuel sizes than stokers and fluidized beds and may necessitate processing of the biomass before combustion. There are two basic approaches to cofiring in this case: co-feeding the biomass through the coal processing equipment or separately processing and then injecting the biomass in the boiler. The first approach blends the fuels and feed them together to the coal processing equipment (crushers, pulverizers, etc.). In a cyclone boiler, up to 10 percent of the coal heat input can be replaced with biomass using this method. Pulverizers in a PC boiler are not designed to process relatively low density biomass, and fuel replacement is generally limited to around 2 or 3 percent if the fuels are mixed. The second approach (separate biomass processing and injection) allows higher cofiring percentages (10 to 15 percent) in a PC unit but costs more than processing a fuel blend.

Even at these limited cofiring rates, plant owners and operators have raised numerous concerns about the negative effects of cofiring on plant operations. These include the following:

- Reduced plant capacity.
- Reduced boiler efficiency.
- Ash contamination decreasing the quality of coal ash.
- Increased O&M costs.
- Minimal NOx reduction potential (usually proportional to biomass heat input).
- Boiler fouling/slagging because of the high alkali in biomass ash (more of a concern with fast growing biomass, such as energy crops).
- Potentially negative effects on SCR air pollution control equipment (catalyst poisoning).
- Reopening existing air permits.

These concerns have hampered the widespread adoption of biomass cofiring by electric utilities in the United States. However, these concerns can often be addressed through proper system design, fuel selection, and limits on the amount of cofiring.

Coal and biomass cofiring can also be considered in the design of new power plants. Designing the plant to accept a diverse fuel mix allows the boiler to incorporate biomass fuel, ensuring high efficiency with low O&M impacts. Fluidized bed technology is often the preferred boiler technology for cofiring since it has inherent fuel flexibility. There are many fluidized bed units around the world that burn a wide variety of fuels, including biomass. An example is a 240 MW circulating fluidized bed (CFB) in Finland, which burns a mixture of wood, peat, and lignite. This unit is capable of burning various fuels, ranging from 100 percent biomass to 100 percent coal.

Resource Availability

For viability, the candidate coal plant should be located within 100 miles of suitable biomass resources. The United States has a larger installed biomass power capacity than any other county in the world. The United States-based biomass power plants provide 7,000 MW of capacity to the national power grid. Coal power generation accounted for 2 trillion kWh in 2005, which comprised 49.7 percent of the total generation in the United States. Conversion of as little as 5 percent of this generation to biomass cofiring would increase electricity production from biomass by nearly 400 percent. It is important to note that biomass cofiring projects typically do not result in capacity increases as do other renewables. Instead, they offset fuel use at existing plants.

Cost and Performance Characteristics

Table 4-4 presents the typical characteristics for a biomass and coal cofired plant. The characteristics are based on cofiring 35 MW of biomass (separate injection) in a 400 MW pulverized coal power project. Except for fuel, the characteristics are provided on

an incremental basis (changes that would be expected compared to the coal plant). The primary capital cost for the project would be related to the biomass material handling system. As with direct fired biomass, biomass fuel cost is assumed to range from $1.00/MBtu for urban wood residues to $2.50/MBtu for forestry residues. To calculate the incremental fuel cost, coal has been assumed at a base cost of $1.50/MBtu. The incremental biomass cost is then ($0.50/MBtu) to $1.00/MBtu. Thus on the low-end, the biomass fuel cost is actually assumed to be $0.50/MBtu less expensive than coal.

Analysis of the range of incremental levelized costs presented in Table 4-4 indicates that the costs to cofire biomass with coal would be relatively small. The range of incremental levelized costs is between approximately $0/MWh (no increase) to $9/MWh for urban wood waste (assumed to cost $1/MBtu, which is $0.50/MBtu less than coal), and $18/MWh to $27/MWh for forest residues (assumed to cost $2.50/MBtu, which is $1/MBtu more than coal). This can be interpreted as the additional cost to produce one MWh of biomass energy, over the cost of coal power.

Table 4-4. Cofired Biomass Technology Characteristics.

Performance	
Typical Duty Cycle	Typically baseload, depends on host
Net Plant Capacity (MW)	35
Net Plant Heat Rate (Btu/kWh)	Increase 0.5 to 1.5 percent
Capacity Factor (percent)	Unchanged
Economics (Incremental Costs in 2007$)	
Total Project Cost ($/kW$_{biomass}$)	300 to 500
Fixed O&M ($/kW$_{biomass}$-yr)	5 to 15
Variable O&M ($/MWh$_{biomass}$)	Included with fixed
Levelized Cost, $1.00/MBtu ($/MWh$_{biomass}$)	0 to 9
Levelized Cost, $2.50/MBtu ($/MWh$_{biomass}$)	18 to 27
Applicable Incentives	None
Technology Status	
Commercial Status	Established, not fully commercial

Environmental Impacts

As with direct-fired biomass plants, the biomass fuel supply must be collected in a sustainable manner. Assuming this is the case, cofiring biomass in a coal plant generally has overall positive environmental effects. Clean biomass fuel typically reduces emissions of SO_2, CO_2, NO_x, and potentially heavy metals such as mercury. Further,

compared to other renewable resources, biomass co-firing directly offsets fossil fuel use. It may also provide an alternative to landfilling wastes, particularly wood wastes.

Arizona Biomass Cofiring Outlook

Arizona has several coal fired power plants that might be suitable candidates for biomass cofiring. A list of these is provided in Table 4-5. The outlook for biomass cofiring is further discussed in the next section.

Table 4-5. Arizona Utility Coal Fired Power Plants.

Plant Name	Primary Owner	Unit	Capacity, MW	County
Apache Station	Az Elec Power Coop	2	204	Cochise
Apache Station	Az Elec Power Coop	3	204	Cochise
Cholla	APS	1	113.6	Navajo
Cholla	APS	2	288.9	Navajo
Cholla	APS	3	312.3	Navajo
Cholla	APS	4	414	Navajo
Navajo	SRP	1	803.1	Coconino
Navajo	SRP	2	803.1	Coconino
Navajo	SRP	3	803.1	Coconino
Coronado	SRP	1	410.9	Apache
Coronado	SRP	2	410.9	Apache
H Wilson Sundt	TEP	4	120	Pima
Springerville	TEP	1	424.8	Apache
Springerville	TEP	2	424.8	Apache

Source: EIA

4.2.4 Plasma Arc Gasification

Plasma arc gasification is a combination of gasification with plasma arc technology. Both are mature technologies, but the integration of the two is relatively new.

Gasification is typically thought of as incomplete combustion of a fuel to produce a fuel gas with a low to medium heating value. Heat from partial combustion of the fuel is also generated, although this is not considered the primary useable product. The primary product of conventional air-blown gasification is a low heating value fuel, typically 15 to 20 percent (150 to 200 Btu/ft^3) of the heating value of natural gas (about 1,000 Btu/ft^3). Combustible components of the gas include carbon monoxide, hydrogen,

methane, higher hydrocarbons such as ethane and propane, and tar. The conventional use for this gas is combustion in a boiler to generate steam, although it could potentially be used in higher efficiency engines or combustion turbines if the gas is sufficiently clean.

There are two primary configurations for plasma torches: transferred and non transferred torches. Both configurations use a pair of electrodes across which a large current is applied. An arc, basically manmade lightning, is created when the electricity bridges the gap between the two electrodes. The arc generates temperatures of up to 30,000°F. The transferred torch directly contacts the arc with the material, or a conductor, in the reactor. The non-transferred torch blows a stream of air across the arc inside the torch to produce superheated gas, approximately 5,000°F. This gas provides the thermal input to the reactor that is required to decompose the material. The temperature in the reactor itself is generally around 2,000°F. Plasma arc torches require large amounts of electricity. Depending on the fuel being processed, the facility may not generate net electricity output.

Figure 4-4. Plasma Arc Torch Operating (Source: http://www.zeusgroup.org/applications.html).

Applications

The extreme temperatures produced by plasma torches makes them well-suited for waste remediation applications because the inorganic constituents in the waste that might normally be hazardous are literally melted to form a glassy slag which can be

captured in a solid form. This encapsulation of hazardous waste requires significant amounts of energy and has very specialized economical niche markets. Currently, some industry leaders feel that plasma arc disposal of municipal solid waste (MSW) is not economic. An alternate approach to strictly disposing of the MSW with plasma torches is to gasify the MSW and recover the combustible syngas that results from the thermal reaction. There are very few installations worldwide to benchmark against for economic evaluation. These are summarized in Table 4-6.

Table 4-6. Installed MSW Plasma Arc Gasification Projects.

Vendor - Project	Fuel	Commercial Status	Electrical Capacity, MW	Fuel Throughput, tpd
Westinghouse Plasma Corp.				
Yoshii, Japan	MSW	Pilot	--	25
Utashinai, Japan	ASR/MSW*	Commercial	8	165
Mihama, Japan	MSW	Commercial	--	28
Startech Environmental				
Bristol, Connecticut	Variety	Demonstration	--	5
Integrated Environmental Technologies				
APET, Hawaii	Medical waste	Commercial	--	24

Notes:
* Primary fuel intended to be auto shredder residue (ASR). Plant is capable of using MSW for up to 50 percent of volumetric throughput.

Resource Availability

Plasma arc gasification technologies can process the same basic resources as other biomass and waste to energy technologies. However, plasma arc is particularly well suited to handle difficult materials, such as hazardous waste, auto shredder residue, incinerator ash, low-level radioactive waste, and medical waste. The net power export potential (if any) of a plant depends heavily on the resource being processed.

Cost and Performance Characteristics

Because the technology is pre-commercial, objective cost and performance information for plasma arc systems was not obtainable for this study.

Environmental Impacts

Plasma arc technologies are well-suited for vitrification of waste materials. Extensive documentation of testing shows that the vitreous slag has very low leaching potential, effectively "locking up" contaminants in the solid material. Air emissions are not as well-documented. Technology suppliers claim that the extreme temperatures of the plasma system dissociate any harmful molecular emissions. However, very little discussion of emissions such as mercury can be found. It does not seem that mercury would be captured in the slag because it has such a low boiling point. Conventional waste to energy facilities seem to have achieved compliance with EPA's emissions limits for dioxins and furans; plasma arc gasification would not seem to offer substantial benefits over those technologies in that respect.

Arizona Plasma Gasification Development Prospects

Plasma arc gasification of waste is a developmental technology that has not gained widespread support, particularly as a power generation technology. There do seem to be some instances in which it can be cost effective, such as in highly land constrained areas with significant population density. Even in these favorable conditions, the economic viability of plasma arc projects is subject to technology risk. It is possible that plasma arc gasification of MSW may become commercial in a 10 to 20 year timeframe. In such case, it could be expected to generate approximately the same amount of electricity as other waste to energy options. Due to its pre-commercial nature, it is recommended that plasma arc gasification not be considered further for this study.

4.2.5 Biomass Technologies Development Prospects

There is some potential to develop biomass resources, although they are relatively limited compared to wind and solar resources in the state. Biomass potential is largely based on available resources; however, in the case of cofiring, a suitable host power plant in the vicinity is also necessary.

In December 2005, the National Renewable Energy Laboratory (NREL) published a new set of biomass resource data and documentation, including GIS data layers of major biomass resources on a county level. The data represents fairly uniform set of biomass resource data, and is the most current nation-wide, county level data source available. As described below, much of the resource data is based on statistical estimation. To determine the actual available quantities and suppliers of biomass material in the region, a more detailed resource assessment and supplier survey would be necessary. This survey would be carried out in the next phase of this project.

The NREL data is defined as follows:

- **Agricultural Residues** – This data includes residues from corn, wheat, soybeans, cotton, sorghum, barley, oats, rice, rye, canola, beans, peas, peanuts, potatoes, safflower, sunflower, sugarcane and flaxseed. Residue estimates were developed using the total grain production, crop-to-residue ratio, and moisture content. The total grain production data for each county in 2002 were as reported to the US Department of Agriculture. It was assumed that 35 percent of the total residue could be collected, accounting for residue left for soil protection, grazing, bedding, etc. Animal manures are discussed in the anaerobic digestion section of this report. Agricultural residues are relatively limited in Arizona due to the arid climate.
- **Forest Residues** – Forest residue data is adapted from the 2002 USDA Forest Service Timber Product Output Database. The quantities include commercial logging residues and other practices such as fire management (fuel reduction), pre-commercial thinnings, and land clearing. Since this data source is based on historical sector output, the NREL estimates have been augmented with an estimate of projected availability from fire management forest thinnings. A large portion of Arizona's forested land is located within National Forests. Until the early 1990s, much of this land was harvested for timber. The amount of timber harvested has declined substantially over the past 15 years. Currently, much of the wood removed from Arizona forests is due to fire management.
- **Primary Mill Residues** – Primary mill residue data is also taken from the 2002 USDA Forest Service Timber Product Output Database. The quantities include mill residues such as slabs, edgings, trimmings, sawdust, veneer clippings, and pulp screenings. This includes material that is already utilized as well as material that is disposed as waste. As the amount of timber harvested from Arizona forests declined due to environmental restrictions, the timber available to sawmills also declined. This caused many of the sawmills in Arizona to close their operations. In 1960, there were approximately 38 sawmills; in 1998 there were only 13.[5] In a recent Black & Veatch survey, even fewer mills were identified.

[5] Source: Keegan, Charles E. Arizona's Forest Products Industry: A Descriptive Analysis 1998. School of Business Administration, University of Montana

Figure 4-5. Large Wood Yard in Arizona (Source: SFP).

- **Secondary Mill Residues** – Secondary mill residue includes material from wood manufacturing facilities including pallet, truss, and furniture manufacturers. Data from the US Census Bureau was used to determine the number of businesses in each county. The size of the company was then used to estimate the amount of residue each company generates, using data from a previous NREL study which found that pallet and lumber companies generate about 300 tons per year, and a small woodworking company generates about 5 to 20 tons per year of wood waste.
- **Urban Wood Residues** – Includes municipal solid waste segregated wood (wood chips, pallets, and yard waste), tree trimming services, and construction and demolition (C&D) wood. Quantities were estimated using data from a previous NREL study, which found that approximately 3 to 5 percent of MSW is wood, one tree service generates about 1,000 tons per year of wood waste, and that C&D wood is proportionate to population. Urban wood waste is a promising source in Arizona, particularly around urban centers.

Table 4-7 summarizes the resource data by county, with estimates for the amount of potential generation (MW) possible from these resources. Figure 4-6 shows urban wood waste distribution in the state. It can be seen that this data represents a high-level assessment of the available resources. However, it is based on reasonable assumptions and draws from reliable data sources. Black & Veatch believes that this data provides a first-level representation of the relative quantities of each resource throughout Arizona.

If biomass is economically competitive, Black & Veatch recommends that a more detailed biomass resource assessment be performed.

Table 4-7. Estimated Biomass Resources in Arizona (Dry Tons/Year).

County	Agricult. Residue	Forest Residue	Primary Mill Residue	Secondary Mill Residue	Urban Wood Waste	Total	MW[a]
Apache	0	12,380[b]	0	498	7,403	20,280[b]	4[b]
Cochise	34,207	0	0	20	12,758	46,985	8
Coconino	0	16,125[b]	0	41	11,977	28,142[b]	5[b]
Gila	0	4,083	0	253	5,387	9,723	2
Graham	18,254	0	0	245	3,577	22,076	4
Greenlee	0	1,764	0	0	1,048	2,812	1
La Paz	18,110	0	0	0	2,090	20,200	4
Maricopa	69,267	0	0	28,679	312,337	410,283	74
Mohave	2,394	0	0	1,829	16,628	20,851	4
Navajo	0	24,769[b]	108,588	1,519	10,337	145,213[b]	26[b]
Pima	15,946	0	0	2,964	86,102	105,011	19
Pinal	126,526	0	0	1,025	18,497	146,048	26
Santa Cruz	0	0	0	738	4,073	4,812	1
Yavapai	0	11	0	1,870	17,077	18,958	3
Addl. Forest Thinnings[c]		300,000				300,000	54
TOTAL	**350,990**	**359,132**	**108,588**	**40,954**	**525,609**	**1,385,272**	**249**

Source: NREL (http://www.nrel.gov/gis, accessed 2006), except forest thinnings estimate.

Notes:

[a] Assumes an average biomass HHV of 8,500 Btu/lb, a heat rate of 13,500 Btu/kWh, and a capacity factor of 80 percent. A cofired project at 10,000 Btu/kWh would produce more power.

[b] Does not include supplemental forest thinnings, see note (c).

[c] Projected forest thinnings carried out for fuel reduction in Arizona National Forests, about 90 percent of which are in the Apache-Sitgreaves, Coconino, and Kaibab National Forests (Coconino, Navajo, and Apache counties). Based on thinning 35,000 acres per year with a yield of 10 dry tons per acre. Additional research resulted in a slightly lower estimate, see Section 5.1.

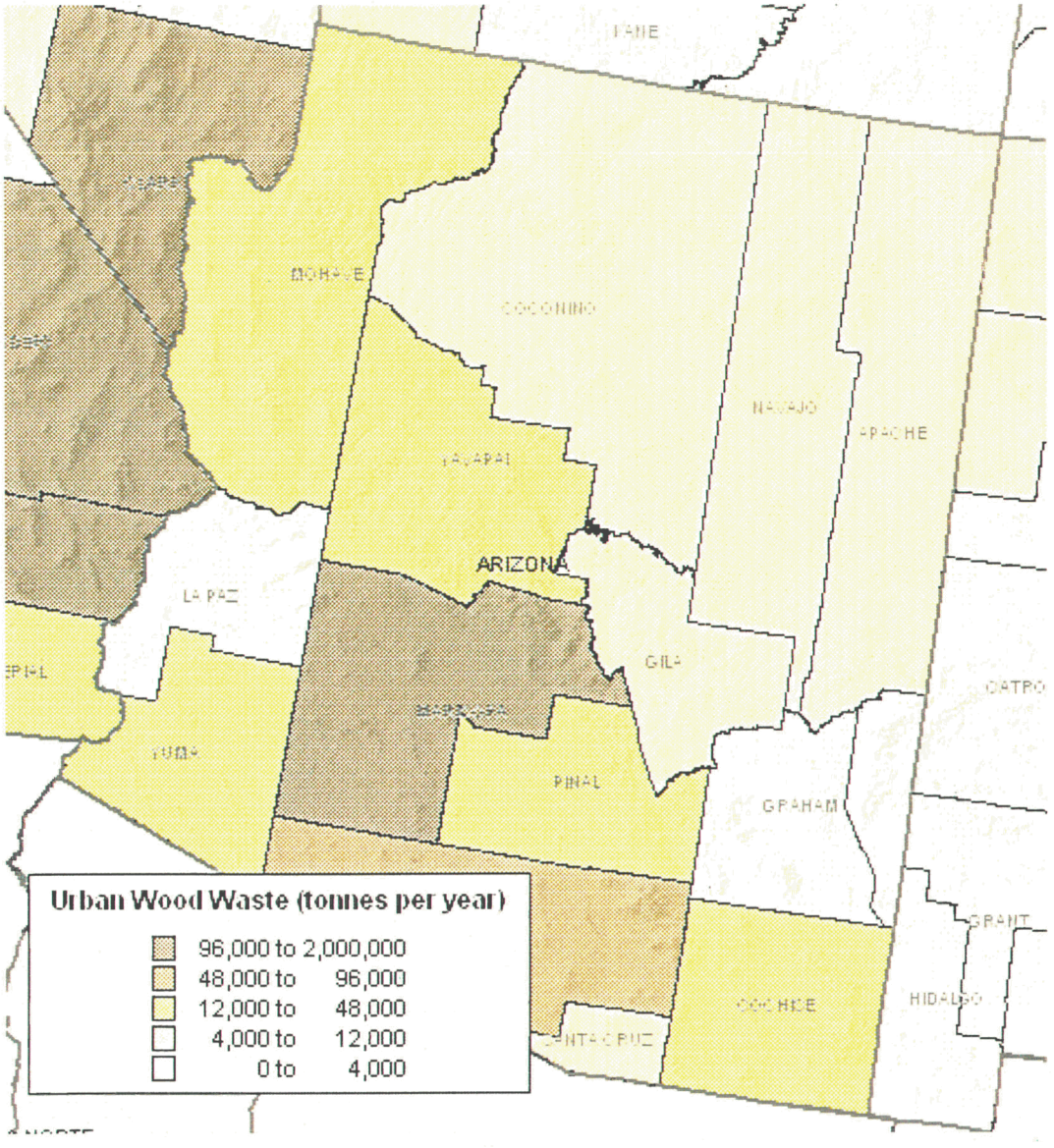


Figure 4-6. Arizona Urban Wood Waste Resource.

This table shows about 250 MW of stand-alone generation potential from biomass resources in Arizona. Different residues are available in different parts of the state. Various projects are conceivable based on these distributions.

- Maricopa County (Phoenix) has the largest potential (74 MW) of all counties, due primarily to the relatively large estimated quantities of urban wood waste. This quantity should be sufficient to support development of a stand-alone biomass plant in the Phoenix area. Permitting constraints and long-term sustainability of the wood supply may make a smaller facility more optimal. The nearest potential host for cofiring is TEP's 120 MW Sundt station.

- In Pinal County, between Phoenix and Tucson, agricultural residues are predominant (26 MW total). Combined with the 19 MW residues from Pima County (Tucson), another biomass plant could be sited. Alternatively, the biomass could be cofired with coal in TEP's Sundt station.
- As noted in the table, there may be 250,000 dry tons/year (45 MW) of forest thinnings from fuel reduction efforts in the Apache-Sitgreaves, Coconino, and Kaibab National Forests located in Coconino, Navajo, and Apache counties. In Navajo County alone there is a relatively large quantity of primary mill residues (20 MW worth). Much of this comes from a single source: the Fort Apache Timber Company's (FATCO) sawmill located in the extreme southern portion of the county. The total resource potential from all sources in Coconino, Navajo, and Apache counties is 89 MW. The proposed 24 MW Snowflake White Mountain Power project will also burn some of the available biomass.

Additional assessment and quantification of potential biomass resources is provided in Section 5 of this report.

4.3 Biogas

Biogas technology refers to the process of generating electricity with gas captured from the anaerobic digestion of manure or naturally occurring landfill gas (LFG). The following subsections describe the formation of these fuels and their ability to produce renewable energy.

4.3.1 Anaerobic Digestion

Anaerobic digestion is a natural process that occurs when bacteria decompose organic materials in the absence of oxygen. The byproduct of this decomposition is generally composed of 50 to 80 percent methane. The most common applications of anaerobic digestion use industrial wastewater, animal manure, or human sewage as feedstock. According to Bioenergy News, the publication of the Bioenergy Association of New Zealand, Inc., the projection of total installed capacity of anaerobic digestion will grow from 185 MW in 2004 to 575 MW in 2013. The projection is that 203 MW will be installed in Western Europe, 68 MW in North America, and 46 MW in Australia.[6]

[6]The World Biomass Report, *Bioenergy News*, December 2004, http://www.bioenergy.org.nz.

Applications

Anaerobic digestion is commonly used in municipal wastewater treatment as a first-stage treatment process for sewage sludge. Increasingly stringent agricultural manure and sewage treatment management regulations are the primary drivers for the heightened interest in anaerobic digestion technologies. Use of anaerobic digestion technologies in wastewater treatment applications results in a smaller quantity of biosolids residue compared to aerobic (digestion in the presence of oxygen) technologies Waste water treatment plants commonly use the biogas for process heating requirements. Power production from digestion facilities is typically a secondary consideration.

The Los Angeles Department of Water and Power has announced a new agreement to purchase power from a proposed 40 MW anaerobic digestion facility that will process 3,000 tons per day of municipal green waste, such as landscape trimmings and food waste to produce biogas for power production. The proposed facility would be the largest of its kind in the world. There are various other high-solids digestion systems installed worldwide, primarily in Europe and Japan.

Biogas produced by anaerobic digestion can be used for power generation, direct heat applications, and absorption chilling. Reciprocating engines are the most common power conversion device, although demonstrations with microturbines and fuel cells have been successful.

Resource Availability

For manure digestion on farms, the resource is readily accessible, and only minor modifications to existing manure management techniques are required to produce biogas suitable for power generation. In some cases, economies of scale may be realized by transporting manure from multiple farms to a central digestion facility. For central plant digestion of manure from several sources, the availability and proximity of a large number of livestock operations is necessary to provide sufficient manure feed rate to the facility. However, the larger size of regional facilities does not necessarily guarantee better economics, because of higher manure transportation costs. For anaerobic digestion of municipal sewage wastes, the resource is readily available at the wastewater treatment plant.

Cost and Performance Characteristics

Table 4-8 presents the typical characteristics of farm-scale dairy manure anaerobic digestion systems utilizing reciprocating engine technology. Costs for anaerobic digestion systems are very site specific. A photo of a dairy manure digester is shown on Figure 4-7.

Table 4-8. Farm-Scale Anaerobic Digestion Technology Characteristics.	
Performance	
Typical Duty Cycle	Baseload
Net Plant Capacity (MW)	0.150
Capacity Factor (percent)	70 to 90
Economics (2007$)	
Total Project Cost ($/kW)	4,000 to 6,000
Variable O&M ($/MWh)	17
Levelized Cost ($/MWh)	68 to 126
Applicable Incentives	$10/MWh PTC (>150 kW only)
Technology Status	
Commercial Status	Commercial
Installed Worldwide Capacity (MW)	185

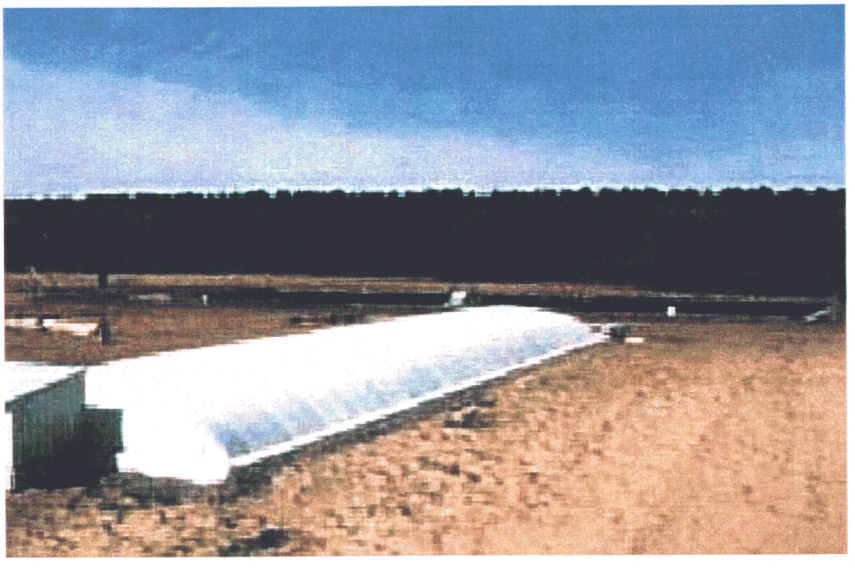


Figure 4-7. 135 kW Dairy Manure Digester.

Environmental Impacts

Anaerobic digesters have multiple positive environmental impacts: they reduce pathogens in the waste stream; they eliminate odor problems; they reduce methane emissions relative to atmospheric decomposition of manure, which are a significant contributor to greenhouse gas emissions; and they can help prevent nutrient overloading in the soil resulting from manure spreading.

Developmental Potential

The potential for power generation from anaerobic digestion depends on the feedstock: animal manures or sewage sludge. Combined, the potential is about 50-60 MW, with sewage sludge being significantly less expensive.

There are over 4 million farm animals in Arizona raised in concentrated animal feeding operations (CAFOs). Typically, farm digesters are installed at either dairy farms or pig farms. As shown in Table 4-9, there is theoretically the potential for about 27 MW of power produced from dairy and swine operations in Arizona. The dairy and swine concentration is heaviest in Maricopa counties, and to a lesser extent, Navajo, Pinal, and Yuma counties. Pinal and Yuma counties also have large concentrations of beef cattle. Because it is dry and dispersed, manure from beef cattle is generally not suitable for anaerobic digestion applications. However, it can be combusted if dry.

Table 4-9. Arizona Biogas Potential (MW) from Dairy and Swine Farms.

County	Dairy	Swine	Total
Cochise	0.1	0.05	0.1
Greenlee	0.1	0	0.1
Maricopa	15.2	0	15.2
Mohave	0.2	0	0.2
Navajo	0	5.2	5.3
Pima	0.2	0	0.2
Pinal	3.0	0	3.0
Yavapai	0.7	0	0.7
Yuma	2.3	0	2.3
Totals	21.8	5.3	27.0

Source: APS, Arizona Department of Environmental Quality, Black & Veatch

Human waste water treatment plants (WWTP) can also be a suitable source for biogas, particularly if anaerobic digestion systems are already installed. There are 13 WWPTs in Arizona with sewage sludge digesters. The largest plant, the 179 million gallon per day (MGD) 91st Avenue Wastewater Treatment Plant, has the potential to produce about 12 MW. There are three other plants between 10 and 100 MGD with a combined capacity of about 8 MW.[7]

Because the anaerobic digestion system is already installed, power generated from biogas at WWTPs can be as little as half the cost of animal manure digestion projects.

[7] Peter Johnston (APS), Daniel Musgrove (Universal Entech), "Biofuels", available at: http://www.cc.state.az.us/utility/electric/EPS-BBG.ppt.

However, it is usually the case that the power demands of the wastewater treatment process are larger than the biogas potential. Therefore the potential for grid export is limited.

4.3.2 Landfill Gas

LFG is produced by the decomposition of the organic portion of waste stored in landfills. LFG typically has methane content in the range of 45 to 55 percent and is considered an environmental risk. There is increased political and public pressure to reduce air and ground water pollution and to reduce the risk of explosion associated with LFG. From a generation perspective, LFG is a valuable resource that can be burned as fuel by reciprocating engines, small gas turbines, or other devices (Figure 4-8). LFG energy recovery is currently regarded as one of the more mature and successful waste-to-energy technologies. There are more than 600 LFG energy recovery systems installed in 20 countries.

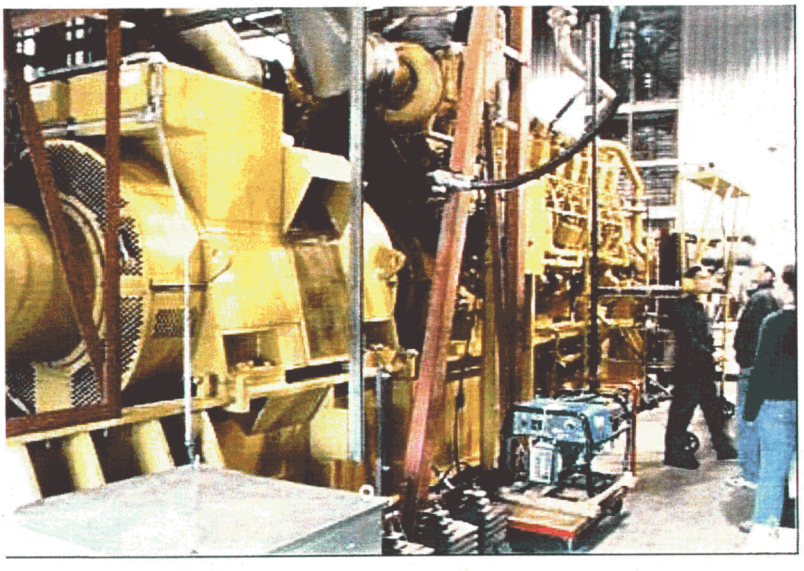


Figure 4-8. Reciprocating Engine Used to Generate Power from LFG.

Applications

LFG can be used to generate electricity and process heat, or can be upgraded for pipeline sales. Power production from an LFG facility is typically less than 10 MW. There are several types of commercial power generation technologies that can be easily modified to burn LFG. Internal combustion engines are by far the most common generating technology choice. About 75 percent of the landfills that generate electricity use internal combustion engines. Depending on the scale of the gas collection facility, it

may be feasible to generate power via a combustion turbine or a boiler and steam turbine. LFG co-firing in larger utility boilers is also in use; TEP currently operates a 5 MW co-fired LFG operation in Tucson. Nearly 35 percent of all landfill gas projects in the U.S. are co-fired.[8] Testing with microturbines and fuel cells is also under way, although these technologies do not appear to be economically viable for power generation.

Resource Availability

Gas production at a landfill is primarily dependent on the depth and age of waste in place and the amount of precipitation received by the landfill. In general, LFG recovery may be economically feasible at sites that have more than 1 million tons of waste in place, more than 30 acres available for gas recovery, a waste depth greater than 40 feet, and at least 25 inches of annual precipitation. The arid conditions in Arizona limit LFG productivity.

The economic life of an LFG resource is limited. After waste deliveries to a landfill cease and the landfill is capped, LFG production will decline, typically following a first order decay.

Cost and performance Characteristics

The economics of installing an LFG energy facility depend heavily on the characteristics of the candidate landfill. The payback period of an LFG energy facility at a landfill that has an existing gas collection system can be as short as 2 to 5 years, especially if environmental credits are available. However, the cost of installing a new gas collection system at a landfill can prohibit installing an LFG facility. Table 4-10 presents cost and performance estimates for typical LFG projects using reciprocating engines.

[8] Source: Tucson Electric Power

Table 4-10. Landfill Gas Technology Characteristics

Performance	
Typical Duty Cycle	Baseload
Net Plant Capacity (MW)	2 to 10
Capacity Factor (percent)	70 to 90
Economics (2007$)	
Total Project Cost ($/kW)	1,500 to 2,000
Variable O&M ($/MWh)	17
Fuel Cost ($/MBtu)	1.00 to 3.00*
Levelized Cost ($/MWh)	40 to 80
Applicable Incentives	$10/MWh PTC
Technology Status	
Commercial Status	Commercial
Installed US Capacity (MW)	1,100

* Fuel cost is variable. The low end of this range is unlikely unless an existing gas purchase contract is in place, or responsibility for the gas collection system is assumed. .

Environmental Impacts

Combustion of LFG releases pollutants similar to those released by many other fuels, but the combustion of LFG is generally perceived as environmentally beneficial. Since LFG is principally composed of methane, if it is not combusted, LFG is released into the atmosphere as a greenhouse gas. As a greenhouse gas, methane is 23 times more harmful than CO_2. Collecting the gas and converting the methane to CO_2 through combustion greatly reduces the potency of LFG as a source of greenhouse gas emissions.

Arizona Landfill Gas Outlook

The potential for landfill gas project developments in Arizona is limited, although project economics are generally very competitive. Based on data acquired from the US Environmental Protection Agency's (EPA) Landfill Methane Outreach Program (LMOP) database, there are at least 25 candidate landfills with the potential for power generation from landfill gas. These projects are listed in Table 4-11. The estimated potential generation at the different locations ranges from a few kilowatts up to around 10 MW. In aggregate, 20 to 30 MW of potential may be possible. The actual amount of generation which is achievable at these locations will depend on the actual gas generation levels, landfill gas composition, the level of coverage of the collection system, and the net plant heat rate (NPHR) of the engine-generators or other appropriate conversion technology.

The potential for project development at these locations will depend on the gas availability and the details of any existing gas rights contracts.

Table 4-11. Candidate Landfill Gas Project Locations in Arizona.

Landfill Name	City	Waste in Place (tons)
Apache Junction LF	Apache Junction	1,000,000
Cinder Lake MSW LF	Flagstaff	2,150,000
City of Glendale Municipal Landfill	Glendale	5,000,000
Grey Wolf Landfill	Dewey	3,000,000
Huachuca City Landfill	Huachuca	1,200,000
North Center Street Landfill	Phoenix	2,000,000
Northwest Regional MSW Landfill	Phoenix	1,000,000
Painted Desert Landfill	Joseph City	1,500,000
Queen Creek MSW Landfill	Queen Creek	1,500,000
Rio Rico MSW Landfill	Rio Rico	1,000,000
Salt River Landfill	Phoenix	3,000,000
Skunk Creek Landfill	Phoenix	12,000,000
Cave Creek Landfill	Phoenix	NA
Cocopah Landfill	Somerton	2,200,000
Copper Mountain Landfill	Wellton	NA
Dudleyville Landfill	Winkelman	8,902
Harrison City Landfill	Tucson	2,250,000
Ironwood Landfill	Florence	286,464
La Paz County Landfill	Parker	NA
Lake Havasu Landfill	Lake Havasu City	NA
Mohave Valley Landfill	Mohave Valley	NA
Sierra Estrella Landfill	Maricopa	NA
Southwest Regional Landfill	Buckeye	NA
Tangerine Road MSW Landfill	Tucson	2,100,000
Vincent Mullins Landfill	Tucson	NA

Source: EPA Landfill Methane Outreach Program (LMOP) database

4.4 Solar Electric

Solar radiation can be captured in numerous ways with a variety of technologies. The two major groups of technologies are solar thermal and solar photovoltaics.

4.4.1 Solar Thermal Power

The performance, commercial readiness, cost, reliability, and technical risk of solar thermal power technology are characterized in this section. The technologies discussed include:

- Parabolic trough
- Parabolic dish
- Power tower
- Compact Linear Fresnel Reflector (CLFR)

Concentrating solar thermal power plants (CSP) produce electric power by converting the sun's energy into high temperature heat using various mirror or lens configurations. For solar thermal electric systems (trough, dish-Stirling, and power tower), the heat is transferred to a turbine or engine for power generation. Thermal plants consist of two major subsystems: a collector system that collects solar energy and converts it to heat, and a power block that converts heat energy to electricity.

All CSP systems make use of the direct normal insolation (DNI) component of solar radiation, that is, the radiation that comes directly from the sun. Global radiation, which is reflected radiation, is present on sunny and cloudy days but is unusable by CSP systems. Since all CSP systems use DNI and concentration of DNI allows a solar system to achieve a high working fluid temperature, there is a need for the collector systems to track the sun. Parabolic trough and CLFR systems use single-axis trackers to focus radiation onto a linear receiver while parabolic dish engine and power tower CSP systems use two-axis trackers.

Trough, power tower and CLFR systems collect heat to drive central turbine-generators making them best suited for relatively large plants—50 MW or larger. Trough, tower and CLFR plants, with their large central turbine generators and balance of plant equipment, have a cost advantage of economy of scale—that is, cost per kW goes down with increased size. Dish systems are modular in nature, with single units producing power in the range of 10 kW to 35 kW making them ideal for distributed or remote generation applications. Dish systems can also be sited as large plants by aggregating many units. Dish systems have the potential advantage of mass production of individual units, similar to the mass production of automobiles

Trough and tower systems have the potential advantage over dish systems in that an amount of dispatchability can be designed into the system with thermal storage or the use of hybrid fossil fuel. Storage for CLFR systems, while being explored in concept, has not been developed. Dispatchability allows the solar plant to generate electricity during short duration cloudy periods or to generate electricity into the evening after sunset. This gives the plant potential to receive capacity credit, and provides the ability to more closely match the utility peak load profile. At this time, dish engine systems have not been configured to provide hybrid fossil capability.

Parabolic Trough Systems

Parabolic trough solar thermal systems have been the dominant solar thermal technology installed to date. Parabolic trough systems concentrate DNI using single axis tracking, parabolic curved, trough-shaped reflectors onto a receiver pipe or heat collection element (HCE) located at the focal line of the parabolic surface. A high temperature heat transfer fluid (HTF) picks up the thermal energy in the HCE. Heat in the HCE is then used to make steam in the steam generator. The steam drives a conventional steam-Rankine power cycle to generate electricity. Figure 4-9 shows trough collectors. A collector field contains many parallel rows of troughs connected in series. Rows are typically placed on a north-south axis, allowing the single-axis troughs to track the sun from east to west during the day.

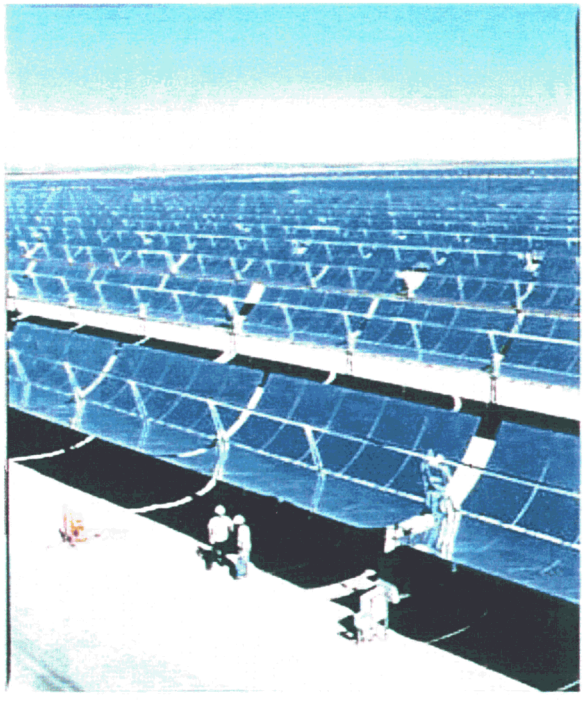


Figure 4-9. Kramer Junction Trough Plant (NREL).

The largest collection of parabolic systems in the world is the Solar Energy Generating Systems (SEGS) I through IX plants in the Mohave Desert in southern California. The SEGS plants were built in the 1985 to 1991 time frame. The Kramer Junction site has five 30 MW systems. The largest of the SEGS plants, SEGS IX, located at Harper Lake, is 80 MW. All of the SEGS plants are "hybrids," using fossil fuel to supplement the solar output during periods of low solar radiation. Each plant is allowed to generate 25 percent of its energy annually using fossil fuel.

There are several commercial parabolic trough projects in the planning or active project development stage. Solargenix, (now Acciona) constructed a 1 MW plant in Arizona, which became operational in spring 2006. There are several plants under construction, including Nevada Solar One, an Acciona 64 MW plant in Nevada, and several 50 MW plants in Spain. The Andasol Spanish plants will include 7 hours of thermal storage. Other projects in various stages of planning include integrated solar combined cycle system (ISCCS) in southern California, India, Egypt, Morocco, Mexico, and Algeria. In addition, there are plans for a series of SEGS type plants in Israel.

Parabolic trough systems are considered commercially available for industrial applications. The primary developers of this technology include Acciona, Solel Solar Systems, Solar Millennium and Solucar. Suppliers of components for trough systems include reflector supplier Flabeg and receiver suppliers Schott Glass and Solel Solar Systems. Other major glass companies have expressed interest in entering the trough mirror market. The currently planned technology, for thermal storage, is the molten salt two-tank system. This provides a feasible storage capacity of up to 12 hours and is considered to have a low-to-moderate associated technology risk.

Parabolic Dish-Engine Systems

A solar parabolic dish-engine system comprises of a solar concentrator (or "parabolic dish") and the power conversion unit (PCU). The concentrator consists of mirror facets which combine to form a parabolic dish. The dish redirects DNI to a receiver mounted on a boom at the dish's focal point. The system uses a two-axis tracker such that it points at the sun continuously.

A parabolic dish-engine system using a Stirling engine is shown on Figure 4-10. The PCU includes the thermal receiver and the engine-generator. In the solar receiver, radiant solar energy is converted to heat in a closed hydrogen loop which drives the Stirling engine-generator. Because the PCUs are air cooled, water cooling is not required. This is important because water cooling is necessary for the large, central power blocks associated with trough and power tower technologies. Thermal storage is not currently considered to be a viable option for dish engine systems.

Figure 4-10. Dish Engine System (NREL).

Relatively level land is preferable for construction and maintenance ease; however, siting requirements on slope are likely less significant than those for trough and tower systems.

Individual dish engine units range in size from 10 to 25 kW. Because they can operate independent of power grids, they can be used for remote applications as well as grid connected applications. With their high efficiency and modular construction, the cost of dish engine systems is expected to be competitive in distributed markets. Stirling Engine Systems (SES), the principal dish engine developer in the United States, projects that the cost of dishes will decrease dramatically with hundreds of MWs of central station, grid connected deployment.

At the present time, there are no operating commercial dish engine power plants. A six dish test deployment at Sandia National Laboratories (SNL) in Albuquerque, New Mexico, was completed in 2005. This development is under a joint agreement between SES and SNL. In 2005, Southern California Edison publicly announced the completion of negotiations on a 20 year power purchase agreement with SES for between 500 to 850 MW of capacity (producing 1,182 to 2,010 GWh/year) of dish engine units. Also in 2005, SES announced a contract with San Diego Gas & Electric to provide between 300 and 900 MW of solar power using the dish technology. If successful, this large deployment of dish engine systems is expected to drastically reduce capital and O&M costs and result in increased system reliability.

While pricing for these power purchase agreements remains confidential, based on stated claims it must be under the California Market Price Referent (MPR) which is roughly $110/MWh using solar time of day factors applied to the base MPR (of $75).

Other planned deployments of dish engine systems include contracted deployments of a 25 kW demonstration dish by SES at Eskom in South Africa and a 10 kW Schlaich Bergermann und Partner (SBP) dish providing power to the grid in Spain. Proposed or planned deployments include a 10 kW SBP dish in France and a 10 kW SBP dish in Italy.

Power Tower Systems

A power tower uses thousands of sun-tracking mirrors called heliostats to redirect DNI to a receiver at the top of a tower. In the most recent receiver deployment, a molten nitrate salt HTF heated in the receiver is used to generate steam, which in turn is used in a conventional turbine generator to produce electricity. An earlier power tower generated steam directly in the receiver; however, the current US design uses molten nitrate salt because of its superior heat transfer and energy storage capabilities. Systems with air as the working fluid in the receiver or power system have also been explored in international research and development programs. Commercial power tower plants can be sized to produce anywhere from 50 to 200 MW of electricity. Figure 4-11 is a photograph of the 10 MW Solar Two prototype molten salt system.

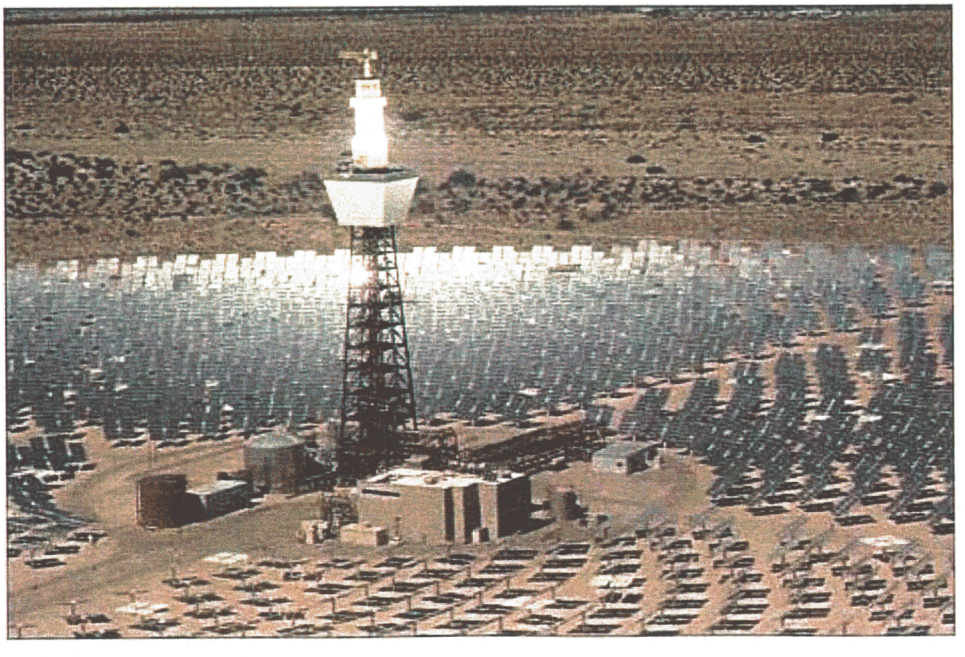


Figure 4-11. 10 MW Solar Two Power Tower System (NREL).

An advantage of power tower plants is that molten salt can be heated to 1,050°F, with steam generation at 1,000°F, which is utility-standard main steam temperature. This results in slightly higher cycle efficiency than is achievable with the lower temperature (about 735°F) steam produced in a trough system. Furthermore, power towers have the advantage that the molten salt is used both as the HTF and as the storage medium, unlike the trough system which uses high temperature oil as the HTF, and requires oil-to-salt and salt-back-to-oil heat exchange for thermal storage. The result is that storage is less costly and more efficient for power towers than for troughs.

There are no commercial power tower plants in operation today. In 1982, a 10 MW power tower plant, Solar One, located near Barstow, California, operated from 1982 to 1988 and produced over 38 million kilowatt-hours (kWh) of electricity. Solar One generated steam directly in the receiver. To implement improved heat transfer and thermal storage, the plant was retrofitted (and renamed Solar Two). Solar Two operated from 1998 to 1999. Although Solar Two successfully demonstrated efficient collection of solar energy and dispatch of electricity, including the ability to routinely produce electricity during cloudy weather and at night, the plant encountered various technical issues. Solutions to these issues have been identified; however, successful demonstration of certain improvements is required prior to commercial financing of a large-scale plant.

In addition to Solar One and Solar Two, experimental and prototype systems have operated in Spain, France, and Israel. Solucar Energia, S.A., an Abengoa company, recently announced the completion of an 11 MW solar power tower near Seville, Spain. Called PS 10, the power plant is the first tower-based solar power system to generate electricity commercially. PS 10 uses a water-steam receiver. Abengoa has plans for a second, 20 MW plant. In addition, ESKOM, the largest utility in South Africa, is considering a 100 MW molten-salt plant. A 17 MW molten salt plant in Spain, Solar Tres, is also being planned by Ghersa, Boeing, and Nexant. However, this plant appears unlikely to be built at this time. The primary developer of molten salt technology for power towers is United Technologies Corporation.

Compact Lens Fresnel Reflector (CLFR)

The compact linear Fresnel reflector (CLFR) is a solar thermal technology in which rows of mirrors reflect solar radiation on a linear receiver located on towers above the mirror field. Solar Heat & Power from Australia is developing a CLFR technology (Ausra is the US affiliate). Liddell 1, the first generation CLFR system is shown in Table 4-12. That system is located at the Macquarie Liddell Power Station near Singleton, New South Wales, Australia. Liddell 2 is under construction at the same site. Liddell 2 will supply steam to the Liddell Power Station for feedwater heating. Ausra is developing a

6.5 MWe solar electric demonstration plant in Portugal. The company is marketing large solar electric systems in the United States.

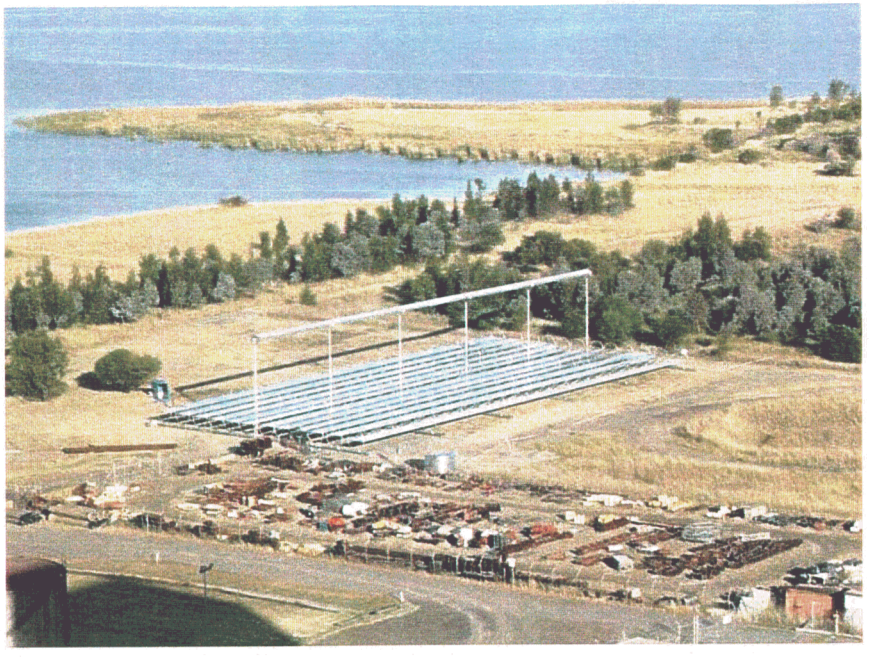


Figure 4-12. Liddell Phase 1 CLFR Demonstration System.

In the CLFR, collector mirrors rotate on the linear axis parallel to the receiver, following the sun's movement throughout the day. The CLFR is similar to the more commercially mature solar parabolic trough systems in that it uses one-axis tracking to focus solar radiation on a linear receiver. However, the CLFR has major difference from the trough system. These include several advantages.

- The CLFR optics are less stringent than optics of a trough. This allows a less expensive collector/receiver system.
- The CLFR receiver does not move, such that no flexible hoses or ball joints are required as in a trough system.
- The CLFR is more compact in terms of land use. A CLFR may have a ground cover ratio (GCR), which is the ratio of mirror area to land area, of about 70 percent versus a GCR of about 30 percent for a trough.

Disadvantages of the CLFR compared to the trough include the following.

- The CLFR is less mature in technical and commercial development.
- Trough cost and performance are fairly well known, whereas CLFR cost and performance are unproven.

- The saturated steam generated by the CLFR is relatively low temperature and being saturated, rather than superheated, results in less efficient power generation.
- The overall CLFR solar to steam efficiency is substantially lower than trough.

Cost and Performance Characteristics

While there are several solar thermal technologies being actively promoted, the most commercial technology is parabolic trough. Representative characteristics for a parabolic trough system with 6 hours of energy storage operating in Arizona are presented in Table 4-12. This table also includes cost estimates for a 14 MW solar dish system. Costs for 100 MW plus systems should be much lower (perhaps by as much as half) if technology development and large-scale manufacturing is successful. Further discussion of potential solar configurations and costs are provided in Section 5 of this report.

Table 4-12. Solar Thermal Technology Characteristics.

	Parabolic Trough	Parabolic Dish
Performance		
Typical Duty Cycle	Peaking - Intermediate	As Available, Peaking
Net Plant Capacity (MW)	100	14
Integrated Storage	6 hours	None
Capacity Factor (percent)	37 to 43	20 to 25
Economics ($2007)		
Total Project Cost ($/kW)	5400 to 6300	5,000 to 6,000
Variable O&M ($/MWh)	20 to 25	10 to 20
Levelized Cost ($/MWh)	132 to 176	184 to 281
Applicable Incentives	30% ITC	30% ITC
Technology Status		
Commercial Status	Commercial	Demonstration
Installed US Capacity (MW)	~350	< 1

4.4.2 Photovoltaics

Due to its high cost, intermittency, and low capacity factor, solar photovoltaics (PV) has had little penetration into the electricity market. While solar, in general, represents a very small portion of the overall electricity generated in the US, solar PV represents an even smaller fraction. However, there is recent strong growth being

observed in the PV industry. In the US in 2005, 70 MW of grid connected PV was installed, which is nearly double the installations in 2003. This section provides a background into the solar PV industry, the benefits of solar PV energy, and the incentives available to solar PV installations.

Operating Principles

Solar PV converts sunlight (also known as insolation) directly into electricity. The power produced depends on the material involved and the intensity of the solar radiation incident on the cell. Single or polycrystalline silicon cells are most widely used today. Single crystal cells are manufactured by growing single crystal ingots, which are sliced into thin cell-size material. The cost of the crystalline material is significant. The production of polycrystalline cells can cut material costs but with some reduction in cell efficiency. Thin film solar cells are made from layers of semiconductor materials only a few micrometers thick. These materials make applications more flexible, as thin film PV can be integrated into roofing tiles or windows. Thin film cells significantly reduce cost per unit area, but also result in lower efficiency cells. Gallium arsenide cells are among the most efficient solar cells and have other technical advantages, but they are also more costly and typically are used only where high efficiency is required even at a high cost, such as space applications or in concentrating PV applications. Additional advanced technologies are under development including dye sensitized solar cells (DSSC) and organic light emitting diodes (OLED). These technologies hope to achieve dramatic reductions in cell cost, but likely will have efficiencies on the lower end of the range for PV cells.

Markets

Currently, the commercial PV market is dominated by silicon-based cells, with about 90 percent market share including thin-film silicon cells. Recent shortages and cost increases of silicon have driven the market for new materials. The following chart shows production by technology type.

Table 4-13. 2005 World Cell Production by Technology Type (MW).

Technology	US	Japan	Europe	ROW	Total	%
Monocrystalline flat plate	58	179.4	149	100	486.4	28
Polycrystalline flat plate	23	495	277	196	991	56
Amorphous silicon	23	36.2	6.1	6	71.3	4
Silicon ribbon	27	-	26	-	53	3
Cadmium telluride	20	-	12	0	32	2
Copper indium diselenide	3	-	2	-	5	0
A-si/CZ slice	-	122	-	-	122	7
Total (all technologies)	154	833	472	302	1760	100

Source: PV News, Vol. 25, No. 4, April 2006.

Solar photovoltaics have achieved enviable growth over the last few years. Worldwide grid-connected residential and commercial installations grew from 120 MW per year in 2000 to nearly 1,200 MW per year in 2005. The majority of these installations were in Japan and Germany, where strong subsidy programs have made the economics of PV very attractive. The US grid connected market was 70 MW in 2005, with most of these installations in California.

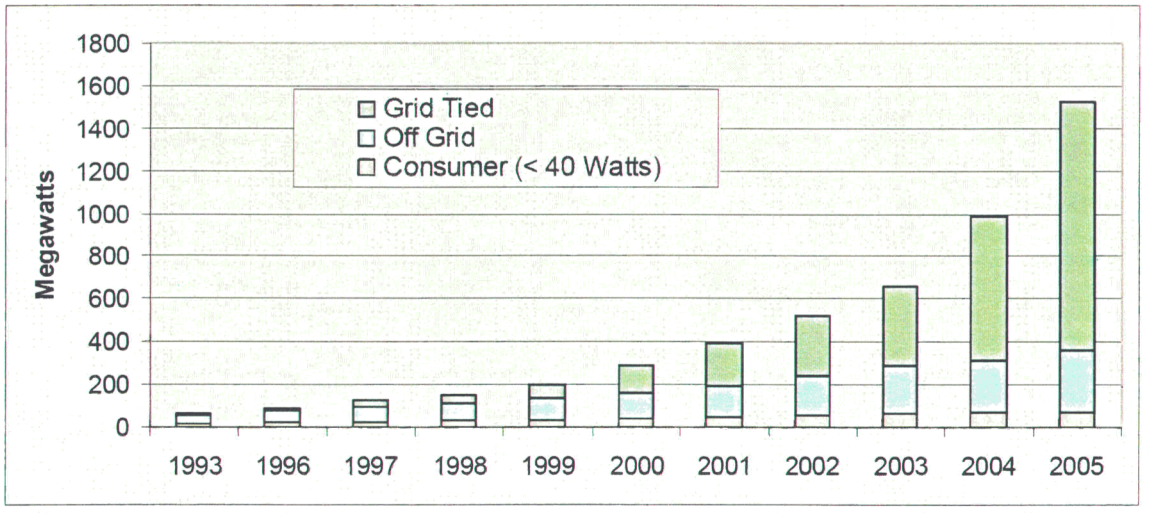


Figure 4-13. Worldwide PV Installations, MW (Source: Renewable Energy World).

Applications

Solar PV was originally developed as a power source for the space program. PV found its first terrestrial uses in remote industrial and residential applications. This "off

grid" use of solar has been cost effective for some time, as it is generally less expensive than extending the electricity grid to remote locations. While these off-grid installations were roughly half the worldwide PV market in 1999, the explosive growth of "grid tied" PV has dropped its share of the total PV market to 19 percent by 2005. Grid tied solar is the focus of this report – PV systems that are connected to the electricity grid and simply offset energy purchased from the grid. Figure 4-14 displays the PV application by market sector in the US.

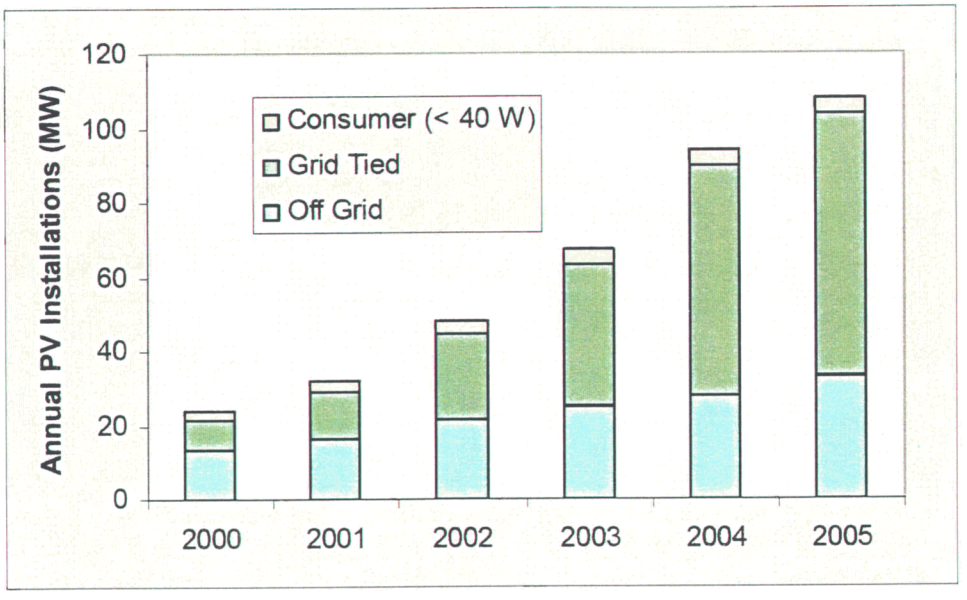


Figure 4-14. US Annual PV Installations (Renewable Energy World).

Concentrating Solar Photovoltaic Systems

Concentrating photovoltaic (CPV) plants provide power by focusing solar radiation onto a photovoltaic (PV) module, which converts the radiation directly to electricity. Either mirrors or lenses can be used to concentrate the solar energy for a CPV system. Most of the CPV systems use two axis tracking to achieve point focus images on PV cells. Single axis, line focus CPV systems have been built, but do not appear to have the long term commercial potential that the two axis tracking CPV systems have.

Concentrating photovoltaic (CPV) systems have potential for cost reduction compared with conventional, non-concentrating (also referred to as flat plate) PV systems in two key ways. First, a major portion of the conventional PV system cost is for the semiconductor material which makes up the PV modules. By concentrating sunlight onto a small cell, the amount of semiconductor material can be reduced, albeit at additional cost for mirrors or lenses and for tracking equipment. Recent rises in solar module prices

due to semiconductor-grade silicon have made CPV more attractive. Second, use of smaller cells allows for more advanced and efficient cell technology, making the overall system efficiency higher than for a conventional flat plate system.

CPV systems have been under development since the 1970's. This development has included single axis tracking, line focus CPV and two axis tracking, point focus CPV. Recent development has primarily been on the two-axis tracking systems. Developers of CPV technology include Amonix (Figure 4-15), Solar Systems (Figure 4-16), Energy Innovations, Sharp, EMCORE, and SolFocus.

Amonix systems have been deployed at Nevada Power (75 kW at Clark generating station) and Arizona Public Service (APS) facilities for a total capacity of over 600 kW. Planned deployments in the near future include 10 to 20 MW in Spain. Solar Systems Pty, Ltd, has a different approach to CPV, using a parabolic dish concentrator to focus DNI on a high concentration PV receiver. Ten dishes have been deployed since 2003, for a total capacity of 220 kW, with the construction of an additional 720 kW under way. Solar Systems recently announced a 154 MW solar power plant, but using distributed power towers with CPV receivers instead of dish systems.

It is unclear if any of these CPV technologies will achieve their desire cost targets of $70-$80/MWh. It does appear, however, that CPV may be more appropriate for utility-scale PV due to lower land requirements and reduced silicon use.

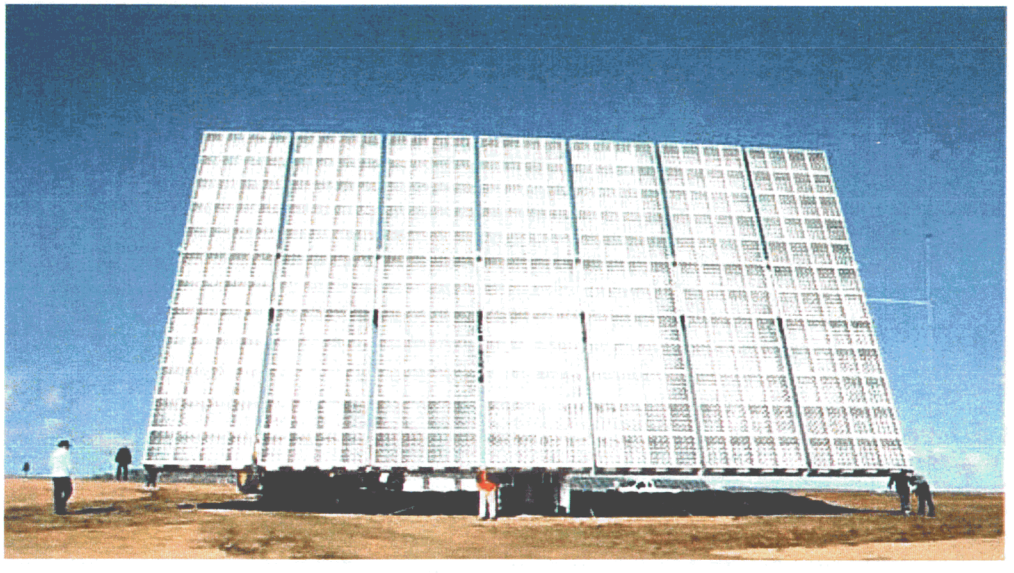


Figure 4-15. Amonix: Flat Acrylic Lens Concentrator with Silicon Cells (NREL).

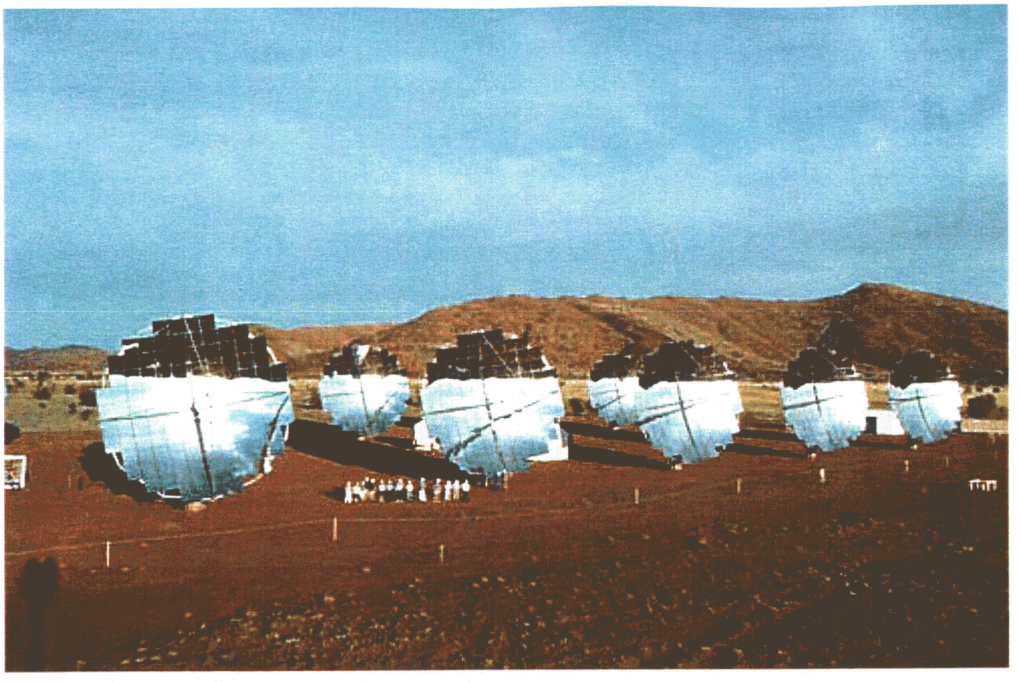


Figure 4-16. Solar Systems Pty, Ltd: Parabolic Dish PV Concentrator (NREL).

Resource Availability

Most PV systems installed today are flat plate systems that use global insolation. CPV systems require DNI, as discussed under the Solar Thermal section. Figure 4-17 shows the solar insolation resource for a flat plate collector in the US.

Cost and Performance Characteristics

Solar advocates have believed that solar costs would continue to decrease as better technology and manufacturing economies-of-scale reduced costs. Solar PV module costs were roughly $10 per watt in 1985, and were on a downward trajectory for almost two decades. In early 2004, however, increased worldwide demand (especially from Germany and Japan) started pushing module prices back up from their low of $5 per watt, due to a scarcity of silica. Module costs represent about half of the total cost of a system, so solar installations are especially sensitive to movement in module pricing. Figure 4-18 shows module prices for the past few years; note these represent published retail costs, not bulk purchase costs available to PV installers.

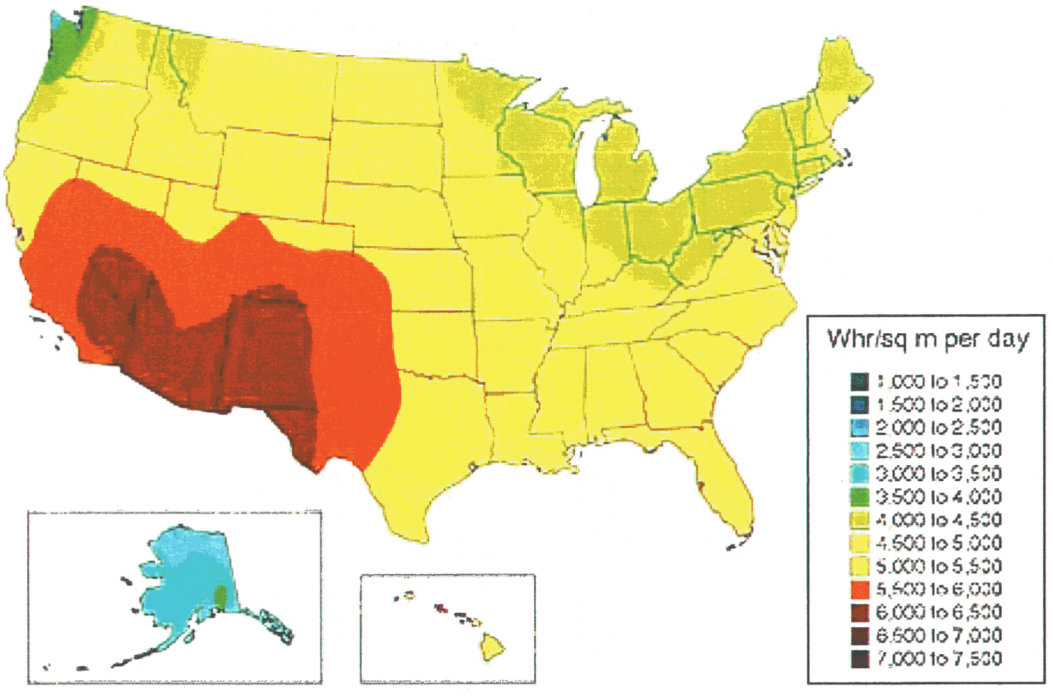


Figure 4-17. Solar Insolation Resource for a Flat-Plate Collector (Source NREL).

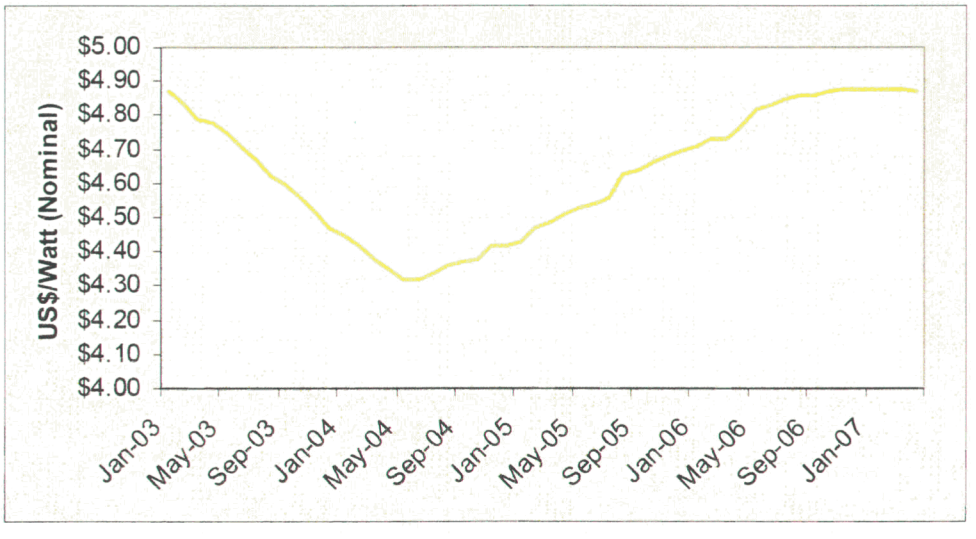


Figure 4-18. US Module Costs, $/Watt (Source: Solarbuzz).

Table 4-14 presents cost and performance characteristics of a 4 kW residential and a 250 kW commercial fixed-tilt, single crystalline PV system. The table also includes costs for a 3 MW utility scale tracking system.

Table 4-14. Solar PV Characteristics.

	Residential	Commercial	Utility Scale
Performance			
Typical Duty Cycle	As Available, Peaking	As Available, Peaking	As Available, Peaking
Net Plant Capacity (kWp)	4	250	3,000
Capacity Factor (percent, based on kWp)	18	20	23
Economics ($2007)			
Total Project Cost ($/kWp)	7,200 to 10,500	6,000 to 7,500	5,000 to 6,500
Fixed O&M ($/kWp-yr)	50	30	30
Levelized Cost ($/MWh)	358 to 509	321 to 407	278 to 365
Applicable Incentives	30% ITC*		
Technology Status			
Commercial Status	Commercial		
Installed US Capacity (MW)	~400		

Notes:
* Requires, taxable, non-utility ownership

4.4.3 Solar Technologies Development Prospects

The technical potential for both solar thermal and solar photovoltaic projects in Arizona is very large.

Concentrating solar projects rely on DNI resources. Figure 4-19 shows the DNI with Arizona with several exclusion factors. The map excludes areas of Arizona with less than 6.75 kWh/m²/day, areas with a slope greater than 1 percent, major urban areas and water, environmentally sensitive lands and remaining areas smaller than 5 km². This is done to focus on areas that have greatest potential for concentrating solar power. Concentrating solar power plants (thermal or CPV) generally require that the previous conditions be met.

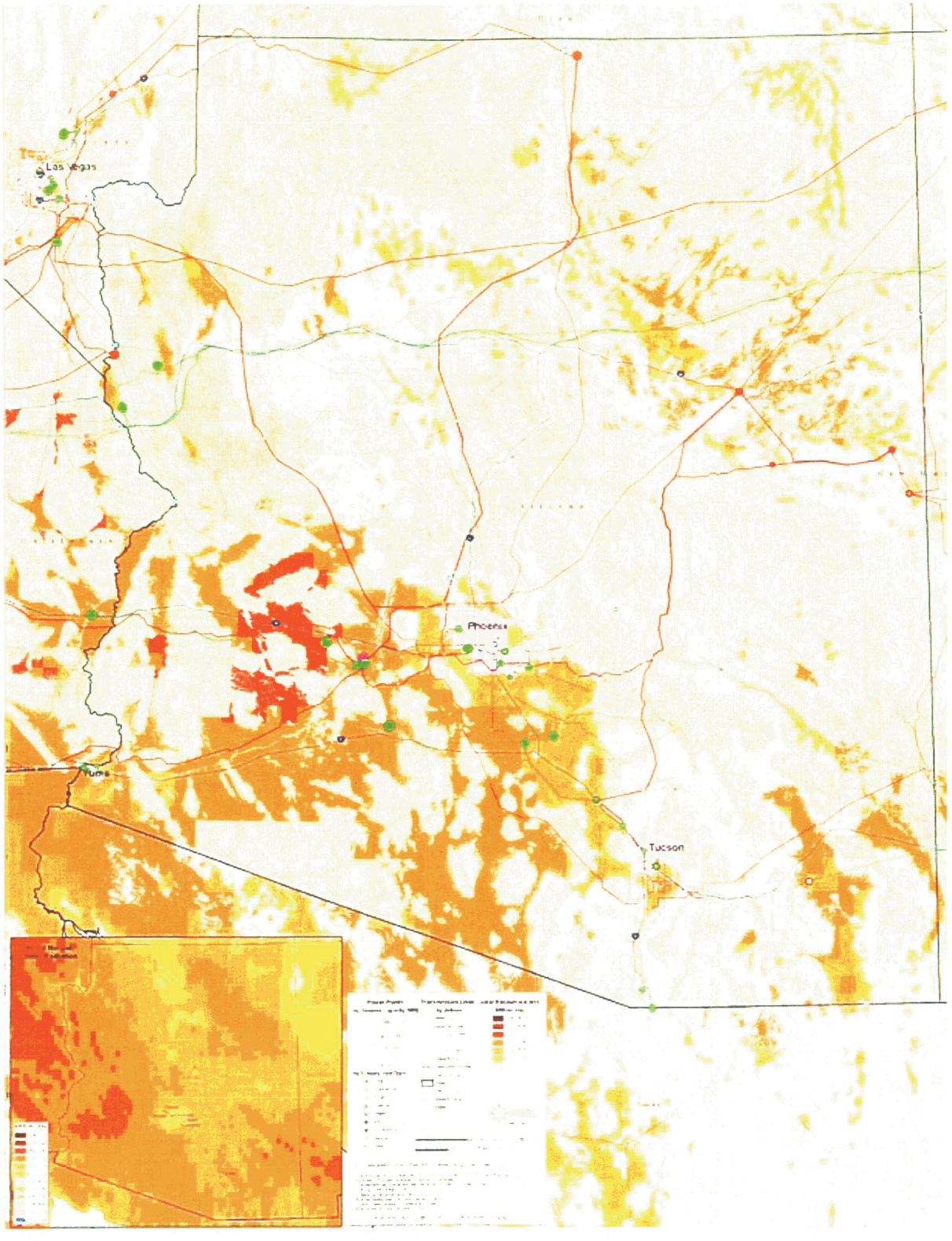


Figure 4-19. Arizona Concentrating Solar Power (DNI) Resources (NREL).

Flat panel photovoltaics installations have the ability to function in less sunny environments (at lower production levels) and can be installed on a wide range of sites including rooftops and urban areas. As an example of the theoretical potential for solar PV, see Table 4-15. Solar insolation data was gathered from NREL and the average annual solar insolation for a flat-plate collector was calculated for Arizona. The solar potential was calculated. The technical potential estimate assumes that there are no constraints on equipment availability, cost, or other site-specific criteria. Technical potential is not the same a developable potential which only includes projects that would be able to be financed and are subject to the constraints of product availability, cost and site-specific criteria. This estimate was based on installing photovoltaic panels on 0.25 percent of the land area in Arizona. This estimate yielded a photovoltaic potential capacity estimate in excess of the current demand for energy in Arizona.

Table 4-15. Theoretical Solar Power Production in Arizona.

AZ Total Square Miles	113,635
0.25% of Arizona Land Area in Square Miles	284 (17x17 mi)
Total Theoretical Solar Annual MWh PV Production in Arizona	123,500,000
Arizona Total Annual MWh Generation 2005	101,478,654
Notes: Assumes 4.6 kWh/m²/day insolation (an AZ minimum value), and 10% solar conversion efficiency.	

With energy storage, solar could theoretically supply the entire electricity needs of the state. It is interesting to note that the land requirements for solar are very reasonable compared to the suitable land available in the state for concentrating solar and the excellent resource even in urban areas for PV.

Given that the solar resource is so large, in the near term, developable solar potential is more limited by cost, manufacturing capacity of equipment suppliers, transmission adequacy and congestion issues,m and the development of suitable energy storage technologies to handle the intermittent output of the resource.

4.5 Hydroelectric

Hydroelectric power is generated by capturing the kinetic energy of water as it moves from a higher elevation to a lower elevation by passing it through a turbine. The amount of kinetic energy captured by a turbine is dependent on the head (vertical height the water is falling) and the flow rate of the water. Often, the water is raised to a higher potential energy by blocking its natural flow with a dam. If a dam is not feasible, it is

possible to divert water out of the natural waterway, through a penstock, and back to the waterway. Such "run-of-river" applications allow for hydroelectric generation without the impact of damming the waterway. The existing worldwide installed capacity for hydroelectric power is by far the largest source of renewable electricity at over 800,000 MW.

Applications

Hydroelectric projects are divided into a number of categories according to their size. Micro hydroelectric projects are below 100 kW. Systems between 100 kW and 1.5 MW are classified as mini hydroelectric projects. Small hydroelectric systems are between 1.5 and 30 MW. Medium hydroelectric projects range up to 100 MW, and large hydroelectric projects are greater than 100 MW. Medium and large hydroelectric projects are good resources for baseload power generation if they have the ability to store a large amount of potential energy behind a dam and release it consistently throughout the year. Small hydroelectric projects generally do not have large storage reservoirs and are not dependable as dispatchable resources (Figure 4-20).

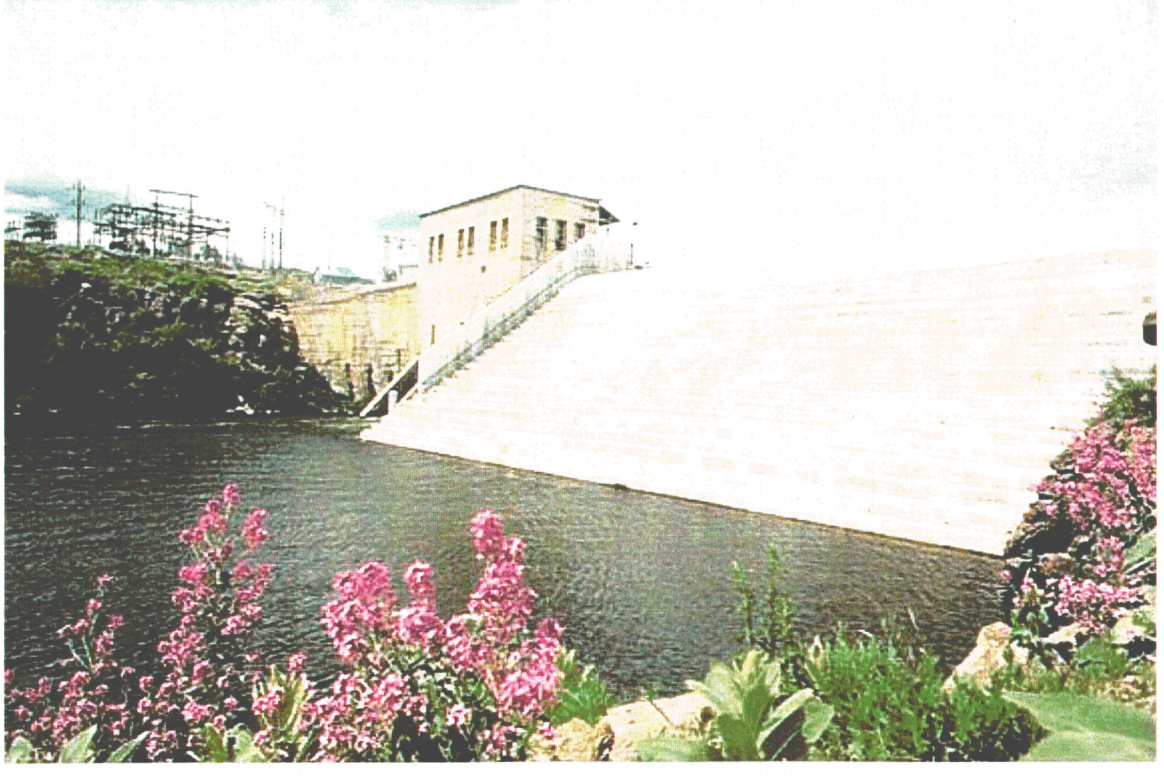


Figure 4-20. 3 MW Hydroelectric Plant.

Resource Availability

A hydroelectric resource can be defined as any flow of water that can be used to capture the kinetic energy. Projects that store large amounts of water behind a dam can regulate the release of water through turbines and generate electricity regardless of the season. These facilities can generally serve base loads. Run-of-river projects do not impound the water, but instead divert a part or all of the current through a turbine to generate electricity. At run-of-river projects, power generation varies with seasonal flows and can sometimes help serve summer peak loads.

All hydroelectric projects are susceptible to drought. In fact, the variability in hydroelectric output is rather large, even when compared to other renewable resources. The aggregate capacity factor for all hydroelectric plants in the United States has ranged from a high of 47 percent to a low of 31 percent.

Cost and Performance Characteristics

Hydroelectric generation is regarded as a mature technology that is unlikely to advance. Turbine efficiency and costs have remained somewhat stable, but construction techniques and costs continue to change. Capital costs are highly dependent onsite characteristics and vary widely. Table 4-16 provides ranges for performance and cost estimates for hydroelectric projects for two categories: new projects at undeveloped sites and additions or upgrades to hydroelectric projects at existing sites. These values are for representative comparison purposes only. Capacity factors are highly resource dependent and can range from 10 to more than 90 percent. Capital costs also vary widely with site conditions.

Environmental Impacts

The damming of rivers for small- and large-scale hydroelectric applications may have significant environmental impacts. One major issue involves the migration of fish and disruption of spawning habits. For dam projects, one of the common solutions to this problem is the construction of "fish ladders" to aid the fish in bypassing the dam when they swim upstream to spawn.

A second issue involves flooding existing valleys that often contain wilderness areas, residential areas, or archeologically significant remains. There are also concerns about the consequences of disrupting the natural flow of water downstream and disrupting the natural course of nature.

Table 4-16. Hydroelectric Technology Characteristics.

	New	Incremental
Performance		
Typical Duty Cycle	Varies with Resource	Varies with Resource
Net Plant Capacity (MW)	<50	1 to 160
Capacity Factor (percent)	40 to 60	40 to 60
Economics (2007$)		
Total Project Cost ($/kW)	2,500 to 4,000	600 to 3,000
Fixed O&M ($/kW-yr)	5 to 25	5 to 25
Variable O&M ($/MWh)	5 to 6	3.5 to 6
Levelized Cost ($/MWh)	44 to 121 (w/PTC)	5 to 92
Applicable Incentives	$10/MWh PTC – No dams or impoundments; 150 kW-5 MW	$10/MWh PTC
Technology Status		
Commercial Status	Commercial	
Installed US Capacity (MW)	99,000	

Arizona Hydroelectric Development Prospects

In general, the prospects for new hydroelectric development are limited. Arizona covers approximately 114,000 square miles with only 364 square miles covered by water. More than half of Arizona consists of mountains and dry plains. Arizona is arid. Some mountain regions can receive an annual rainfall of more than 30 inches but precipitation in most of the state is very low on average, 6 to 8 inches per year. Much of Arizona's history is that of having an inadequate water supply. Due to the geography and Arizona's mostly dry and arid climate hydroelectric potential is limited.

In spite of limited water resources, Arizona imports and transfers relatively large quantities of water over large distances. This results in a large portion of potential resources coming from numerous manmade conveyances.

It is important to consider the requirements of Arizona's Renewable Energy Standard when evaluating hydroelectric opportunities. In the previous Environmental Portfolio Standard hydroelectric was not eligible as a renewable electricity technology. However, in Arizona's new RES two kinds of hydroelectric are eligible to meet the RES requirements:

1) **"Eligible Hydropower Facilities"** under RES requirement are hydroelectric generators that were in existence prior to 1997 and that satisfy one of the following two criteria:

a) New Increased Capacity of Existing Hydroelectric Facilities: A hydroelectric facility that increases capacity due to improved technological or operational efficiencies or operational improvements resulting from improved or modified turbine design, improved or modified wicket gate assembly design, improved hydrological flow conditions, improved generator windings, improved electrical excitation systems, increases in transformation capacity, and improved system control and operating limit modifications. The electricity kWh that are eligible to meet the Annual Renewable Energy Requirements shall be limited to the new, incremental kWh output resulting from the capacity increase that is delivered to Arizona customers to meet the Annual Renewable Energy Requirement.

b) Generation from pre-1997 hydroelectric facilities that is used to firm or regulate the output of other eligible, intermittent renewable resources: The electricity kWh that are eligible to meet the Annual Renewable Energy Requirements shall be limited to the kWh actually generated to firm or regulate the output of eligible intermittent Renewable Energy Resources and that are delivered to Arizona customers to meet the Annual Renewable Energy Requirements.

2) **"New Hydropower Generator of 10 MW or Less"** under RES requirement is a generator, installed after January 1 2006 that produces 10 MW or less and is either:

a) A low-head, micro hydroelectric run-of-the-river system that does not require any new damming of the flow of the stream; or

b) An existing dam that adds power generation equipment without requiring a new dam, diversion structures, or a change in water flow that will adversely impact fish, wildlife, or water quality; or

c) Generation using canals or other irrigation systems.

Other hydroelectric resources not regulated by RES Rules, such as the Salt River Project, are generally considered a renewable resource by many states if less than 30 MW.

There are 21 existing dam sites in Arizona with additional hydroelectric potential identified by the federal government. The U.S. Department of Energy Idaho National Engineering and Environmental Laboratory (INL) provides this information as part of the National Energy Strategy. These sites consist of 13 undeveloped sites with no developed impoundment or diversion structure, 6 developed sites with some kind of impoundment or diversion structure, and 2 sites with developed hydroelectric generation but where the

potential has not been fully developed. Of these 21 sites, all are located within two major river basins, the Colorado Main Stream River Basin and the Gila River Basin. However, only 12 of the sites were identified by INL as hydroelectric prospects presumably because they were undeveloped or had the greatest potential for further development.

Table 4-17 and Table 4-18 list 12 sites which have been identified by INL. Table 4-17 lists undeveloped projects which due to environmental concerns based on INL opinion reduce the likelihood that the sites may be developed to their physical potential. All of these sites would also be ineligible for the RES because they are new sites larger than 10 MW. Table 4-18 lists projects that show the most promise. These projects are likely eligible for the RES and have little or no environmental concerns.

Table 4-17. Further Development Unlikely (environmental concerns).

Plant Name	Stream Name	Owner	Capacity (MW)
Livingstone	Pinal Creek	Salt River Project	11.5
Orme	Orme Canal	N/A	20.0
Walnut Canyon	Salt River	Salt River Project	25.2
Knob	Salt River	Salt River Project	28.5
Mule Hoof	Salt River	Salt River Project	43.5
Source: INL			

Table 4-18. Some Likelihood (little or no environmental concerns).

Plant Name	Stream Name	Owner	Capacity (MW)
Beardsley Canal Drop	Beardsley Canal	Maricopa County Municipal	1.0
Yuma Main Canal	Yuma Main Canal	Bureau of Reclamation	1.4
Waddell	Aqua Fria River	Maricopa County Municipal	1.5
CAP Canal Turnout	CAP Canal	Maricopa County Municipal	2.5
Roosevelt	Roosevelt Canal	Roosevelt Water Conservation District	3.2
Tucson	CAP Aqueduct	City of Tucson	0.4
Glen Canyon Upgrade	Colorado	Bureau of Reclamation	71.8
Total			**81.8**
Source: INL			

Of the seven sites in Table 4-18 the Aqua Fria and the Colorado River are the only natural waterways. The majority of the Aqua Fria River runs through Federal land. Permitting issues may cause problems or delays with any upgrades to the system as is common with any work or modifications to natural river bodies. Land use for the Aqua Fria watershed is irrigated pasture and hayland with rangeland being the vast majority of the usage. The Beardsley Canal, Yuma Main Canal, and Roosevelt Canal are primarily for irrigation purposes. The Central Arizona Project (CAP) Aqueduct's primary purpose is municipal water supply to the city of Tucson to supplement the City's dependence on groundwater. The CAP Canal is primarily municipal and irrigation. The 72 MW Glen Canyon project would be an upgrade of an existing project, with no new dams, impoundments, or diversion of water. As such, it appears eligible for the RES. Further study is recommended for all the sites in Table 4-18 with exception of Aqua Fria River, with a total of 80.3 MW.

The following map, Figure 4-21, shows the possible hydroelectric project locations from Table 4-17 and Table 4-18 (excluding Glen Canyon):

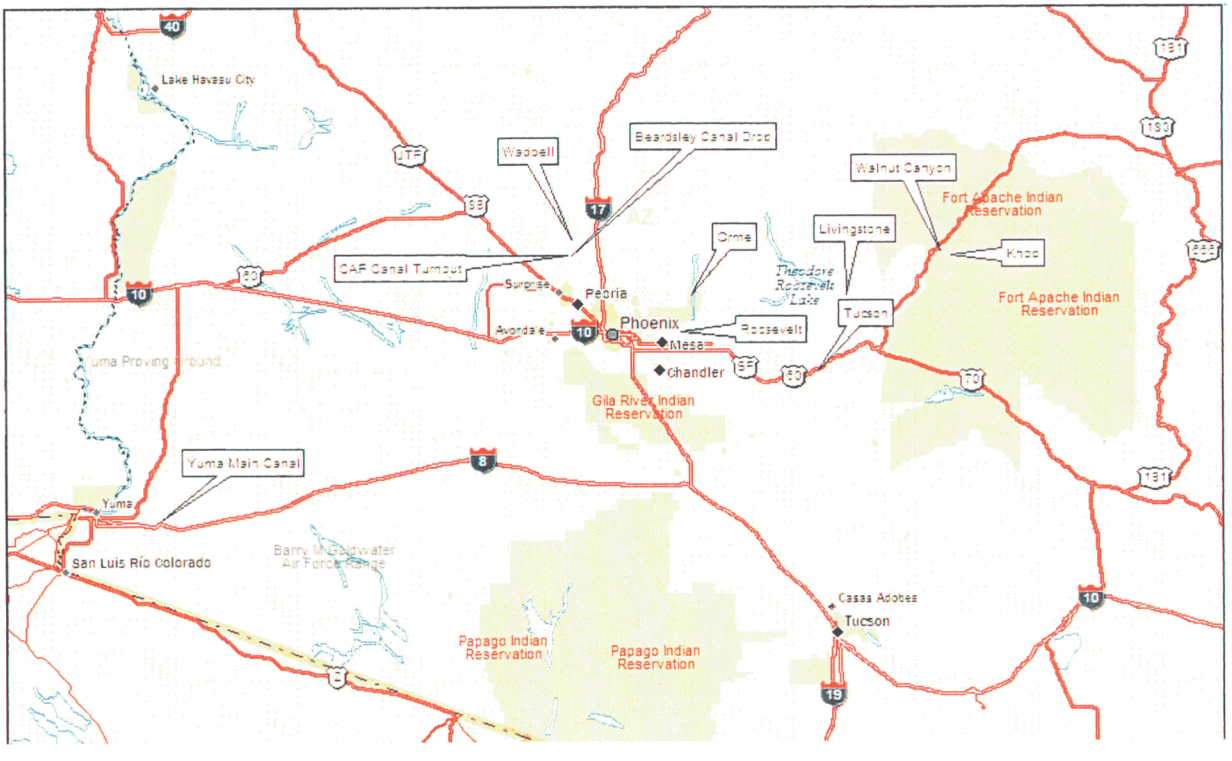


Figure 4-21. Potential Hydroelectric Locations in Arizona.

4.6 Wind Power

Wind power systems convert the movement of air to power by means of a rotating turbine and a generator. Wind power has been among the fastest growing energy sources over the last decade, with around 30 percent annual growth in worldwide capacity over the last five years. Cumulative worldwide wind capacity is now estimated to be more than 50,000 MW. In the United States, wind turbine capacity exceeded 10,000 MW in 2006. The US wind market has been driven by a combination of growing state mandates and the production tax credit (PTC), which provides an economic incentive for wind power. The PTC has expired and been renewed several times and is currently set to expire on December 31, 2008.

Applications

Typical utility-scale wind energy systems consist of multiple wind turbines that range in size from 1 to 2 MW. Wind energy system installations may total 5 to 300 MW, although the use of single, smaller turbines is also common in the United States for powering schools, factories, water treatment plants, and other distributed loads. Furthermore, offshore wind energy projects are now being built in Europe and are planned in the United States, encouraging the development of larger turbines (up to 5 MW) and larger wind farm sizes.

Wind is an intermittent resource, with average capacity factors generally ranging from 25 to 40 percent. The capacity factor of an installation depends on the wind regime in the area and energy capture characteristics of the wind turbine. Capacity factor directly affects economic performance; thus, reasonably strong wind sites are required for cost-effective installations. Since wind is intermittent, it cannot be relied upon as firm capacity for peak power demands. To provide a dependable resource, wind energy systems may be coupled with some type of energy storage to provide power when required, but this is not common and adds considerable expense to a system. Figure 4-22 shows a wind farm in California.

Resource Availability

Turbine power output is proportional to the cube of wind speed, which makes small differences in wind speed very significant. Wind strength is rated on a scale from Class 1 to Class 7, as shown in Table 4-19.

Figure 4-22. Wind Farm near Palm Springs, California.

Table 4-19. US DOE Classes of Wind Power.

Wind Power Class	Height Above Ground: 50 m (164 ft)*	
	Wind Power Density (W/m^2)	Speed** (m/s)
1	0 to 200	0 to 5.60
2	200 to 300	5.60 to 6.40
3	300 to 400	6.40 to 7.00
4	400 to 500	7.00 to 7.50
5	500 to 600	7.50 to 8.00
6	600 to 800	8.00 to 8.80
7	800 to 2000	≥ 8.80

Notes:

* Vertical extrapolation of wind speed based on the 1/7 power law, defined in Appendix A of the *Wind Energy Resource Atlas of the US, 1991.*

** Mean wind speed is based on Rayleigh speed distribution of equivalent mean wind power density. Wind speed is for standard sea level conditions. To maintain the same power density, wind speed must increase 3 percent per 1,000 m (5 percent per 5,000 ft) elevation.

Cost and Performance Characteristics

Table 4-20 provides typical characteristics for a 50 to 100 MW wind farm. Substantially higher costs are necessary for wind projects that require grid upgrades or

long transmission tie lines. Capital costs for new onshore wind projects had remained relatively stable for several years, but current demand has driven up the cost significantly over the past two years. Additionally, due to the increased demand and impending PTC expiration, the current earliest delivery date for new turbines is 2008. Significant gains have been made in recent years in identifying and developing sites with better wind resources and improving turbine reliability. As a result, the average capacity factor for all installed wind projects in the United States has increased from about 24 percent in 1999 to over 32 percent in 2005.

Table 4-20. Wind Technology Characteristics.

Performance	
Typical Duty Cycle	As Available
Net Plant Capacity (MW)	50 to 100
Capacity Factor (percent)	25 to 35[a]
Economics ($2007)	
Total Project Cost ($/kW)	1,600 to 1,900
Fixed O&M ($/kW-yr)	28
Variable O&M ($/MWh)	8
Levelized Cost ($/MWh)	51[b] to 93
Applicable Incentives	$20/MWh PTC, 5-yr MACRS
Technology Status	
Commercial Status	Commercial
Installed US Capacity (MW)	10,500[c]

Notes:
[a] Typical values for Class 3 to 4 winds, which make up the majority of the resource in Arizona.
[b] Ideal scenario, assumes highest capacity factor and lowest capital costs.
[c] Estimate as of September 2006.

Environmental Impacts

Wind is a clean generation technology from an emissions perspective. However, there are still environmental considerations associated with wind turbines. Opponents of wind energy frequently cite visual impacts and noise as drawbacks. Turbines are approaching and exceeding heights of 400 feet and, for maximum wind capture, tend to be located on ridgelines and other elevated topography. Turbines can cause avian fatalities and other wildlife impacts if sited in sensitive areas. To some degree, these

issues can be partially mitigated through proper siting, environmental review, and the involvement of the public during the planning process.

Arizona Wind Potential

Arizona has relatively large wind potential, although most of it is lower quality resources. Much of the wind resource in Arizona is considered to be Class 2 or less, which is generally considered to be non-economic. There are fairly large areas of Class 3 winds, which are considered marginal wind resources. These are in a long line that passes near Flagstaff and continues to the eastern part of the state. Higher wind resources are predicted to exist along ridgelines as well. The map in Figure 4-23 shows the Class 3 and above wind resources in Arizona.

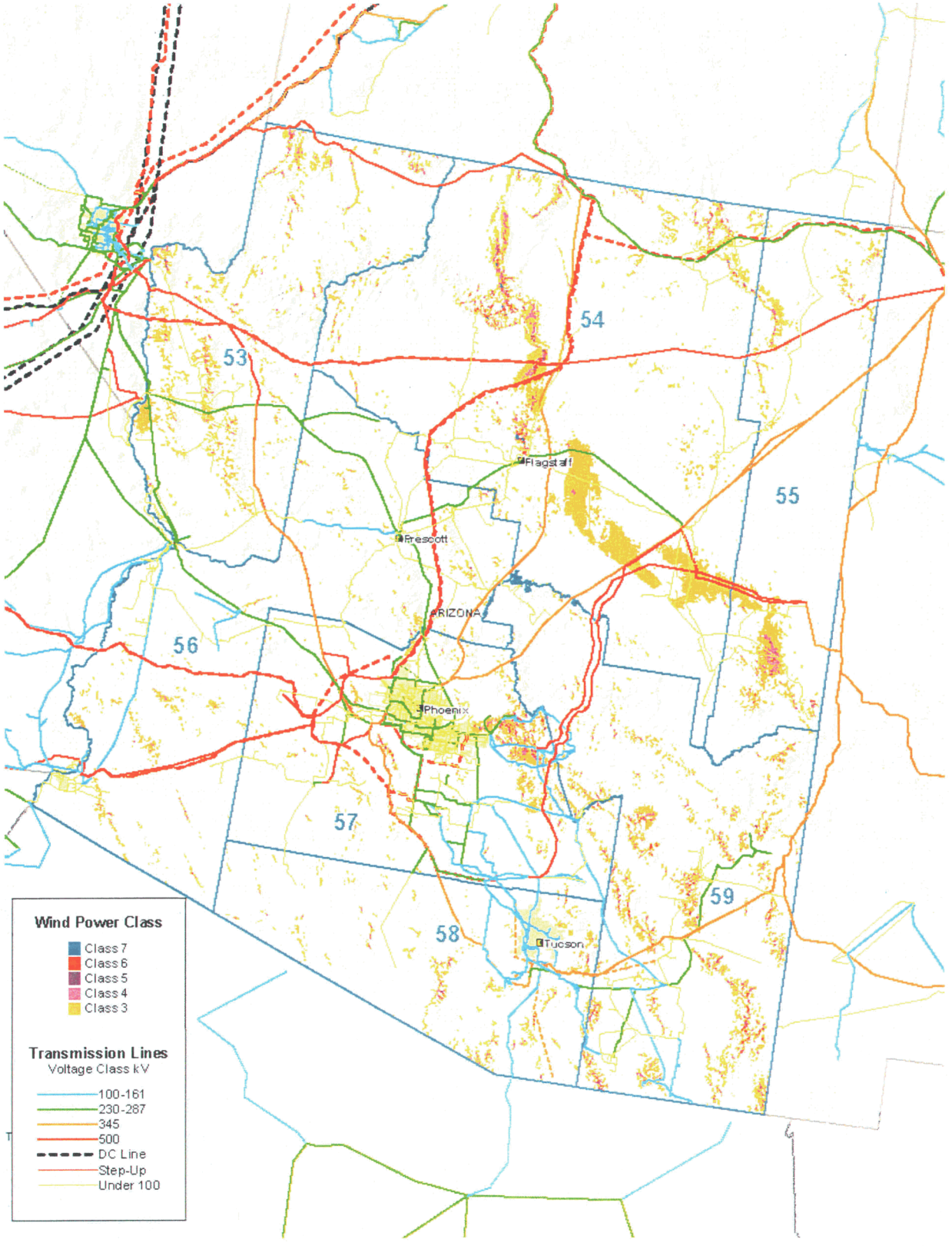


Figure 4-23. Wind Resources in Arizona, Class 3 and Above.

Table 4-21 shows the theoretical potential capacity from wind power class in seven regions in Arizona as estimated by NREL. The regions correspond to the large regions shown in the wind resource map. The greatest potential is shown in Region 54 (north central Arizona), which contains most of the large areas of Class 3 winds. This theoretical or technical potential is not bound by the constraints of product availability (backordered turbines, for instance), site-specific constraints such as transmission capacity, environmental restrictions, or cost. The next section of this report identifies the near-term developable potential for wind. This is a much smaller set of resources that could potentially be built and financed in the near term.

Table 4-21. Arizona Wind Technical Potential

Region	Capacity by Wind Power Class					Total Capacity
	3	4	5	6	7	
53	2,042	255	47	9	1	**2,355**
54	12,764	586	240	104	12	**13,706**
55	3,376	407	62	18	1	**3,864**
56	129	22	2	0	0	**152**
57	713	115	33	16	2	**879**
58	194	60	12	2	0	**267**
59	1,321	370	123	53	4	**1,870**
Total	**20,538**	**1,814**	**519**	**202**	**20**	**23,093**

Source: Donna Heimiller, NREL, 2006
Note: Total technical potential, assuming 5 MW of capacity per square km.

Arizona currently has no operating wind facilities, but there are several proposed projects. Transmission lines exist near several of the larger Class 3 areas, and the terrain does not appear to be particularly challenging to development. However, the existence of transmission lines is not the same as transmission path availability, and a more detailed review of at transmission issues is needed (outside the scope of this study).

Wind energy appears to be a good source of renewable energy for Arizona, although further investigation is needed to define how much of the theoretical capacity is actually developable.

4.7 Geothermal

Geothermal resources can provide energy for power production and other applications by using heat from the earth to generate steam and drive turbine generators.

The global installed capacity for geothermal power plants is about 8,900 MWe (megawatt electrical). Additionally, about 16,000 MWth is used in direct heat applications. It is estimated that geothermal resources using today's technology could support between 35,500 and 72,000 MWe of electrical generating capacity worldwide. Using enhanced technology that is currently under development, global geothermal resources have the potential to support between 65,500 and 138,000 MWe.

It is estimated that US geothermal resources could support between 6,300 and 11,700 MWe of electric power with current technology and 15,000 to 25,000 MWe with advanced technology.

Applications

In addition to generation of electricity and direct space heating applications, hot water and saturated steam from a geothermal resource can be used for a wide variety of process heat applications.

Resource Availability

Geothermal power can be developed where subsurface temperature gradients are elevated, such as in areas of young volcanism. However, there are other geologic settings favorable to geothermal development, including (for example) the Basin and Range province of the United States, where the crust is relatively thin, which leads to greater heat flow from the earth's interior. Tectonically active (but not necessarily volcanic) areas are also favorable because of the presence of significant faulting and fracturing that can allow deep circulation and heating of ground waters. Subsurface temperature gradients measured in wells help to determine the potential for geothermal development and the type of geothermal power plant installed. High energy sites are suitable for electricity production, while low energy sites are suitable for direct heating. Most of the known and most easily accessible geothermal resources in the United States are concentrated in the west and southwest parts of the country. Figure 4-24 shows the 90 MW Coso Junction Navy II geothermal plant in California.

Figure 4-24. COSO Junction Navy II Geothermal Plant.

Cost and Performance Characteristics

Geothermal power is generated in two kinds of plants: flash steam and binary. In the former, the produced geothermal fluid is separated into steam and water phases; the steam is supplied directly to the turbine generator, and the separated water is injected back into the ground. In a binary power plant, a working fluid is passed through a heat exchanger, where it is heated by the geothermal fluid to its boiling point. The vapor passes through the turbine generator and condensed to be re-used again. Both the working fluid and the geothermal fluid are kept in separate, sealed loops. After its heat is transferred to the working fluid, the geothermal fluid is injected back into the ground.

For representative purposes, a binary cycle power plant is characterized in Table 4-22. Capital costs of geothermal facilities can vary widely for several reasons, but one of the most important variables is the drilling cost to develop the resource. First, exploration wells must be drilled to find and prove the resource; there are almost always one or two "dry holes" (those that do not provide commercially attractive temperatures and/or flow rates) drilled during this process. Once defined and proven, the development wells (production and injection) are drilled. Well costs increase non-linearly with depth, so the geologic controls on the geothermal system need to be well-understood (as a result of the exploration drilling program) to arrive at accurate cost estimates. However, because the "fuel supply" is developed up-front, fuel price risks are non-existent. This, combined with the high availability of geothermal projects (typically more than 95

percent) makes geothermal attractive for baseload generation and managing portfolio risk.

Table 4-22. Geothermal Technology Characteristics.

Performance	
Typical Duty Cycle	Baseload
Net Plant Capacity (MW)	30
Capacity Factor (percent)	70 to 90
Economics ($2006)	
Total Project Cost ($/kW)	3,000 to 4,000
Variable O&M ($/MWh)	25 to 30
Levelized Cost ($/MWh)	46 to 81
Applicable Incentives	$20/MWh PTC, 5-yr MACRS
Technology Status	
Commercial Status	Commercial
Installed US Capacity (MW)	2,534

Environmental Impacts

Binary geothermal development has relatively few environmental impacts. As with any power project, land area must be set aside for the power plant, substation and power lines. Some road access into remote areas may be required. Areas disturbed for exploration activities, drilling and pipelines are typically restored and re-vegetated. Although geothermal fluids contain small quantities of non-condensable gases, the power plants are designed to either remove them or keep them in solution to be reinjected underground. Owing to strict well design guidelines, there is no pollution of surface or groundwaters. Geothermal power plants with modern emission control technologies have minimal environmental impact. They emit less than 0.2 percent of the CO_2, less than 1 percent of the SO_2, and less than 0.1 percent of the particulates of the cleanest fossil fuel plant.

There is the potential for geothermal production to cause ground subsidence. However, proper resource management (most importantly including an effective injection strategy) mitigates this risk.

Arizona Geothermal Outlook

Geothermal potential for electric power production in Arizona is undemonstrated at present. Relative to developments in other western states, Arizona is at an early stage

of development. After a long period of relative inactivity, geothermal development in the US is booming. Table 4-23 lists current development prospects as identified by the Geothermal Energy Association. There is one project in Arizona identified with 2 to 20 MW of potential. This is the Clifton project that has been under development by Vulcan, although there is not project activity at this time.

Table 4-23. Current Geothermal Development Prospects.

	Projects	MW
Alaska	2	20.6
Arizona	1	2-20
California	15	821-870
Hawaii	2	38
Idaho	2	36
New Mexico	2	21
Nevada	19	547-661
Oregon	6	186-211
Utah	2	47.6
Total	51	1,720-1,925

Source: Geothermal Energy Association, Jan 2007, http://www.geo-energy.org/

4.8 Fuel Cells Using Renewable Fuels

Fuel cell technology has been developed by government agencies and private corporations. Fuel cells are an important part of space exploration and are receiving considerable attention as an alternative power source for automobiles. In addition to these two applications, fuel cells continue to be considered for power generation for permanent power and intermittent power demands. Figure 4-25 shows an example of a fuel cell in operation.

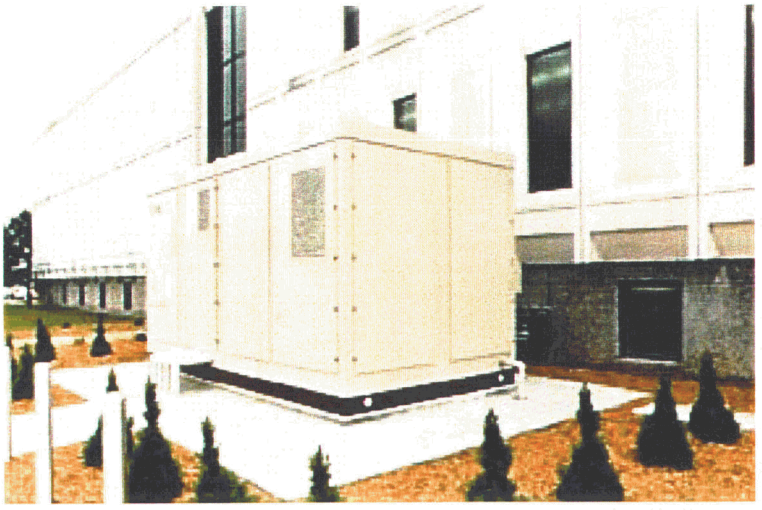


Figure 4-25. 200 kW Fuel Cell (Source: UTC Fuel Cells).

Operating Principles

Fuel cells convert hydrogen-rich fuel sources directly to electricity through an electrochemical reaction. Fuel cell power systems have the promise of high efficiencies because they are not limited by the Carnot efficiency that limits thermal power systems. Fuel cells can sustain high efficiency operation even under part load. The construction of fuel cells is inherently modular, making it easy to size plants according to power requirements.

There are four major fuel cell types under development: phosphoric acid, molten carbonate, solid oxide, and proton exchange membrane. The most developed fuel cell technology for stationary power is the phosphoric acid fuel cell (PAFC). PAFC plants range from around 200 kW to 11 MW in size and have efficiencies on the order of 40 percent. PAFC cogeneration facilities can attain efficiencies approaching 88 percent when the thermal energy from the fuel cell is utilized for low grade energy recovery. The potential development of solid oxide fuel cell/gas turbine combined cycles could reach electrical conversion efficiencies of 60 to 70 percent.

Applications

Most fuel cell installations are less than 1 MW. Commercial stationary fuel cell plants are typically fueled by natural gas, which is converted to hydrogen gas in a reformer. However, if available, hydrogen gas can be used directly. Other sources of fuel for the reformer under investigation include methanol, biogas, ethanol, and other hydrocarbons.

In addition to the potential for high efficiency, the environmental benefits of fuel cells remain one of the primary reasons for their development. High capital cost, fuel cell stack life, and reliability are the primary disadvantages of fuel cell systems and are the focus of intense research and development. The cost is expected to drop significantly in the future as development efforts continue, partially spurred by interest by the transportation sector.

Performance and Cost Characteristics

The performance and costs of a typical fuel cell plant are shown in Table 4-24. A significant cost is the need to replace the fuel cell stack every 3 to 5 years due to degradation. The stack alone can represent up to 40 percent of the initial capital cost. Most fuel cell technologies are still developmental and power produced by commercial models is not competitive with other resources. For reference, the price of fuel was assumed to range from $1 to $3/MBtu, which is representative of a landfill gas type resource.

Table 4-24. Fuel Cell Technology Characteristics.

Performance	
Net Capacity per Unit, kW	100-250
Net Plant Heat Rate, Btu/kWh	7,000-9,500
Capacity Factor, percent	70-90
Economics	
Capital Cost, $/kW	6,000-8,400
Fixed O&M, $/kW-yr*	650-910
Variable O&M, $/MWh	7-13
Fuel Cost ($/MBtu)	1.00 to 3.00
Levelized Cost, $/MWh	189 to 367
Applicable Incentives	30% ITC, capped at $1,000/kW
Technology Status	
Commercial Status	Early Commercial

Notes: Includes costs for cell stack replacement every four years.

Arizona Outlook

Fuel cells are a promising technology that shows potential for clean, renewable, distributed power generation in the future. Continued research and development is required to reduce the capital and O&M cost and increase the fuel cell stack life. In the near-term, fuel cells would be only be competitive with conventional power generation

technologies with considerable subsidies, and a low cost (or free) hydrogen fuel source. In the long-term (10-20 years), fuel cells could be a competitive power generation technology, pending advancements in R&D.

Methane sources (such as landfill, manure, MSW) are a good source of renewable hydrogen. Especially at a facility that already harvests the methane for power, reforming the gas instead to produce H2 is a good possibility. Because landfill, and digester gas is low heating value gas, the treatment to make H2 is more attractive. However, currently reciprocating engines are much more economical for these types of fuels.

Arizona State University has a significant fuel cell research effort. Most recently it has garnered some recognition for its work on fuel cells for laptop computer sized equipment. The Salt River Project has had two 5 kW fuel cells (Plug Power and GenSys 5CS) connected to its grid since 2005 for the purposes of testing them in the Arizona heat.

4.9 Compressed Air Energy Storage

Although it is not a renewable energy technology, compressed air energy storage can potentially help enable development of intermittent renewable energy sources, such as wind and solar. The technology is briefly introduced here.

Compressed air energy storage (CAES) is a technique used to supply electrical power to meet peak loads within an electric utility system. This method uses the power surplus from power plants during off-peak periods to compress and store air in an underground formation. The compressed air is later heated (with a fuel) and expanded through a gas turbine expander to produce electrical power during peak demand. A simple compressed air storage plant consists of an air compressor, turbine, generator unit, and a storage vessel. Exhaust gas heat recuperation can be added to increase efficiency.

The thermodynamic cycle for a compressed air storage facility is similar to that of a simple cycle gas turbine. Typically, gas turbines will consume 50 to 60 percent of their net power output to operate an air compressor. In a compressed air storage plant, the air compressor and the turbine are not connected, and the total power generated from the gas turbine is supplied to the electrical grid. By using off-peak energy to compress the air, the need for expensive natural gas or fuel oil is reduced by as much as two thirds, compared with conventional gas turbines.[9] This results in a very attractive heat rate for CAES plants, ranging from 4,000 to 5,000 Btu/kWh. Since fuel (typically natural gas) is supplied to the system during the energy generation mode, CAES plants actually provide

[9] Nakhamkin, M., Anderson, L., Swenson, E., "AEC 110 MW CAES Plant: Status of Project," *Journal of Engineering for Gas Turbines and Power*, October 1992, Vol. 114.

more electrical power to the grid than was used to compress the air. The capital costs for CAES facilities are approximately the same as a similar sized combined cycle facility.

The location of a CAES plant must be suitable for cavern construction or for the reuse of an existing cavern. However, suitable geology is widespread throughout the United States, with more than 75 percent of the land area containing appropriate geological formations.[10] There are three types of formations that can be used to store compressed gases: solution mined reservoirs in salt, conventionally mined reservoirs in salt or hard rock, and naturally occurring porous media reservoirs (aquifers).

CAES can potentially be a good match with renewable energy sources. CAES units are highly flexible; they have quick start-up times, high ramp rates, and good part-load efficiency. These attributes make them suitable to help balance intermittent wind and solar resources. In addition, it is possible that the fuel input needed during the expansion phase of the CAES cycle could be provided by biomass or biofuels.

The basic components of a CAES plant are proven technologies, and CAES units have a reputation for achieving good availability. The first commercial-scale CAES plant in the world was a 290 MW plant in Huntorf, Germany. This plant has been operating since 1978, providing 2 hours of generation with 8 hours of charging. In 1991, a 110 MW CAES facility was installed in McIntosh, Alabama. This plant remains the only US CAES installation, although several new plants have been announced. For example, the Iowa Association of Municipal Utilities is developing the Iowa Stored Energy Park. This project will combine up to about 200 MW of CAES with a wind farm.

Because it operates on the difference between off and on peak electricity prices, the economics of a CAES plant must be evaluated within the context of a specific market. Such an evaluation is outside the scope of this study. However, based on other studies Black & Veatch has performed, the following general conclusions can be drawn:

- CAES can be a very competitive option to serve intermediate loads.
- Because of its low heat rate, CAES can be more economical than combined cycle, especially at higher gas prices.
- To be cost effective, CAES requires access to low cost, off-peak energy from either coal, nuclear, hydroelectric, or wind facilities.
- Although CAES can help balance renewable energy resources, there is typically not enough value to justify a CAES project solely for this purpose. If new balancing or back-up capacity must be developed to "firm" wind and solar, simple cycle combustion turbines may offer a less expensive option.
- CAES can provide high value ancillary services (quick-start, spinning reserve, etc.) that need to be considered in an evaluation of CAES economics.

- The economics of CAES are not straightforward and are not easy to assess without detailed production cost modeling.

Although CAES seems to be gaining increased interest, it is not clear that there is a need for CAES in the near-term in Arizona to enable development of additional renewable resources. Based on the projections in this study, intermittent wind projects (which would benefit most from CAES) will likely comprise a relatively small fraction (< 5 percent) of the overall Arizona energy portfolio going forward. This level of wind penetration should be able to be accommodated without the need for a dedicated CAES facility. For this reason, CAES is not considered further in this study.

4.10 Renewable Energy Technology Summary

The technology cost and performance assumptions developed in the previous sections are summarized in Table 4-25. The values shown in the table were chosen as representative of the technology application in Arizona.

[10] Mehta, B., "Compressed Air Energy Storage: CAES Geology," *EPRI Journal*, October/November 1992.

Table 4-25. Renewable Technologies Performance and Cost Summary.[a]

	Net Plant Capacity, MW	Net Plant Heat Rate, Btu/kWh	Capacity Factor	Capital Cost, $/kW	Fixed O&M, $/kW-yr	Variable O&M, $/MWh	Fuel Cost, $/MBtu	Levelized Cost, $/MWh
Direct Biomass (UWW)	35	13500	70-90	2750-3500	83	11	1	66-94
Direct Biomass (FR)	35	13500	70-90	2750-3500	83	11	3	90-118
Biomass IGCC (UWW)	35	10000-11500	70-90	3000-4000	83	11	1	65-99
Biomass IGCC (FR)	35	10000-11500	70-90	3000-4000	83	11	3	82-120
Cofired Bio. (UWW)	30	10000	70-90	300-500	5-15	0	-0.5[c]	0-9
Cofired Bio. (FR)	30	10000	70-90	300-500	5-15	0	1	18-27
Anaerobic Digestion	0.15	11500	70-90	4000-6000	0	17	0	68-126
Landfill Gas	2-10	11500	70-90	1500-2000	0	17	1-3	40-80
Solar Thermal (trough)	100		37-43	5400-6300	0	20-25		132-176
Solar Thermal (dish)	14		20-25	5000-6000	0	10-20		184-281
Solar PV (residential)	0.004		18	8500-12500	50	0		358-509
Solar PV (commercial)	0.250		20	7000-9000	30	0		321-407
Solar PV (utility)	3		22	6000-8000	30	0		278-365
Hydro (new)	<50		40-60	2500-4000	5-25	5-6		44-121
Hydro (incremental)	1-160		40-60	600-3000	5-25	4-6		5-92
Wind	50-100		25-35	1600-1900	28	8		51-93
Geothermal	30		70-90	3000-4000	0	25-30		46-81
Fuel Cells	0.1-.25	7000-9500	70-90	5000-7400	650-910	7-13	1-3	189-367

Notes:
[a] Includes applicable incentives, subsidies, etc. All costs are in 2007 dollars.
[b] UWW = Urban Wood Waste ; FR = Forestry Residues
[c] Assumes payment for disposal of waste not taken to landfill.

4.10.1 Relative Costs

Of the renewable energy technologies evaluated, cofiring has the lowest capital cost per kW installed at $300-500/kW. The majority of the capital costs are associated with adding material handling equipment to an existing coal plant, as opposed to development of new plants for most other technologies. Wind has the next lowest capital cost at $1,600-1,900/kW. This has been a main driver in the 30 percent annual increase in wind installations worldwide over the last five years. Recently, however, system costs have begun to rise. In comparison, conventional biomass and geothermal technologies have capital costs in the range of $2,750-3,500/kW and $3,000-4,000/kW, respectively. The high cost of biomass plants is due to their relatively small size, extensive fuel and ash handling requirements, and the need for a robust plant design to handle the variability in the fuel quality. New hydroelectric power plants have a wide range of capital costs from $2,500-4,000/kW. Given that hydroelectric technology is quite mature and costs are low, the civil work that needs to be done to build dams and penstocks tends to be the driving factor behind the capital cost of these systems. Incremental hydroelectric improvements can be much lower in costs. Photovoltaic systems are by far the most expensive renewable energy technology, with capital costs from $6,000-12,500/kW and a capacity factor of only about 20 percent.

When comparing the levelized cost of energy produced by these systems, biomass, hydroelectric, anaerobic digestion, landfill gas, hydroelectric, wind and geothermal all have the potential to produce power at rates competitive with new coal and gas power generation. Although these resources have high capital costs, low operating costs combined with high operating capacity factors reduce the overall life-cycle costs.

Continued improvements will result in improvements in efficiency, capital cost, and operating and maintenance cost for several of the technologies. The technology areas where the levelized cost of power production should come down in the future are wind, biomass gasification, photovoltaics, solar thermal, and fuel cells. Large improvements are expected for solar technologies, with relatively modest improvements in other technologies.

4.10.2 Recommendations for Further Study

Based on the profiles described previously in this study, Table 4-26 presents our recommendations for further study. Due to their resource potential or low cost, these are the most promising technologies in Arizona.

Table 4-26. Promising Technologies for Arizona.

RECOMMENDED FOR FURTHER STUDY
Large Potential
• Wind • Solar Thermal (trough) • Solar Thermal (dish) • Solar PV (utility-scale, commercial)
Limited Potential, But Relatively Low Cost
• Direct Biomass • Cofired Biomass • Anaerobic Digestion • Landfill Gas • Hydroelectric (new) • Hydroelectric (incremental) • Geothermal
NOT RECOMMENDED FOR FURTHER STUDY
Emerging Technology / Technology Doesn't Yet Offer Compelling Cost Advantages over Other Alternatives
• Biomass IGCC • Fuel Cells • Plasma Arc • Compact Lens Fresnel Reflector
Distributed Applications (Outside Scope)
• Solar PV (residential)

5.0 Renewable Resource Assessment

The objective of this section is to assess the renewable energy resources of Arizona that are suitable for development in the near- to mid-term (next 20 years). Potential development prospects are identified, levelized generation costs are calculated, and a set of supply curves is developed. An end result of this process was the identification of a list of over 100 hypothetical renewable energy projects that might be developed to meet demands for renewable energy in Arizona.

The technologies reviewed in this section are:

- Direct Fired and Cofired Biomass
- Landfill Gas
- Anaerobic Digestion
- Solar Thermal Electric
- Solar Photovoltaic
- Hydroelectric
- Wind Power
- Geothermal

All costs presented in this section are in 2007$ unless otherwise stated. Additional economic assumptions impacting the projects are presented in Section 7.2.

5.1 Direct Fired and Cofired Biomass

Both direct-fired biomass and cofired biomass were identified as promising technologies in the first stage of the analysis. Cofiring is generally more economical, but it is limited to locations where biomass is available near an existing coal plant. If there are no coal plants in the vicinity, direct fired biomass is a more appropriate technology. This section characterizes the resources suitable for both technologies.

5.1.1 General Methodology

The feasibility of direct fired and cofired biomass projects is largely dependent upon obtaining an economical biomass fuel supply. A high-level review of biomass resources based primarily on data assembled by the National Renewable Energy Laboratory (NREL) was presented in Section 4 This estimate provided county-level estimates of biomass resources with the state. As discussed in Section 4, the national forests in Coconino, Navajo and Apache counties provide the largest sources of woody biomass resources. There are significant quantities of residues from forest thinning activities, and these residues are supplemented by mill residues from the Fort Apache

Timber Company (FATCO). Significant quantities of urban wood waste are found in the Phoenix and Tucson area. These metropolitan areas are surrounded by agricultural areas, which provide crop residues for smaller scale biomass energy facilities.

To obtain information regarding specific point sources of biomass resources that could be utilized to secure biomass fuel for actual biomass projects, Black & Veatch contacted potential suppliers of biomass resources via telephone. An initial round of phone calls were made to potential suppliers of biomass identified in a previous assessment of Arizona's biomass resources. This previous assessment, conducted by Black & Veatch in 2005 as part of a larger study for APS, identified over 60 potential suppliers, and the objective of the phone survey conducted for this present study was to verify that the resource previously identified were currently available and to determine if any additional resources were available. The focus of this effort was in the northern and eastern portions of the state as this is where much of the state's wood resources are located.

Following the initial round of calls, additional suppliers and agencies were contacted. Forestry and renewable energy experts at the University of Arizona and Northern Arizona University were consulted regarding biomass resources within the state, and national and state forestry officials were contacted to obtain information regarding potential forest thinning residues. Landfills were contacted to determine the availability of urban wood waste streams for use in biomass energy facilities.

Based on the conversations with biomass suppliers, forestry officials, and renewable energy experts, key findings of the updated assessment include:

- In general, the survey confirmed the presence of the biomass resources previously identified.
- One significant source of mill residues not previously identified was found. Southwest Forest Products has constructed a new sawmill in Ash Fork, which generates roughly 55 dry tons per day (dtpd) of mill residues.
- A significant competitor of biomass resources was also identified. An oriented strand board manufacturing facility is being developed in Winslow. This proposed facility would consume 1 million tons per year of biomass and may begin operation as soon as winter of 2008.
- The significant suppliers of primary mill residues are summarized in Table 5-1.
- The United States Forestry Service provided the current forest treatment plan for the national forests in Arizona. The estimated residues from forest thinning activities are summarized in Table 5-2.

- Information from landfills related to urban wood waste collection was inconsistent, and the specific quantity of potential resources could not be quantified. It is likely that smaller suppliers of urban wood waste, such as tree trimmers and landscapers, collect significant amounts of urban wood waste, but these suppliers were not contacted during this survey.

The general finding of the supplier survey is that the quantities of biomass resources identified in Section 4 of this report are currently available.

Table 5-1. Significant Primary Mill Residue Suppliers.

Supplier	Location	Quantity Available (dtpd)[1]
Fort Apache Timber Company (FATCO)	Whiteriver	210
Precision Pine and Timber	Heber	27
Southwest Forest Products	Ash Fork	55
Southwest Forest Products	Phoenix	36

Notes:
[1] Quantities listed are in units of dry tons per day (dtpd).

Table 5-2. Estimated Average Annual Forest Thinning Residues (2006-2015).

Forest	Quantity Available (dtpd)[1]	Quantity Available (dtpy)[1]
Apache-Sitgreaves	434	158,600
Coconino	176	64,400
Coronado	15	5,500
Kaibab	57	20,700
Prescott	18	6,500
Tonto	61	22,200

Source: United States Forestry Service, "Southwest Region 10-Year Treatment Plan." Obtained via e-mail from Marlin Johnson, USFS, on February 12, 2007.
Notes:
[1] Quantities listed are in units of dry tons per day (dtpd) and units of dry tons per year (dtpy).

In addition to the wood resources available, livestock population estimates listed in a spreadsheet of concentrated animal feeding operations (CAFOs) in Arizona were reviewed to determine the potential availability of animal manures and poultry litter (dryer material is suitable for combustion, wetter material is suitable for anaerobic digestion).

Following the rounds of resource assessment and review, the biomass resource estimates were aggregated. Considering the geographic distribution of the resources and the quantities available, two potential cofiring projects and one potential direct fired project were identified. The estimate of available resources is considered to be somewhat conservative, and it is likely that additional biomass projects could be developed if all of the resources identified were utilized by biomass facilities. However, biomass project developers generally attempt to identify at least 2 to 3 times the required tonnage needed for full-scale operation, and this assumption was used as a limit for the projects proposed in this study. Furthermore, the potential for biomass energy in Arizona is limited due to competition for the existing resources. In addition to typical competition for wood residues such as animal bedding and the new oriented strand board facility being developed in Winslow, there are also at least two significant biomass consumers in eastern Arizona:

- Forest Energy Corporation: Located in Show Low, Forest Energy produces almost 200 dry tons per day of pelletized wood, which is used as fuel for residential and commercial heating. Pellet fuel is generally thought to be too expensive for utility applications.
- Snowflake White Mountain Power (SWMP): Located near Snowflake, SWMP is a 24 MW biomass power facility scheduled to begin operation in 2008. In addition to burning recycled paper fibers from Abitibi, this facility will require roughly 250 additional dry tons per day of biomass.

The competition from these operations and other potential consumers of biomass resources will constrain the capacities of other biomass facilities.

5.1.2 Major Assumptions

The two potential cofiring projects identified in Arizona are assumed to be located at TEP's Springerville Generating Station and APS's Cholla Generating Station. Cofiring could also take place at SRP's Coronado station (with similar economics to that shown for Springerville). However, there may not be enough resources to support three cofiring projects in eastern Arizona.

The following assumptions were made in the evaluation of cofired biomass potential.

- The cofiring projects would employ a gasification system close coupled to the existing boiler.
- A Net Plant Heat Rate (NPHR) of 11,000 Btu/kWh was assumed for Cholla, based on boiler modeling conducted by Black & Veatch in a previous study. An NPHR of 10,000 was assumed for Springerville, based on information

available in Velocity Suite, a database of utility industry data maintained by Global Energy Decisions.

- The cofiring project at Springerville would utilize forest thinnings from Apache National Forests and mill residues from the Fort Apache Timber Company (FATCO). The thinning residues available from Apache National Forest are assumed to be one half of the total estimate for the combined Apache-Sitgreaves Forest provided by the US Forest Service.
- The cofiring project at Cholla would utilize forest thinnings from Coconino, Kaibab and Prescott National Forests and mill residues from Precision Pine and Timber (located in Heber, AZ) and Southwest Forest Products (located in Ash Fork, AZ).
- Only 50 percent of the forest thinnings estimated (according to the USFS plan) are assumed to be collected from the forests, as shown in Table 5-3.
- It was assumed that Springerville would only be able to obtain roughly 40 percent of the available resources from Apache National Forest and FATCO due to competition from existing biomass industries (e.g., Forest Energy) and planned biomass projects (e.g., Snowflake White Mountain Power), as shown in Table 5-4. The thinning residues available from Apache National Forest are assumed to be one half of the total estimate for the combined Apache-Sitgreaves Forest estimated by the US Forest Service.
- It was assumed that Cholla would be able to obtain 50 percent of the available mill residues from Precision Pine and Timber and Southwest Forest Products, as shown in Table 5-4.

Table 5-3. Potential Forest Thinnings.

National Forest	Total Estimate (dtpy)	Feasible Collection[1] (dtpy)
Apache	79,300	39,650
Coconino	64,400	32,200
Kaibab	20,700	10,350
Prescott	6,500	3,250

Source: US Forestry Service.
Notes:
[1] It was assumed that 50% of estimated forest thinnings would be collected.

Table 5-4. Biomass Resources Available for Cofiring.

	Total Resource Available (dtpy)	Percentage Available for Cofiring (%)	Resource Available for Cofiring (dtpy)
Springerville Cofiring			
Apache-Sitgreaves	39,650	40	15,900
FATCO	76,650	40	30,700
Total	**116,300**		**46,600**
Cholla Cofiring			
Coconino	32,200	100	32,200
Kaibab	10,350	100	10,350
Prescott	3,250	100	3,250
Precision Pine and Timber	9,850	50	4,900
SW Forest Prod.–Ash Fork	20,100	50	10,500
Total	**75,750**		**60,750**

The direct fired project identified is assumed to be located south of the Phoenix metropolitan area in Maricopa, Arizona.

The following assumptions were made in the evaluation of direct fired biomass potential.

- An NPHR of 14,500 Btu/kWh was assumed, which is typical of relatively small-scale (25 MW or less) combustion systems
- The proposed direct fired project would utilize a variety of biomass fuels, including mill residues, urban wood waste from Phoenix and Tucson, agricultural residues and beef manure.

If the cofiring projects face too many obstacles, an additional direct fired biomass facility could be developed in Northern Arizona in lieu of the cofiring projects. If all the biomass in the area were made available to the project, it is possible it could be sized as large as 20 MW. This project would be similar to the Maricopa project. There appears to be sufficient biomass in the vicinity to support either the cofiring projects or a direct fired, but not both. Because cofiring is likely less costly, it was decided to represent the renewable generation capacity as the two cofiring projects.

5.1.3 Future Cost and Performance Projections

Direct fired biomass is largely a mature technology. No changes in future cost or performance were assumed other than adjustments to account for normal inflation. The technology for gasifying biomass for use in cofiring PC units is still in the early

commercialization phase. While cost and performance improvements of such systems may change as expertise grows, improvements are expected to be relatively small. Therefore, no changes in future cost or performance were assumed other than adjustments to account for normal inflation.

5.1.4 Data Sources

Data sources used in this analysis included:

- Black & Veatch, "Cholla #1 Biomass Cofiring Conceptual Design Study." December, 2005.
- Spreadsheet of Concentrated Animal Feeding Operations (CAFO) in Arizona, provided by Thomas Ramey of APS on November 30, 2006.
- United States Forestry Service, "Southwest Region 10-Year Treatment Plan." Obtained via e-mail from Marlin Johnson, USFS, on February 12, 2007.
- Survey of Arizona biomass suppliers, forestry officials and landfills conducted by telephone. Survey conducted January-March, 2007.

5.1.5 Projects Identified

As mentioned above, two biomass cofiring projects have been identified. Based on the resources available and the assumptions listed above, a 10 MW cofiring project is feasible at Springerville Generating Station, and a 10 MW cofiring project is feasible at Cholla Generating Station. Assuming a capacity factor of 80 percent for both projects, annual biomass generation at Springerville and Cholla would be approximately 70 GWh/yr. These generation amounts do not represent additional generation, rather they represent displacement of coal with a renewable fuel. It is expected permitting and construction of the cofiring projects could be conducted in 18 to 24 months. Given a notice to proceed (NTP) of January 1, 2008, both cofiring projects could be operational by January 1, 2010.

A potential direct fired project has been identified south of the Phoenix metropolitan area. Based on the geographic distribution of the potential biomass resources, a likely potential site for this facility is Maricopa, Arizona. This location would allow the facility to utilize mill residues and urban wood wastes from Phoenix, urban wood wastes from Tucson and agricultural residues from Maricopa and Pinal counties.

A detailed permitting study was not completed for this task. However, both Maricopa County and Pinal County, in which the Maricopa facility would be located, are non-attainment areas for NOx and PM10. It is likely that a Selective Non-Catalytic Reduction (SNCR) would be required to control NOx, and a baghouse or electrostatic

precipitator (ESP) would be required to control particulate. A small scrubber may be necessary depending on the fuel mix. Although it is a relatively small plant, it is possible that the biomass facility would be considered a major source for these pollutants, in which case the purchase of offsets would also be required. A detailed review of these issues was beyond the scope of this study.

The proposed project has a nominal capacity of 20 MW, and assuming a capacity factor of 80 percent, the facility would produce roughly 140 GWh per year. It is expected permitting and construction of the direct fired project could be conducted in 42 to 48 months. Given a notice to proceed (NTP) of January 1, 2008, the Maricopa direct fired biomass project would likely be operational by January 1, 2012.

Table 5-5 shows the direct fired and cofired biomass projects identified for this study. All characteristics are year 2007 values, before any future cost and performance modifications have been made. Figure 5-1 shows the supply curve for cofired biomass and direct fired biomass projects. For the purposes of visualizing the projects on the supply curve, it has been assumed that all projects could be built in 2007. Appendix A shows a consolidated list of projects; Appendix B shows the same list with forecast levelized costs for each project from 2007 to 2025.

Considering the other renewable energy options evaluated in this study, the costs of the two cofiring projects are relatively low (about $60/MWh in 2010), and the costs of cofiring are certainly lower than the direct fired project (about $162/MWh in 2012). In general, the costs of biomass in Arizona are relatively high due to the lack of low cost biomass and the small scale of biomass projects.

Table 5-5. Direct Fired and Cofired Biomass Project Characteristics.

Project	Capacity, MW	CF, %	Generation, GWh	First Year Available	Capital Cost, $/kW	Fixed O&M, $/kW-yr	Var. O&M, $/MWh	Fuel Cost,[1] $/MBtu	Nearest Utility	Transmission Line		
										Voltage, kV	Dist. to TL, miles	Owner
Cholla cofiring	10.0	80%	70	2010	900	61	0	2.50	APS	N/A	N/A	N/A
Springerville cofiring	10.0	80%	70	2010	900	61	0	2.30	TEP	N/A	N/A	N/A
Maricopa City Direct	20.0	80%	140	2012	4,000	160	11.50	1.89	APS	115	2	APS

Note:
[1] The fuel cost for cofiring projects is the incremental cost of biomass above the cost of coal.

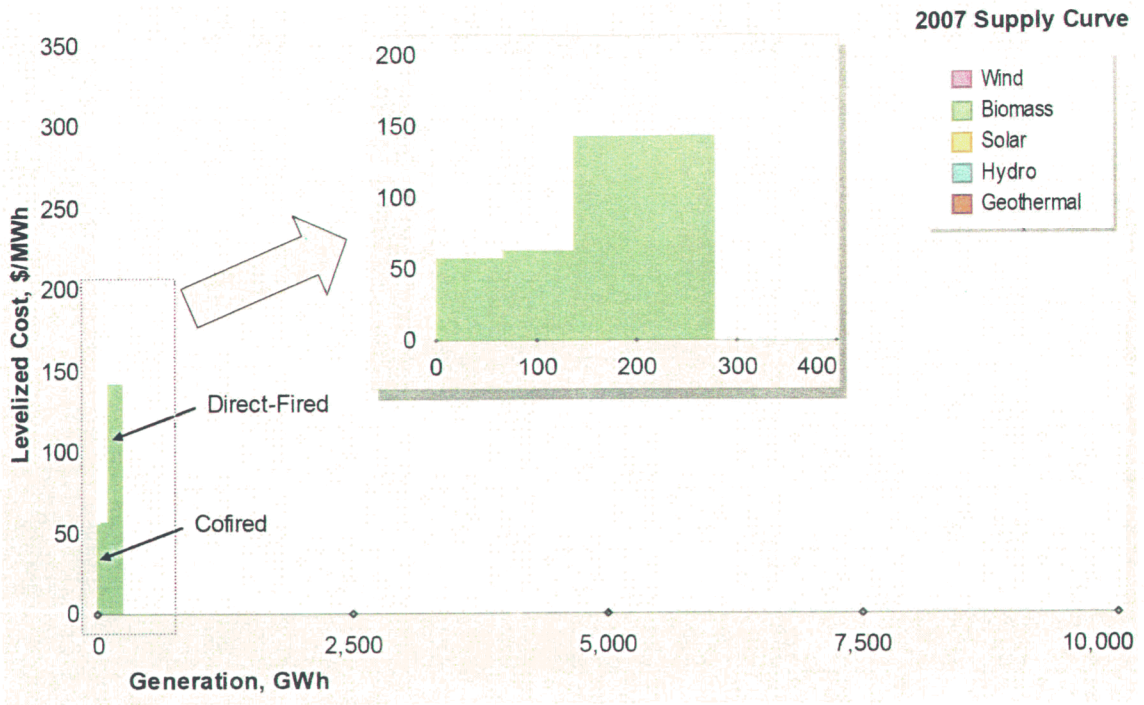


Figure 5-1. Levelized Cost Supply Curve for Solid Biomass Projects.

5.2 Landfill Gas

Landfill gas (LFG) is formed from the decomposition of waste buried in the landfill. The gas is primarily composed of methane and carbon dioxide, with sulfur oxides and other miscellaneous constituents making up the balance. Gas production varies significantly by site, depending on the composition of the waste, dimensions of the landfill, and climate. For example, Arizona's arid climate slows the rate of decomposition in landfills, thus reducing the volumetric rate of gas that can be recovered. However, a strong correlation exists between the tons of waste in place and quantity of gas production.

5.2.1 General Methodology

Black & Veatch utilized the Environmental Protection Agency (EPA) Landfill Methane Outreach Program (LMOP) database of landfills in Arizona to estimate the technical potential for landfill gas power generation at 27 sites. The database provides figures for the landfill size, waste in place, gas generation, and in some cases contact information. Of the 27 sites listed as candidate landfill gas projects, 2 are currently in development and are scheduled to come online in the future (27th Ave landfill and Skunk

Creek landfill). Black & Veatch considered the remaining 25 sites as the pool of potential renewable generation projects.

Black & Veatch attempted to contact candidate landfills to determine the amount of waste in place, yearly fill rate, gas collection system situation, plans to utilize landfill gas, ownership of landfill gas, and any other information to help gauge the potential for electric generation. Black & Veatch was able to make contact with representatives at 16 of the landfills Table 5-6.

Table 5-6. Candidate Landfill Contact Results.

Landfill	Made Contact?	On Potential Project List?
Butterfield Station Landfill	Yes	Yes
Salt River Landfill	Yes	Yes
27th Avenue Landfill	Yes	No – already in development
Apache Junction LF	No	Yes
Cinder Lake MSW LF	Yes	Yes
City of Glendale Municipal Landfill	Yes	Yes
Grey Wolf Landfill	Yes	Yes
Huachuca City Landfill	No	Yes
North Center Street Landfill	Yes	Yes
Northwest Regional MSW Landfill	No	Yes
Painted Desert Landfill	Yes	Yes
Queen Creek MSW Landfill	No	Yes
Rio Rico MSW Landfill	Yes	Yes
Skunk Creek Landfill	Yes	No – already in development
Cave Creek Landfill	No	No
Cocopah Landfill	No	Yes
Copper Mountain Landfill	Yes	No
Dudleyville Landfill	No	No
Harrison City Landfill	Yes	No
Ironwood Landfill	No	No
La Paz County Landfill	No	No
Lake Havasu Landfill	Yes	No
Mohave Valley Landfill	Yes	No
Sierra Estrella Landfill	No	No
Southwest Regional Landfill	Yes	Yes
Tangerine Road MSW Landfill	No	Yes
Vincent Mullins Landfill	Yes	No

Black & Veatch tried to contact all the LMOP landfills for which we could find contact information. The goal was to get data on waste in place, fill rate, typical waste

composition, gas production rate, gas collection system status, gas rights ownership, and known plans for using gas for generation. For some landfills it was difficult to reach a manager or engineer who was knowledgeable about the factors needed to assess the landfill's potential. For all landfills it was also difficult to get sufficient information on all pertinent factors needed to estimate generation potential with a high degree of accuracy. Additional information obtained from the phone survey helped better determine which projects have real potential, approximate how much generation could be expected, and estimate the earliest year each project could come online if project development were prioritized.

Some landfills were removed from the potential project list due to extremely small volumes and limited prospects for achieving a critical mass to make development worthwhile. For promising sites that we were not able to contact, we used the information included in the LMOP database to assess potential.

5.2.2 Major Assumptions

- The following assumptions were made in the evaluation of landfill gas potential.
- One million tons of waste in place can support 260 kW of generation capacity. This number was obtained by "normalizing" projections for Arizona landfill gas projects in development to data from previous landfill gas studies, based on waste in place. One million tons of waste in temperate conditions would generate gas sufficient to sustain 700+ kW of generation. While some arid landfills add water and microorganisms to the waste to increase the rate of gas production, all landfills were modeled to have the same waste to generation ratio. It should be noted that Black & Veatch did not prepare gas flow models for any of the potential projects.
- Although microturbines, larger combustion turbines, and other types of power conversion equipment are used to convert landfill gas to electricity, internal combustion engines account for a great majority of installations. Cost and performance data for internal combustion engines was used as a basis for this study.
- An annual capacity factor of 80 percent is assumed for all landfill gas projects.
- Responsibility for the gas collection system cost and maintenance was assumed to be on the landfill owner.
- Landfills that cannot support electric generation of at least than 250 kW were not included in the list of potential projects.

- Capital cost estimates were based on guidance from the EPA LMOP and range from $2330/kW for a 250 kW facility to $1980/kW for a 5 MW facility. These estimates do not include the cost of installing a gas collection system.
- Project construction period is one year.
- Operating and maintenance costs were estimated to be $17.5/MWh for all generation levels. This includes both fixed and variable cost components.
- Specific transmission lines were not identified. It was assumed that all landfills are currently being served with power, and the generation would back feed. Projects larger than 1 MW are assumed to have a small 34.5 kV substation.
- Interconnection costs are included in the capital costs for projects less than 1 MW.
- Landfill gas fuel cost was assumed to be $2/MBtu. This is the cost that a project developer would pay for the rights to the gas. This cost would support maintenance of the landfill gas collection system.

5.2.3 Future Cost and Performance Projections

Power generation from landfill gas is a largely a mature technology. No changes in future cost or performance were assumed other than adjustments to account for inflation.

5.2.4 Data Sources

Data sources used in this analysis included:

- EPA LMOP database. Available at http://epa.gov/lmop/proj/xls/lmopdata.xls
- EPA LOMP program. Available at http://epa.gov/lmop/
- Survey of Arizona landfills conducted by telephone. Survey conducted January-March, 2007.

5.2.5 Projects Identified

Fifteen potential projects were identified, totaling 9.8 MW of capacity and 68 GWh of annual generation, most of which could be available by 2010 if development were prioritized. As mentioned earlier, this capacity is much smaller than what would be expected for similar sized landfills in other states due to Arizona's dry climate. However, because the refuse in arid landfills decomposes at a slower rate, the gas production is expected to last longer than in temperate landfills.

The potential Arizona projects modeled in the supply curves do not include two projects that are currently under development—27th Ave. landfill (3 MW of capacity, online in 2008) and Skunk Creek landfill (3 MW of capacity, online in 2009). All of the candidate projects are less than 3 MW in capacity and most are less than 1 MW. Most of the projects are located near transmission lines owned by SRP or APS.

Many of the identified projects are not far-removed from development and commercial operation. Most of the sites already have a gas collection system in place and could have online generation by 2010. As these projects are smaller in scale than other projects such as wind farms or solar trough fields, they are better suited for coming online in the near future to increase Arizona's developed renewable energy. However, there are not enough landfill gas resources in Arizona to make landfill gas facilities a large portion of the state's overall renewable energy portfolio. Additionally, the economics for small landfill projects can be challenging. Development costs are prohibitively high for any one project to absorb all of the costs; individually projects are not attractive, but collectively they are acceptable. Black & Veatch would recommend a small-scale modular technology with lower capital and maintenance costs, such as provided by INGENCO. INGENCO provides small-scale engines designed to be modularly installed in landfills that are not viable for other types of equipment. INGENCO projects have potentially lower construction and maintenance costs than the "typical" landfill gas project characteristics assumed for this study.

Table 5-7 shows the landfill gas projects identified for this study. All characteristics are year 2007 values, before any future cost and performance modifications have been made. Figure 5-2 shows the supply curve for landfill gas generation potential (anaerobic digestion projects are also shown). For the purposes of visualizing the projects on the supply curve, it has been assumed that all projects could be built in 2007.

The overall prospects for landfill gas generation are small. Landfill gas projects can take less time to develop than large solar or wind projects, so landfill gas may play a more significant role in the near term.

Table 5-7. Landfill Gas Project Characteristics.

Project	Capacity, MW	CF, %	Genera-tion, GWh	First Year Available	Capital Cost, $/kW	Fixed O&M, $/kW-yr	Var. O&M, $/MWh	Fuel Cost, $/MBtu	Nearest Utility	Transmission Line		
										Voltage, kV	Dist. to TL, miles	Owner
Butterfield Station Landfill	2.4	80%	17	2009	2062	0	18	2	APS	34.5	N/A	APS
Salt River Landfill	0.8	80%	5	2009	2193	0	18	2	SRP	N/A	N/A	SRP
Apache Junction LF	0.3	80%	2	2010	2328	0	18	2	APS	N/A	N/A	SRP
Cinder Lake MSW LF	0.6	80%	4	2011	2233	0	18	2	APS	N/A	N/A	APS
City of Glendale Municipal Landfill	1.3	80%	9	2009	2132	0	18	2	SRP	34.5	N/A	APS
Grey Wolf Landfill	0.8	80%	5	2012	2193	0	18	2	APS	N/A	N/A	APS
Huachuca City Landfill	0.3	80%	2	2012	2305	0	18	2	TEP	N/A	N/A	TEP
North Center Street Landfill	0.5	80%	4	2008	2242	0	18	2	SRP	N/A	N/A	SRP
Northwest Regional MSW Landfill	0.3	80%	2	2010	2328	0	18	2	SRP	N/A	N/A	APS
Painted Desert Landfill	0.4	80%	3	2010	2277	0	18	2	APS	N/A	N/A	APS
Queen Creek MSW Landfill	0.4	80%	3	2011	2277	0	18	2	SRP	N/A	N/A	SRP
Rio Rico MSW Landfill	0.3	80%	2	2008	2328	0	18	2	TEP	N/A	N/A	TEP
Cocopah Landfill	0.6	80%	4	2011	2230	0	18	2	APS	N/A	N/A	APS
Southwest Regional Landfill	0.3	80%	2	2010	2302	0	18	2	APS	N/A	N/A	APS
Tangerine Road MSW Landfill	0.5	80%	4	2008	2236	0	18	2	TEP	N/A	N/A	TEP

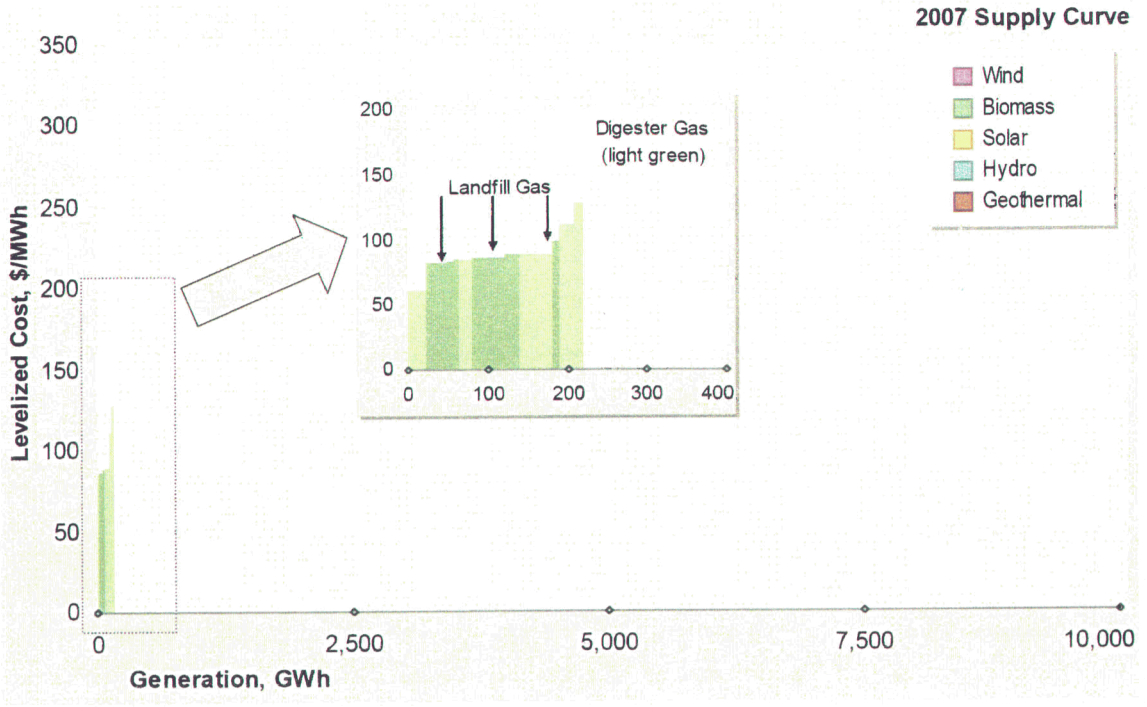


Figure 5-2. Levelized Cost Supply Curve for Biogas Projects.

5.3 Anaerobic Digestion

The utilization of biogas generated from anaerobic digestion was identified as a technically feasible option in the first stage of the analysis. While this resource has a relatively limited generation potential, anaerobic digestion projects could be executed relatively quickly and with low levels of risk. Electrical generation systems could be installed around anaerobic digestion systems co-located with either concentrated animal feeding operations (CAFOs) or waste water treatment plants (WWTPs). As mentioned in the first stage of the analysis, power demands at WWTPs often exceed the quantities of electricity generated from biogas, and little electricity is exported to the grid. Therefore, anaerobic digestion projects identified in this stage of the analysis are based upon the utilization of anaerobic digestion systems operated in association with CAFOs. These projects are discussed in this section.

5.3.1 General Methodology

Potential anaerobic digestion projects were selected based on the concentration of livestock operations within an area. The focus was on identification of larger projects (>1 MW), that could export significant quantities of power. A spreadsheet of CAFOs in Arizona provided by APS was used to identify single CAFOs with sufficient animal

populations to sustain a project and geographic areas with multiple CAFOs from which significant animal wastes could be aggregated and utilized to sustain a project. The populations of dairy cattle, swine and egg-laying chickens were reviewed to identify potential projects. The populations of beef cattle and chicken broilers were not considered for anaerobic digestion projects because these wastes are more suited for combustion projects due to their drier composition. Based on the livestock estimates provided in the CAFO spreadsheet, a total of four anaerobic digestion projects were identified in the counties of Maricopa, Navajo and Pinal.

5.3.2 Major Assumptions

The following assumptions were made in the evaluation of anaerobic digestion potential.

- It was assumed that each head of livestock could sustainably support electrical generation capacity ranging from 1.0 to 100.0 kW. This value depended upon the type of livestock, as shown in Table 5-8. These values are considered conservative.
- To simplify system design and operation, projects were identified and defined such that each project would process only one type of animal waste.
- Permitting is assumed to require 12 months and construction is assumed to require an additional 12 months.

Table 5-8. Per Head System Capacity for Anaerobic Digestion Processes.

Livestock Type	System Capacity (Watts per Head)
Dairy cattle	100.0
Swine	28.0
Chicken (layers)	1.0
Sheep	7.0

5.3.3 Future Cost and Performance Projections

Anaerobic digestion systems are relatively mature technologies. No changes in future cost or performance were assumed other an adjustments to account for inflation.

5.3.4 Data Sources

Data sources used in this analysis included:

- Spreadsheet of Concentrated Animal Feeding Operations (CAFO) in Arizona, provided by Thomas Ramey of APS on November 30, 2006

5.3.5 Projects Identified

Four anaerobic digestion projects were identified:

- A 3.5 MW swine manure digestion project located in Snowflake
- A 2.5 MW dairy cattle manure digestion project located in Buckeye
- A 1.5 MW dairy cattle manure digestion project located in Chandler
- A 2.4 MW poultry waste digestion project located in Maricopa

The swine manure project is proposed at Pigs for Farmer John (PFFJ) in Snowflake. The swine population of PFFJ is estimated to be 120,000 head, which could support approximately 3.5 MW of electrical generation. Assuming a capacity factor of 80 percent, this project could generate 25 GWh per year of electricity. It is assumed that this project would be located on the site of the hog operation, which will eliminate the cost of transporting manure to another location. It should be noted that Arizona voters in 2006 passed a proposition that will force this plant to change its animal management practices in the next few years. Local plant management has noted that plant closure is an option being considered. For this reason, there is some uncertainty regarding the viability of a renewable energy project at this site.

Two dairy manure projects are proposed in Maricopa County. The first project would be located in Buckeye and would produce 2.5 MW of electricity. Assuming a capacity factor of 80 percent, this facility would generate approximately 18 GWh per year of electricity. There are 29 dairy operations in Buckeye according to the CAFO spreadsheet, and the total size of the dairy population from these 29 operations is roughly 26,000 head. This population could support the entire 2.5 MW of generation proposed. However, there are also 14 dairy operations in Tolleson with over 15,000 head of cattle and additional operations in the vicinity to supplement the dairy manure resource.

The second dairy manure project would be located in Chandler and would produce 1.5 MW of electricity. Assuming a capacity factor of 80 percent, this facility would generate approximately 11 GWh per year of electricity. There are 17 dairy operations in Chandler, with another 10 operations in nearby Gilbert and Higley. The combined cattle population of these 27 operations is over 30,000 head, which is more than sufficient to provide the manure resources to provide 1.5 MW of capacity.

The chicken manure project would be located at Hickman's Egg Ranch in Maricopa. The size of the Hickman operation is estimated at 2,400,000 chickens, and this population could support 2.4 MW of electrical generation. Assuming a capacity factor of 80 percent, this project could generate roughly 17 GWh per year of electricity. Because this project is supplied by manure from one location (similar to the swine

manure project), the transportation cost of the manure will be significantly reduced, if not eliminated.

Given a notice to proceed of January 1, 2008, all of the proposed anaerobic digestion projects would likely be operational by January 1, 2010. The costs for the anaerobic digestion projects range from $70/MWh to $140/MWh (in 2010), largely dependent on project scale.

Table 5-9 shows the anaerobic digestion projects identified for this study. All characteristics are year 2007 values, before any future cost and performance modifications have been made. Figure 5-2 in the previous section shows the supply curve for anaerobic digestion gas generation potential (landfill gas projects are also shown). For the purposes of visualizing the projects on the supply curve, it has been assumed that all projects could be built in 2007. Appendix A shows a consolidated list of projects; Appendix B shows the same list with forecast levelized costs for each project from 2007 to 2025.

Table 5-9. Anaerobic Digestion Project Characteristics.

Project	Capacity, MW	CF, %	Genera-tion, GWh	First Year Available	Capital Cost, $/kW	Fixed O&M, $/kW-yr	Var. O&M, $/MWh	Fuel Cost, $/MBtu	Nearest Utility	Transmission Line		
										Voltage, kV	Dist. to TL, miles	Owner
Snowflake Digester (Swine)	3.50	80%	25	2010	2,000	0.00	20.00	$0.00	APS	34.5	0	N/A
Buckeye Digester (Dairy)	2.50	80%	18	2010	3,000	0.00	20.00	$1.50	SRP	34.5	0	N/A
Chandler Digester (Dairy)	1.50	80%	11	2010	3,500	0.00	20.00	$1.50	SRP	34.5	0	N/A
Maricopa Digester (Poultry)	2.40	80%	17	2010	3,000	0.00	20.00	$0.00	SRP	34.5	0	N/A

5.4 Solar Thermal Electric

The various solar thermal electric technologies were discussed in detail in Section 4. One solar thermal electric technology, parabolic trough, is currently proven commercially, with over 350 MW operating in the Mohave Desert since about 1990, and with multiple plants of 50 MW or larger being constructed in the US and in Spain. This section will primarily focus on trough plants. Parabolic dish engine systems, for which there are power purchase agreements in California for hundreds of MWs, are unproven, but are treated as a special sensitivity case. Power tower and compact linear Fresnel reflector (CLFR) technologies hold potential, but are not included in this section because of uncertainty in cost and performance.

5.4.1 General Methodology

The potential for solar thermal was characterized in a different manner than other technologies. Whereas technologies such as biomass and geothermal are largely limited by resource availability, solar resources in Arizona are much larger than the potential near-term demand. Rather than being limited by resource, the technology is practically limited by equipment availability, development timelines, and ultimately economics. These factors were taken into account when forecasting potential solar thermal development.

The first parabolic trough plant was assumed to be a 100 MW facility with no thermal storage, but with hybrid fossil capability, which would go on line in 2011. Hybrid fossil capability means that the plant would have the ability to burn natural gas to generate electricity when the solar resource is unavailable.[11] This design is identical to the operating solar trough plants in California. The size is consistent with first trough plants in planning. Subsequent plants would be 200 MW with levels of thermal storage as discussed later in this section.

Broad siting regions were identified rather than specific sites. A map of Arizona direct normal insolation overlaid with terrain constraints was obtained from the National Renewable Energy Laboratory (see Figure 4-19 in the previous chapter). This map was used to identify broad areas of interest. It should be noted that Arizona has vast areas which could be suitable for solar thermal electric plants. Generally, solar resource is quite high throughout the state, with terrain, transmission, and water availability being key constraints. For this study, terrain was considered via the NREL maps. It has been

[11] In California, natural gas may be used for up to 25 percent of the facility output, without impacting the eligibility of the facility for renewable energy designation. For the purposes of this study, although the

assumed that projects would be sited such that water for wet cooling would be available. Should water not be available, dry cooling would substantially lower water requirements, but would result in performance decreases and capital cost increases that would generally raise the cost of energy by about 10 percent.

Performance estimates have been based on Black & Veatch's use of the NREL Excelergy model for Phoenix. Output was adjusted for direct normal insolation (DNI) estimates and latitude of the subject site. Excelergy estimates trough output on an hourly basis, estimating through collector field and power block thermal flows through the system, leading to net electrical output. Excelergy, which was developed by NREL, has been checked versus SEGS plant operation by NREL.

Phoenix output was modeled using Typical Meteorological Year (TMY2) data for Phoenix, along with the Phoenix latitude and longitude. Annual output for other sites was based on a comparison of satellite DNI for 0.1 degree latitude, 0.1 degree longitude pixels (about 5.7 miles east-west and 6.9 miles north-south in Arizona), and adjustment for latitude (trough output decreases with increase in latitude).

5.4.2 Major Assumptions

Solar thermal development will be constrained in the near term due to the practical limitations of the industry's supply chain. Demand for solar thermal equipment and supporting engineering and construction services is at an unprecedented level worldwide. Due to these constraints, it has been assumed that the first 100 MW trough plant in Arizona could not be completed until 2011. Beginning in 2013, plants will be 200 MW to take advantage of economy of scale of larger plants. It is assumed that the near term supply chain constraints in the industry will be alleviated by 2013, and two to four 200 MW plants could be constructed per year thereafter.

Solar thermal plants need large amounts of contiguous land for a project. A 200 MW plant can require up to 1,400 acres. Securing such parcels of land with ideal terrain and transmission characteristics is sometimes difficult. As an example of the total amount of land that might be necessary for a large-scale solar expansion, Black & Veatch's base case forecast estimates 2100 MW of solar trough development. Assuming a density of 7 acres/MW, this results in a need for 14,700 acres (23 square miles) of total land. By comparison, Phoenix proper covers an area of about 500 square miles.

The land used for solar thermal plants would likely be a mix of Arizona state land and BLM land. There is a bill currently proposed in congress designating "solar park" land for several GW of solar plants in the Southwest, with a lease fee of $200/acre/year.

facility is assumed capable of burning natural gas to provide a firm resource, no generation from gas was assumed.

This may ease permitting requirements on federal lands. The Arizona land office is currently contemplating streamlined permitting requirements for solar parks. Private land is also an option, but it may be more expensive and more difficult to aggregate large contiguous parcels.

Unlike most other technologies evaluated for this study, it is expected that significant technical and cost advances will be realized for solar thermal trough plants. The initial plant available to be built in 2011 would be based on existing technology. This plant will have no thermal storage, but will have hybrid fossil capabilities. Plants built through 2016 will use current heat transfer fluid (HTF) technology: synthetic oil such as Therminol VP-1 or Dowtherm A. Beginning in 2017, plants are expected to use molten salt as the HTF to take advantage of higher temperatures, higher efficiencies, and cost savings. Moving to molten salt as the HTF will require technology and engineering advances. Such advances are consistent with industry projections.

Energy storage capability would be incorporated into plants beginning in 2013. Plants built in 2013 are assumed to have 3 hours of thermal storage. These plants would also have an increased solar multiple (larger solar field thermal output to turbine thermal input ratio), and thus larger mirror field, to accommodate longer operating hours using thermal storage. These plants would use synthetic oil as the HTF, with molten salt as the storage medium. This will require an oil-to-molten salt heat exchanger. Plants starting in 2014 are assumed to have 6 hours of thermal storage, increasing the operating hours and allowing increased dispatchability.

The following additional assumptions have been made in characterizing projects:

- Projects would be sited in areas with access to sufficient cooling water for wet cooling.
- Projects would be sited near existing transmission (a 230 kV substation with a 1 mile interconnect is assumed for all projects).
- Transmission constraints or the need for new transmission development have not been considered (similar to the remainder of the study).

5.4.3 Future Cost and Performance Projections

Future cost and performance projections are shown in Table 5-10 for four prospective sites. (Note that costs are in constant 2007$). The sites are discussed further in Section 5.4.5. Cost projections show the following trends, which can be somewhat off-setting.

- Cost per kW increases with the addition of storage and increase of solar multiple.
- Cost per kW decreases with capacity increase from 100 MW to 200 MW.

- Costs decrease with time for the following reason.
- Increased deployment results in lower costs associated with perceived risk, with more efficient construction means.
- Increased competition by suppliers.
- More locally based manufacturing, and in particular, mirrors and receiver tubes decreasing shipping costs, import fees, and exchange rate issues.
- Improved technology, increasing efficiency and decreasing required mirror area.

Cost decreases have been estimated from data in Excelergy, the Western Governors Association report, the Sargent & Lundy report, and the Black & Veatch NREL report referenced in the next section.

Future performance projections include modest improvements with technology. These estimates were based on Excelergy model projections.

Table 5-10. Solar Thermal Electric Project Characteristics (Constant 2007$).

COD Year	MW	HTF*	Hrs Storage	$/kW	O&M $/kW-year	Land Area Acres	Water Usage Acre-ft/year**	Capacity Factors (%)			
								Stoval	Yuma	Phoenix	Tucson
2011	100	VP-1	0	4,200	55	570	610	29.8	29.3	27.3	28.7
2012	200	VP-1	3	4,000	50	1,300	1,450	35.1	34.5	32.2	33.8
2013	200	VP-1	3	4,000	50	1,300	1,450	35.1	34.5	32.2	33.8
2014	200	VP-1	6	4,500	48	1,500	1,740	42.3	41.6	38.8	40.7
2015	200	VP-1	6	4,500	48	1,500	1,740	42.3	41.6	38.8	40.7
2016	200	VP-1	6	4,500	48	1,500	1,740	42.3	41.6	38.8	40.7
2017	200	MS	6	4,500	45	1,450	1,740	42.3	41.6	38.8	40.7
2018	200	MS	6	4,200	45	1,450	1,780	43.3	42.6	39.7	41.7
2019	200	MS	6	4,200	45	1,450	1,780	43.3	42.6	39.7	41.7
2020	200	MS	6	4,200	45	1,450	1,780	43.3	42.6	39.7	41.7
2021	200	MS	6	3,700	45	1,450	1,820	44.3	43.6	40.6	42.7
2022	200	MS	6	3,700	45	1,450	1,820	44.3	43.6	40.6	42.7
2023	200	MS	6	3,700	45	1,450	1,820	44.3	43.6	40.6	42.7
2024	200	MS	6	3,700	45	1,450	1,820	44.3	43.6	40.6	42.7
2025	200	MS	6	3,700	45	1,450	1,820	44.3	43.6	40.6	42.7

* VP-1 is a silicone oil. MS is molten salt.

**Water usage based on Stoval site. All plants assumed to use wet cooling.

5.4.4 Data Sources

Cost data for the trough evaluation are based on several sources:

- Black & Veatch Engineer, Procure, Construct bid price developed for confidential client, 2006.
- *Preferred Plant Size,* Bruce Kelly, Nexant, draft prepared for National Renewable Energy Laboratory, 2005-2006
- *Economic, Energy, and Environmental Benefits of Concentrating Solar Power in California*, NREL/SR-550-39291, Black & Veatch, Prepared for National Renewable Energy Laboratory, April 2006.
- *Assessment of Parabolic Trough and Power Tower Solar Technology Cost and Performance Forecasts,* Sargent & Lundy Consulting Group, Prepared for Department of Energy and National Renewable Energy Laboratory (NREL), May 2003.
- *Excelergy,* Parabolic Trough Spreadsheet Model, developed by NREL.
- *"Solar Task Force Report,"* Western Governor's Association, January 2006.
- Southwestern US DNI Satellite Data, spreadsheet obtained from NREL.
- Arizona DNI Map Overlaid with 1 Percent Slope, NREL website.

It should be noted that parabolic trough system costs are considerably higher than shown in many of the referenced documents. Costs of commodities, such as steel and copper, have risen significantly in the last two years. Furthermore, many of the trough components are manufactured in Europe, resulting in cost increases as the dollar has weakened compared to the euro.

5.4.5 Projects Identified

Specific site locations were not identified at this stage of analysis. Generic projects have been identified for four areas in Arizona:

- Stoval
- Yuma
- Phoenix
- Tucson

Characteristics for these plants are shown in Table 5-11.

The Stoval area, about 80 miles southwest of Phoenix along Interstate 8, has the highest DNI of the potential sites (7.4 kwh/m^2/day – per satellite data), with potential areas of low land slope. Because of the improved performance, it has been assumed that

initial project deployment would occur at Stoval. A key issue with this area is that a large portion of the land in the region is within the Barry M. Goldwater Air Force Range.

The Yuma site would be southeast of Yuma in the Yuma Desert. The Yuma area has a high satellite DNI of 7.3 kwh/m^2/day. Like the Stoval area, the Yuma area could be subject to constraints because of the Barry M. Goldwater Air Force Range.

The Phoenix area would generally be west of Phoenix because of terrain constraints. The area has a satellite DNI of 6.8 kwh/m^2/day. The Phoenix TMY2 DNI is 6.9 kWh/m^2/day.

The Tucson area could include areas such as the Avra Valley to the west of Tucson and the Sulphur Springs Valley to the east. The area has a satellite DNI of 7.2 kwh/m^2/day.

Figure 5-3 shows the supply curve for solar thermal trough projects. The supply curve is relatively flat with the lowest cost projects generating power for about $160/MWh (hypothetical 2007 project, includes 30 percent investment tax credit). This cost is substantially higher than non-solar resources profiled in this study. The potential supply of solar thermal potential is vast, and exceeds what is shown on the chart. For the purposes of visualizing the projects on the supply curve, it has been assumed that all projects could be built in 2007.

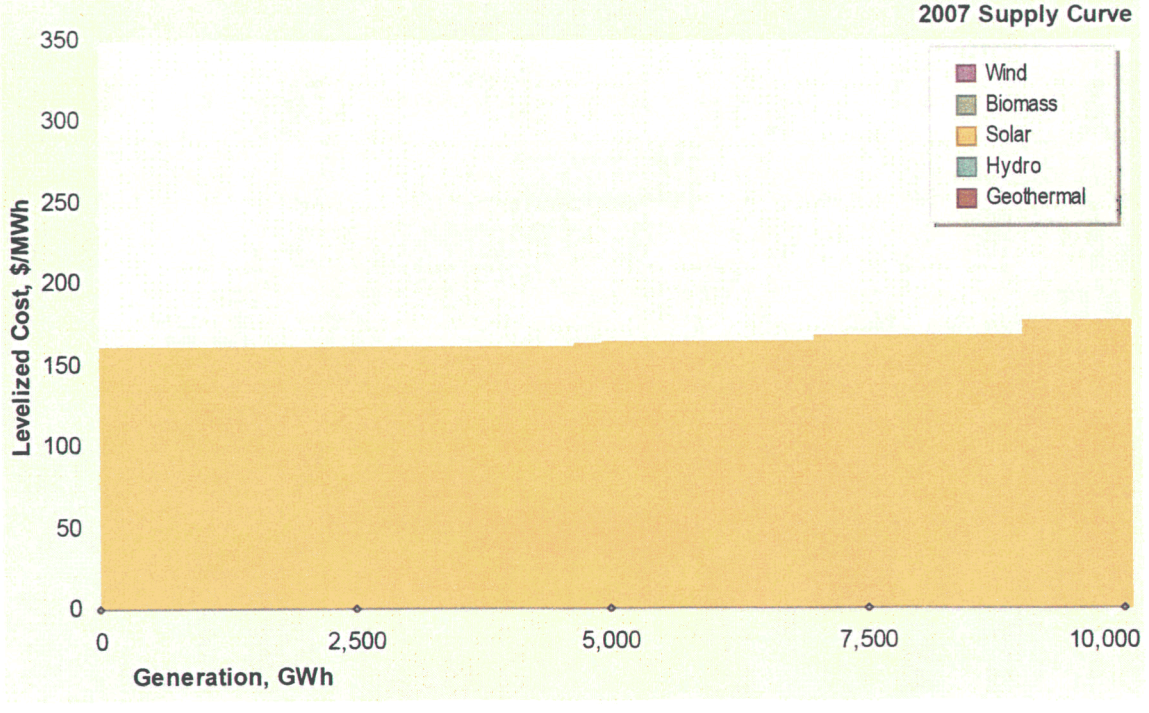


Figure 5-3. Levelized Cost Supply Curve for Solar Thermal Electric (Trough) Projects.

5.4.6 Parabolic Dish Engine Assumptions

At the present time, there are no operating commercial dish engine power plants. There are, however, hundreds of megawatts of proposed projects which, if implemented successfully, would substantially advance the technology. For this reason, dish engine technology was not included in the base renewable energy development model (Section 7), but was included as a special sensitivity run. Stirling Engine Systems (SES), the principal dish engine developer in the United States, projects that the cost of dishes will decrease dramatically with hundreds of MWs of central station, grid connected deployment.

Cost and performance data (Table 5-11) for the dish engine systems were provided by SES, and represent a projection by SES of costs for 100 MW block system. Black & Veatch is unaware of any current independent cost estimates for parabolic dish Stirling systems. The estimate assumes significant deployment of dish systems, resulting in substantially lower capital costs than exist at present. The estimate also assumes that with the large deployment there are appropriate gains in system reliability.

The 100 MW system would comprise 4,000 x 25 kW dishes. The system would provide electricity in a sun-following mode, i.e., it would generate electricity when DNI is available and would not generate electricity at night or during cloud cover. The assumed capacity factor for dish systems at higher DNI sites in Arizona is 27.4 percent. Capacity factor will vary slightly depending on the site; however, this has not been included in the model.

Engineering, permitting, and other indirect costs are lower for dish engine plants than for parabolic trough plants. Trough plants require significant site-specific engineering compared to the far more modular dish systems.

Table 5-11. Solar Thermal Electric Project Characteristics.

Project	Capacity, MW	CF, %	Genera-tion, GWh	First Year Available	Capital Cost, $/kW	Fixed O&M, $/kW-yr	Var. O&M, $/MWh	Fuel Cost, $/MBtu	Nearest Utility	Transmission Line		
										Voltage, kV	Dist. to TL, miles	Owner
Stoval Trough 1	100	30%	261	2011	4,200	55	–	–	APS	230	1	APS
Stoval Trough 2	200	30%	522	2013	4,200	55	–	–	APS	230	1	APS
Stoval Trough 3	200	30%	522	2013	4,200	55	–	–	APS	230	1	APS
Stoval Trough 4	200	30%	522	2014	4,200	55	–	–	APS	230	1	APS
Stoval Trough 5	200	30%	522	2014	4,200	55	–	–	APS	230	1	APS
Stoval Trough 6	200	30%	522	2015	4,200	55	–	–	APS	230	1	APS
Stoval Trough 7	200	30%	522	2015	4,200	55	–	–	APS	230	1	APS
Stoval Trough 8	200	30%	522	2016	4,200	55	–	–	APS	230	1	APS
Stoval Trough 9	200	30%	522	2016	4,200	55	–	–	APS	230	1	APS
Stoval Trough 10	200	30%	522	2016	4,200	55	–	–	APS	230	1	APS
Phoenix Trough 1	200	27%	478	2019	4,200	55	–	–	APS	230	1	APS
Phoenix Trough 2	200	27%	478	2019	4,200	55	–	–	APS	230	1	APS
Phoenix Trough 3	200	27%	478	2019	4,200	55	–	–	APS	230	1	APS
Phoenix Trough 4	200	27%	478	2019	4,200	55	–	–	APS	230	1	APS
Tucson Trough 1	200	29%	503	2018	4,200	55	–	–	TEP	230	1	Local
Tucson Trough 2	200	29%	503	2018	4,200	55	–	–	TEP	230	1	Local
Tucson Trough 3	200	29%	503	2018	4,200	55	–	–	TEP	230	1	Local
Tucson Trough 4	200	29%	503	2018	4,200	55	–	–	TEP	230	1	Local
Yuma Trough 1	200	29%	513	2017	4,200	55	–	–	APS	230	1	APS
Yuma Trough 2	200	29%	513	2017	4,200	55	–	–	APS	230	1	APS
Yuma Trough 3	200	29%	513	2017	4,200	55	–	–	APS	230	1	APS
Yuma Trough 4	200	29%	513	2017	4,200	55	–	–	APS	230	1	APS
Solar Dish 1	100	27.4%	240	2011	3,300	23	25	–	N/A	230	1	N/A
Solar Dish 2	100	27.4%	240	2012	3,300	23	25	–	N/A	230	1	N/A
Solar Dish 3	100	27.4%	240	2013	3,300	23	25	–	N/A	230	1	N/A
Solar Dish 4	200	27.4%	480	2014	3,300	23	25	–	N/A	230	1	N/A
Solar Dish 5	200	27.4%	480	2015	3,300	23	25	–	N/A	230	1	N/A
Solar Dish 6	200	27.4%	480	2016	3,300	23	25	–	N/A	230	1	N/A
Solar Dish 7	400	27.4%	960	2017	3,300	23	25	–	N/A	230	1	N/A
Solar Dish 8	400	27.4%	960	2018	3,300	23	25	–	N/A	230	1	N/A
Solar Dish 9	400	27.4%	960	2019	3,300	23	25	–	N/A	230	1	N/A
Solar Dish 10	400	27.4%	960	2020	3,300	23	25	–	N/A	230	1	N/A
Solar Dish 11	400	27.4%	960	2020	3,300	23	25	–	N/A	230	1	N/A

Table 5-11. Solar Thermal Electric Project Characteristics.

Project	Capacity, MW	CF, %	Genera-tion, GWh	First Year Available	Capital Cost, $/kW	Fixed O&M, $/kW-yr	Var. O&M, $/MWh	Fuel Cost, $/MBtu	Nearest Utility	Transmission Line		
										Voltage, kV	Dist. to TL, miles	Owner
Solar Dish 12	400	27.4%	960	2021	3,300	23	25	–	N/A	230	1	N/A
Solar Dish 13	400	27.4%	960	2021	3,300	23	25	–	N/A	230	1	N/A

Future capital cost projections for solar dish plants assume significant cost reductions obtained due to large and sustained manufacturing economies of scale. For the purposes of this study, Black & Veatch has assumed that 50 percent of SES's forecasted improvement will actually be realized. Figure 5-4 compares the relative capital cost forecasts for different solar technologies examined in this study. Photovoltaic (PV) and concentrating photovoltaic (CPV) are included for comparison (PV assumptions are detailed in the next section). It can be seen that both dish and CPV technologies assumed dramatic improvements in project capital cost. A comparison of all-in levelized costs for different solar technologies over time is given in Section 7.

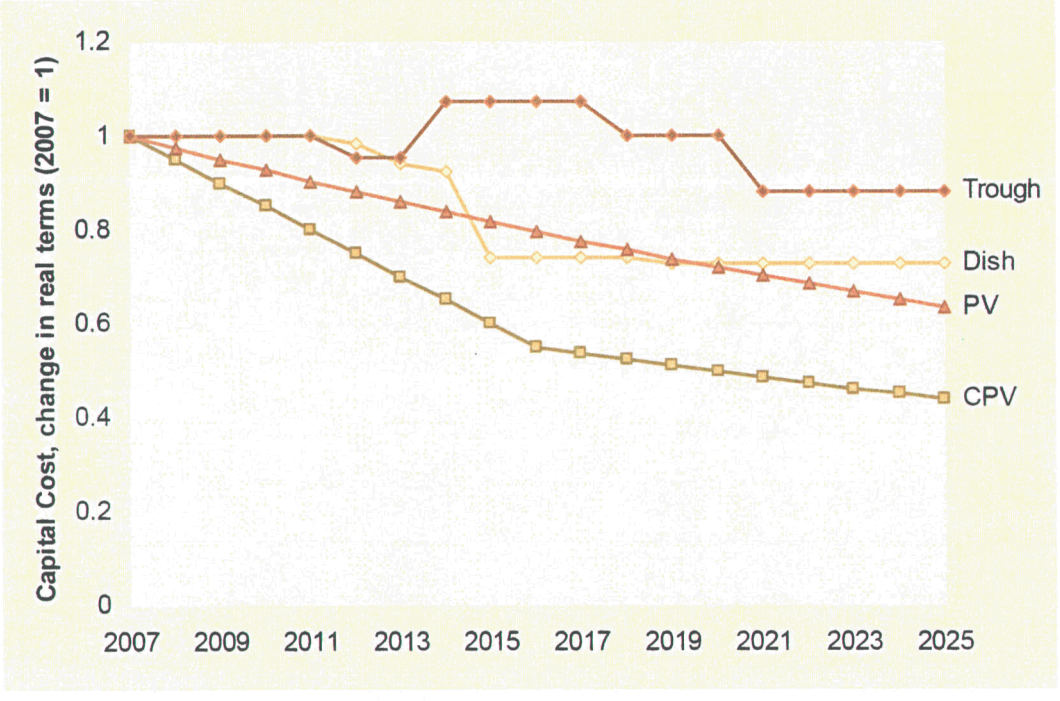


Figure 5-4. Relative Capital Cost for Forecasts for Different Solar Technologies.

5.5 Solar Photovoltaic

Solar photovoltaics (PV) and concentrating photovoltaics (CPV) were identified as promising technologies in the first stage of the analysis. The solar resource in Arizona is very large, but both of these technologies have high capital costs and intermittent generation. The focus for both of these technologies was on utility scale projects, not on distributed residential or commercial PV.

5.5.1 General Methodology

As discussed in the previous section, solar is a special case because the resource is generally available anywhere in the state; the constraints in solar are mainly capital costs and equipment availability. PV and CPV use little water, and projects were assumed to be in the 5-10 MW range, requiring 50-100 acres of land and minimal transmission capacity. Resource, transmission and land were assumed to be available for PV and CPV development. The approach was to make assumptions about future capital costs and the equipment available for utility scale projects.

5.5.2 Major Assumptions

The following assumptions were made in the evaluation of solar photovoltaic potential.

- Siting for PV or CPV projects is not a major constraint, due to modest land requirements and low environmental impact.
- PV projects will be up to 10 MW in any given location through 2015, allowing interconnection to distribution networks or low voltage transmission. We would expect larger plants after that time if economics are viable.

5.5.3 Future Cost and Performance Projections

Black & Veatch feels traditional flat plate for utility scale will see modest cost reduction in the near term. Utility scale PV has limited economies of scale, and module costs make up a large portion of total capital costs. Current capital costs for utility scale PV in the US are around $6,000/kWp, and there is little room for future improvement in non-module costs such as inverters and wiring. While there are promising developments in thin-film PV and non-silicon materials, these modules may be better suited for the distributed PV market. Most current utility scale PV projects are using traditional silicon materials due to concerns about degradation and the life of thin-film modules. Black & Veatch assumed that PV costs would remain flat in nominal dollars for the indefinite future. This translates to a 2.5 percent annual decrease in real dollars.

Concentrating PV was seen as more promising for cost reductions in utility applications. Concentrating PV uses far less silicon than traditional PV, and high efficiency chips are more cost-effective in CPV applications. Spectrolab, a Boeing subsidiary and a leader in high performance triple-junction solar cells, recently crossed the 40 percent efficiency barrier. Concentrating PV is still an immature industry, which makes cost reductions more likely. Mass production of lenses and tracking components could bring costs down over the next decade. There are a number of companies addressing concentrating PV, including Amonix, Sharp, Sol Focus, Green Volts, and

others. Many of these companies have been recently funded by venture capital and are currently developing products.

Black & Veatch assumed capital costs for CPV would decrease in real dollars by approximately 5 percent annually, maturing in 2016 at 55 percent of current costs (a 5 MW CPV plant would drop from $7,200/kWp to $3,960/kWp in 2016). Capacity factors would remain unchanged.

Figure 5-4 in the previous section compares the relative capital cost forecasts for different solar technologies examined in this study. A comparison of all-in levelized costs for different solar technologies over time is given in Section 7.

5.5.4 Data Sources

Data sources used in this analysis included:

- Black & Veatch Independent Engineering report for utility scale PV and CPV plant, confidential client, March 2007.
- Western Governor's Association, Clean and Diversified Energy Initiative, "Solar Task Force Report" January 2006. Available at http://www.westgov.org/wga/initiatives/cdeac/solar.htm
- Maycock, Paul. "PV Market Update" Renewable Energy World, July-August 2005
- Navigant Consulting, "Arizona Solar Electric Roadmap Study" prepared for the Arizona Department of Commerce, January 2007. Available at http://www.azcommerce.com/doclib/energy/az_solar_electric_roadmap_study_full_report.pdf
- Wiser, Ryan et al "Letting the Sun Shine on Solar Costs: An Empirical Investigation of Photovoltaic Cost Trends in California" LBNL January 2006. Available at http://eetd.lbl.gov/EA/EMP
- "The US Photovoltaic Industry Roadmap," Available at http://www.sandia.gov/pv/docs/PVRMPV_Road_Map.htm Western Governor's Association, Clean and Diversified Energy Initiative, "Solar Task Force Report" January 2006. Available at http://www.westgov.org/wga/initiatives/cdeac/solar.htm

5.5.5 Projects Identified

Most flat plate PV is sensitive to temperature and insolation, which varies capacity factors across the state. PV, especially crystalline silicon used in most utility scale PV projects, performs best in areas of low temperatures and high insolation, such as TEP's Springerville plant or APS's Prescott plant. For flat plate PV, Black & Veatch

assumed a typical 5 MWp plant, either a fixed installation (such as Springerville) or with single axis tracking (Prescott). Capital costs shown are $/kWp and do not include the federal 30 percent ITC. Capital costs are from current utility scale PV projects. Black & Veatch used PV simulation software to estimate the capacity factors for four locations in the state: Prescott, Tucson, Phoenix and Flagstaff. The software takes insolation and temperature into account to generate capacity factors.

While the main limits to PV are cost, there are also limitations in the global supply chain for PV modules. Black & Veatch assumed that 15 MW were available for utility scale projects in Arizona for 2008 and 2009, ramping up to 500 MW in 2010 and later. However, because of the high cost of solar photovoltaics, larger projects are not forecast to be built.

Concentrating PV is less sensitive to ambient temperature, as the solar modules are designed to withstand higher temperatures, and CPV systems typically include heat rejection. Concentrating PV has a higher capacity factor than flat plate PV due to increased cell efficiency and the use of dual-axis tracking. Concentrating PV, like solar thermal technologies, use direct normal insolation (DNI). The best locations for CPV are therefore similar to the locations for solar thermal. Black & Veatch did not specify individual sites for CPV, due to the small size of projects and the lack of resource and transmission constraints.

Because of the immaturity of the industry, there are limitations to the amount of concentrating PV systems that can be installed in any given year. CPV is also capital intensive – 100 MW of CPV represents a $500 million investment. In addition, PV industry is a global industry and other markets (Germany, Japan, California) will place demands on the global supply. Black & Veatch assumed the following ramp up of the industry

- 1 MW of CPV could be installed in 2008
- A single 5 MW CPV plant could be installed in 2009
- Two 5 MW CPV plants (10 MW total) could be installed in 2010
- Two 10 MW CPV plants (20 MW total) could be installed in 2011
- Four 10 MW CPV plants (20 MW total) could be installed in 2012
- Ten 10 MW CPV plants (100 MW total) could be installed in 2013-2015

Figure 5-5 shows the supply curve for PV projects. The curve does not include CPV projects, but they are considered in Section 8.

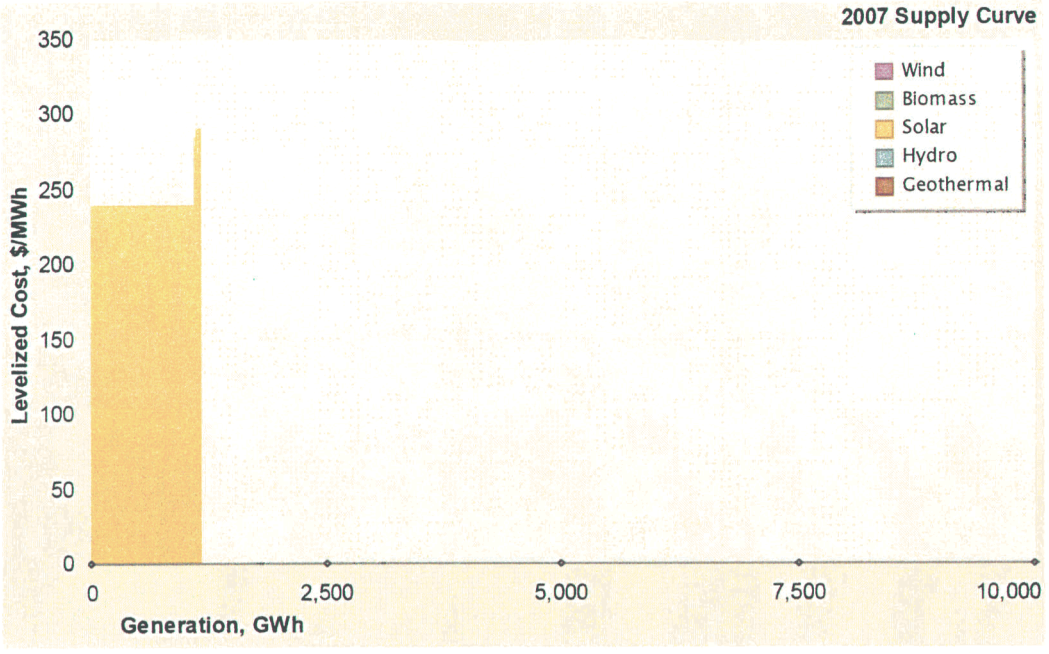


Figure 5-5. Levelized Cost Supply Curve for PV Projects.

Table 5-12 shows the solar photovoltaic projects identified for this study. These projects are largely generic without specific sites identified. All characteristics are year 2007 values, before any future cost and performance modifications have been made. Appendix A shows a consolidated list of projects; Appendix B shows the same list with forecast levelized costs for each project from 2007 to 2025.

Table 5-12. Solar Photovoltaic Project Characteristics.

Project	Capacity, MW	CF, %	Genera-tion, GWh	First Year Available	Capital Cost, $/kW	Fixed O&M, $/kW-yr	Var. O&M, $/MWh	Fuel Cost, $/MBtu	Nearest Utility	Transmission Line		
										Voltage, kV	Dist. to TL, miles	Owner
CPV 1	1.00	29.0%	3	2008	7,600	100	–	0	N/A	35	0	N/A
CPV 2	5.00	29.0%	13	2009	7,200	60	–	0	N/A	35	0	N/A
CPV 3	5.00	29.0%	13	2010	7,200	60	–	0	N/A	35	0	N/A
CPV 4	5.00	29.0%	13	2010	7,200	60	–	0	N/A	35	0	N/A
CPV 5	10.00	29.0%	25	2011	6,800	50	–	0	N/A	35	0	N/A
CPV 6	10.00	29.0%	25	2011	6,800	50	–	0	N/A	35	0	N/A
CPV 7	10.00	29.0%	25	2012	6,800	50	–	0	N/A	35	0	N/A
CPV 8	10.00	29.0%	25	2012	6,800	50	–	0	N/A	35	0	N/A
CPV 9	10.00	29.0%	25	2012	6,800	50	–	0	N/A	35	0	N/A
CPV 10	10.00	29.0%	25	2012	6,800	50	–	0	N/A	35	0	N/A
CPV 11	10.00	29.0%	25	2013	6,800	50	–	0	N/A	35	0	N/A
CPV 12	10.00	29.0%	25	2013	6,800	50	–	0	N/A	35	0	N/A
CPV 13	10.00	29.0%	25	2013	6,800	50	–	0	N/A	35	0	N/A
CPV 14	10.00	29.0%	25	2013	6,800	50	–	0	N/A	35	0	N/A
CPV 15	10.00	29.0%	25	2013	6,800	50	–	0	N/A	35	0	N/A
CPV 16	10.00	29.0%	25	2013	6,800	50	–	0	N/A	35	0	N/A
CPV 17	10.00	29.0%	25	2013	6,800	50	–	0	N/A	35	0	N/A
CPV 18	10.00	29.0%	25	2013	6,800	50	–	0	N/A	35	0	N/A
CPV 19	10.00	29.0%	25	2013	6,800	50	–	0	N/A	35	0	N/A
CPV 20	10.00	29.0%	25	2013	6,800	50	–	0	N/A	35	0	N/A
CPV 21	10.00	29.0%	25	2014	6,800	50	–	0	N/A	35	0	N/A
CPV 22	10.00	29.0%	25	2014	6,800	50	–	0	N/A	35	0	N/A
CPV 23	10.00	29.0%	25	2014	6,800	50	–	0	N/A	35	0	N/A
CPV 24	10.00	29.0%	25	2014	6,800	50	–	0	N/A	35	0	N/A
CPV 25	10.00	29.0%	25	2014	6,800	50	–	0	N/A	35	0	N/A
CPV 26	10.00	29.0%	25	2014	6,800	50	–	0	N/A	35	0	N/A
CPV 27	10.00	29.0%	25	2014	6,800	50	–	0	N/A	35	0	N/A
CPV 28	10.00	29.0%	25	2014	6,800	50	–	0	N/A	35	0	N/A
CPV 29	10.00	29.0%	25	2014	6,800	50	–	0	N/A	35	0	N/A
CPV 30	10.00	29.0%	25	2014	6,800	50	–	0	N/A	35	0	N/A
Tucson Fixed PV 1	5.00	21.2%	9	2008	5,200	30	–	0	TEP	35	0	TEP
Phoenix Fixed PV 1	10.00	20.1%	18	2008	5,200	30	–	0	APS	35	0	APS
Tucson Fixed PV 2	5.00	21.2%	9	2009	5,200	30	–	0	TEP	35	0	TEP

Table 5-12. Solar Photovoltaic Project Characteristics.

Project	Capacity, MW	CF, %	Genera-tion, GWh	First Year Available	Capital Cost, $/kW	Fixed O&M, $/kW-yr	Var. O&M, $/MWh	Fuel Cost, $/MBtu	Nearest Utility	Transmission Line		
										Voltage, kV	Dist. to TL, miles	Owner
Phoenix Fixed PV 2	10.00	20.1%	18	2009	5,200	30	–	0	APS	35	0	APS
Tucson Fixed PV tracked (overall AZ)	500.00	26.9%	1,178	2010	6,000	30	–	0	TEP	35	0	TEP

5.6 Hydroelectric

Black & Veatch reviewed hydroelectric options that included power production options from man-made water flows, improvements at existing facilities, new sites and pumped storage for load management. This assessment is based on projects previously identified as promising in the Interim Report (Section 4). Seven projects were identified for further investigation

5.6.1 General Methodology

Black & Veatch identified seven hydroelectric projects for characterization and an additional seven pumped storage projects. The overall number of projects were limited to these based on water resource availability and environmental concerns.

5.6.2 Major Assumptions

There are a variety of methods to estimate performance of proposed hydroelectric projects. One useful method of estimating plant performance is to review generation records. Except for the Glen Canyon project, power generation records for the existing hydroelectric facilities were not available for review for this study. Flow duration curves can also be used to estimate performance; however, these were not available either. For this study 40 percent capacity factor was assumed for the smaller hydroelectric projects. This percentage was based on Black & Veatch experience with projects of these characteristics. Forty-five percent was assumed for Glen Canyon dam which is classified as medium hydroelectric project. Without specific site layouts it is impossible to determine a site specific capacity factor. Therefore the capacity factors in the model are estimates only.

A nationwide database of hydroelectric construction cost information per kW of capacity is available from the Department of Energy. In 2003, the nationwide average to develop a hydroelectric project ranged from about $500-6,000/kW, with a median about $2,700/kW for an undeveloped site, and $700/kW for upgrade projects at sites with existing generation. As would be expected, specific costs decrease with plant size and previous development of the site. Most of the selected projects fit within this range.

Like wind and solar, capital costs for hydroelectric projects make up most of the overall costs since the "fuel" is "free" once the required infrastructure is in place. For hydroelectric projects, much of the cost is often off-site from the power plant in the diversion structures, penstock, and their associated access roads. The variability in project site requirements leads to broad ranges of potential costs. For this reason, it is

difficult to develop generic estimates of project costs without detailed site studies, and past detailed estimates, despite their age, are preferred.

Project O&M costs are estimated based on percent of construction cost and staff allocation. O&M costs are expected to be higher for upgrade plants because, though some of the equipment would be new, the diversion and conveyance structures may still require a greater level of maintenance than a new project.

Hydroelectric projects are expected to take longer to develop than other renewable energy projects. Except for Glen Canyon, all the projects identified in this report assume installation by 2013. The Glen Canyon addition is assumed to not be complete until 2015.

5.6.3 Future Cost and Performance Projections

Hydroelectric power generation and hydroelectric pumped storage are largely mature technologies. No changes in future cost or performance were assumed other than adjustments to account for inflation.

5.6.4 Data Sources

Data sources used in this analysis included:

- U.S. Hydropower Resource Assessment for Arizona, Rinehart, Ben, Conner, Alison and Francfort, James, October 1997, Idaho National Engineering and Environmental Laboratory, and Renewable Energy Products Department, Lockheed Martin Idaho Technologies Company, http://hydropower.inel.gov/resourceassessment/pdfs/states/az.pdf.
- Telephone conversations with Doug Hall, Program Manager for INL Hydropower Program.
- Contacts with individual site owners, as possible.

5.6.5 Projects Identified

This section provides descriptions of seven hydroelectric projects identified previously in Section 4. These projects have been previously identified and studied by the Idaho National Laboratory (INL), previously INEEL, the Idaho National Engineering and Environmental Laboratory. Six of the seven project sites are located in the southern portion of the state and have a relatively small capacity in comparison to the total capacity of hydroelectric in the state.

Using the INL database as a starting point, this study included a further detailed search of public records on the internet, contacting the reported owners of each of the projects, and contacting Doug Hall who is the current program manager for the INL

hydroelectric program. After several discussions via telephone and email correspondence with Mr. Hall it was discovered that INL had limited or no information available for the exact project locations and site layouts of the identified projects for the study. This was confirmed by Mr. Hall after his staff performed a brief search for the Arizona hydroelectric information INL had on the initial study performed. Because of this, some assumptions were made to identify approximate project locations using aerial maps provided by Google Earth.

After contacting the project site owners it appeared the owners were very interested and willing to assist in providing data for this study. However, because the INL report lacked detailed location information, data was not readily available to take this study beyond a desktop level study and therefore site visits are recommended to pinpoint and identify specifics on these projects.

Table 5-13 below, gives a summary of the identified projects. The projects are described further in this section.

Table 5-13. Potential Hydroelectric Projects for Arizona.

No.	Project Name	Location	Head Available (ft)	Flow (cfs)	Assumed Type of Project
1	Beardsley	Not Known	77	47	New site with single generator
2	Yuma	Not Known	32	476	New or Existing site with single generator
3	Waddell	New Waddell Dam	264	600	Existing site with single generator
4	CAP Canal	Not Known	150	57	New site with single generator
5	Roosevelt	Not Known	Not Known	Not Known	New site with single generator
6	Tucson	Southern Tucson	92	Not Known	New site with single generator
7	Glen Canyon	Glen Canyon Dam	583	15,000 max	Existing site with new generator(s)

Beardsley Canal Drop

Information provided by INL and public records do not give the precise location or details of the Beardsley canal drop project. The estimated Beardsley Canal project site is located approximately 26 miles from Phoenix, Arizona with overhead power owned by Arizona Public Service available along the presumed project location. The average flowrate in the canal is estimated at 47 cubic feet per second (cfs) with a hydraulic head of 77 feet (ft). Since the information provided on the location of this project can not reasonably pinpoint the project site location it is unclear how to take advantage of the 77 ft of hydraulic head. A local drop in the canal might make it attractive as an open flume, however the hydraulics of this situation with the energy extraction at the powerhouse, would create a sizeable tailwater pool. Further study would be necessary to locate a local drop.

Yuma Main Canal

The locations from the INL database do not clearly identify the location or details of the Yuma Main Canal project. Coordinates listed by INL show the location near the canal. The estimated Yuma Main Canal project site is located approximately 140 miles from Phoenix, with overhead power owned by the Department of Energy available along the presumed project location. Hydraulic head for this site is 32 ft and the flow rate for this site is estimated at 476 cfs. The flow rate is quite large for a canal indicating that a location at the end of a canal run is questionable. Further research uncovered an existing siphon-drop power plant located along the Yuma Main Canal located near Yuma, Arizona. The new power plant began operation in 1987, replacing an earlier power plant located 500 ft downstream that ended operation in 1972. Further study would be necessary to identify this project as a new site or simply an upgrade to the existing power plant.

Waddell

The locations from the INL database do not clearly identify the location or details of the Waddell project. Coordinates listed by INL show the location near the New Waddell Dam. New Waddell Dam is located approximately 30 miles from Phoenix and is located at the New Lake Pleasant Reservoir. The U.S. States Department of the Interior website listed New Waddell Dam as not currently having power generation at the site. However further research uncovered an existing hydroelectric facility in operation. The outlet works capacity is listed at 600 cfs and has a hydraulic head of approximately 264 ft. It is assumed that this project would consist of adding a generator at the existing power plant at New Waddell Dam.

CAP Canal Turnout

Information provided by INL does not give the precise location or details of the CAP Canal Turnout project. The estimated site of the CAP Canal Turnout project is located approximately 26 miles from Phoenix, with overhead power owned by the Arizona Public Service available near the presumed project location. The average flow rate in the canal is estimated at 57 cfs with a hydraulic head of 150 ft. The information provided on the location of this project can not reasonably pin point the project site location. In order to take advantage of the 150 ft of head available a drop in the canal might make it attractive as an open flume, however the hydraulics of this situation, with the energy extraction at the powerhouse, would create a sizeable tailwater pool. Further study would be necessary to locate a local drop this project.

Roosevelt

Information provided by INL does not give specifics on the precise location or details of the Roosevelt project. The estimated site for the Roosevelt project is located approximately 20 miles from Phoenix with overhead power owned by the Salt River Project available near the presumed project location. No hydraulic head or flow information was available for this site. The information provided on the location of this project can not reasonably pin point the project site. The canal appears to traverse down relatively steep terrain which makes a site located at the end of this canal foreseeable. Further study would be necessary to verify this project location.

Tucson

The Tucson hydroelectric site is located at a CAP pressure breakdown station at Technical Way and Palo Verde in southern Tucson. It is operated by Tucson Water. The site was analyzed by TEP in 2000 to produce power at a levelized cost of $0.105 per kWh. The site has available overhead power, owned by TEP. Head was calculated at about 92 feet, varying with upstream reservoir elevation. Flow was estimated to sustain 400 kW of generation at a 99 percent capacity factor due to the reliable flow of water.

Glen Canyon

Glen Canyon Dam is located approximately 250 miles from Phoenix. The dam forms Lake Powell Reservoir and is part of the Colorado River Storage Project. The United States Department of the Interior website listed Glen Canyon Dam's discharge as not exceeding 15,000 cfs with a hydraulic head of 583 ft.

Glen Canyon Dam provides more storage capacity than all other storage features of the Colorado River Storage Project combined. The power plant at the toe of the dam

consists of four 118,750 kW and four 136,562 kW generators driven by eight turbines. Total generating capacity for the power plant is 1,021,248 kW. Eight penstocks through the dam convey water to the turbines. The project would consist of adding an additional 71.8 MW generator at the power plant, however drought conditions have lowered Lake Powel considerably the past few years and there is now question as to the long term sustainable rate of electrical production possible at this site. This project is by far the largest of all projects profiled.

Based on past studies and upgrades, the 1995 environmental flow restrictions placed on Glen Canyon Dam, and environmental concerns, Black & Veatch and Jane Blaire of the Bureau of Reclamation believe that the 71.8 MW identified by INL is an upgrade to existing machines. However, no mention of a 71.8 MW upgrade was found by the Bureau or INL to verify this assumption.

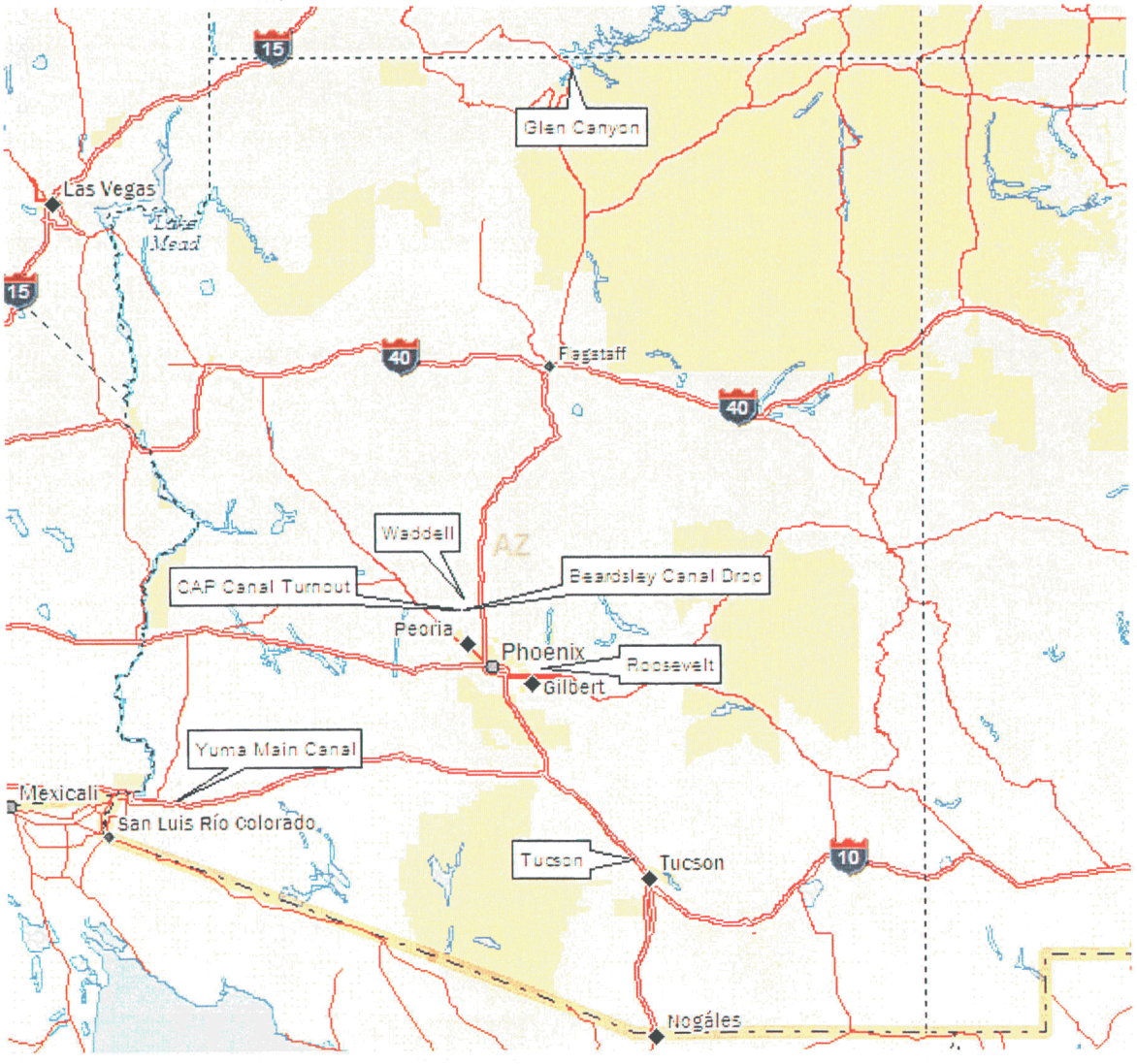


Figure 5-6. Potential Hydroelectric Locations in Arizona.

Table 5-14 shows the hydroelectric projects identified for this study. All characteristics are year 2007 values, before any future cost and performance modifications have been made. Figure 5-7 shows the supply curve for potential hydroelectric projects in Arizona. For the purposes of visualizing the projects on the supply curve, it has been assumed that all projects could be built in 2007. Appendix A shows a consolidated list of projects; Appendix B shows the same list with forecast levelized costs for each project from 2007 to 2025.

The total combined capacity of the seven projects identified is 85.7 MW, with an energy generation potential of 330 GWh/yr. The Glen Canyon project makes up about 85 percent of this total. Of the seven projects, Glen Canyon and Waddell are the only projects that could be reasonably identified. These sites have the most head and flow available compared to other sites. They also have existing hydroelectric installed and therefore show the most potential for further study. The Glen Canyon project is the lowest cost project of all the renewable energy projects surveyed for this study. It is forecast to cost about $50/MWh in 2015. The other hydroelectric projects are all projected to be much more expensive, at costs over $150/MWh in 2013, the first year they are projected to be available.

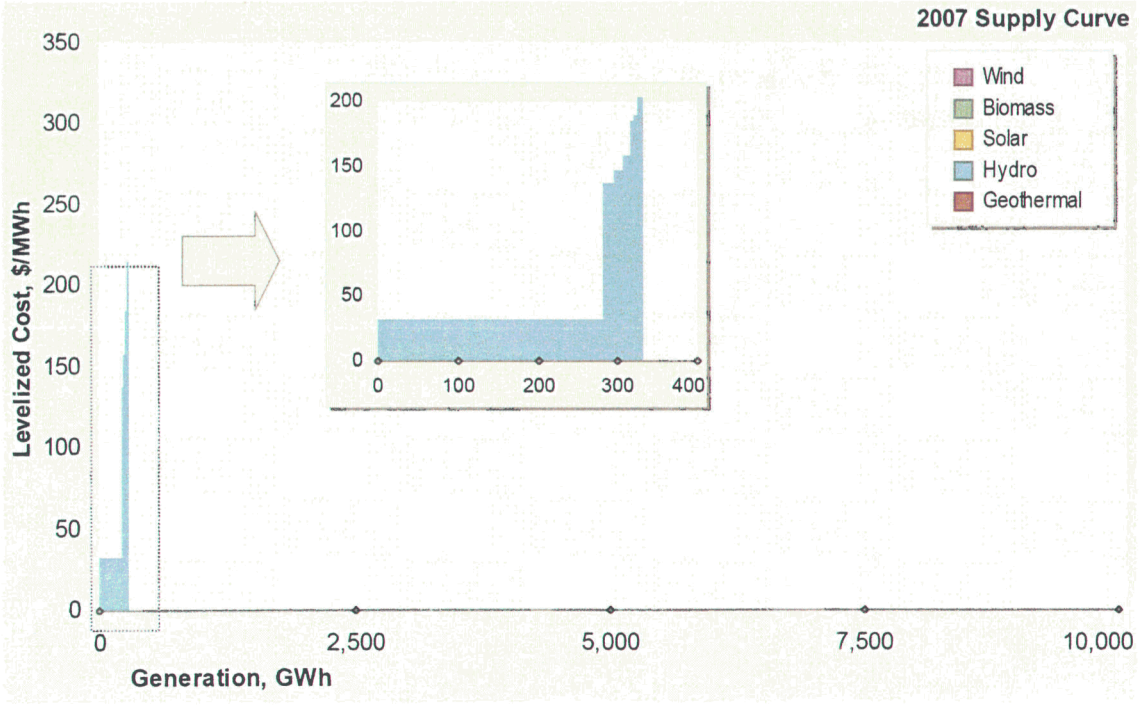


Figure 5-7. Levelized Cost Supply Curve for Hydroelectric Projects.

Table 5-14. Hydroelectric Project Characteristics.

Project	Capacity, MW	CF, %	Genera-tion, GWh	First Year Available	Capital Cost, $/kW	Fixed O&M, $/kW-yr	Var. O&M, $/MWh	Fuel Cost, $/MBtu	Nearest Utility	Transmission Line*		
										Voltage, kV	Dist. to TL, miles	Owner
Beardsley Canal Drop	1.0	40%	3.5	2013	4,324	24	5.6	0	APS	N/A	N/A	N/A
Yuma Main Canal	1.4	40%	4.9	2013	4,079	22	5.2	0	APS	N/A	N/A	N/A
Waddell	1.5	40%	5.3	2013	4,037	21	5.2	0	APS	N/A	N/A	N/A
CAP Canal Turnout	2.5	40%	8.8	2013	3,718	19	4.7	0	APS	N/A	N/A	N/A
Roosevelt (RWCD)	3.2	40%	11.2	2013	3,579	18	4.4	0	SRP	N/A	N/A	N/A
Tucson	0.4	99%	3.5	2013	3,429	17	4.2	0	TEP	N/A	N/A	N/A
Glen Canyon	71.8	45%	283.1	2015	997	8	2.4	0	APS	500	1	

Pumped Storage

The following provides and a brief introductory study and summary of two existing and five proposed pumped storage hydroelectric projects. As part of the preliminary study, pumped storage was not included. For this report existing pumped storage projects were researched using public records available on the internet. Some of the projects looked at had no identifiable locations and limited or no data readily available.

Pumped storage methods are typically used to provide power during peak demand periods. In a pumped storage facility, water is pumped during off-peak demand periods from a reservoir at a lower elevation for storage in a reservoir at a higher elevation. Electricity is then generated during peak demand periods by releasing the pumped water from the higher reservoir and allowing it to flow downhill through the hydraulic turbine(s) connected to generators. During the off-peak pumping cycle, the pumped storage facility is a consumer of electricity which can account for the lower capacity factor. Pumped storage facilities, however, can be economical because they consume low-cost off-peak electricity, but generate high-value on-peak electricity. As with hydroelectric plants, drought conditions can reduce the quantity of on-peak electricity pumped storage facilities can generate.

To date, only a few pumped storage facilities have been built and all are associated with existing dams. Pumped storage can easily be complimented by other renewable resources if available to increase off-peak efficiency. For this study pumped storage was included and was assumed to have a capacity factor of 33 percent.

Table 5-15 lists a summary and descriptions of existing and proposed pumped storage projects in Arizona:

Table 5-15. Potential Pumped Storage Development in Arizona.

Plant Name	Owner	Location	Capacity (MW)
Montezuma	Not Known	25 miles South of Phoenix	500
Starhills	Arizona Independent Power, Inc.	20 miles West of Phoenix	Not Known
Ford Canyon	Arizona Independent Power, Inc.	30 miles North-West of Phoenix	1,250
Azipco	Arizona Independent Power, Inc.	30 miles North-West of Phoenix	1,250
Spring Canyon	Not Known	225 miles North-West of Phoenix	2,000
Horse Mesa	Bureau of Reclamation	45 miles North-East of Phoenix	Not Known
Mormon Flat	Bureau of Reclamation	40 miles North-East of Phoenix	Not Known
Total (Known)			**5,000**

Source: ASCE Compendium of Pumped Storage Plants in the United States, & Web Search

Montezuma Pumped Storage Project

The Montezuma project is to be located approximately twenty-five miles south of the city of Phoenix. It appears that this project may be located at an existing water plant. No other information on permit status was available for this study.

Starhills Pumped Storage Project

Arizona Independent Power, Inc. has filed an application with the commission for this proposed project that would be located on lands administered by the Bureau of Indian Affairs on the Gila River Indian Reservation, in Pinal County, Arizona. The permit was issued in November 2002 and Arizona Independent Power, Inc. has since requested that its preliminary permit be terminated.

Ford Canyon Pumped Storage Project

Arizona Independent Power, Inc. filed an application in February 1997 for this project which would be located in White Tank Mountain Regional Park, in Maricopa County, Arizona. The project will utilize water from the Colorado River System and have an annual generation of 1,250 MW.

Azipco Pumped Storage Project

This project was to be located on the Beardsley Canal, in Maricopa County. The proposed project would consist of a 350 foot high by 1700 foot long earth and rockfill upper dam. This proposed reservoir would have a surface area of 180 acres and a storage capacity of 13,000 acre-feet and have a normal water surface elevation of 3,000 feet with a proposed 200 foot high by 2600 foot long earth and rockfill lower dam. A proposed reservoir having a surface area of 150 acres and a storage capacity of 14,000 acre-feet with a normal water surface elevation of 1,800 feet would complete the lower portion of this project. The proposed powerhouse would consist of five generating units having a total capacity of 1,250 MW. The original permit was issued in February 2001. Arizona Independent Power, Inc. has requested that its preliminary permit be terminated.

Spring Canyon Pumped Storage

Spring Canyon Pumped Storage Project was to have been a 2,000 MW pumped storage project. This project never went beyond the planning phases. No other information was readily available for this study. This project may have been stopped due to its impacts on the environment. Further study would be necessary to confirm this assumption. No information on permit application could be found, however the application was most likely applied for in the mid to late 1980's.

Horse Mesa Dam and Reservoir

The Horse Mesa Dam and reservoir is located on the Salt River approximately 65 miles northeast of Phoenix. Horse Mesa Dam forms Apache reservoir.

One pumped storage hydroelectric unit was added in 1972 and rated at 97,000 kW. The pumped storage unit permits recycling of water for hydroelectric production and keep lake levels relatively constant. The turbine generating units at this dam produce power during periods of peak demands. The turbines are reversed to pump water during off peak periods from the lower reservoir back to the upper reservoir for repeated usage.

Mormon Flat Dam and Reservoir

Mormon Flat Dam is a 224-foot high concrete thin-arch structure and is located on the Salt River 51 miles northeast of Phoenix. Constructed by the Salt River Valley Water Users' Association from 1923-1926, it creates Canyon Lake reservoir.

The pumped storage unit was built in 1971 and is rated at 50,000 kW. The pumped storage unit permits recycling of water for hydroelectric production and keep lake levels relatively constant. The turbine generating units at this dam produce power

during periods of peak demands. The turbines are reversed to pump water during off peak periods from the lower reservoir back to the upper reservoir for repeated usage.

Pumped Storage Summary & Location Map

Of the potential capacity identified in Arizona to date, only two pumped storage facilities have been built and all are associated with existing dams. Pumped storage projects do not appear to be a viable alternative due to it low capacity factor, evaporation, environmental impacts. New pumped storage sites were not identified in this study however, and it is not recommended to consider new pumped storage sites. Due to environmental impacts and permitting issues, it is unlikely that a new pumped storage project would make it past the application process.

Figure 5-8, below identifies the pumped storage projects discussed in this report.

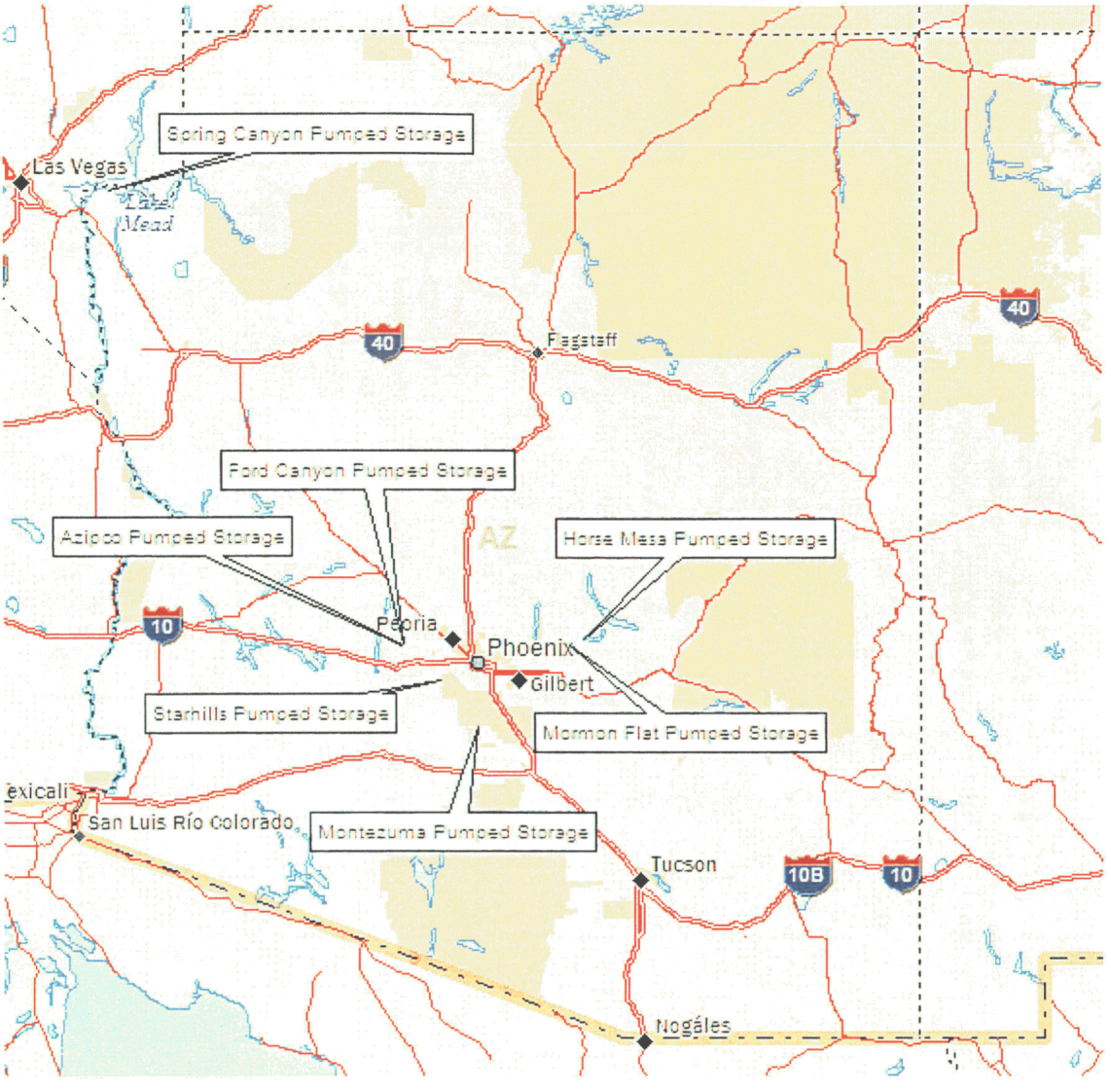


Figure 5-8. Potential Pumped Storage Locations in Arizona.

5.7 Wind Power

Wind power was identified as a promising technology in the first stage of the analysis. Most of Arizona wind resources are marginal, especially when compared to higher speed wind resources in adjacent states. The economics of wind energy in Arizona vary based on the resource, and the specific attributes of each site will dictate suitable turbine models. This section characterizes the resources suitable for wind technology and those turbines thought to be appropriate for use at the prospective sites.

5.7.1 General Methodology

Information was gathered on Arizona's estimated wind resource, geological characteristics, transmission infrastructure, environmental and federal land areas in order to identify specific areas conducive to the development of a utility scale wind energy project. Information was collected on current wind development activity in the state. Black & Veatch also spoke with several wind developers, Northern Arizona University, and a member of the Arizona Wind Working group.

An initial list of sites was created based upon the presence of significant land area of at least a class 3 wind resource (greater than 6.3 m/s annual wind speed), which is considered marginal, and specific terrain features that allow a project to be oriented perpendicular with the prevailing wind direction. Each of the sites on this list was then reviewed in light of the following characteristics:

- Close proximity to adequate transmission (greater than 69 kV)
- Not located within or close to federal or environmentally sensitive areas
- Constructability

Sites that were not located within 8 to 10 miles of transmission lines with voltages above 69 kV were eliminated from the list. In addition, sites were eliminated in areas with "fatal flaws" due to environmental or other reasons. Of the remaining sites, the next review criteria were based on the overall constructability and suitability of the site.

Each site's constructability was measured by the ability to both access the wind resource area and construct turbines on it. Sites that had numerous areas of high slope grades and access routes that presented insurmountable equipment delivery issues were eliminated from the list. For those sites deemed to be constructable, site boundaries where created around areas that could likely support the installation of numerous utility scale wind turbines, and had existing access roads or areas where access road construction would likely not be cost prohibitive.

An analysis was then performed for those sites remaining on the list to determine key cost and performance metrics. The following site specific parameters were calculated

for use in the supply curve model; other values pertaining to project costs were also input into the analysis and will be discussed separately in the sections below.

- Nameplate capacity (MW)
- Net Capacity Factor (%)
- Net Generation (GWh/yr)

The Gamesa G87 2 MW turbine was used in the supply curve analysis to provide an equal platform on which to compare each of the perspective projects. This turbine has an 87 meter rotor and is assumed to be installed on an 80 meter tower. Nameplate capacity, net generation and capacity factor inputs for the supply curve model are all based upon the specifications of this particular turbine. Other turbines were considered for the supply curve analysis; basis for the turbine selection and the results of the analysis will be discussed in the sections below.

Nameplate capacity was determined for each site by estimating how many G87's could be placed within the prospective wind class areas within each site. While the final spacing of turbines is dependent on many site specific characteristics, research has shown that energy deficits tend to decrease with increasing wind speed. Also, the amount of land available to install turbines will vary based on terrain features (i.e. flat pasture vs. mountain tops). As such, Black & Veatch implemented a general wind class specific "rule of thumb" where each subsequently higher wind class area is assigned a tighter spatial distribution for turbine placement and each area is assigned specific terrain multiplier to compensate for land availability issues at each site. These values for terrain and spacing are based upon approved industry standards and Black & Veatch's project experience.

Most of the wind sites in Arizona are at altitude, where lower air density reduces the energy density of the wind. Energy production estimates were made using manufacturer published annual production values as a function of annual wind speed, Weibull parameter and air density. In order to use these production tables, the annual average wind speed at each site was estimated using the AWS Truewind 70 meter wind speed map and then adjusted for elevation. Annual production was then identified and a 15 percent loss was applied to obtain net annual generation and capacity factor values for each site. The results of this analysis are presented in the following sections.

5.7.2 Major Assumptions

The following assumptions were made in the evaluation of wind power potential. Table 5-17 shows the wind class comparison assumptions used for the desktop analysis.

- Transmission constraints were not considered.
- All projects developed with the Gamesa G87 2 MW wind turbines, or similar
- Terrain multipliers are based on an overall desktop observation of slope grade
- Project distance is an approximate straight line distance from project site to location specified
- Capital costs are based on the following criteria presented in Table 5-16

Table 5-16. Cost Assumptions.

Capital Costs	$1,600 per kW, excluding substation and transmission costs[12]
Flat Terrain Multiplier	1.00; Less than 4% grade
Hills Terrain Multiplier	1.05; 4%-8% grade
Mtn Terrain Multiplier	1.15;10% grade or higher
Fixed O&M	$25/kW-yr
Variable O&M	$7-9/MWh

Table 5-17. Wind Class Comparison Assumptions by Wind Class

Parameter	Class 3		Class 4		Class 5		Class 6	
WTG Spacing; row: column *(rotor Dia.)*	3.4	11	3	10	2.6	9	2.2	7
Average Net Capacity Factor	23%		26%		32%		35%	

5.7.3 *Turbine Selection*

While the energy production estimates for the G87 were used as inputs for the supply curve model, energy production values for another Gamesa turbine, the G80, and two versions of the Vestas turbine, the V80, also were also calculated. The purpose of this comparison was to show the variance of energy production that can exist between similar turbine types.

Different wind turbines are designed to operate in a variety of wind resource areas and are classified as such. The wind turbine classes are essentially defined by the nature of the wind speeds and the characteristic turbulence intensity at 15 meters per second. Developers often specify one or more particular set of turbines for energy production

[12] Although the wind industry appears to be on solid footing, wind capital costs have increased substantially over the past five years due to a number of factors including the weakness of the dollar, rising materials costs, a concerted movement towards increased manufacturer profitability, and a shortage of components and turbines. This trend may continue for the next couple of years, but is expected to wane over the long term. It is expected that costs will moderate by 2010 when the first Arizona projects are expected. Section 8 analyzes the impact of higher costs.

estimates, but ultimately it is the manufacturer who will dictate what turbine can be used for a project. Due to the low anticipated wind speeds at these sites, an IEC Class II[13] machine would be preferential; however, the expected high turbulence intensities associated with these sites would likely warrant a special case Class II turbine to be used. It is Black & Veatch's experience from other projects that turbine vendors will require a Class I turbine (to reduce the stresses on the rotor, tower, gearbox, etc.) instead of a modifying a Class II.

The differences in the machines used in this analysis are related to how the manufacturer will modify the one design to satisfy the requirements for different wind turbine classes. The Gamesa G80 and G87 are essentially the same machines in that they use the same type of tower, same generator, etc. The only major difference between the two turbines is the size of rotor diameter; the G80 has an 80 meter rotor diameter and the G87 has an 87m rotor diameter. The Vestas approach is similar, in that the V80 class I turbine uses a different gear box than the V80 class II, which results in the different nominal rotor speed for each class.

Black & Veatch has provided estimates of the net capacity factors in the table below for each of the perspective project sites using the turbines mentioned above.

Table 5-18. Net Capacity Factors Per Wind Turbine Type.

Project Site Name	Wind Turbine Net Capacity Factor Data			
	G80; IEC I	G87; IEC II	V80; IEC I	V80; IEC II
Rattlesnake Crater 1	22.5%	25.6%	24.4%	23.6%
Rattlesnake Crater 2	26.3%	29.5%	28.5%	27.6%
Buckhorn	26.3%	29.5%	28.5%	27.6%
Buffalo Range	26.3%	29.5%	28.5%	27.6%
Chevelon 1	29.2%	32.5%	31.5%	30.6%
Chevelon 2	26.3%	29.5%	28.5%	27.6%
Chevelon 2	26.3%	29.5%	28.5%	27.6%
Chevelon 3	26.3%	29.5%	28.5%	27.6%
Greens Peak	26.3%	29.5%	28.5%	27.6%
Kingstone	24.0%	27.1%	26.0%	25.2%

The net capacity factors for turbines used in this analysis can change with a different project loss assumptions and site specific annual wind speed data and climate information. Overall, these turbines represent technology that has been well studied.

[13] IEC 61400-1 2005, classifies turbines by reference wind speed average over 10 minutes and expected mean characteristic turbulence intensity at 15 meters per second.

5.7.4 Future Cost and Performance Projections

Wind technology has improved measurable over the last few years. As part of work performed for the American Wind Energy Association, Black & Veatch analyzed monthly capacity factor data from over 5,000 MW of wind plants installed in the US Midwest for the years 2000 through 2005. The Midwest was chosen to ensure all the plants were in a similar wind regime. Capacity factors have shown enormous improvement, *averaging 15 percent improvement every two years*. This improvement is due to improved availability, increased hub heights and rotor diameters, as well as better siting. Average hub heights went from roughly 60 meters in 2000-2001 to 85 meters in 2005. Rotor diameters increased from 47 meters to 80 or 90 meters, doubling swept area.

Black & Veatch believes this improvement will continue, although at a slower pace. Capacity factors are forecast to increase another 20 percent from 2005 to 2030, based on higher hub heights, larger rotors, and advanced power electronics.

5.7.5 Data Sources

Data sources used in this analysis included:

- AWS TrueWind, Arizona Wind Maps
- Elliott, D.L, 1991, "Status of Wake and Array Loss Research", Pacific Northwest Laboratory, Richland, Washington
- "The Arizona Meteorological Network", available at: http://ag.arizona.edu/AZMET/.html, accessed: March, 2007
- "Geospatial Data and Metadata Statewide Coverages for Arizona BLM", available at: http://www.blm.gov/az/gis/files.htm, accessed: March, 2007
- Northern Arizona University, available at: http://wind.nau.edu/, accessed: March, 2007
- IEC 61400-1 2005, Wind Turbines – Part 1: Design requirement

5.7.6 Projects Identified

At the conclusion of the review, ten projects at six sites totaling 991 MW of wind energy remained from the original list. Black & Veatch estimates that the total production of these projects will annually yield 2,551 GWh, with an average project net capacity factor of 28.9 percent. The characteristics of these individual projects are provided in Table 5-19. Figure 5-9 shows the general locations of each of the identified project areas overlain on a wind speed map for Arizona. The following sections contain descriptions of each project. Each section contains a map which has the local wind speed map overlain on the site topography. Transmission lines are also indicated. Military training zones may impact the total developable amounts of wind generation and should be

reviewed in detail before project development. Additionally, the Arizona Fish and Game Department has recommended that a three year bird and bat study be performed prior to commencing a wind project in Arizona. Finally, while it is possible that other wind sites could be developed in Arizona, these sites are either further from transmission, have environmental restrictions, are in difficult to construct areas, or have weaker wind resources.

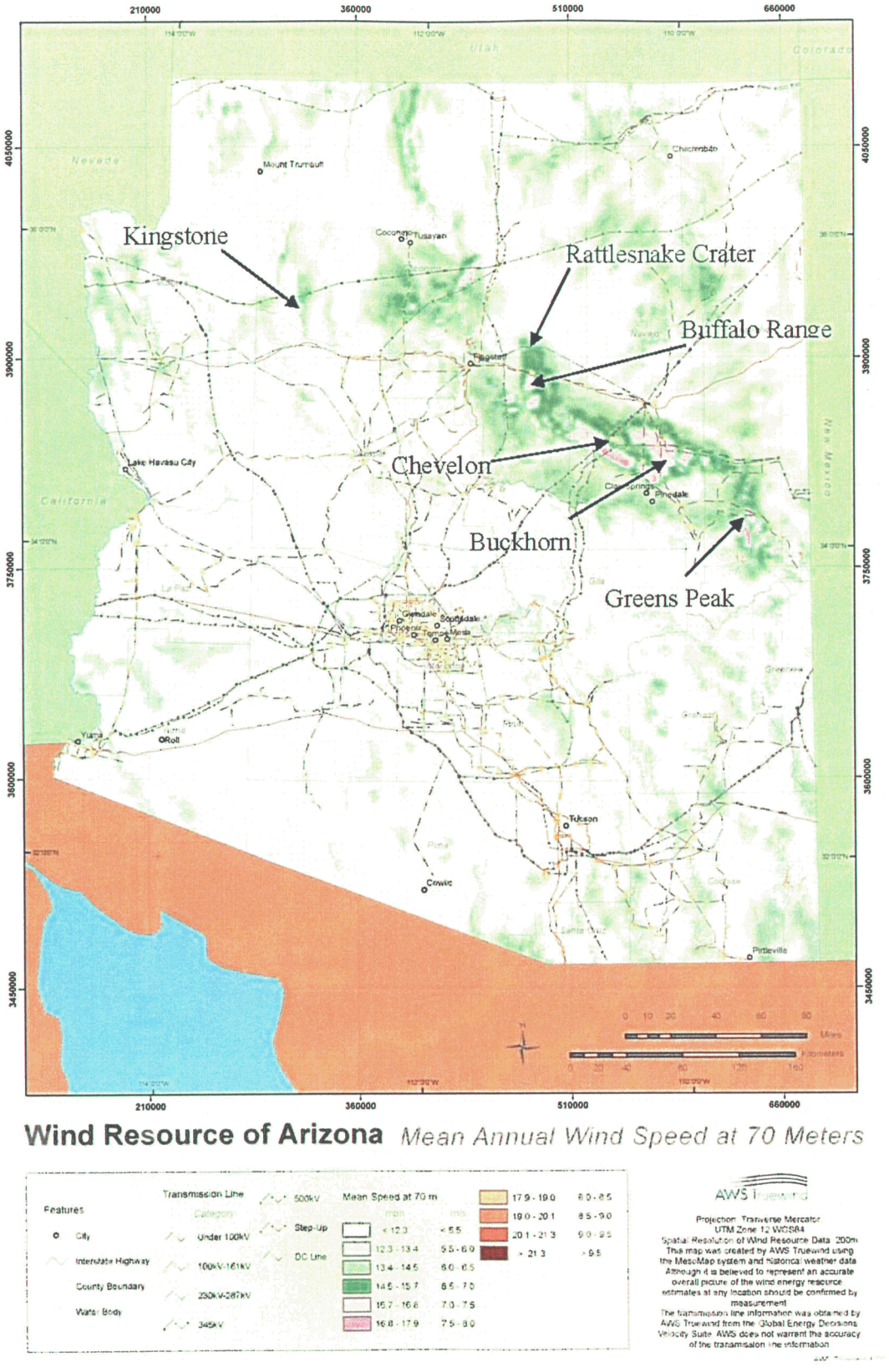


Figure 5-9. Arizona Wind Energy Project Site Areas (Wind Map: AWS Truewind).

Buckhorn Project Site

The Buckhorn project area is located on the north side of Route 277, approximately 8 miles west of Snowflake, AZ. This site area is primarily desert with rolling hills and a moderate decrease in elevation the northeast. This site maintains good exposure to the prevailing winds and sits within a class 4 and 5 wind resource. Several of the existing roads that appear to run through project site that would likely provide an easy means of access to many of the class 4 and 5 wind resource areas shown in light and dark pink in Figure 5-10. Two 69 kV transmission lines were identified to exist near the project site; however, the owners of these lines are not known. A 46 MW project sited at this location is estimated to have and annual average 70m wind speed of 7.3 meters per second, producing 139 GWh annually with a capacity factor of approximately 25.6 percent. Buckhorn is near the proposed PPM Energy Dry Lake project.

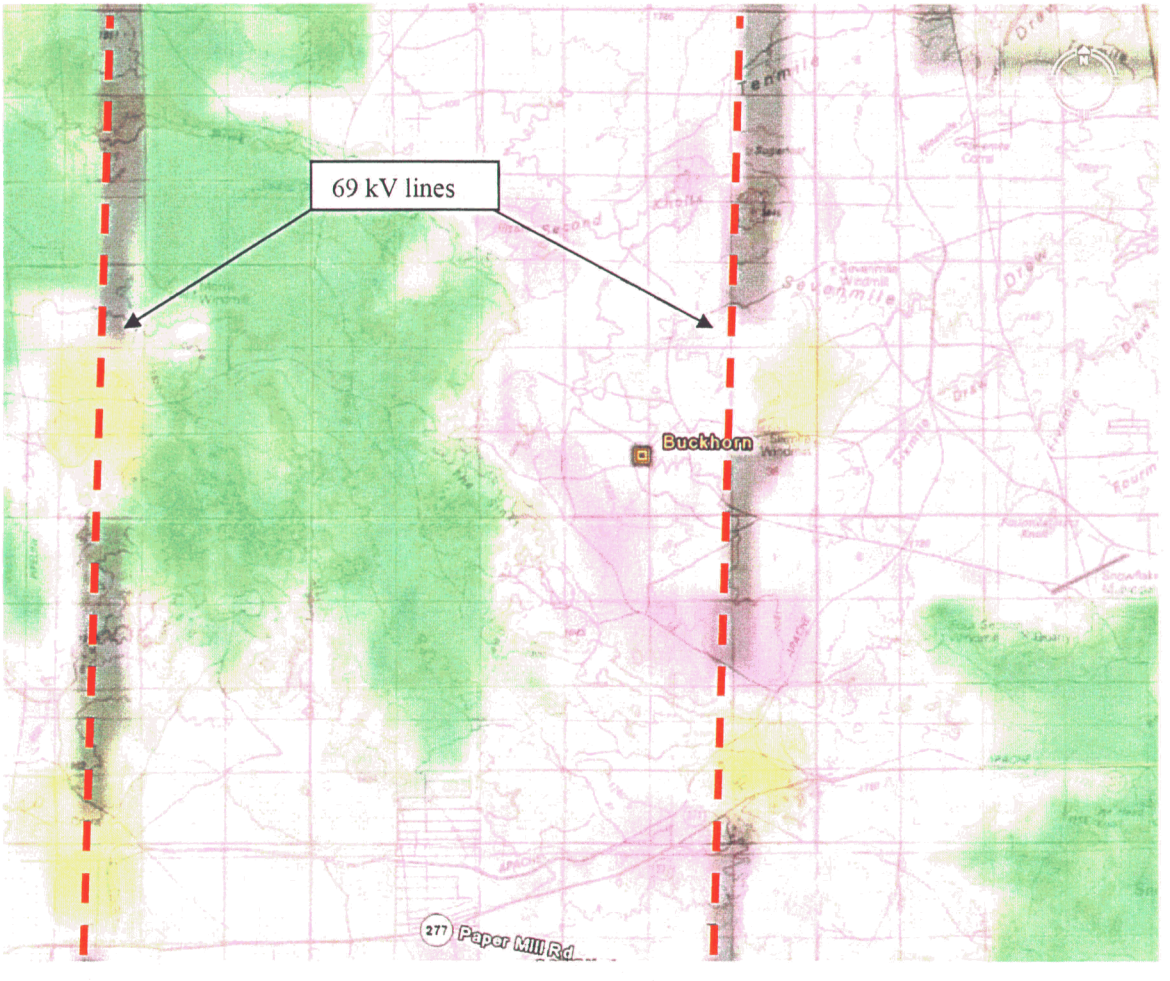


Figure 5-10. Buckhorn Project Area.

Buffalo Range Project Site

The Buffalo Range site area is located along the southern side of Interstate 40, twenty miles east of Flagstaff, AZ. The site is primarily made up of flat desert land providing many options for project size and layout. Existing roads that appear to run through project site would provide an easy means of access to many areas within the class 4 resources of this site shown as light pink areas in Figure 5-11. The site is located in close proximity to an APS 230 kV and a 69 kV transmission line. A 158 MW project sited at this location is estimated to have and annual average 70m wind speed of 7.3 meters per second, producing 409 GWh annually with a capacity factor of approximately 29.5 percent. Buffalo Range is on the other side of I-40 from the planned Foresight Energy Sunshine wind park.

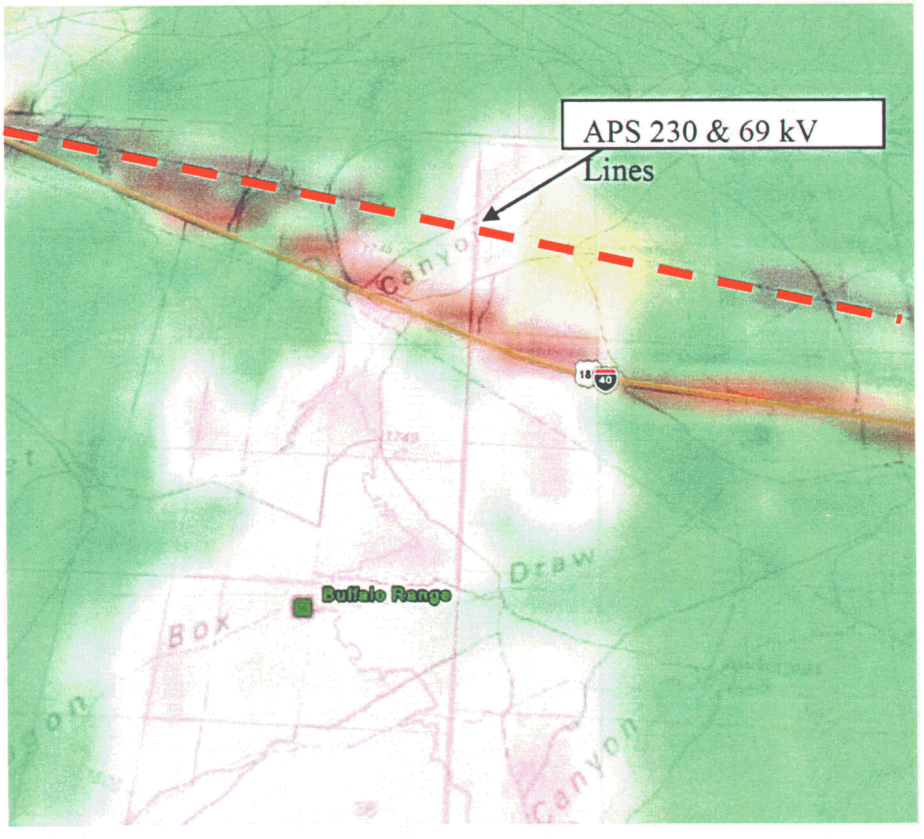


Figure 5-11. Buffalo Range Project Site.

Chevelon Project Sites

The Chevelon project area is located on the west side of highway 99, approximately 30 miles from Clay Springs, AZ. This vast site area consists primarily of wide open flat desert land with a moderate decrease in elevation the northeast. This site has little vegetation, maintains good exposure to the prevailing winds and sits within a class 4 and 5 wind resource. Several of the existing roads that appear to run through project site that would likely provide an easy means of access to many of the class 4 and 5 wind resource areas that are shown in light and dark pink in Figure 5-12. Two APS owned 500 kV transmission lines and one APS owned 345 kV line were identified that run directly through the project site. Due to the vast area of wind resource, this project area could support the build out of several large phases. Three 171 MW projects were sited at this location and estimated to have and annual average 70m wind speed of 7.3 meters per second, producing 442 GWh annually with a capacity factor of approximately 29.5 percent. One 84 MW project was also sited at this location and estimated to have and annual average 70m wind speed of 7.8 meters per second, producing 239 GWh annually with a capacity factor of approximately 32.5 percent.

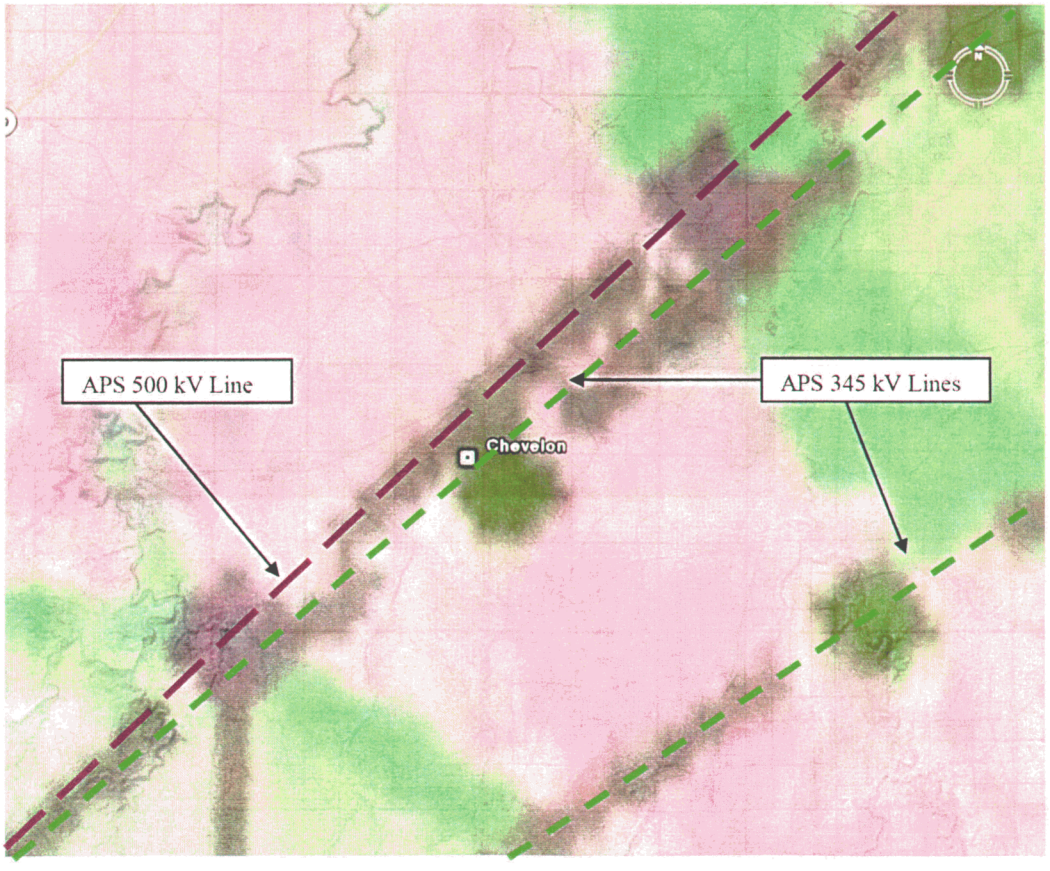


Figure 5-12. Chevelon Project Area.

Greens Peak Project Site

The Greens Peak project area is located on the north side of Highway 260, approximately 14 miles west of Springerville, AZ. While this site area is primarily desert with rolling hills, the landscape is covered with thick vegetation and a few areas of complex terrain features. Exposure of this site to prevailing winds appears to be somewhat restricted to specific areas; however, wind resource maps indicate that strong class 4 and 5 wind resources present in this area. Several of the existing roads that appear to run through project site that would likely provide an easy means of access to many of the wind resource areas shown in light and dark pink in Figure 5-13. Several Navopache Electric Cooperative owned 69 kV transmission lines were identified to exist near the project site. A 31 MW project sited at this location is estimated to have and annual average 70m wind speed of 7.6 meters per second, producing 79 GWh annually with a capacity factor of approximately 29.5 percent.

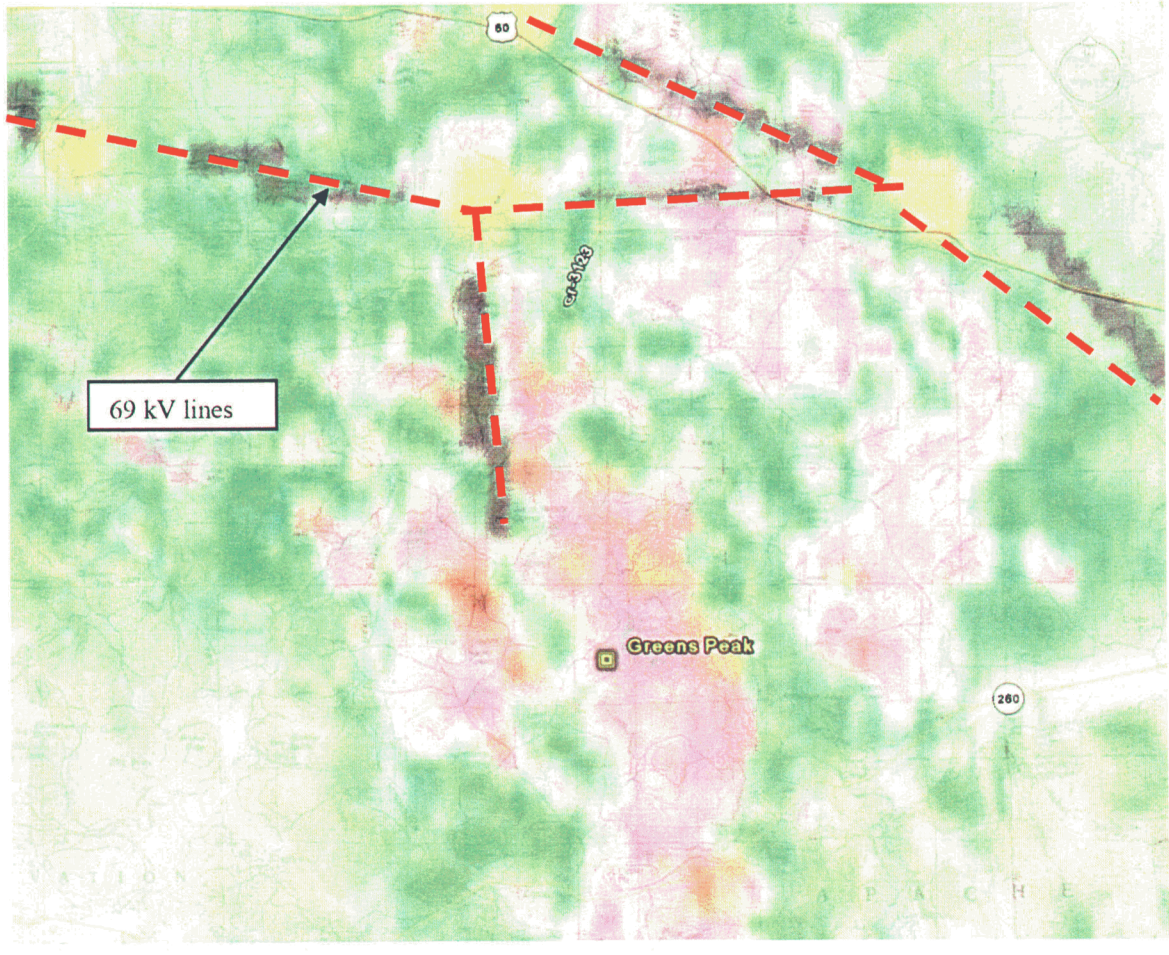


Figure 5-13. Greens Peak Project Area.

Kingstone Project Site

The Kingstone project area is located on the north side of interstate 40, approximately 10 miles north of Seligman, AZ. This project is located along the Aubrey Cliff that provides excellent exposure to the prevailing winds that make up the class 3 and 4 and wind resources in this area. Several of the existing roads appear to run along the project site that would likely provide an easy means of access to many of the resource areas as shown in light and dark green in Figure 5-14. An APS owned 230 kV transmission lines was identified to exist near the project site. An 18 MW project sited at this location is estimated to have and annual average 70m wind speed of 7.0 meters per second, producing 44 GWh annually with a capacity factor of approximately 27.1 percent.

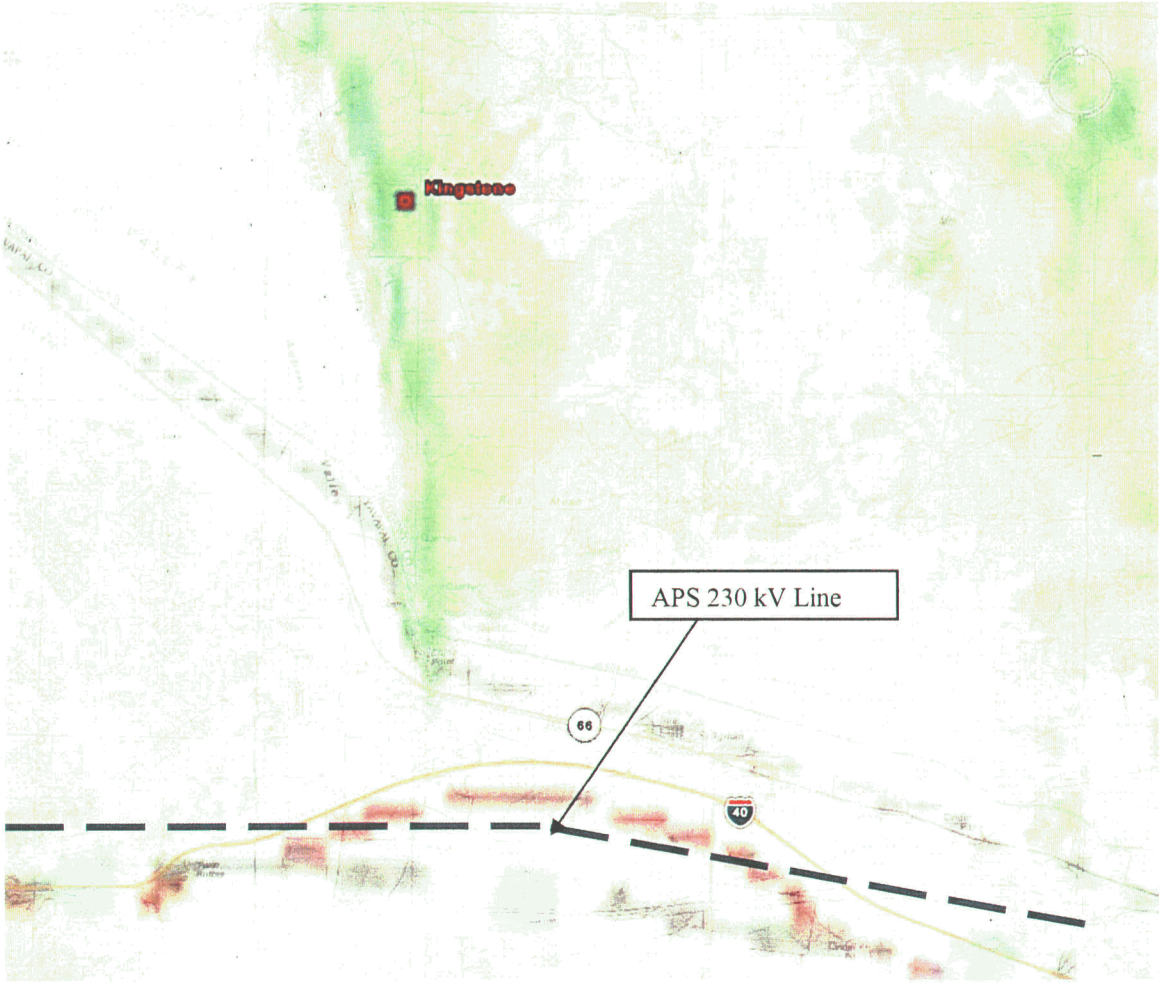


Figure 5-14. Kingstone Project Area.

Table 5-19 shows the wind power projects identified for this study. All characteristics are year 2007 values, before any future cost and performance modifications have been made. Figure 5-15 shows the supply curve for wind power. For the purposes of visualizing the projects on the supply curve, it has been assumed that all projects could be built in 2007. Appendix A shows a consolidated list of projects; Appendix B shows the same list with forecast levelized costs for each project from 2007 to 2025.

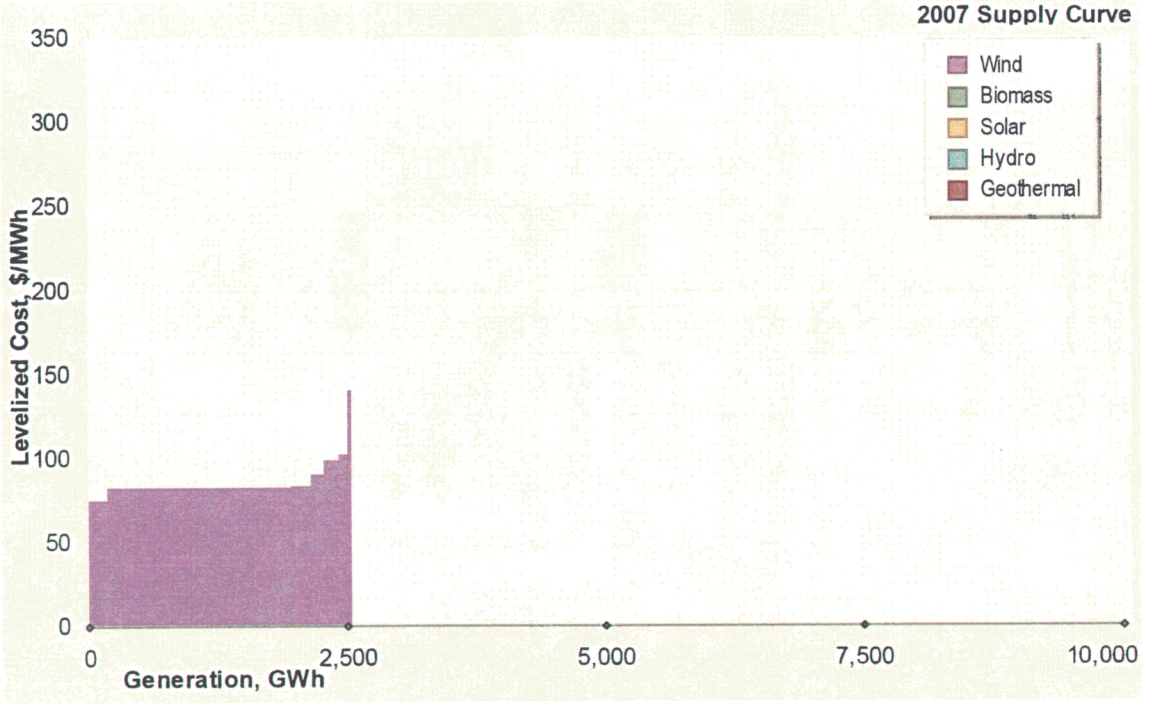


Figure 5-15. Levelized Cost Supply Curve for Wind Power Projects.

Table 5-19. Wind Power Project Characteristics.

Project	Capacity, MW	CF, %	Generation, GWh	First Year Available	Capital Cost, $/kW	Fixed O&M, $/kW-yr	Var. O&M, $/MWh	Fuel Cost, $/MBtu	Nearest Utility	Transmission Line		
										Voltage, kV	Dist. to TL, miles	Owner
Rattlesnake Crater 1	62	26%	139	2010	1,600	25	9		APS	230	0	APS
Rattlesnake Crater 2	78	30%	203	2011	1,600	25	8		APS	230	0	APS
Buckhorn	46	30%	119	2010	1,680	25	8		APS	69	7	APS
Buffalo Range	158	30%	409	2010	1,600	25	8		APS	230	1	APS
Chevelon 1	171	30%	442	2010	1,600	25	8		APS	345	0	APS
Chevelon 2	171	30%	442	2011	1,600	25	8		APS	345	0	APS
Chevelon 3	171	30%	442	2012	1,600	25	8		APS	345	0	APS
Chevelon 4	84	33%	239	2013	1,600	25	7		APS	345	0	APS
Greens Peak	31	30%	79	2010	1,680	25	8		APS	69	6	APS
Kingstone	18	27%	44	2012	1,840	25	8		APS	230	5	APS

5.8 Geothermal

Geothermal was identified as a relatively unquantified, but potentially promising resource in the first phase of this study. This section explores two potential projects in more detail.

5.8.1 General Methodology

In Arizona, the geothermal resource is not as well explored and characterized as in some areas of the Southwestern United States. Electric power production from geothermal is undemonstrated in Arizona. Because of the limited work done to this point to identify specific developable geothermal resources in the state, projects are based on the two areas where there has been some focus on understanding the resource potential.

Without a known location that would support a flash steam geothermal facility, binary cycle type plants have been characterized.

5.8.2 Major Assumptions

Because projects are still in their early exploratory state, there is not enough data available to accurately characterize the geothermal projects with a high degree of precision. Even identifying the potential project size is still speculative. For this reason, generic project assumptions (similar to those presented in Section 4) were adjusted for economies of scale and then applied to the two projects identified.

The following assumptions were made in the evaluation of geothermal potential.

- Two sites, Gillard Hot Springs and Clifton
- 15 and 20 MW power plants
- Binary cycle plant type
- Construction time of 3.5 years
- Available for operation in 2013 and 2014
- Capacity factor of 70 percent, which is typical for dry-cooled binary resources (the most likely type to be developed in Arizona)

At best, these assumptions identify "place-holder" projects that must be further defined as more information about the true potential of each site is discovered.

5.8.3 Future Cost and Performance Projections

The geothermal technologies of flash steam and binary cycle are largely mature technologies. No changes in their future cost or performance were assumed. "Enhanced Geothermal Systems" described below, are new techniques that may bring more

geothermal development to Arizona, not because of lower costs or higher efficiencies, but because they may make new geothermal resource areas available for production.

Although the focus for most geothermal projects to date has been conventional hydrothermal resources, there is considerable potential in Arizona for the so-called "Enhanced Geothermal Systems" or "Hot Dry Rock" type of projects. Such projects are developed in areas with high underground temperatures but insufficient permeability to support commercial flow rates. In such projects, the reservoir rock is stimulated by hydraulic and/or chemical methods, creating a large network of fine fractures, thus forming an underground heat exchanger. Fluid is injected at one location and produced at another, having passed through the fracture network, gaining heat on the way. These non-conventional resources are experimental and strategic at this point, but many projects are underway in the US, Europe and Australia to determine the most effective methods of stimulation and heat recovery. The project at Soultz-sous-Forêts in France is likely to be the first to produce power from EGS/HDR resources, with one of the Australian projects likely to be the next. This type of development is probably 10 years or more from being commercial; more experience in the development and operational aspects of EGS/HDR resources is needed, and cost reductions need to enable this technology to be considered commercial. EGS/HDR resources were not explicitly modeled in this study. However, there appears to be sufficient promise that development of the technology should be closely monitored.

5.8.4 Data Sources

Data sources used in this analysis included:

- NOAA (National Oceanic and Atmospheric Administration, 1982. Geothermal Resources of Arizona. Oversized map with text and tables.
- INL (Idaho National Engineering and Environmental Laboratory), 2003. Arizona Geothermal Resources. One-page map. Publication No. INL/MIS-2002-1616 Rev.1.
- Witcher, James C., 1995. Geothermal Resource Data Base: Arizona." Southwest Technology Development Institute, New Mexico State University.
- David Brown and Associates, 2006. GRED III Final Report, Clifton Hot Springs Geothermal Project, Greenlee County, Arizona. Report on worked funded by US Department of Energy, DE-FC36-04GO14346.
- Morgan, P., W. Duffield., J. Sass and T. Felger, 2003. Searthing for an electrical-grade geothermal resource in northern Arizona to help Geopower the West. Transactions, Geothermal Resources Council, Vol. 27.

5.8.5 Projects Identified

The two known geothermal resources with the highest temperatures are located in the eastern part of the state: the Clifton Hot Springs project, and the Gillard Hot Springs. Interpretation of temperature and geochemical data suggest that resource temperatures may be as high as 140°C (just under 300°F) at both areas, which would enable binary power generation.

One of the springs at Gillard Hot Springs has a temperature of 183.2°F (84°C), but no wells have been drilled to intercept a potential resource. Exploration is somewhat further advanced at Clifton, including drilling funded under the GRED III program of US Department of Energy. Two core holes were drilled to 635 feet and 1,000 feet respectively. The deeper well had a temperature of 129°F at bottomhole, and a linear temperature gradient of 100°C/km, which is attractive. Deeper drilling is required to determine if this gradient results from a relatively shallow (but deeper than 1,000 feet), low-temperature resource or a deeper, higher temperature resource. Geochemistry suggests resource temperatures may be on the order of 140°C (just under 300°F); as mentioned above, this would be appropriate for a binary power development. The resistivity survey that was carried out as part of the same DOE-funded work may help to understand the subsurface better, but the resource can only be proven by drilling. APS is a collaborator on this project.

Another USDOE program (GRED II) provided funding in 2004 to Northern Arizona University to evaluate the geothermal potential of the San Francisco Peaks area, north of Flagstaff. The results of this work show that the San Francisco Peaks have silicic eruptions as young as 50,000 years in age, which is promising for the presence of high-temperature geothermal resources. However, there are no hot springs associated with these young volcanoes, and Morgan et al. (2003) believe that thermal waters are rising and mixing into a large, deep regional aquifer, which is obscuring the geothermal "signature." Funding is being sought for deep core hole drilling in the area to evaluate this hypothesis and hopefully identify a geothermal resource.

Table 5-20 shows the geothermal projects identified for this study. All characteristics are year 2007 values, before any future cost and performance modifications have been made. Figure 5-16 shows the supply curve for geothermal. For the purposes of visualizing the projects on the supply curve, it has been assumed that all projects could be built in 2007. Appendix A shows a consolidated list of projects; Appendix B shows the same list with forecast levelized costs for each project from 2007 to 2025.

Table 5-20. Geothermal Project Characteristics.

Project	Capacity, MW	CF, %	Genera-tion, GWh	First Year Available	Capital Cost, $/kW	Fixed O&M, $/kW-yr	Var. O&M, $/MWh	Fuel Cost, $/MBtu	Nearest Utility	Transmission Line		
										Voltage, kV	Dist. to TL, miles	Owner
Clifton	20.0	70%	123	2013	4,000		30	0	APS	35	10	
Gillard	15.0	70%	92	2014	4,500		30	0	APS	35	10	

Note: Transmission Line voltage and Distance to transmission line is unknown. Fixed O&M costs are included in the capital cost and variable O&M cost numbers.

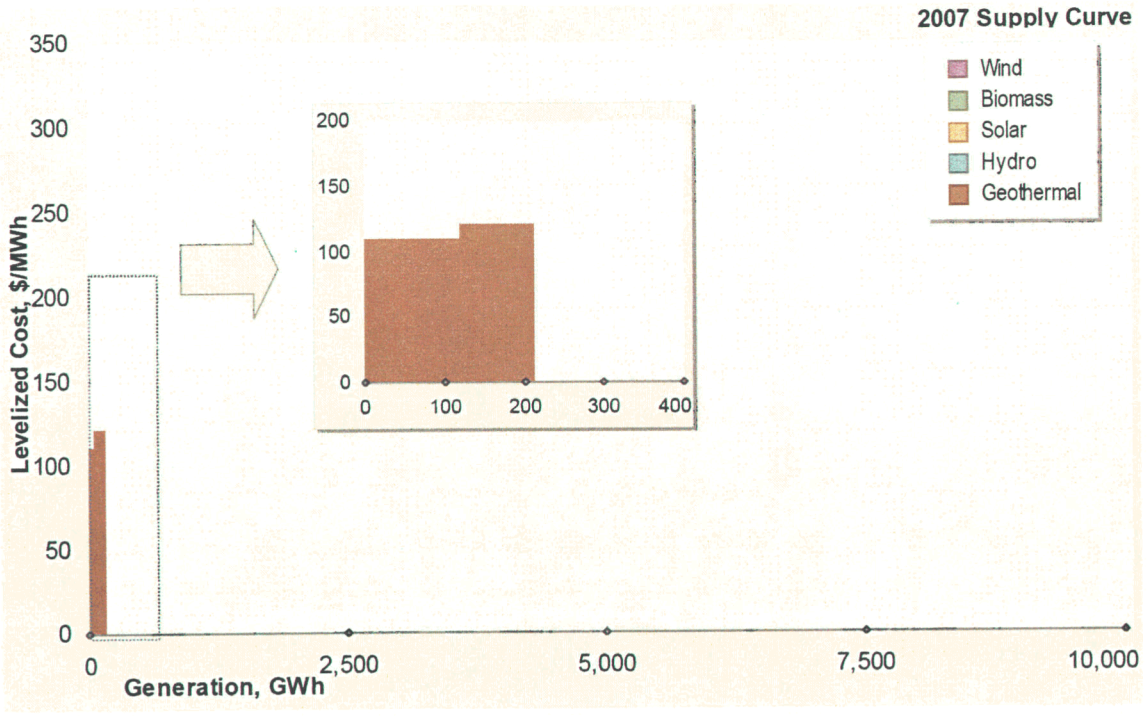


Figure 5-16. Levelized Cost Supply Curve for Geothermal Projects.

6.0 Renewable Energy Financial Incentives

A number of financial incentives are available for the installation and operation of renewable energy technologies. These incentives can substantially influence profitability and can make the difference between a non-viable and a viable project. The following discussion provides a brief list of existing and proposed incentives that are available to new renewable energy facilities. Although many of these incentives are designed as tax credits, it may still be possible for non-taxable entities (or others with limited tax appetite) to benefit from the incentives by establishing facility ownership through a third-party taxable entity or other project structures. It should be noted that the intent of this section is to provide general information on available incentives; Black & Veatch cannot provide tax advice concerning the implications of the specific incentive programs.

6.1 Tax Related Incentives

The predominant incentive offered by the federal government for renewable energy has been through the US tax code in the form of tax deductions, tax credits, or accelerated depreciation. An advantage of this form of incentive is that it is defined in the tax code and is not subject to annual congressional appropriations or other limited budget pools (such as grants and loans). Tax related incentives include:

- Section 45 Production Tax Credit (PTC)
- Section 48 Investment Tax Credit (ITC)
- Accelerated depreciation

The ability to utilize tax credits is limited not only by specific legal considerations, but also by practical considerations. It can be difficult to line up the risks and benefits of a specific transaction with the appropriate participants and their tax status.

Government-owned utilities and other tax-exempt entities are not able to directly take advantage of these tax incentives. Tax-exempt entities, however, do enjoy a number of other benefits when financing and operating capital investments. The most obvious benefit is freedom from federal and state income tax liability. Depending on project location and local laws, payment of property taxes may also be reduced or eliminated. These entities are also able to issue tax-exempt debt, which carries considerably lower interest rates than comparable corporate debt.

The Section 45 PTC is available to private entities subject to taxation for the production of electricity from various renewable energy technologies. The *Energy Policy Act of 2005* expanded and extended the PTC through 2007. The PTC was further extended in late 2006 until the end of 2008. For most technologies, the facility must be in service by December 31, 2008. The income tax credit amounts to 1.5 cents/kWh

(subject to annual inflation adjustment and equal to 2.0 cents/kWh in 2007) of electricity generated by wind, solar, geothermal, and closed-loop biomass. The credit is equal to 0.75 cents/kWh (inflation adjusted, equal to 1.0 cents/kWh in 2007) for all other renewable energy technologies. A problem with the credit is the ever present threat of expiration, which promotes boom and bust building patterns.

Table 6-1 shows the provisions of the production tax credit for renewable energy, as revised by the Energy Policy Act of 2005.

Table 6-1. Major Production Tax Credit Provisions.

Resource	Eligible In-service Dates	Credit Size*	Special Considerations
Wind	12/31/93 - 12/31/08	**Full**	None
Biomass			
Closed-Loop	12/31/92 - 12/31/08	**Full**	Crops grown specifically for energy
Closed-Loop Cofiring	Before 12/31/08	**Full**	Only specific coal power plants; based on % of biomass heat input
Open-Loop	Before 12/31/08	Half	Does not include cofiring
Livestock Waste	10/22/04 - 12/31/08	Half	>150 kW; Does not include cofiring
Poultry Waste	12/31/99 - 12/31/03	**Full**	Incorporated with "livestock waste" with the American Jobs Creation Act of 2004
Geothermal	10/22/04 - 12/31/08	**Full**	Can't also take investment tax credit
Solar	10/22/04 - 12/31/05	**Full**	Can't also take investment tax credit; eligibility expired Dec. 31, 2005
Small Irrigation Hydro	10/22/04 - 12/31/08	Half	No dams or impoundments; 150 kW-5 MW
Incremental Hydro	8/8/05 - 12/31/08	Half	Increased generation from existing sites
Landfill Gas	10/22/04 - 12/31/08	Half	Can't also take Sec. 29 tax credit
Municipal Solid Waste	10/22/04 - 12/31/08	Half	Includes new units added at existing plants.

Notes:
* All PTCs are inflation-adjusted and equaled $20/MWh ("Full") or $10/MWh ("Half") in 2007.

The Section 48 ITC effectively offsets a portion of the initial capital investment in a project. The *Energy Policy Act of 2005* modified the ITC to include additional resources and to increase the credit amount. The current ITC provisions:

- **Solar** – Eligible solar equipment includes solar electric and solar thermal systems. The credit amount for solar is 30 percent for projects that come online prior to December 31, 2008; otherwise, it is 10 percent.
- **Fuel cells** – Fuel cells installed prior to December 31, 2008 are eligible for the ITC. The credit amount is 30 percent with the maximum credit capped at $1,000/kW.

- **Microturbines** – Microturbines installed prior to December 31, 2008 are eligible for the ITC. The credit amount is 10 percent with the maximum credit capped at $200/kW.
- **Geothermal** – Geothermal includes equipment used to produce, distribute, or use energy derived from a geothermal deposit. It does not include geothermal heat pumps. The credit amount is 10 percent, but it cannot be taken in conjunction with the PTC.

The language of the PTC extension does not allow claiming of both the PTC and the ITC. Project developers must choose one or the other. For capital intensive solar projects, the ITC is typically more attractive. For geothermal projects, the PTC is more attractive. The ITC also interacts with accelerated depreciation, as discussed further below.

Section 168 of the Internal Revenue Code contains a Modified Accelerated Cost Recovery System (MACRS) through which certain investments can be recovered through accelerated depreciation deductions. There is no expiration date for the program. Under this program, certain power plant equipment may qualify for 5-year, 200 percent (i.e., double) declining-balance depreciation, while other equipment may also receive less favorable depreciation treatment. Renewable energy property that will receive the 5-year MACRS includes:

- **Solar** – Solar property that meets the same standards for eligibility required by the federal 10 percent investment tax credit.
- **Wind** – Wind property subject to the same 25 percent limit on dual-fueled equipment required for solar property.
- **Geothermal** – Geothermal property up to the electrical transmission stage.
- **Biomass** – Qualifying Facilities 80 MW or less that directly burn at least 50 percent biomass to generate electricity. The power plant must burn the biomass directly to qualify.

The accelerated depreciation law also specifies that the depreciable basis is reduced by the value of any cash incentives received by the project, and by half of any federal investment tax credits (e.g., the ITC). This provision has the effect of lowering the depreciable basis to 95 percent for projects that receive the 10 percent ITC (and 85 percent for projects that take the 30 percent ITC) but no other cash incentives.

6.2 Non Tax-Related Incentives

The Renewable Energy Production Incentive (REPI) program was developed as a public sector counterpart to the PTC (Section 45) discussed previously. The REPI has been recently renewed through September 30, 2016 as part of the Energy Policy Act of

2005. Qualifying facilities must use solar, wind, ocean, geothermal, or biomass (except for municipal solid waste) generation technologies. Under the REPI program, qualifying facilities are eligible for an annual incentive payment of 1.5 cents/kWh (subject to annual inflation adjustment and equal to 1.9 cents/kWh in 2005). The payment is given for a period of ten years after the facility begins operation. The payment is subject to the availability of annual congressional appropriations.

There are two major shortcomings of the REPI program as it currently exists. First, the REPI program's reliance on annual Congressional appropriations limits its effectiveness as a financial incentive. Second, program appropriations for recent years (2003 and 2004) have not been sufficient to make full incentive payments for electricity. As a result, planners of renewable energy generation facilities have often not relied on REPI payments when evaluating the feasibility of projects. The DOE recognizes the problems of the REPI program and has sought and reviewed comments on options to make REPI a more effective incentive. These options would require either regulatory or statutory change and would need significantly higher levels of appropriations, which may be unrealistic.

Clean Renewable Energy Bonds (CREBs) were introduced as part of the Energy Policy Act of 2005 as a response to the perceived problems with the REPI program. CREBs provide interest-free loans to public utilities (including rural electric co-ops), while providing tax credits to purchasers (the investors who buy the bonds). Qualifying projects are renewable energy projects which meet the same technical definitions as the Section 45 PTC (with the exception of the placed-in-service date). Congress originally authorized $800 million in bonds over two years with repayment terms of 12 to 15 years.

Of the $800 million allocated, a maximum of $500 million is for governmental entities, with the remainder reserved for co-ops. The deadline for applying for the first round of CREBs was April 26, 2006. The IRS allocated funding beginning with the smallest request and continuing with the next smallest until the funds are exhausted. This makes the CREB funds much more likely to be available for small projects. Although the initial pool of $800 million of CREBs has been allocated, in December 2006 the government authorized an additional $400 million to continue the CREB program.

7.0 Renewable Energy Development Model Results

Black & Veatch has developed a model to help utilities, states, and other entities identify and compare renewable resources to develop renewable energy plans. This tool has been used for resource assessment, RPS compliance cost projections, renewable energy credit market price forecasts, and strategic planning. For the utilities represented in this study, Black & Veatch evaluated the renewable energy potential for the state of Arizona in light of increased demand for renewable energy stimulated \y an increased Renewable Energy Standard and other factors. The model was then used to forecast potential renewable energy development in the state through 2025.

This section describes the model methodology, assumptions, and results.

7.1 Methodology

Black & Veatch developed an objective methodology to model renewable energy potential and development based on sound utility generation planning fundamentals and the specific challenges inherent to analyzing renewable energy generation technologies. This methodology evaluates the total lifecycle cost of renewable energy projects, including capital and operating costs, performance, and transmission system impacts. Projections are made for future changes in technology cost and performance based on Black & Veatch's experience in the field. This methodology can be used to identify the single most economic project, or to analyze a portfolio of projects to meet a specified renewable energy demand or other regulatory requirement. By allowing the model to consider all possible renewable energy resources in Arizona, the study assesses the full potential of all renewable energy resources while accounting for the economic variables of developing those resources.

The approach includes the following major steps:

- Technology characterization and selection
- Project characterization
- Future Cost and Performance Projections
- Transmission System Cost Analysis
- Levelized Cost Calculation
- Supply Curve Generation

Figure 7-1 shows a basic flow-chart of the renewable energy planning process and illustrates how the various steps integrate to produce an overall assessment plan.

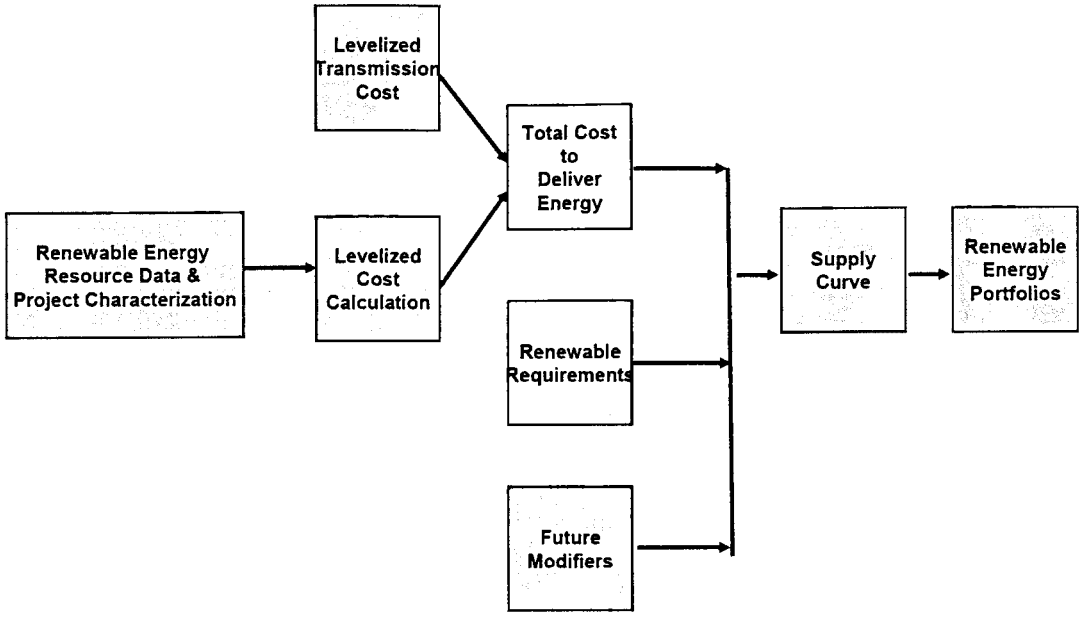


Figure 7-1. Renewable Resource Assessment Methodology.

7.1.1 Technology Characterization and Selection

Technology characterization and selection consists of identifying those renewable energy technologies that could be reasonably applied to harness the available resources in a particular area. Black & Veatch assessed the level of commercialization for each technology in comparison to Arizona's overall resource supply. As a result, the analysis focused on the more promising technologies for Arizona, namely:

- Direct Fired and Cofired Biomass
- Landfill Gas
- Anaerobic Digestion
- Solar Thermal Electric
- Solar Photovoltaic
- Hydroelectric
- Wind Power
- Geothermal

7.1.2 Project Characterization

For each promising renewable energy resource, Black & Veatch determined the potential capacity and locations where development is possible. Using several data sources, including maps, GIS data, and databases, renewable energy technology specialists identified high potential locations across Arizona for their respective technologies. For each location, these specialists quantified the generation potential of

each renewable energy resource (e.g. biomass quantity, direct solar insolation, etc.) This information led to estimating capacity and annual production realizable from developing projects in these locations. The results of the project characterization are presented in Section 5.

Black & Veatch then determined how much of the theoretical resource potential can practically be developed. This "developable potential" is the available resource that can be realistically developed with the appropriate technology and siting constraints. The developable resource is determined by considering constraints on land use, proximity to transmission, resource quality, and theoretical efficiency. Land constraints are critical in Arizona, where much of the available land is national park, national forest, Native American lands, or rugged and remote.

Black & Veatch assigned performance and cost assumptions for each project or resource class that reflect current industry operating experience and actual costs observed to develop projects based on previous experience. Black & Veatch worked with representatives from the utilities to agree on realistic assumptions for the current Arizona renewable energy climate.

7.1.3 Future Cost and Performance Projections

Since renewable energy technologies are still developing, cost and performance are expected to change in the future. The model reflects these changes to estimate penetrations of each resource in the future, as current assumptions for these technologies will likely not be valid within 10 to 20 years. For example, solar photovoltaic modules are expected to decline considerably in cost over the next 10 to 20 years. Black & Veatch evaluated changes to all technology characteristics, including:

- Capacity factor
- Typical capacity
- Applicable incentives
- Capital cost
- O&M costs
- Fuel costs (if applicable)
- Tax credits and other incentives

7.1.4 Transmission System Cost Analysis

The transmission cost analysis for this project was necessarily simplified. Transmission costs were considered up to the point of grid connection (that is, costs for substation and project tie-line were included), but no costs for system upgrades or wheeling were identified. In addition, the availability of capacity on specific

transmission lines was not assessed. Lines were assumed to have available capacity to accommodate the projects.

Based on input from the utilities, Black & Veatch estimated interconnection substation and transmission line spur costs for each potential project. Black & Veatch also identified the utility that corresponded to the service area and transmission line.

7.1.5 Levelized Cost of Electricity Calculations

Black & Veatch calculated the levelized cost of electricity by using the performance and cost assumptions for each project combined with the appropriate financing and economic assumptions for the type of development (see Table 7-3). The levelized cost is a measure of the life-cycle cost to generate electricity with a particular project. This cost allows various technologies, both conventional and renewable, to be compared on an equal economic basis ($/MWh). The methodology for levelized cost calculation is described in Section 4.1.

7.1.6 Supply Curve Development

Black & Veatch developed supply curves for the aggregate mix of renewable energy projects available to Arizona. Supply curves are used in economic analysis to determine the quantity of a product that is available for a particular price (e.g., the amount of renewable energy that can be generated within a utility system for under $50/MWh). The supply curve is constructed by plotting the amount of generation or capacity added by each technology or project against its corresponding levelized cost. For this study, the renewable generation added by each project class is plotted against its levelized cost of electricity in ascending order. As an example, see Figure 7-2. In this case, generation (GWh/yr) is on the x-axis and levelized cost ($/MWh) is shown on the y-axis. The supply curve shows that there are only a few projects that would be able to supply power for under $100/MWh by 2020. However, there is a large pool of solar resources at a cost of about $200/MWh.

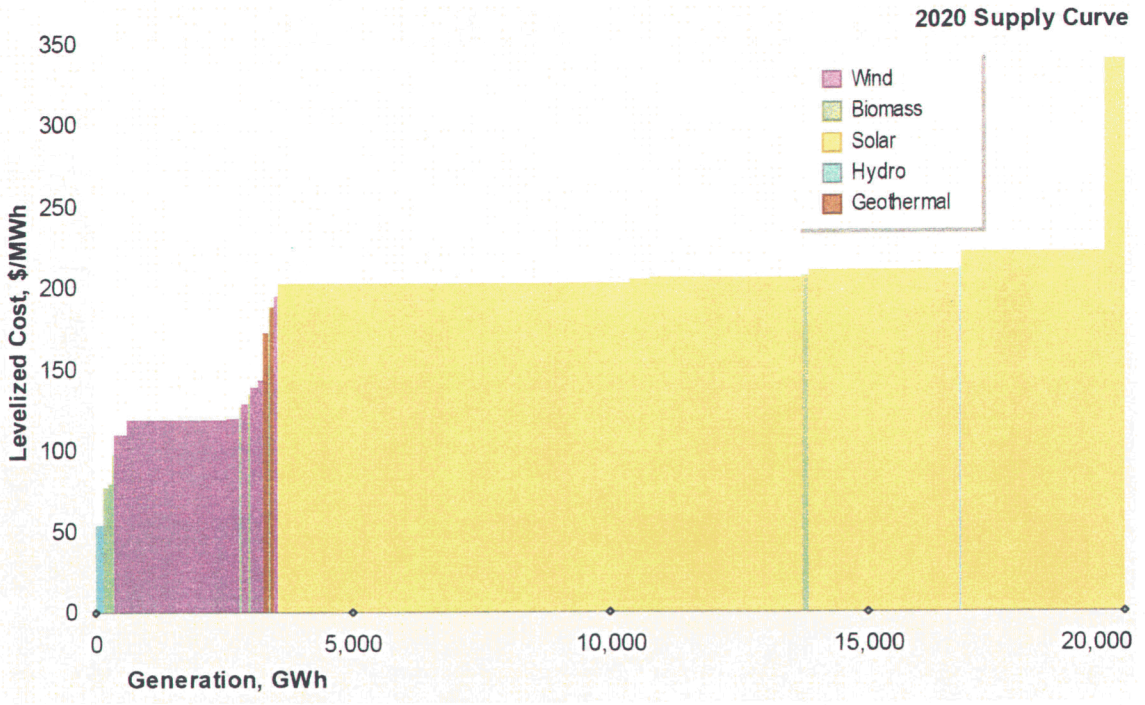


Figure 7-2. Arizona Resource Supply Curve.

Every "step" on the graph represents an individual project color-coded by its technology type. The curve compares the quantities and costs for the renewable resources and shows which products can be brought to market at the lowest cost (resources towards the left side). Supply curves were generated for each of the technologies under study (Section 5) and then combined.

Because a supply curve models potential projects, every year has a different supply curve. Due to time required for resource procurement, engineering, ACC approval, and construction, many projects are not feasibly available for energy production for several years. Of the many potential projects in Arizona, only a select few could be available over the next two years. However, by 2015, the majority of potential projects could feasibly be available. The further out the time horizon, the "longer" the supply curves become, representing a large pool of available generation.

As time proceeds, the lower cost renewable energy resources are most likely to be developed first, while higher price resources would likely be developed in future years. However, it is important to note that supply curves will change each year for variety of factors, including:

- The least-cost projects are assumed to be developed first and can no longer be considered as part of the supply curves for new generation

- Minimum project development timelines constrain project development (e.g., not all wind resource could be developed in 2009)
- Improvements in technology over time affect costs
- Commercial availability of new renewable technologies (e.g., dish engine solar in 2015)
- Timing of development of proposed transmission projects enabling development of new resources
- Expiration of tax credits and other incentives

The supply curves help the utilities determine the optimal mix of renewable energy to balance cost and generation. Importantly, however, there are numerous other factors to consider in addition to the generation cost shown in the supply curves. These are described below.

7.1.7 Model Limitations

The model used for this report was a relatively simple linear model. The renewable energy supply curves were developed based largely on best available public information and they represent a snapshot of what could be developed in the near term without consideration of significant future technology advancements. The projects identified, although based on analysis of best-available data, should be considered hypothetical but representative of actual projects that could be developed to meet renewable energy demand. In addition, the model has the following limitations, many of which were established by the agreed-upon scope of work for this project:

- No resources were considered outside of Arizona (including existing power purchase agreements)
- No distributed generation resources were considered
- No banking of excess renewable generation was included to meet future demands. In addition there was no carry-forward of under-procurement.
- The transmission assessment has been simplified, as described previously.
- No consideration has been made for the differential value of different resources (avoided cost).
- Except for already announced projects (assumed to fail at a 50 percent rate), project failure was not explicitly modeled.
- No intra-annual variability of resources was considered.
- Costs to integrate intermittent resources (e.g., firming of wind) were not included. (Note, however, that wind comprises a relatively small portion of the portfolio. Solar projects largely include integrated thermal storage.)

- The model is not a production cost model and does not simulate system dispatch.

In selecting projects to develop or procure, utilities may further consider these limitations, which may result in a different order of resource/project development than shown in the supply curves in this report. The most important additional factors that should be considered are competitiveness of out-of-state resources, transmission costs needed to access some resources (particularly wind), and the differential avoided cost (or value) of resources.

Consideration of avoided costs is particularly important. Avoided cost is typically determined by assessing a resource's capacity value (based on degree of "firmness" at the time of a utility's system peak demand) and its energy value (based on time of delivery). This is important when comparing resources such as wind and solar. For example, wind energy projects only provide fractional capacity value (often estimated at 20 percent or less of the nameplate capacity) and are more likely to offset low cost energy resources during the winter and spring. Solar resources can readily provide firm capacity with gas hybridization or thermal storage. Further, solar is generally coincident with times of higher energy needs, when less efficient (and more expensive) peaking resources are more likely to be offset.

There are numerous methods to calculate avoided cost, and costs are specific to individual utility systems. Figure 7-3 shows an example calculation for wind and solar. For wind, the following assumptions have been made:

- Energy – offsets electricity from a natural gas combined cycle. The wind would offset the variable component of a combined cycle plant, which is the sum of the variable operations and maintenance cost and the fuel cost (heat rate times gas cost).
- Capacity – offsets 20 percent of the capacity of a natural gas simple cycle. The fixed carrying cost of a simple cycle has been assumed to be $100/kW-yr.
- Integration cost – the intermittent nature of wind results in higher system operations costs for utilities to integrate its varying output. This cost is generally relatively small at low levels of penetration. A value of $3.50/MWh has been assumed as an additional cost for wind.

For solar thermal (with natural gas back-up or integrated storage), the following assumptions have been made:

- Energy – offsets electricity from a natural gas simple cycle.
- Capacity – offsets 100 percent of the capacity of a natural gas simple cycle.

- Integration cost – No additional cost. (Note that solar photovoltaic projects, which are typically built without any storage, would likely incur integration costs due to the intermittency effect caused by cloudiness.)

Energy Component			Energy Component		
Characteristics of marginal unit offset			*Characteristics of marginal unit offset*		
Heat rate, MBtu/MWh		7.50	Heat rate, MBtu/MWh		10.00
Gas Price, $/MWh		$7.50	Gas Price, $/MWh		$7.50
Variable O&M, $/MWh		$2.50	Variable O&M, $/MWh		$2.00
Marginal Energy Value, $/MWh		**$58.75**	Marginal Energy Value, $/MWh		**$77.00**
Capacity Component			**Capacity Component**		
Wind Capacity Factor		35%	Solar Capacity Factor		45%
Wind Capacity Credit		20%	Solar Capacity Credit		100%
Simple Cycle NG Capacity value, $/kW-yr		$100	Simple Cycle NG Capacity value, $/kW-yr		$100
Wind Capacity Value, $/kW-yr		$20	Solar Capacity Value, $/kW-yr		$100
Capacity value, $/MWh	$	**6.52**	Capacity value, $/MWh	$	**25.65**
Additional Integration Cost	$	**3.50**	**Additional Integration Cost**	$	-
Total Avoided Cost		**$61.77**	**Total Avoided Cost**		**$102.65**
WIND			**SOLAR**		

Figure 7-3. Hypothetical Avoided Cost Calculation for Wind and Solar Resources.

This example shows the avoided cost of wind at about $60/MWh and the avoided cost of solar (with natural gas back-up or integrated storage) at over $100/MWh. While solar costs more than wind, it has substantially higher value. For this reason, it is important for utilities to consider not only the costs of various resources, but their value (avoided cost) as well.

7.2 Assumptions

Conservative assumptions for the performance and financing of renewable technologies were made to construct realistic estimates of the development potential and costs. This section describes the general assumptions, economic assumptions, and Arizona renewable energy demand assumptions used for the resource assessment.

7.2.1 General Assumptions

Interconnection substation costs and transmission spur line costs were included in total levelized cost of electricity calculations (see Table 7-1). Transmission wheeling costs were not included. Transmission assumptions were based on current market conditions in Arizona. Voltage was identified by determining the voltage of the nearest transmission line to which a project would most likely connect.

Table 7-1. Transmission Assumptions.

Transmission Line Voltage (kV)	Substation Cost ($)*	Spur Line Cost ($/mile)*
34.5	1,200,000	200,000
69	2,400,000	400,000
115	3,000,000	800,000
138	3,500,000	1,200,000
230	4,100,000	1,600,000
287	4,900,000	1,650,000
345	5,700,000	1,700,000
500	10,500,000	2,600,000

Source: APS OASIS site.

Note: Does not include siting and ROW.

* All projects less than 1 MW of capacity are assumed to have their interconnection costs already included with the project capital costs.

It was assumed that technology learning for less mature technologies would result in improving capacity factors and declining costs (in real terms). This was implemented in the model through a set of future modifiers shown in Table 7-2. The other technologies' costs are assumed to stay constant in real terms. The future modifiers have the effect of making wind, solar trough, concentrating PV (CPV), and solar dish less expensive in later years relative to earlier years in the study. These assumptions are based on Black & Veatch forecasts of technology improvement and published data from independent sources (see Section 5 for further discussion)

Table 7-2. Future Modifiers (Costs decrease in real terms).					
	2007	**2010**	**2015**	**2020**	**2025**
Capacity Factor					
Solar Trough	1.00	1.00	1.42	1.45	1.45
Wind	1.00	1.06	1.09	1.13	1.16
Capital Cost					
Solar Trough	1.00	1.00	1.07	1.00	0.88
Solar Dish	1.00	1.00	0.74	0.72	0.72
PV	1.00	0.93	0.82	0.72	0.63
CPV	1.00	0.85	0.60	0.55	0.55
Variable O&M					
Wind	1.00	0.86	0.78	0.72	0.70
Solar Dish	1.00	1.00	0.60	0.56	0.56
Fixed O&M					
CPV	1.00	0.97	0.92	0.90	0.90
Solar Trough	1.00	1.00	0.87	0.82	0.82
Solar Dish	1.00	1.00	0.74	0.57	0.57

7.2.2 Economic Assumptions

A levelized generation cost for each of the technology classifications identified in the resource assessment was calculated. This cost allows the various technologies to be compared to identify the least cost renewable energy resources likely to be developed earlier. To develop an estimate of the cost to generate power over the life of the project, the following assumptions are required:

- Project performance
- Project life
- Financing structure (debt/equity)
- Debt cost
- Loan term
- Equity cost
- Depreciation cycle
- Levelized fixed charge rate

Table 7-3 shows the economic assumptions made for the resource assessment.

Table 7-3. Economic Assumptions.

Technology	Economic Life	Financing Structure (Debt/Equity)	Debt Term	Interest Rate	Equity Cost	Tax Life	Fixed Charge Rate
Biomass Digester	15	70/30	10	8%	15%	12	16.4%
Landfill Gas	15	70/30	10	8%	15%	12	16.4%
Biomass Cofiring	20	70/30	20	7.5%	11%	20	14.0%
Biomass Direct	20	70/30	15	8%	15%	5	13.0%
Geothermal	20	70/30	15	8%	15%	5	13.0%
Hydro	30	70/30	15	8%	15%	20	13.6%
PV	20	70/30	20	7.5%	11%	5	11.7%
Solar Dish	20	70/30	15	8%	15%	5	13.0%
Solar Trough	20	70/30	15	8%	15%	5	13.0%
CPV	20	70/30	15	8%	15%	5	13.0%
Wind	20	70/30	15	8%	15%	5	13.0%

The economic life of each technology was selected to reflect current industry expectations for the life of each project. The financing structure of 70 percent debt and 30 percent equity was chosen for all technologies to reflect a common structure for project developers. The interest rate for debt is indicative of current market rates, and those received by recent projects. Debt terms were chosen to reflect current industry practice for each technology. The cost of equity is an approximation of the return on investment a renewable energy project investor would require taking into account the rate of return that an investor could receive on a comparable market. It was assumed that the utilities would be the most likely developers of biomass cofiring and PV projects, thereby achieving reduced financing costs. These technologies were given a lower interest rate and cost of equity for a lower overall weighted cost of capital. The levelized fixed charge rate is used to calculate a constant annual charge to offset a project's fixed costs. This rate is applied to the total capital cost of a project and accounts for financing costs, taxes, and other fixed costs related to the plant.

Alternative project and cost structures for solar PV projects are currently being refined that have the potential to substantially lower the all-in cost of energy from solar PV. Given the high capital costs for PV, any improvement in capital structure or financing costs has a relatively strong impact on the final levelized cost. These structures have not been modeled in this report.

Expanded federal tax incentive programs were included in the analysis of the cost to generate electricity. The Federal Production Tax Credit (PTC) was modeled at

$20/MWh (2007$) for wind and geothermal resources and at $10/MWh (2007$) for biomass digester, landfill gas, biomass direct, and hydroelectric resources. The production incentive was modeled to be available for 10 years of a project's life and escalated at 2.5 percent per year. Although the PTC is set to expire at the end of 2008, there is a strong belief that it will be extended as it has previously. For the study the PTC was modeled to be extended through 2012. A federal investment tax credit for all solar technologies was also applied. This credit was modeled as 30 percent of capital cost, available for projects built by the end of 2012. A sensitivity analysis in Section 8 explores the impacts of different tax credit assumptions.

7.2.3 Arizona Renewable Energy Demand Assumptions

Table 7-4 outlines the forecasted renewable energy demand in Arizona. This forecast was based partially on the objectives to meet the RES standard through 2025. The renewable energy demand was developed based on a simple load forecast estimate. Total capacity demand for Arizona utilities from 2007 to 2015 was provided by the utilities. Using the average growth rate for those years (approximately 3.5 percent), Black & Veatch estimated the total capacity (MW) demand from 2016 to 2025. A load factor of 50 percent was used to calculate total energy (GWh) required for every year.

While APS and TEP are mandated to meet the ACC's RES requirements, SRP and some other utilities are not required to do so. However, SRP and other utilities have established their own goals, which will increase demand for renewables. SRP's goal is 15 percent by 2025, but it includes existing large hydroelectric and energy efficiency. It was assumed that 75 percent of the total state load would "meet the spirit" of goals set out in the RES. The impacted load was multiplied by the corresponding non-DG RES requirement (see Table 3-3) to calculate the total amount of renewable energy required for each year. Black & Veatch subtracted the amount of energy produced from existing renewable generation projects and other planned projects (Table 3-2) to ensure that the renewable energy demand in the model represented incremental amounts beyond current and expected production. Only 50 percent of potential energy from announced projects was included, as some will likely not come on-line as planned. This "failure rate" is consistent with experience in other states, but a conservative estimate as this number may decline due to RFP risk management protocol, more experienced developers, increased financial resources, and industry experience.

Table 7-4. Arizona Renewable Energy Demand Forecast (Cumulative GWh).

Year	Total Renewable Demand	Existing and Planned Projects	Net New Development Required
2007	884	312	572
2008	1,010	683	328
2009	1,128	825	303
2010	1,373	825	548
2011	1,597	825	773
2012	1,799	825	974
2013	2,126	825	1,302
2014	2,474	825	1,650
2015	2,844	825	2,019
2016	3,532	825	2,707
2017	4,265	825	3,440
2018	5,045	825	4,220
2019	5,874	825	5,049
2020	6,755	825	5,930
2021	7,691	825	6,866
2022	8,683	825	7,859
2023	9,736	825	8,912
2024	10,852	825	10,028
2025	12,034	825	11,210

7.3 Results

The model was used to simulate the renewable resources that could be developed to meet the 2025 demand of 11,210 GWh shown in Table 7-4. Although the model includes a variety of renewable energy resources that could be developed, other than solar, these resources appear relatively limited. In the mid to near-term, developable potential for new biomass, geothermal, and hydroelectric projects combined could contribute about 1,080 GWh/yr, or 1 percent of the electricity that was generated in Arizona in 2005. Wind could contribute about 2.5 percent. Despite the relatively limited potential of wind, biomass, geothermal and hydroelectric resources, they serve an important role in forestalling the need to install expensive solar. As such, their development may be important to keep renewable energy costs lower in the near term.

However, the relatively limited potential of these resources compared to surrounding states may serve as a deterrent for large, out-of-state renewable energy project developers.

Based on the resource assessments and future modifiers developed for each resource, supply curves were generated at annual increments from 2007 through 2025. Each supply curve was then compared against the total renewable energy demand required for each period. Supply curves for each year are provided in Appendix C. Figure 7-4 provides an example supply curve for 2015. This curve shows the Glen Canyon upgrade project the first year it is available as the lowest cost project (about $50/MWh). The potential demand line for 2015 crosses the supply line at the Glen Canyon project, indicating that Glen Canyon would likely be developed in 2015. The supply curve analysis was conducted under the assumption that each project would be developed and sold at its cost (including a reasonable developer profit), and not at the highest cost ("market clearing" price) in the respective period. This assumption is reasonable if it assumed that developers are pricing projects based on their costs and not unreasonably raising prices to take advantage of supply constraints in the market. This assumption is further examined in Section 8.

The projects selected for a particular year are removed from the next year's supply curve. Thus, the supply curve in the last year does not represent a comprehensive supply curve of all resources available, but only those resources available for development at that time. It can be seen that the cost paid for renewable and advanced energy gradually increases as the lower cost resources are developed earlier in the RES term.

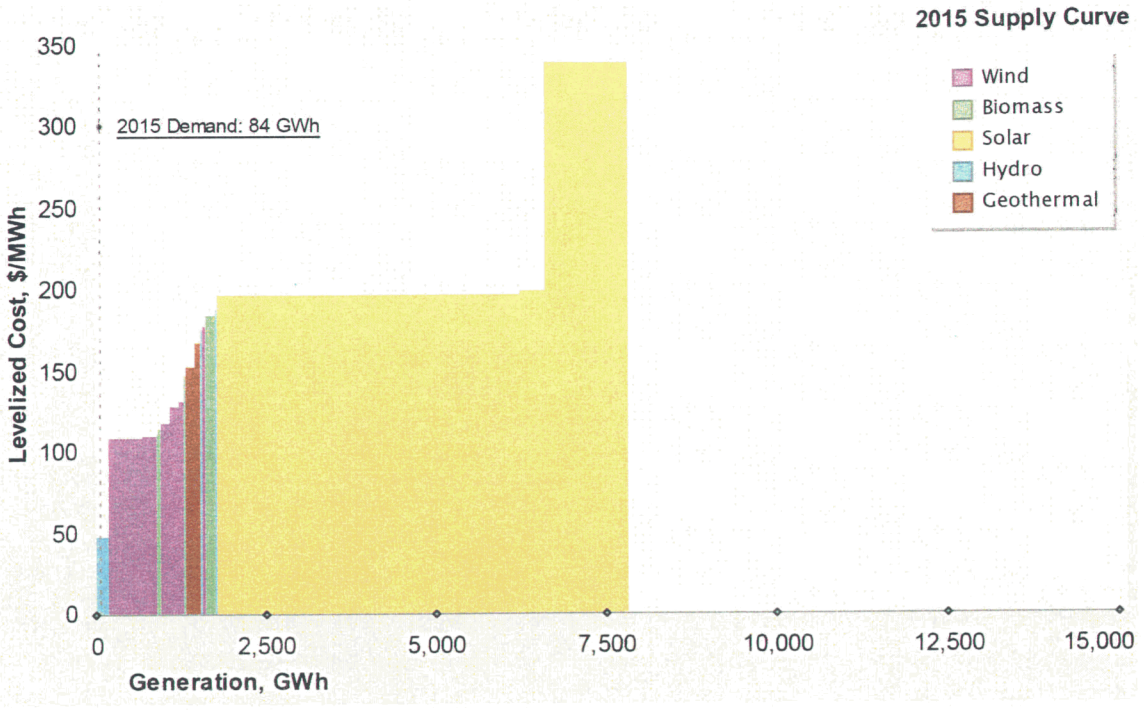


Figure 7-4. 2015 Supply Curve.

Figure 7-5 illustrates how the supply curves are different for each year, as new projects are added as they become available and other projects are removed as they are developed.

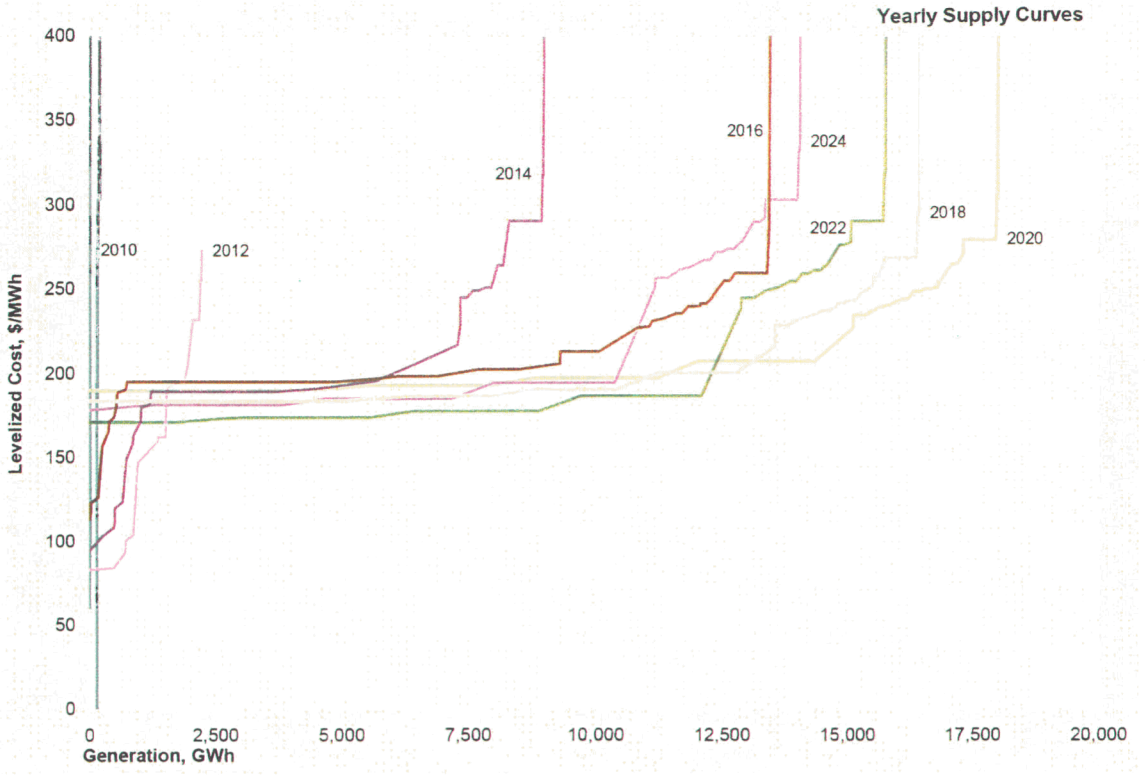


Figure 7-5. Supply Curves.

Figure 7-6 shows the total supply curve for Arizona in the year 2025. This supply curve is different from the others in that it has been assumed that no projects would be developed prior to 2025. The other supply curves do not show projects that have already been built. The 2025 curve shown has all the potential projects that were identified in this study and their cost in 2025. The curve also shows a demand line indicating the projected 2025 renewable energy demand of 11,210 GWh. If development of renewables in Arizona were economically optimum, then all of the projects to the left side of the demand line would be built by 2025.

It should be noted that there are additional higher cost resources that would extend the potential supply of renewables further to the right than indicated on this chart. However, once sufficient projects were identified to meet demand, Black & Veatch did not continue to identify higher cost projects.

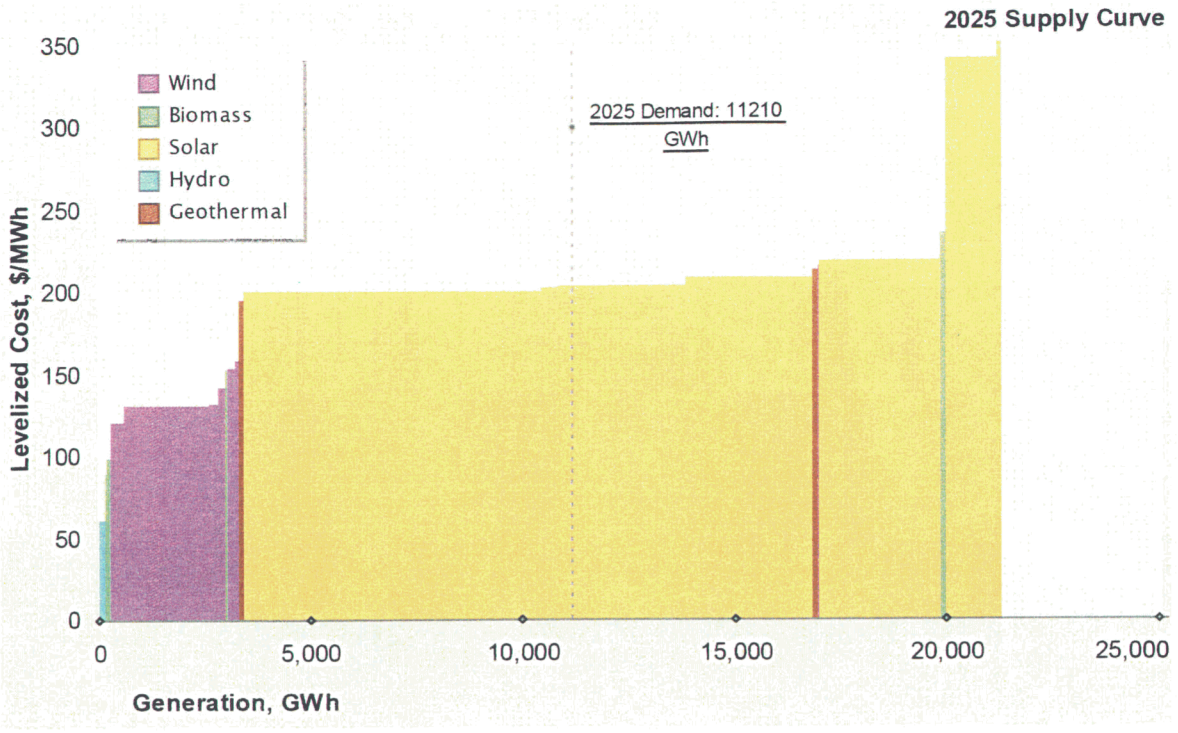


Figure 7-6. Total Arizona Renewable Supply Potential in 2025.

Figure 7-7 shows the breakdown of the total portfolio by energy for 2009, 2017, and 2025. This analysis shows three different phases of renewable energy development. Until 2009, there are only a few renewable energy projects available to come online (solar PV and landfill gas). During this stage, the model assumes that any potential project needs to be developed to meet demand, regardless of cost. From 2009 to 2017, several large wind projects are constructed as the least expensive renewable technologies. A handful of other projects are also built during this time. After 2017, most of the non-solar projects have already been developed, so solar trough projects provide the rest of the renewable energy as the lowest cost technology.

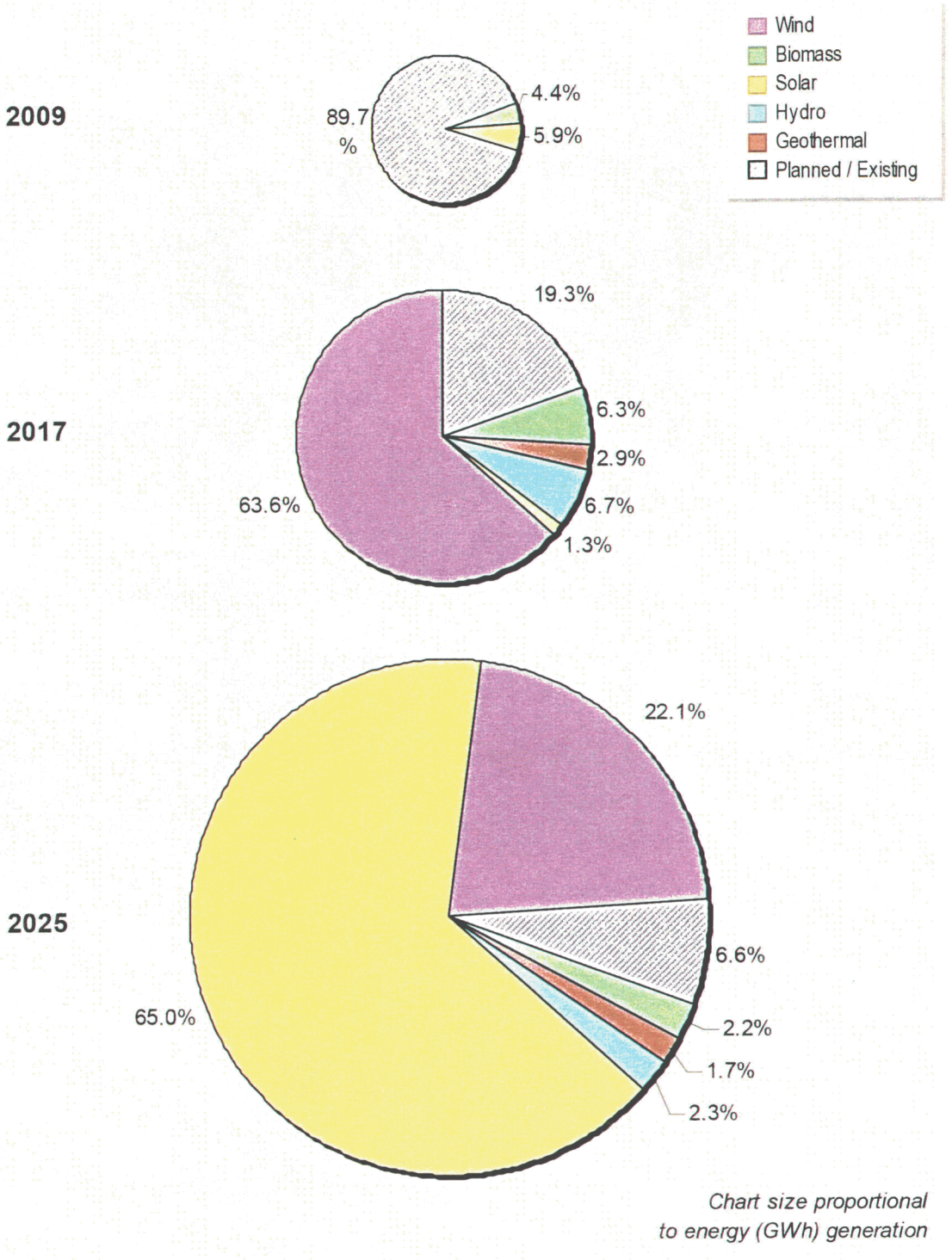


Figure 7-7. Renewable Energy Mix.

Because there are few renewable energy projects available to come online in the near future, there is a renewable energy deficit compared to the demand (see Figure 7-8).

In the near term, in-state resources are insufficient to meet demand. Arizona utilities may have to obtain renewable energy from out-of-state resources. After 2010, there will be sufficient developable projects to "catch up" with demand. In the long run, Arizona will have sufficient renewable resources.

This study did not include an assessment of regional renewable energy supply and demand. Neighboring states, namely California, New Mexico, and Nevada, have aggressive renewable energy standards. These states may have more economical renewable energy sources than Arizona (for example, Salton Sea geothermal resources and New Mexico wind); however, given their own aggressive in-state demands and transmission limitations, they are not a dependable source for Arizona to meet its long-term renewable energy needs. While the importation of renewable energy may help to meet a portion of Arizona's needs, it is not likely to fully satisfy them.

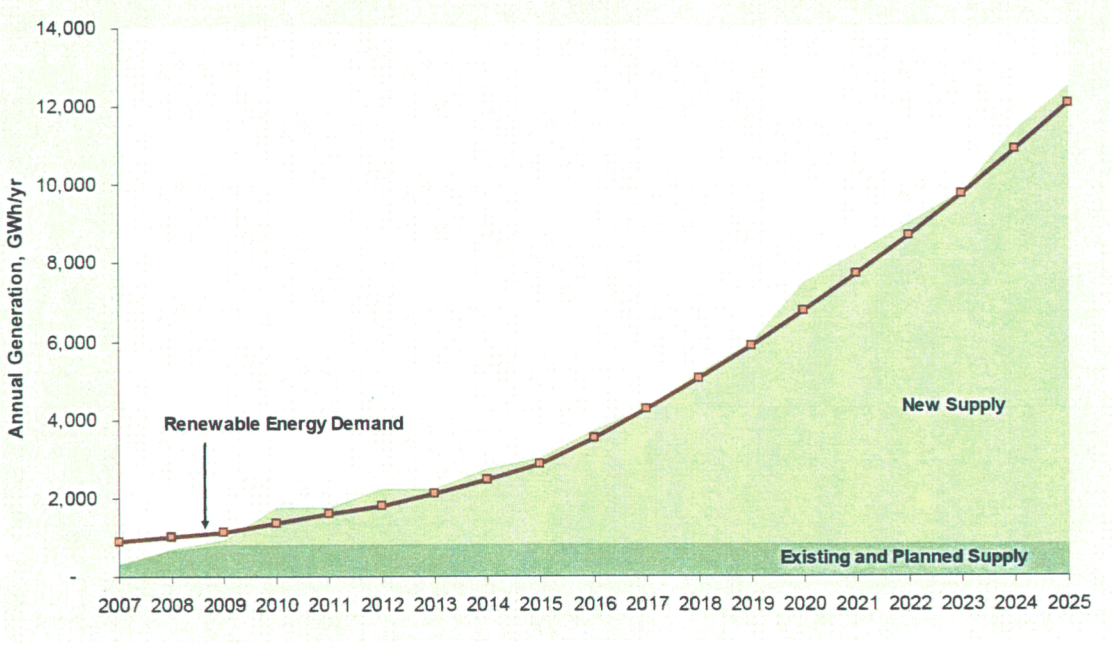


Figure 7-8. Development Compared to Demand.

8.0 Assessment of Key Risk Factors

Black & Veatch analyzed some of the risk factors of interest to utilities in Arizona to determine how sensitive the supply curve results would be to changing situations. These factors include tax credit changes, implementation of advanced solar technologies, delayed technical advances, escalating construction costs, manufacturing/supply chain constraints, near term performance learning curve, and competition for limited resources.

8.1 Sensitivity to Tax Credit Changes

The base model assumes that the PTC and ITC will remain in place for another five years, until 2012. Because these tax credits have a significant impact on the cost of power from renewable sources, two sensitivity runs were performed around this assumption:

- Tax credits expire at the end of 2008 (current law)
- Tax credits never expire

Tax credits do not affect the availability of renewable resources, but they do impact the economics. In the long term, whether tax credits expire in 2008 or 2012 has surprisingly little impact on the cumulative average cost of meeting renewable energy demand in Arizona (less than 1 percent). This is because many of the most expensive, large solar projects would likely be built after 2012; they have the same cost under both scenarios. In the near term (through 2014), impacts are more significant. Costs are about 20 percent higher in the period 2009-2012. If tax credits never expire, the impact is significant. By 2025, the total renewable energy cost is about 25 percent lower than the base case assumption.

8.2 Advanced Solar Technologies

Solar is the most expensive of the renewable resources profiled in this study. The lower cost solar resources (about $180-205/MWh in 2007) are about twice as expensive as the bulk of the non-solar resources (about $70-110/MWh in 2007). The base case model included only proven, fully commercial solar technologies such as solar photovoltaics and solar thermal trough. Concentrating PV (CPV) and dish engine technologies have the potential to lower the cost of electricity from solar.

Figure 8-1 shows the forecasted levelized costs for representative solar projects included in the model (the large jump after 2012 is due to tax credit expiration). It can be seen that the solar photovoltaic technologies do not compete with the solar thermal technologies for large, centralized generation using the financing assumptions in the base case model (Section 7 describes the possibility of innovative financing approaches for

solar PV reducing costs substantially). However, if Black & Veatch's assumptions for advancement of dish engine systems prove correct, costs for this technology will become competitive with conventional parabolic trough systems.

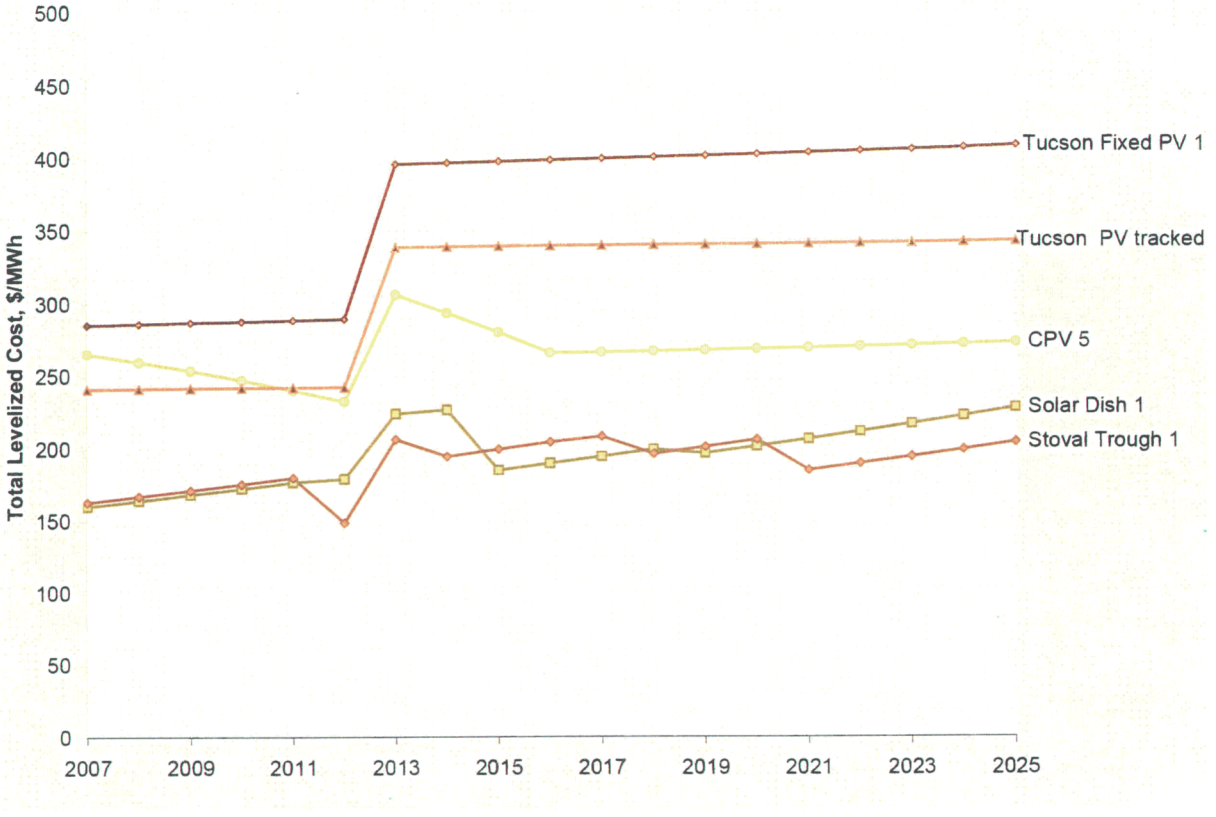


Figure 8-1. Representative Solar Costs.

Arizona appears unique in the U.S. in its dependence on in-state solar energy to meet its mandated renewable energy demands. In the base case, it is estimated that 65 percent of the Arizona renewable demand in 2025 will be met by solar. Generally speaking, other states in the Southwest U.S. will likely be less reliant on solar to meet their renewable energy requirements. This is because other states generally have a larger base of non-solar renewables that they can rely on for near-term needs. By comparison, Arizona's non-solar resources are relatively limited. Solar technologies will play a key part of renewables future in Arizona.

8.3 Delayed Technical Advances

The model base case accounts for expected incremental advances in wind and solar technologies. These are characterized by increasing capacity factors, decreasing

O&M costs, and falling capital costs for solar technologies. However, there is a risk that such advancement may be delayed or not realized. To assess the risk that wind and solar projects would experience delayed technical improvements, Black & Veatch reduced projected technology improvements in the model. To model no improvements in wind turbine design for wind projects, it was assumed that project capacity factors would not increase and O&M costs would not improve on a real basis. For solar thermal projects, it was assumed that capacity factor improvements due to storage would not be available until 2017 instead of 2012 and O&M costs would not improve on a real basis. For solar PV projects, it was assumed that capital costs would not improve on a real basis.

In this sensitivity analysis, wind and solar thermal projects were not as productive compared to the base case. Solar projects, particularly in the out years, are higher cost than the base case. The reduced technical advances will keep levelized costs for wind and solar higher, which will make other technologies (biomass and geothermal) comparatively more attractive in early years. The cumulative effect on the total renewable energy cost will likely be an increase of 15 to 20 percent by 2025. Overall, the delayed technical advances should not be expected to significantly alter the aggregate project mix. The general trend of exhausting nearly all potential biomass, wind, and hydroelectric, and geothermal projects before building solar trough projects holds true.

8.4 Escalating Construction Costs

The model base case has a capital cost escalation of 2.5 percent, which is meant to track close to general inflation. There is a risk that construction costs escalate at a higher rate, depending on future markets for materials and labor. For the sensitivity analysis of construction costs escalating faster than inflation, the capital cost escalator was changed to 5.0 percent.

Increasing the escalator increased levelized busbar costs for all projects. The increase is particularly pronounced for projects further into the future. At year 2025, levelized costs are about 37 percent higher than the base case.

8.5 Manufacturing and Supply Chain Constraints

Manufacturing and supply chain constraints are already built into the model. The projects most likely to be impacted by such constraints are solar and wind. For wind projects, there is currently a delay of up to two years between turbine order and turbine delivery because demand is greater than manufacturing capability. Wind projects were assigned "first year available" dates with this constraint in mind. The earliest any wind project is modeled to be available is 2010, with some not available until 2012 or 2013. If there are additional constraints in the wind supply chain, then it is likely that renewable

energy demand would likely not be met in some years with in-state resources. It should be noted that turbine delivery time is dependent upon the developer. Large developers have framework agreements that may bring turbines to projects more quickly than for smaller developers. Several of the developers of announced wind projects in Arizona should have access to turbines for their pipeline projects.

Solar projects were also modeled with manufacturing constraints in mind. For example, there is a supply constraint for reflective mirrors that are used in solar trough projects. Because of a supply lag, the first solar trough project is not modeled to be available until 2011. After that point, the number of solar trough facilities that can be developed each year is limited by the anticipated future manufacturing capability. Similarly, CPV projects are modeled to be available on a small scale in the near future. However, the amount of CPV potential capacity slowly grows to reflect an expanding manufacturing base.

8.6 Near-Term Performance Learning Curve

In the near-term, projects may under-deliver renewable energy as they gain experience during the initial operational and development learning period. For example, many planned wind projects in Arizona have experienced significant delays or have been completely stalled. Projects may also fail outright, and not supply any renewable energy. Both factors would impact overall renewable energy portfolio development.

Most entities obligated by an RPS have chosen to purchase renewable generation from an independent power producer (IPP), as opposed to owning a renewable generation facility. IPP ownership of renewable generation is due to historical factors, especially the Public Utility Regulatory Policies Act (PURPA) of 1978. There is less experience contracting for renewable energy compared to more mature energy technologies. Utilities are forced to stay aware of the risk of contract failure that comes as a result of learning curve effects.

Even if a renewable project has made it far enough in the development cycle to secure a power purchase agreement (PPA) with a utility, there are still many things that can go wrong to end or significantly delay a project. In 2006 Black & Veatch co-authored a report on contract failure for the California Energy Commission.[14] Black & Veatch surveyed roughly 30 utilities regarding their renewable purchases, and collected data on nearly 3,000 MW of renewable energy contracts.

[14] "Building a "Margin of Safety" into Renewable Energy Procurements: A Review of Experience with Contract Failure" January 2006. California Energy Commission contractor's report. Available at www.energy.ca.gov

The results from the study, summarized in Figure 8-2 show that close to half of renewable energy contracts fail after contract execution. While "failure" here is defined as projects that were canceled, significantly delayed, or were in default, even if failure is defined as canceled, a quarter of all projects fail. The report attempts to capture some of the reasons for contract failure, such as site or permit problems, inability to obtain financing, or other reasons. The issues mentioned by utility personnel as reasons for contract failure are shown in Figure 8-3.

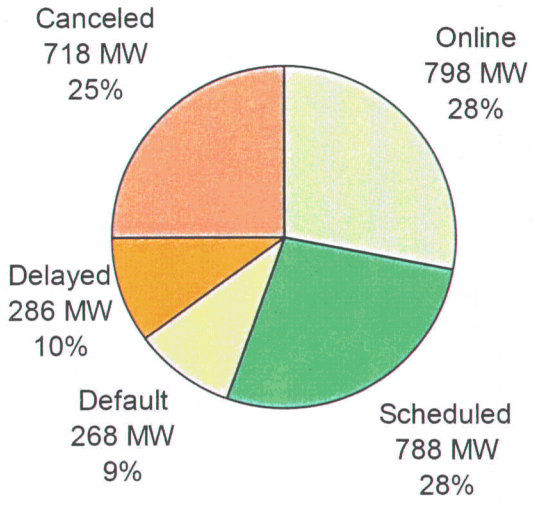


Figure 8-2. Contract Failure Data for North American Renewables

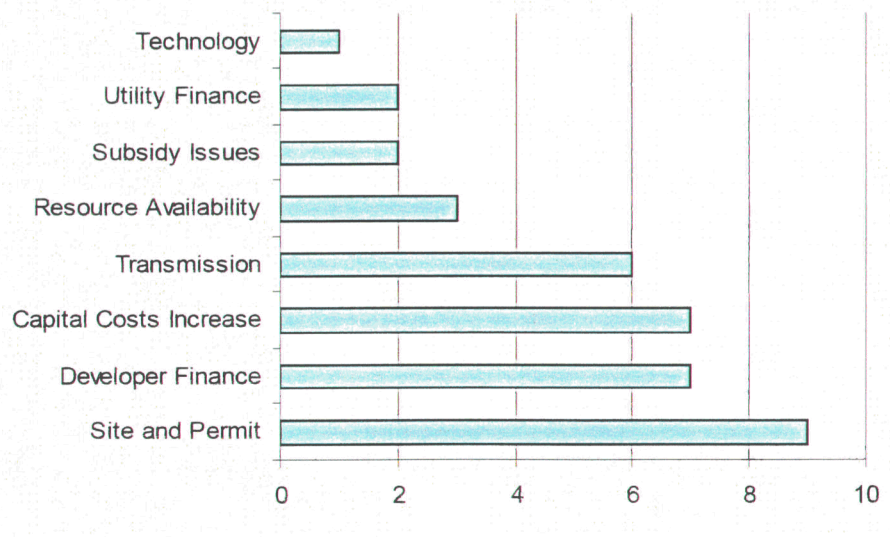


Figure 8-3. Causes of Contract Failure, Frequency of Mentions.

Most, if not all, of the reasons renewable energy contracts fail are beyond the control of the utility, and some are beyond the control of the developer. No matter the cause, contract failure is a real problem for utilities trying to meet renewable energy demands.

To apply learning curve effects, it is important to understand that one of the reasons renewable energy contracts fail is a lack of experience with contracting for renewables. To mitigate this risk, utilities may "over-procure" renewable energy. For example, if a utility wanted renewable projects to produce 600 GWh for a certain year, the utility might enter into contract with projects for 800 GWh or more with the assumption that some projects would either be significantly delayed or never come online.

From a supply curve standpoint, contract failure and the utility counter measure of over-procurement serve to shift the supply curve to the left. When a project fails, its generation is removed from the supply curve, while all projects to the right (more expensive projects) shift left to fill in the space. As lower-priced projects fail, utilities will be forced to contract with more expensive renewable projects to secure renewable energy.

8.7 Competition for Limited Renewable Resources

As more and more renewable energy projects are developed, there will be fewer renewable resources to utilize in the future. There is a risk that utility competition for limited renewable resources will increase prices.

For renewable energy procurement, utilities typically contract with the least expensive energy available (projects on the left side of the supply curve). As renewable projects are developed, the supply curve shifts to the left. Utilities see an increasing marginal levelized cost as more expensive projects become the new lowest cost options. That is, costs increase as more renewable energy is developed. This is an expected phenomenon. However, there is a risk that IPPs will charge Arizona utilities the highest price possible that stays below the marginal cost of energy. Consider an example of a utility wanting to procure energy from three renewable energy projects for a certain year. The utility would have likely have several projects at different energy costs from which to choose. Other factors being equal, the three lowest priced projects would be chosen, with the most expensive project setting the marginal cost of energy (the most the utility is willing to pay at the time). If developers of the other two projects knew the utility's marginal cost for renewables, they might be incented to raise their prices to the marginal cost to maximize profit. The utility would be forced to pay more for the energy, with no

other less expensive projects to pursue. This phenomenon occurs in supply constrained markets.

For Arizona utilities, it is possible that renewable energy developers may set energy prices as high as possible while still beating the marginal cost of energy. This would increase the price of power purchase agreements.

Appendix A. Consolidated Project Assumptions

Project Name	Technology	Net Capacity, MW	Capacity Factor	Net Generation, GWhr/yr	First Year Available	Capital Cost, $/kW	Fixed O&M, $/kWyr	Variable O&M, $/MWhr	Fuel Cost, $/Mbtu	NPHR, Btu/kWhr	Interconnection Voltage, kV	Distance to line, miles	Transmission Owner	Project Life, years	Interest during Construction, $/kW
Rattlesnake Crater 1	Wind Onshore	62	26%	138.8	2010	1600	25	9	0.0	0	230	0	APS	20	45
Rattlesnake Crater 2	Wind Onshore	78	30%	202.5	2011	1600	25	8	0.0	0	230	0	APS	20	45
Buckhorn	Wind Onshore	46	30%	119.3	2010	1680	25	8	0.0	0	69	7	APS	20	47
Buffalo Range	Wind Onshore	158	30%	409.0	2010	1600	25	8	0.0	0	230	1	APS	20	45
Chevelon 1	Wind Onshore	171	30%	442.2	2013	1600	25	8	0.0	0	345	0	APS	20	45
Chevelon 2	Wind Onshore	171	30%	442.2	2011	1600	25	8	0.0	0	345	0	APS	20	45
Chevelon 3	Wind Onshore	171	30%	442.2	2012	1600	25	8	0.0	0	345	0	APS	20	45
Chevelon 4	Wind Onshore	84	33%	238.6	2010	1600	25	7	0.0	0	345	0	APS	20	45
Greens Peak	Wind Onshore	31	27%	72.8	2010	1680	25	8	0.0	0	69	6	unknown	20	47
Kingstone	Wind Onshore	18	27%	43.8	2012	1840	25	8	0.0	0	230	5	APS	20	52
Beardsley Canal Drop	Hydro	1.0	40%	3.5	2013	4324	24	6	0.0	0	35	1	unknown	30	363
Yuma Main Canal	Hydro	1.4	40%	4.9	2013	4079	22	5	0.0	0	35	1	unknown	30	343
Waddell	Hydro	1.5	40%	5.3	2013	4037	21	5	0.0	0	35	1	unknown	30	339
CAP Canal Turnout	Hydro	2.5	40%	8.8	2013	3718	19	5	0.0	0	35	1	unknown	30	312
Roosevelt (RWCD)	Hydro	3.2	40%	11.2	2013	3579	18	4	0.0	0	35	1	unknown	30	301
Tucson	Hydro	0.4	99%	3.5	2013	3429	17	4	0.0	0	35	1	unknown	30	288
Glen Canyon	Hydro	71.8	45%	283.1	2015	997	8	2	0.0	0	230	1	APS	30	84
Clifton	Geothermal	20.0	70%	122.6	2013	4000	0	30	0.0	0	35	10	APS	20	392
Gillard	Geothermal	15.0	70%	92.0	2014	4500	0	30	0.0	0	35	10	APS	20	441
Butterfield Station Landfill	Biomass Landfill Gas	2	80%	16.9	2009	2062	0	18	2.0	11500	35	0	APS	15	58
Salt River Landfill	Biomass Landfill Gas	1	80%	5.5	2009	2193	0	18	2.0	11500	0	0	SRP	15	61
27th Avenue Landfill	Biomass Landfill Gas	3	80%	21.0	2050	2037	0	18	2.0	11500	35	0	0	15	57
Apache Junction LF	Biomass Landfill Gas	0	80%	1.8	2010	2328	0	18	2.0	11500	0	0	SRP	15	65
Cinder Lake MSW LF	Biomass Landfill Gas	1	80%	3.9	2011	2233	0	18	2.0	11500	0	0	APS	15	63
City of Glendale Municipal Landf	Biomass Landfill Gas	1	80%	9.1	2009	2132	0	18	2.0	11500	35	0	APS	15	60
Grey Wolf Landfill	Biomass Landfill Gas	1	80%	5.5	2012	2193	0	18	2.0	11500	0	0	APS	15	61
Huachuca City Landfill	Biomass Landfill Gas	0	80%	2.2	2012	2305	0	18	2.0	11500	0	0	TEP	15	65
North Center Street Landfill	Biomass Landfill Gas	1	80%	3.6	2008	2242	0	18	2.0	11500	0	0	SRP	15	63
Northwest Regional MSW Landfi	Biomass Landfill Gas	0	80%	1.8	2010	2328	0	18	2.0	11500	0	0	APS	15	65
Painted Desert Landfill	Biomass Landfill Gas	0	80%	2.7	2010	2277	0	18	2.0	11500	0	0	APS	15	64
Queen Creek MSW Landfill	Biomass Landfill Gas	0	80%	2.7	2011	2277	0	18	2.0	11500	0	0	SRP	15	64
Rio Rico MSW Landfill	Biomass Landfill Gas	0	80%	1.8	2008	2328	0	18	2.0	11500	0	0	TEP	15	65
Skunk Creek Landfill	Biomass Landfill Gas	3	80%	21.0	2050	2037	0	18	2.0	11500	35	0	0	15	57
Cocopah Landfill	Biomass Landfill Gas	1	80%	4.0	2011	2230	0	18	2.0	11500	0	0	APS	15	62
Southwest Regional Landfill	Biomass Landfill Gas	0	80%	2.2	2010	2302	0	18	2.0	11500	0	0	APS	15	64
Tangerine Road MSW Landfill	Biomass Landfill Gas	1	80%	3.8	2008	2236	0	18	2.0	11500	0	0	TEP	15	63
Cholla cofiring	Biomass Cofiring	10	80%	70.1	2010	900	61	0	2.5	11000	0	0	APS	20	24
Springerville cofiring	Biomass Cofiring	10	80%	70.1	2010	900	61	0	2.3	10000	0	0	TEP	20	24
Maricopa City Direct	Biomass Direct	20	80%	140.2	2012	4000	160	12	1.9	14500	115	2	0	20	224
Snowflake Digester (Swine)	Biomass Digester	4	80%	24.5	2010	2000	0	20	0.0	15000	35	0	0	15	112
Buckeye Digester (Dairy)	Biomass Digester	3	80%	17.5	2010	3000	0	20	1.5	15000	35	0	0	15	168
Chandler Digester (Dairy)	Biomass Digester	2	80%	10.5	2010	3500	0	20	1.5	15000	35	0	0	15	196
Maricopa Digester (Beef)	Biomass Digester	6	80%	42.0	2050	3500	0	20	0.0	15000	35	0	0	15	196
Maricopa Digester (Poultry)	Biomass Digester	2	80%	16.8	2010	3000	0	20	0.0	15000	35	0	0	15	168
Solar Dish 1	Solar Dish	100	27%	240.0	2011	3300	23	25	0.0	0	230	1	N/A	20	0
Solar Dish 2	Solar Dish	100	27%	240.0	2012	3300	23	25	0.0	0	230	1	N/A	20	0
Solar Dish 3	Solar Dish	100	27%	240.0	2013	3300	23	25	0.0	0	230	1	N/A	20	0
Solar Dish 4	Solar Dish	200	27%	480.0	2014	3300	23	25	0.0	0	230	1	N/A	20	0
Solar Dish 5	Solar Dish	200	27%	480.0	2015	3300	23	25	0.0	0	230	1	N/A	20	0
Solar Dish 6	Solar Dish	200	27%	480.0	2016	3300	23	25	0.0	0	230	1	N/A	20	0
Solar Dish 7	Solar Dish	400	27%	960.1	2017	3300	23	25	0.0	0	230	1	N/A	20	0
Solar Dish 8	Solar Dish	400	27%	960.1	2018	3300	23	25	0.0	0	230	1	N/A	20	0
Solar Dish 9	Solar Dish	400	27%	960.1	2019	3300	23	25	0.0	0	230	1	N/A	20	0
Solar Dish 10	Solar Dish	400	27%	960.1	2020	3300	23	25	0.0	0	230	1	N/A	20	0
Solar Dish 11	Solar Dish	400	27%	960.1	2020	3300	23	25	0.0	0	230	1	N/A	20	0
Solar Dish 12	Solar Dish	400	27%	960.1	2021	3300	23	25	0.0	0	230	1	N/A	20	0

Solar Dish 13	Solar Dish	400	27%	960.1	2021	3300	23	25	0.0	0	230	1	N/A	20	0
Stoval Trough 1	Solar Trough	100	30%	261.0	2011	4200	55	0	0.0	0	230	1	0	20	0
Stoval Trough 2	Solar Trough	200	30%	522.1	2013	4200	55	0	0.0	0	230	1	0	20	0
Stoval Trough 3	Solar Trough	200	30%	522.1	2013	4200	55	0	0.0	0	230	1	0	20	0
Stoval Trough 4	Solar Trough	200	30%	522.1	2014	4200	55	0	0.0	0	230	1	0	20	0
Stoval Trough 5	Solar Trough	200	30%	522.1	2014	4200	55	0	0.0	0	230	1	0	20	0
Stoval Trough 6	Solar Trough	200	30%	522.1	2015	4200	55	0	0.0	0	230	1	0	20	0
Stoval Trough 7	Solar Trough	200	30%	522.1	2015	4200	55	0	0.0	0	230	1	0	20	0
Stoval Trough 8	Solar Trough	200	30%	522.1	2016	4200	55	0	0.0	0	230	1	0	20	0
Stoval Trough 9	Solar Trough	200	30%	522.1	2016	4200	55	0	0.0	0	230	1	0	20	0
Stoval Trough 10	Solar Trough	200	30%	522.1	2016	4200	55	0	0.0	0	230	1	0	20	0
Phoenix Trough 1	Solar Trough	200	27%	478.3	2019	4200	55	0	0.0	0	230	1	0	20	0
Phoenix Trough 2	Solar Trough	200	27%	478.3	2019	4200	55	0	0.0	0	230	1	0	20	0
Phoenix Trough 3	Solar Trough	200	27%	478.3	2019	4200	55	0	0.0	0	230	1	0	20	0
Phoenix Trough 4	Solar Trough	200	27%	478.3	2019	4200	55	0	0.0	0	230	1	0	20	0
Tucson Trough 1	Solar Trough	200	29%	502.8	2018	4200	55	0	0.0	0	230	1	0	20	0
Tucson Trough 2	Solar Trough	200	29%	502.8	2018	4200	55	0	0.0	0	230	1	0	20	0
Tucson Trough 3	Solar Trough	200	29%	502.8	2018	4200	55	0	0.0	0	230	1	0	20	0
Tucson Trough 4	Solar Trough	200	29%	502.8	2018	4200	55	0	0.0	0	230	1	0	20	0
Yuma Trough 1	Solar Trough	200	29%	513.3	2017	4200	55	0	0.0	0	230	1	0	20	0
Yuma Trough 2	Solar Trough	200	29%	513.3	2017	4200	55	0	0.0	0	230	1	0	20	0
Yuma Trough 3	Solar Trough	200	29%	513.3	2017	4200	55	0	0.0	0	230	1	0	20	0
Yuma Trough 4	Solar Trough	200	29%	513.3	2017	4200	55	0	0.0	0	230	1	0	20	0
CPV 1	Concentrating Solar P	1	29%	2.5	2008	7600	100	0	0.0	0	35	0	N/A	30	399
CPV 2	Concentrating Solar P	5	29%	12.7	2009	7200	60	0	0.0	0	35	0	N/A	30	378
CPV 3	Concentrating Solar P	5	29%	12.7	2010	7200	60	0	0.0	0	35	0	N/A	30	378
CPV 4	Concentrating Solar P	5	29%	12.7	2010	7200	60	0	0.0	0	35	0	N/A	30	378
CPV 5	Concentrating Solar P	10	29%	25.4	2011	6800	50	0	0.0	0	35	0	N/A	30	357
CPV 6	Concentrating Solar P	10	29%	25.4	2011	6800	50	0	0.0	0	35	0	N/A	30	357
CPV 7	Concentrating Solar P	10	29%	25.4	2012	6800	50	0	0.0	0	35	0	N/A	30	357
CPV 8	Concentrating Solar P	10	29%	25.4	2012	6800	50	0	0.0	0	35	0	N/A	30	357
CPV 9	Concentrating Solar P	10	29%	25.4	2012	6800	50	0	0.0	0	35	0	N/A	30	357
CPV 10	Concentrating Solar P	10	29%	25.4	2012	6800	50	0	0.0	0	35	0	N/A	30	357
CPV 11	Concentrating Solar P	10	29%	25.4	2013	6800	50	0	0.0	0	35	0	N/A	30	357
CPV 12	Concentrating Solar P	10	29%	25.4	2013	6800	50	0	0.0	0	35	0	N/A	30	357
CPV 13	Concentrating Solar P	10	29%	25.4	2013	6800	50	0	0.0	0	35	0	N/A	30	357
CPV 14	Concentrating Solar P	10	29%	25.4	2013	6800	50	0	0.0	0	35	0	N/A	30	357
CPV 15	Concentrating Solar P	10	29%	25.4	2013	6800	50	0	0.0	0	35	0	N/A	30	357
CPV 16	Concentrating Solar P	10	29%	25.4	2013	6800	50	0	0.0	0	35	0	N/A	30	357
CPV 17	Concentrating Solar P	10	29%	25.4	2013	6800	50	0	0.0	0	35	0	N/A	30	357
CPV 18	Concentrating Solar P	10	29%	25.4	2013	6800	50	0	0.0	0	35	0	N/A	30	357
CPV 19	Concentrating Solar P	10	29%	25.4	2013	6800	50	0	0.0	0	35	0	N/A	30	357
CPV 20	Concentrating Solar P	10	29%	25.4	2013	6800	50	0	0.0	0	35	0	N/A	30	357
CPV 21	Concentrating Solar P	25	29%	63.5	2014	6800	50	0	0.0	0	35	0	N/A	30	357
CPV 22	Concentrating Solar P	25	29%	63.5	2014	6800	50	0	0.0	0	35	0	N/A	30	357
CPV 23	Concentrating Solar P	25	29%	63.5	2014	6800	50	0	0.0	0	35	0	N/A	30	357
CPV 24	Concentrating Solar P	25	29%	63.5	2014	6800	50	0	0.0	0	35	0	N/A	30	357
CPV 25	Concentrating Solar P	50	29%	127.0	2015	6800	50	0	0.0	0	35	0	N/A	30	357
CPV 26	Concentrating Solar P	50	29%	127.0	2015	6800	50	0	0.0	0	35	0	N/A	30	357
CPV 27	Concentrating Solar P	100	29%	254.0	2016	6800	50	0	0.0	0	35	0	N/A	20	357
CPV 28	Concentrating Solar P	100	29%	254.0	2016	6800	50	0	0.0	0	35	0	N/A	20	357
CPV 29	Concentrating Solar P	200	29%	508.1	2017	6800	50	0	0.0	0	35	0	N/A	20	357
CPV 30	Concentrating Solar P	300	29%	762.1	2018	6800	50	0	0.0	0	35	0	N/A	20	357
Tucson Fixed PV 1	Solar Photovoltaic	5	21%	9.3	2008	5200	30	0	0.0	0	35	0	TEP	20	273
Phoenix Fixed PV 1	Solar Photovoltaic	10	20%	17.6	2008	5200	30	0	0.0	0	35	0	APS	20	273
Tucson Fixed PV 2	Solar Photovoltaic	5	21%	9.3	2009	5200	30	0	0.0	0	35	0	TEP	20	273
Phoenix Fixed PV 2	Solar Photovoltaic	10	20%	17.6	2009	5200	30	0	0.0	0	35	0	APS	20	273
Tucson PV tracked	Solar Photovoltaic	500	27%	1178.2	2010	6000	30	0	0.0	0	35	0	TEP	20	315

Appendix B. Forecast Cost of Energy for Each Project

Levelized Cost Calculator

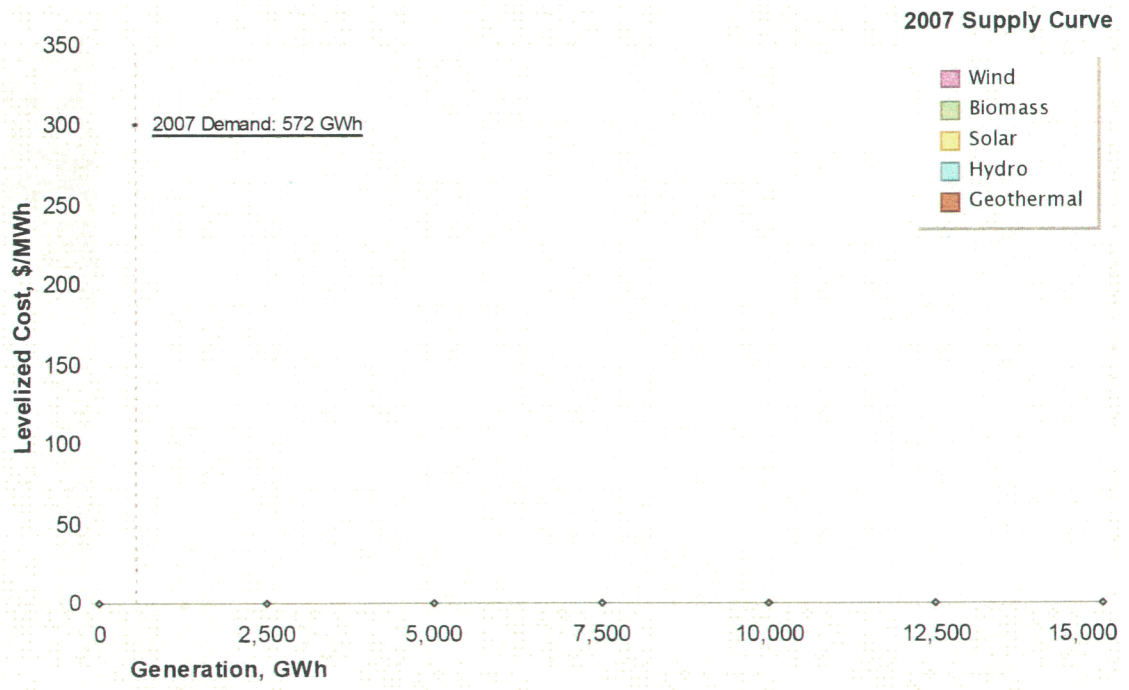
Incremental Levelized Cost

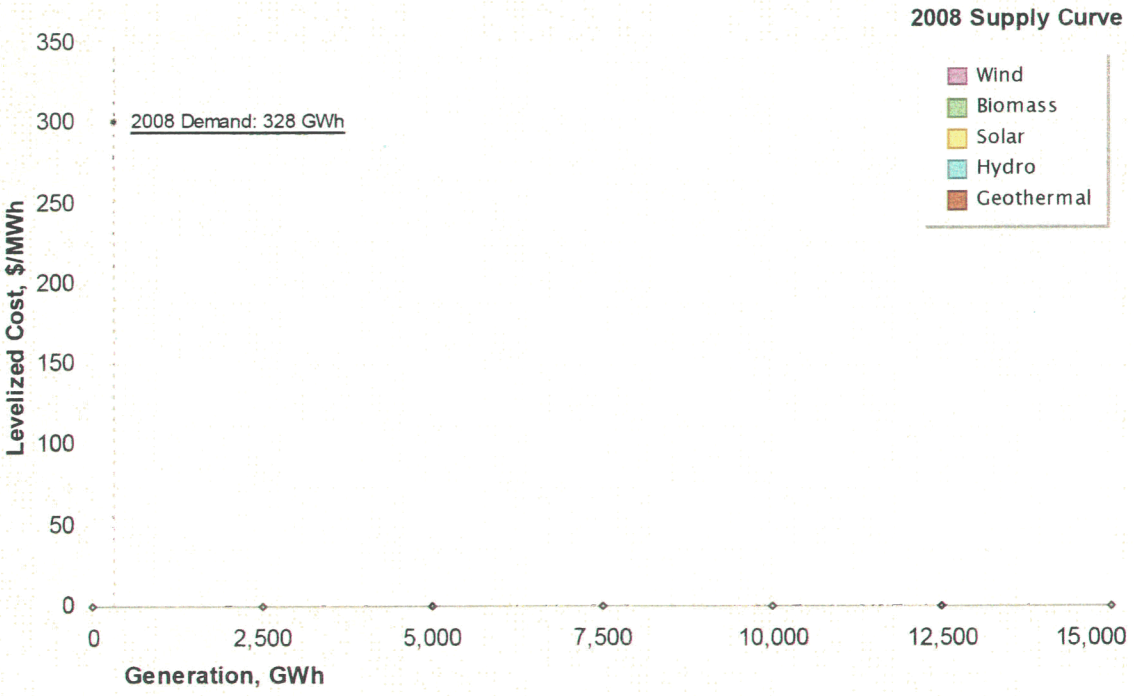
Project Name	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Rattlesnake Crater 1	99	100	101	101	103	104	124	126	128	130	133	135	137	140	143	145	148	151	154
Rattlesnake Crater 2	84	84	84	85	86	88	106	108	110	112	114	116	118	120	123	125	127	130	132
Buckhorn	90	91	92	92	94	95	114	116	118	120	123	125	127	129	132	134	137	140	142
Buffalo Range	83	83	83	84	85	87	105	107	109	111	113	115	117	119	121	124	126	129	131
Chevelon 1	83	83	83	84	85	86	105	107	109	111	113	115	117	119	121	124	126	128	131
Chevelon 2	83	83	83	84	85	86	105	107	109	111	113	115	117	119	121	124	126	128	131
Chevelon 3	83	83	83	84	85	86	105	107	109	111	113	115	117	119	121	124	126	128	131
Chevelon 4	75	76	76	76	77	79	97	99	101	103	105	106	108	110	112	115	117	119	121
Greens Peak	102	103	103	104	106	108	127	129	131	134	136	139	141	144	147	150	152	155	158
Kingstone	141	142	144	145	148	151	171	174	178	181	185	188	192	196	200	204	208	213	217
Beardsley Canal Drop	215	220	226	231	237	243	257	264	270	277	284	291	299	306	314	321	330	338	346
Yuma Main Canal	189	194	199	204	209	214	228	233	239	245	251	257	264	270	277	284	291	299	306
Waddell	185	190	194	199	204	209	223	228	234	240	246	252	258	265	272	278	285	292	300
CAP Canal Turnout	158	162	166	170	174	178	191	196	201	206	211	216	222	227	233	239	245	251	257
Roosevelt (RWCD)	147	151	155	159	162	167	179	184	188	193	198	203	208	213	218	224	229	235	241
Tucson	105	107	110	113	116	118	130	133	136	140	143	147	150	154	158	162	166	170	174
Glen Canyon	32	33	34	35	36	36	46	47	48	49	50	52	53	54	56	57	59	60	62
Clifton	110	113	116	119	122	125	145	149	153	157	161	165	169	173	177	182	186	191	196
Gillard	122	125	128	132	135	138	159	163	167	171	176	180	185	189	194	199	204	209	214
Butterfield Station Landfill	89	91	94	96	98	101	114	117	120	123	126	129	132	136	139	142	146	150	153
Salt River Landfill	82	84	86	88	91	93	106	108	111	114	117	120	123	126	129	132	135	139	142
27th Avenue Landfill	87	89	91	94	96	98	111	114	117	120	123	126	129	132	136	139	142	146	150
Apache Junction LF	85	87	89	91	94	96	109	112	114	117	120	123	126	129	133	136	139	143	146
Cinder Lake MSW LF	83	85	87	89	91	94	107	109	112	115	118	121	124	127	130	133	137	140	143
City of Glendale Municipal Landfill	99	102	104	107	109	112	125	129	132	135	138	142	145	149	153	157	161	165	169
Grey Wolf Landfill	82	84	86	88	91	93	106	108	111	114	117	120	123	126	129	132	135	139	142
Huachuca City Landfill	84	86	89	91	93	95	108	111	114	117	120	123	126	129	132	135	139	142	146
North Center Street Landfill	83	85	87	89	92	94	107	110	112	115	118	121	124	127	130	133	137	140	144
Northwest Regional MSW Landfill	85	87	89	91	94	96	109	112	114	117	120	123	126	129	133	136	139	143	146
Painted Desert Landfill	84	86	88	90	92	95	108	110	113	116	119	122	125	128	131	134	138	141	145
Queen Creek MSW Landfill	84	86	88	90	92	95	108	110	113	116	119	122	125	128	131	134	138	141	145
Rio Rico MSW Landfill	85	87	89	91	94	96	109	112	114	117	120	123	126	129	133	136	139	143	146
Skunk Creek Landfill	87	89	91	94	96	98	111	114	117	120	123	126	129	132	136	139	142	146	150
Cocopah Landfill	83	85	87	89	91	94	107	109	112	115	118	121	124	127	130	133	136	140	143
Southwest Regional Landfill	84	86	89	91	93	95	108	111	114	117	120	122	126	129	132	135	139	142	146
Tangerine Road MSW Landfill	83	85	87	89	92	94	107	109	112	115	118	121	124	127	130	133	137	140	144
Cholla cofiring	63	65	66	68	70	71	73	75	77	79	81	83	85	87	89	91	94	96	99
Springerville cofiring	58	59	61	62	64	65	67	69	70	72	74	76	78	79	81	84	86	88	90
Maricopa City Direct	143	147	151	154	158	162	176	180	184	189	194	199	204	209	214	219	225	230	236
Snowflake Digester (Swine)	62	64	65	67	69	70	82	85	87	89	91	93	96	98	100	103	106	108	111
Buckeye Digester (Dairy)	112	115	117	120	123	126	140	143	147	151	154	158	162	166	170	175	179	184	188
Chandler Digester (Dairy)	128	132	135	138	142	145	159	163	167	171	176	180	185	189	194	199	204	209	214
Maricopa Digester (Beef)	90	92	95	97	99	102	115	118	121	124	127	130	133	136	140	143	147	151	154
Maricopa Digester (Poultry)	86	88	90	92	95	97	110	113	115	118	121	124	127	130	134	137	141	144	148
Solar Dish 1	160	164	168	172	177	179	224	227	185	190	194	199	196	201	206	212	217	222	228
Solar Dish 2	160	164	168	172	177	179	224	227	185	190	194	199	196	201	206	212	217	222	228

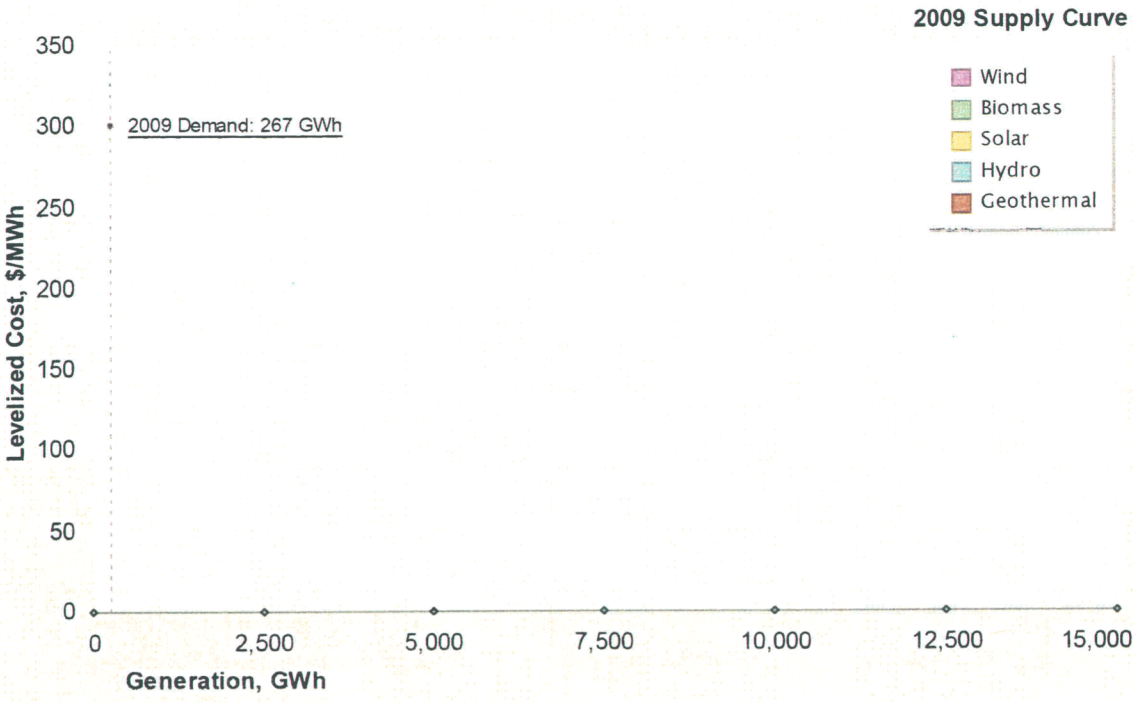
Solar Dish 3	160	164	168	172	177	179	224	227	185	190	194	199	196	201	206	212	217	222	228
Solar Dish 4	158	162	166	171	175	177	222	225	183	188	192	197	194	199	204	209	214	220	225
Solar Dish 5	158	162	166	171	175	177	222	225	183	188	192	197	194	199	204	209	214	220	225
Solar Dish 6	158	162	166	171	175	177	222	225	183	188	192	197	194	199	204	209	214	220	225
Solar Dish 7	158	162	166	170	174	176	221	224	182	187	191	196	193	198	203	208	213	219	224
Solar Dish 8	158	162	166	170	174	176	221	224	182	187	191	196	193	198	203	208	213	219	224
Solar Dish 9	158	162	166	170	174	176	221	224	182	187	191	196	193	198	203	208	213	219	224
Solar Dish 10	158	162	166	170	174	176	221	224	182	187	191	196	193	198	203	208	213	219	224
Solar Dish 11	158	162	166	170	174	176	221	224	182	187	191	196	193	198	203	208	213	219	224
Solar Dish 12	158	162	166	170	174	176	221	224	182	187	191	196	193	198	203	208	213	219	224
Solar Dish 13	158	162	166	170	174	176	221	224	182	187	191	196	193	198	203	208	213	219	224
Stoval Trough 1	163	167	171	175	180	149	206	194	199	204	208	196	201	206	185	189	194	199	204
Stoval Trough 2	161	165	170	174	178	147	205	193	197	202	206	194	199	204	183	187	192	197	202
Stoval Trough 3	161	165	170	174	178	147	205	193	197	202	206	194	199	204	183	187	192	197	202
Stoval Trough 4	161	165	170	174	178	147	205	193	197	202	206	194	199	204	183	187	192	197	202
Stoval Trough 5	161	165	170	174	178	147	205	193	197	202	206	194	199	204	183	187	192	197	202
Stoval Trough 6	161	165	170	174	178	147	205	193	197	202	206	194	199	204	183	187	192	197	202
Stoval Trough 7	161	165	170	174	178	147	205	193	197	202	206	194	199	204	183	187	192	197	202
Stoval Trough 8	161	165	170	174	178	147	205	193	197	202	206	194	199	204	183	187	192	197	202
Stoval Trough 9	161	165	170	174	178	147	205	193	197	202	206	194	199	204	183	187	192	197	202
Stoval Trough 10	161	165	170	174	178	147	205	193	197	202	206	194	199	204	183	187	192	197	202
Phoenix Trough 1	176	181	185	190	194	160	223	210	216	221	225	212	217	223	199	204	210	215	220
Phoenix Trough 2	176	181	185	190	194	160	223	210	216	221	225	212	217	223	199	204	210	215	220
Phoenix Trough 3	176	181	185	190	194	160	223	210	216	221	225	212	217	223	199	204	210	215	220
Phoenix Trough 4	176	181	185	190	194	160	223	210	216	221	225	212	217	223	199	204	210	215	220
Tucson Trough 1	168	172	176	180	185	153	212	200	205	210	214	202	207	212	190	194	199	204	209
Tucson Trough 2	168	172	176	180	185	153	212	200	205	210	214	202	207	212	190	194	199	204	209
Tucson Trough 3	168	172	176	180	185	153	212	200	205	210	214	202	207	212	190	194	199	204	209
Tucson Trough 4	168	172	176	180	185	153	212	200	205	210	214	202	207	212	190	194	199	204	209
Yuma Trough 1	164	168	172	177	181	149	208	196	201	206	210	197	202	207	186	190	195	200	205
Yuma Trough 2	164	168	172	177	181	149	208	196	201	206	210	197	202	207	186	190	195	200	205
Yuma Trough 3	164	168	172	177	181	149	208	196	201	206	210	197	202	207	186	190	195	200	205
Yuma Trough 4	164	168	172	177	181	149	208	196	201	206	210	197	202	207	186	190	195	200	205
CPV 1	376	371	366	361	355	348	432	420	407	394	396	400	403	406	410	414	417	421	425
CPV 2	291	285	279	272	265	257	335	322	308	293	294	295	296	297	298	300	301	302	304
CPV 3	291	285	279	272	265	257	335	322	308	293	294	295	296	297	298	300	301	302	304
CPV 4	291	285	279	272	265	257	335	322	308	293	294	295	296	297	298	300	301	302	304
CPV 5	266	260	254	247	240	233	306	294	280	266	267	267	268	269	270	271	271	272	273
CPV 6	266	260	254	247	240	233	306	294	280	266	267	267	268	269	270	271	271	272	273
CPV 7	266	260	254	247	240	233	306	294	280	266	267	267	268	269	270	271	271	272	273
CPV 8	266	260	254	247	240	233	306	294	280	266	267	267	268	269	270	271	271	272	273
CPV 9	266	260	254	247	240	233	306	294	280	266	267	267	268	269	270	271	271	272	273
CPV 10	266	260	254	247	240	233	306	294	280	266	267	267	268	269	270	271	271	272	273
CPV 11	266	260	254	247	240	233	306	294	280	266	267	267	268	269	270	271	271	272	273
CPV 12	266	260	254	247	240	233	306	294	280	266	267	267	268	269	270	271	271	272	273
CPV 13	266	260	254	247	240	233	306	294	280	266	267	267	268	269	270	271	271	272	273
CPV 14	266	260	254	247	240	233	306	294	280	266	267	267	268	269	270	271	271	272	273
CPV 15	266	260	254	247	240	233	306	294	280	266	267	267	268	269	270	271	271	272	273
CPV 16	266	260	254	247	240	233	306	294	280	266	267	267	268	269	270	271	271	272	273
CPV 17	266	260	254	247	240	233	306	294	280	266	267	267	268	269	270	271	271	272	273
CPV 18	266	260	254	247	240	233	306	294	280	266	267	267	268	269	270	271	271	272	273

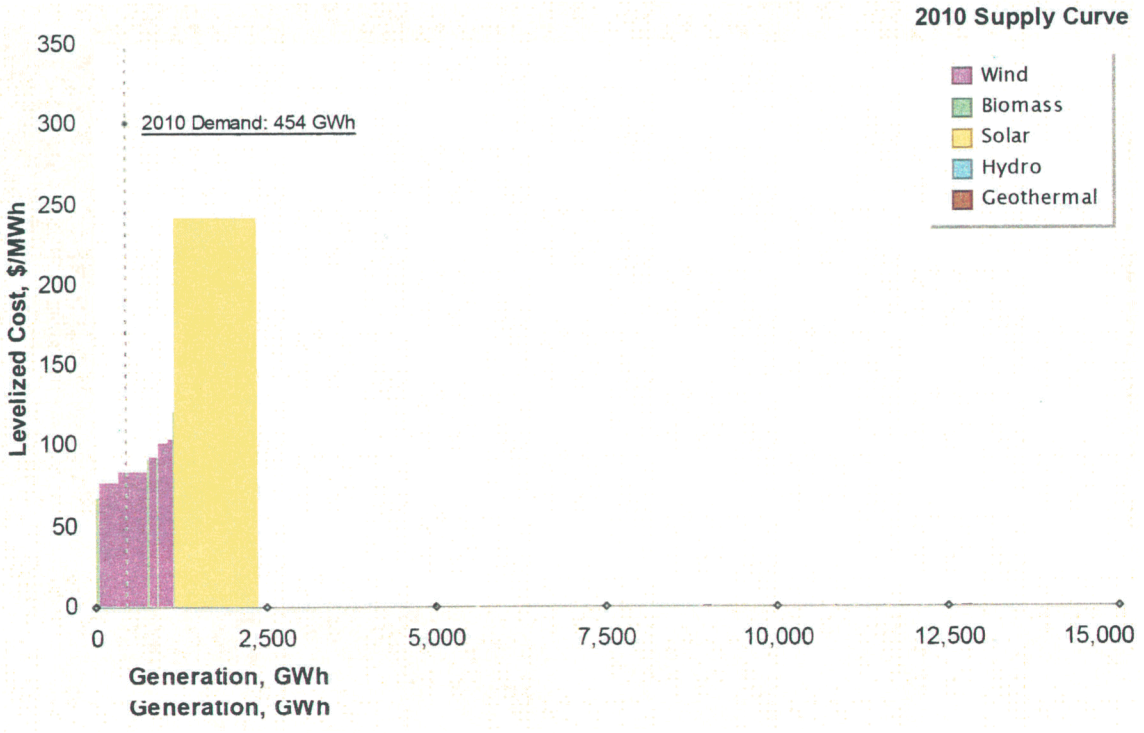
CPV 19	266	260	254	247	240	233	306	294	280	266	267	267	268	269	270	271	271	272	273
CPV 20	266	260	254	247	240	233	306	294	280	266	267	267	268	269	270	271	271	272	273
CPV 21	262	256	250	243	236	228	302	289	276	261	262	262	263	263	264	265	266	266	267
CPV 22	262	256	250	243	236	228	302	289	276	261	262	262	263	263	264	265	266	266	267
CPV 23	262	256	250	243	236	228	302	289	276	261	262	262	263	263	264	265	266	266	267
CPV 24	262	256	250	243	236	228	302	289	276	261	262	262	263	263	264	265	266	266	267
CPV 25	260	255	248	242	234	227	300	288	274	260	260	260	261	262	262	263	264	264	265
CPV 26	260	255	248	242	234	227	300	288	274	260	260	260	261	262	262	263	264	264	265
CPV 27	260	254	248	241	234	226	300	287	273	259	259	260	260	261	261	262	263	263	264
CPV 28	260	254	248	241	234	226	300	287	273	259	259	260	260	261	261	262	263	263	264
CPV 29	259	254	247	241	233	226	299	286	273	258	259	259	260	260	261	262	262	263	264
CPV 30	259	254	247	240	233	226	299	286	273	258	258	259	260	260	261	261	262	263	263
Tucson Fixed PV 1	285	286	287	288	289	290	396	397	398	399	400	401	402	403	404	405	406	408	409
Phoenix Fixed PV 1	292	292	293	294	294	295	407	408	408	409	410	411	411	412	413	414	415	416	416
Tucson Fixed PV 2	285	286	287	288	289	290	396	397	398	399	400	401	402	403	404	405	406	408	409
Phoenix Fixed PV 2	292	292	293	294	294	295	407	408	408	409	410	411	411	412	413	414	415	416	416
Tucson PV tracked	241	241	242	242	242	242	339	339	340	340	340	340	341	341	341	342	342	343	343

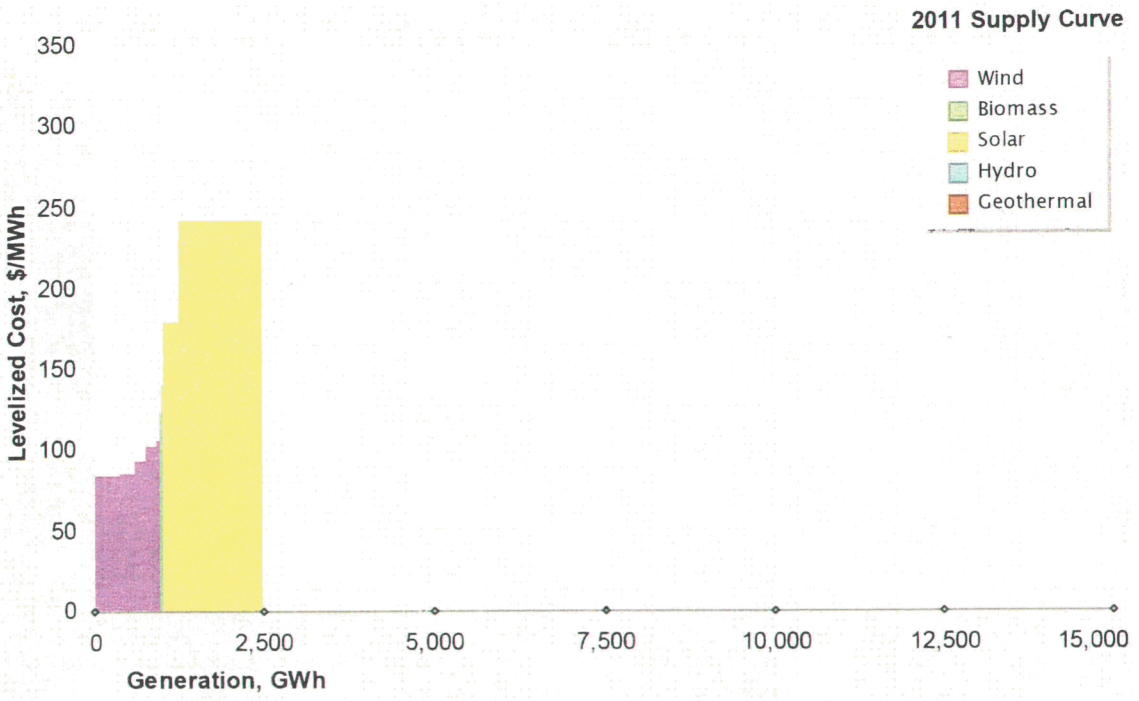
Appendix C. Supply Curves

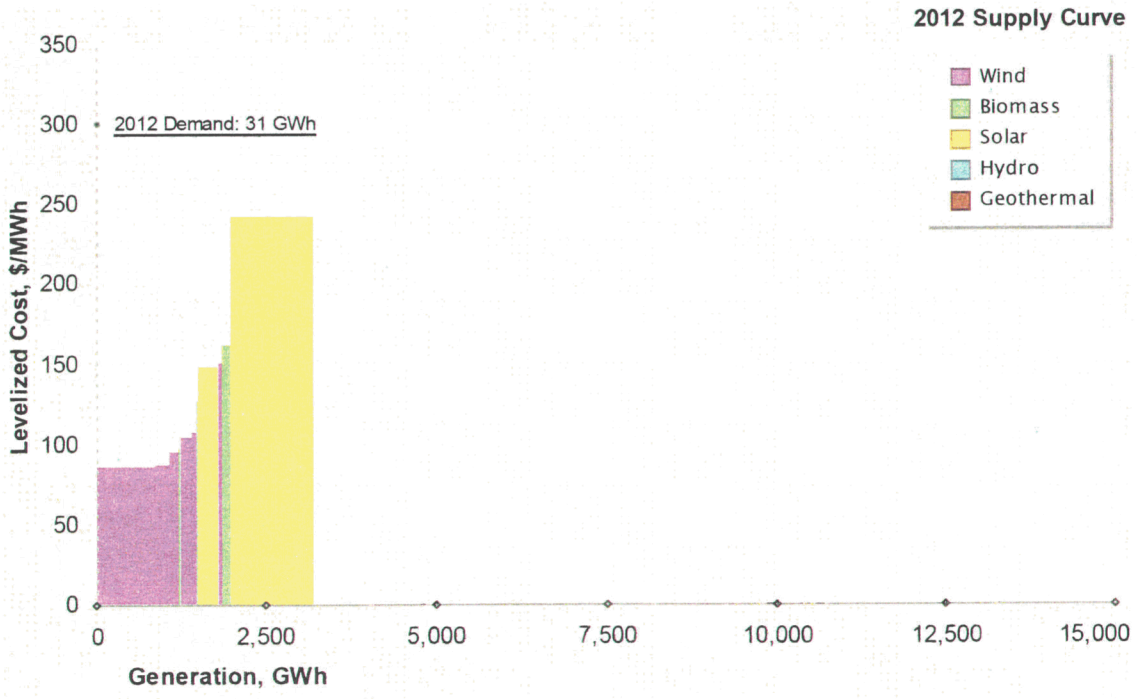


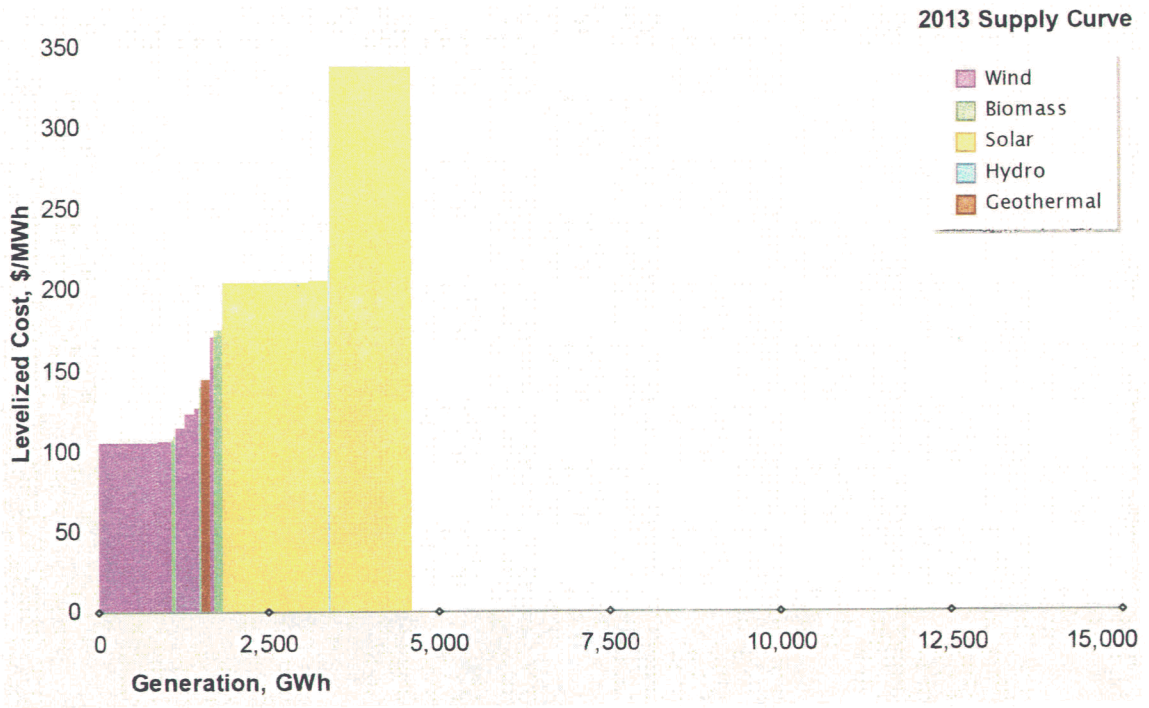


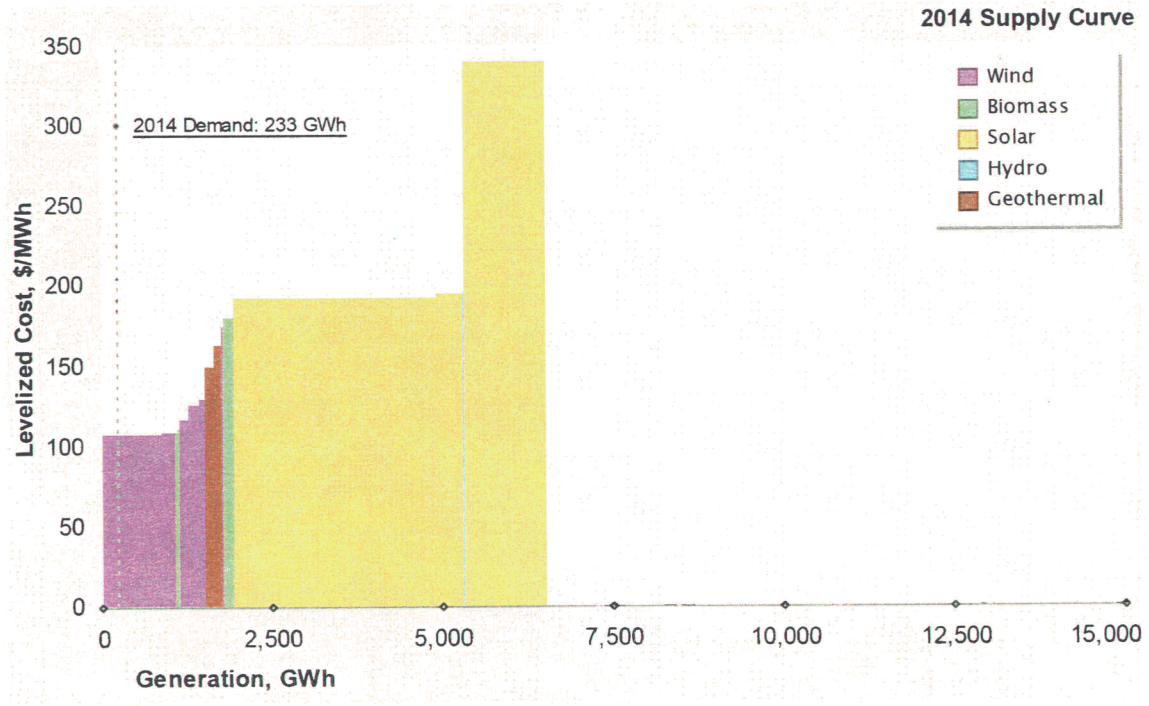

2009 Supply Curve
Wind
Biomass
Solar
Hydro
Geothermal
2009 Demand: 267 GWh
Levelized Cost, $/MWh
350
300
250
200
150
100
50
0
0
2,500
5,000
7,500
10,000
12,500
15,000
Generation, GWh

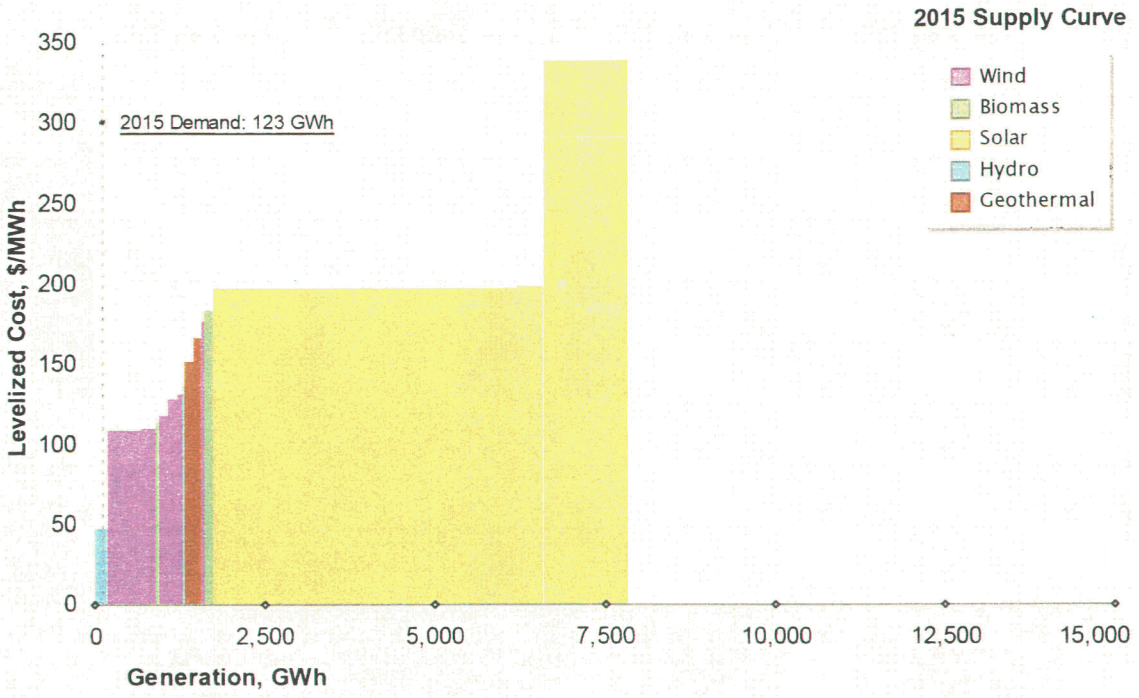

2010 Supply Curve
Wind
Biomass
Solar
Hydro
Geothermal
2010 Demand: 454 GWh
Levelized Cost, $/MWh
350
300
250
200
150
100
50
0
0
2,500
5,000
7,500
10,000
12,500
15,000
Generation, GWh
Generation, GWh

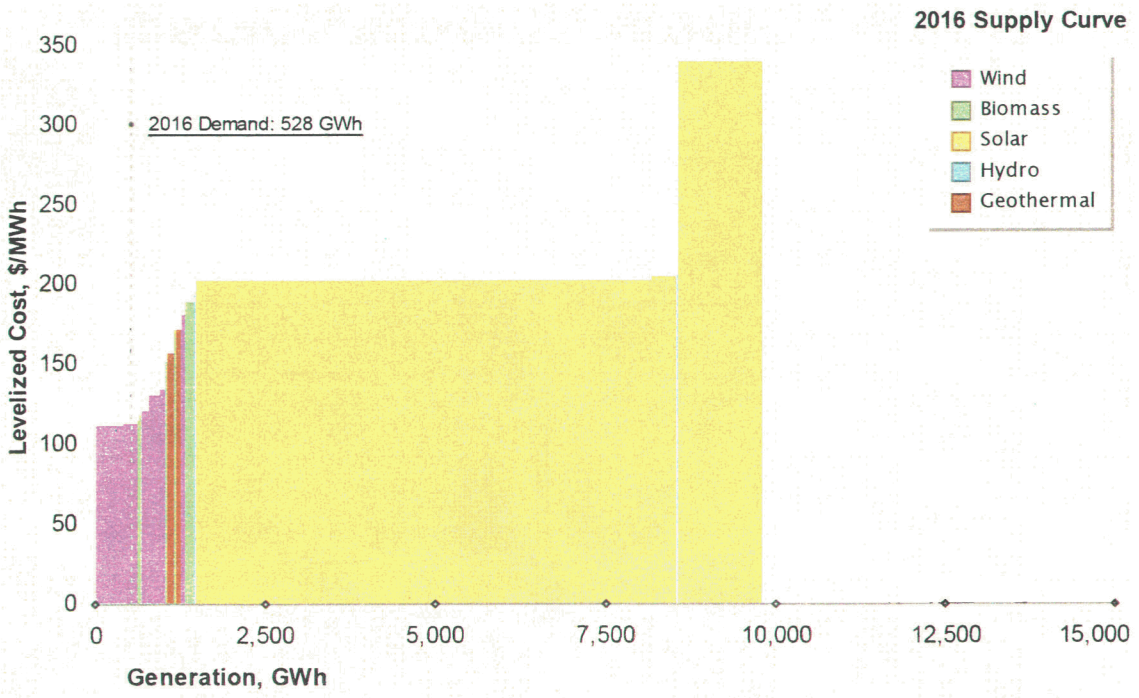

2011 Supply Curve
Wind
Biomass
Solar
Hydro
Geothermal
Levelized Cost, $/MWh
350
300
250
200
150
100
50
0
0
2,500
5,000
7,500
10,000
12,500
15,000
Generation, GWh

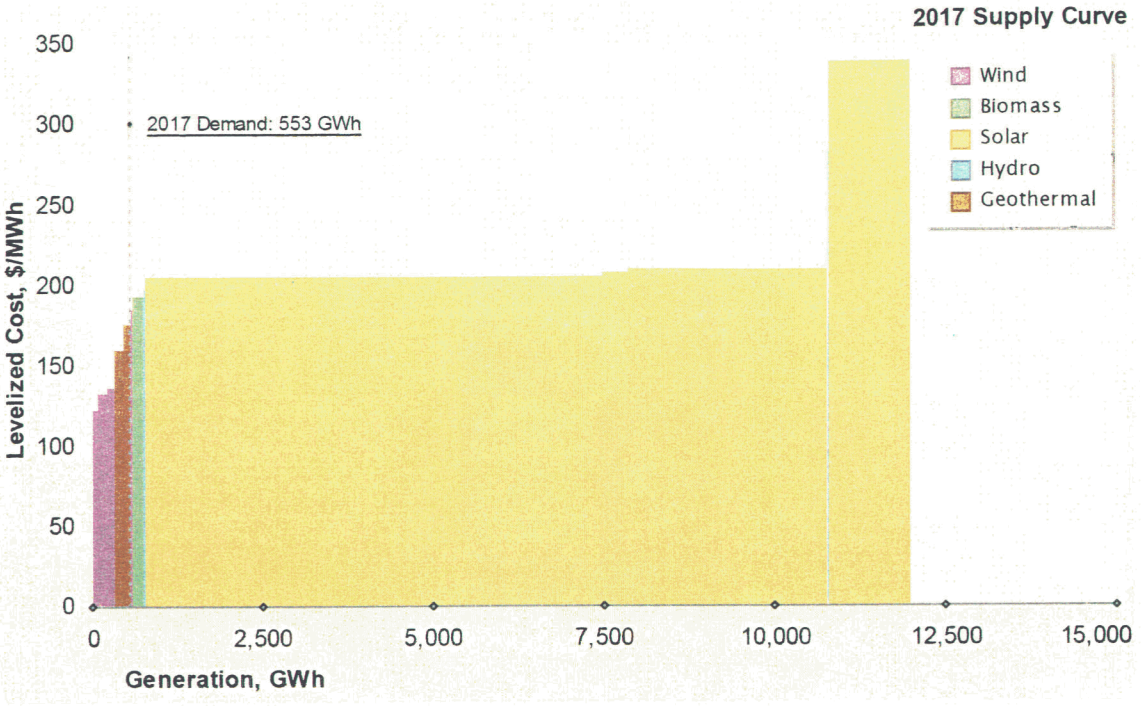

2012 Supply Curve
Wind
Biomass
Solar
Hydro
Geothermal
2012 Demand: 31 GWh
Levelized Cost, $/MWh
350
300
250
200
150
100
50
0
0
2,500
5,000
7,500
10,000
12,500
15,000
Generation, GWh

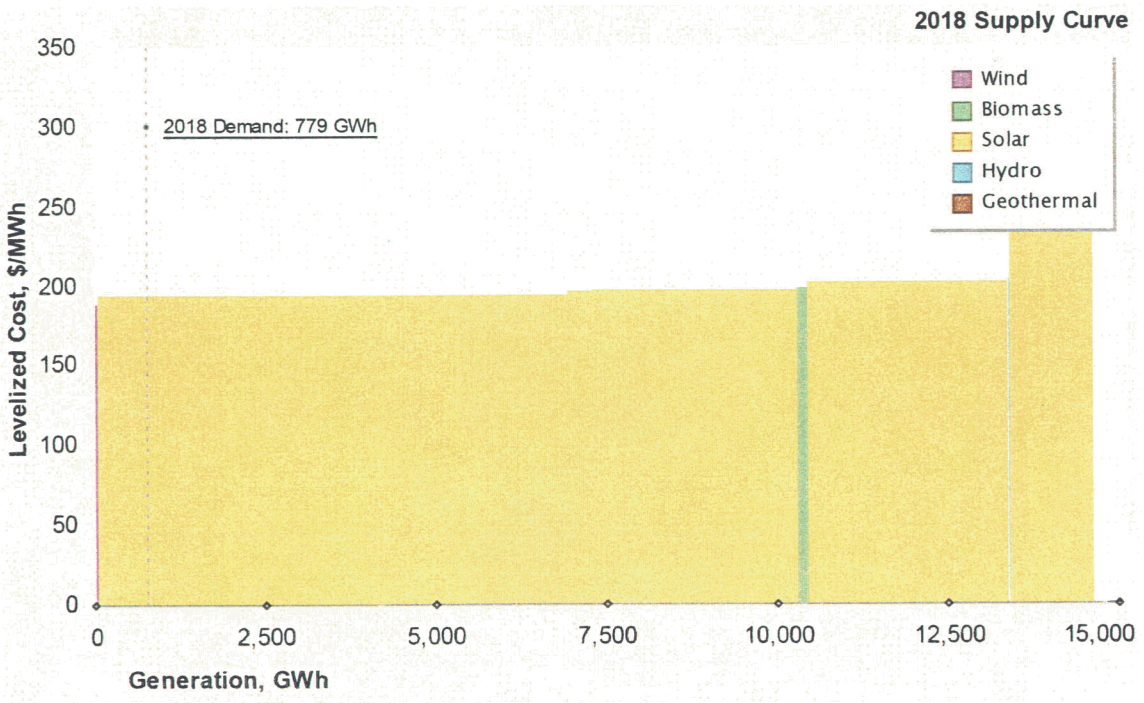

2013 Supply Curve
Wind
Biomass
Solar
Hydro
Geothermal
Levelized Cost, $/MWh
350
300
250
200
150
100
50
0
0
2,500
5,000
7,500
10,000
12,500
15,000
Generation, GWh

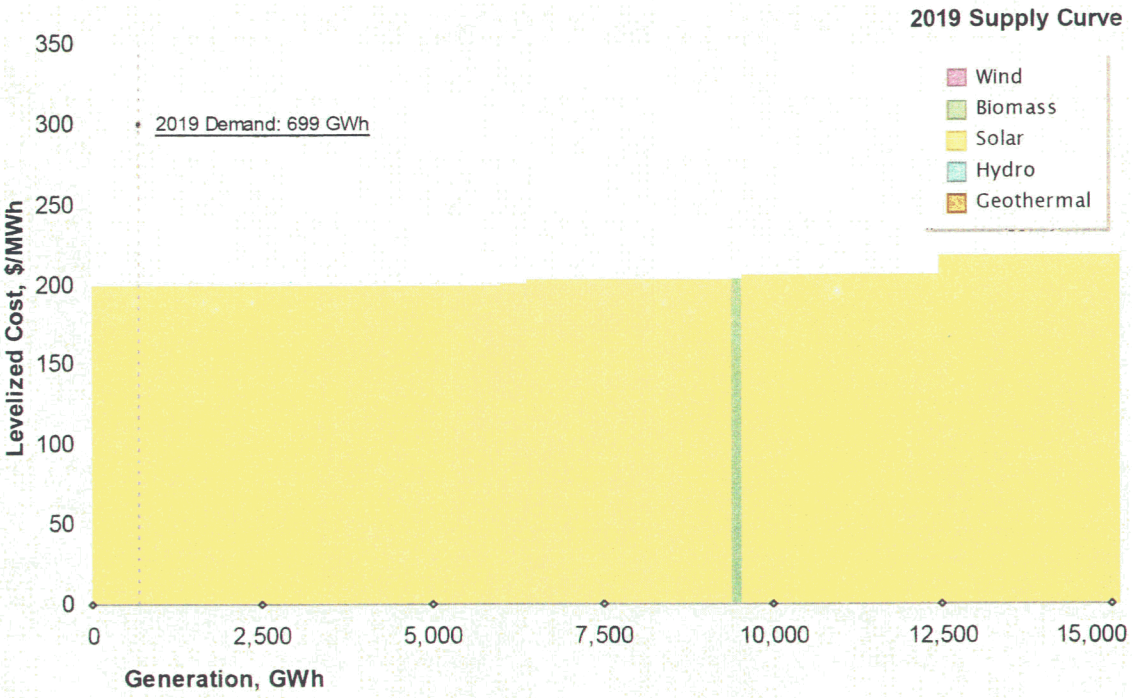

2014 Supply Curve
Wind
Biomass
Solar
Hydro
Geothermal
2014 Demand: 233 GWh
Levelized Cost, $/MWh
350
300
250
200
150
100
50
0
0
2,500
5,000
7,500
10,000
12,500
15,000
Generation, GWh

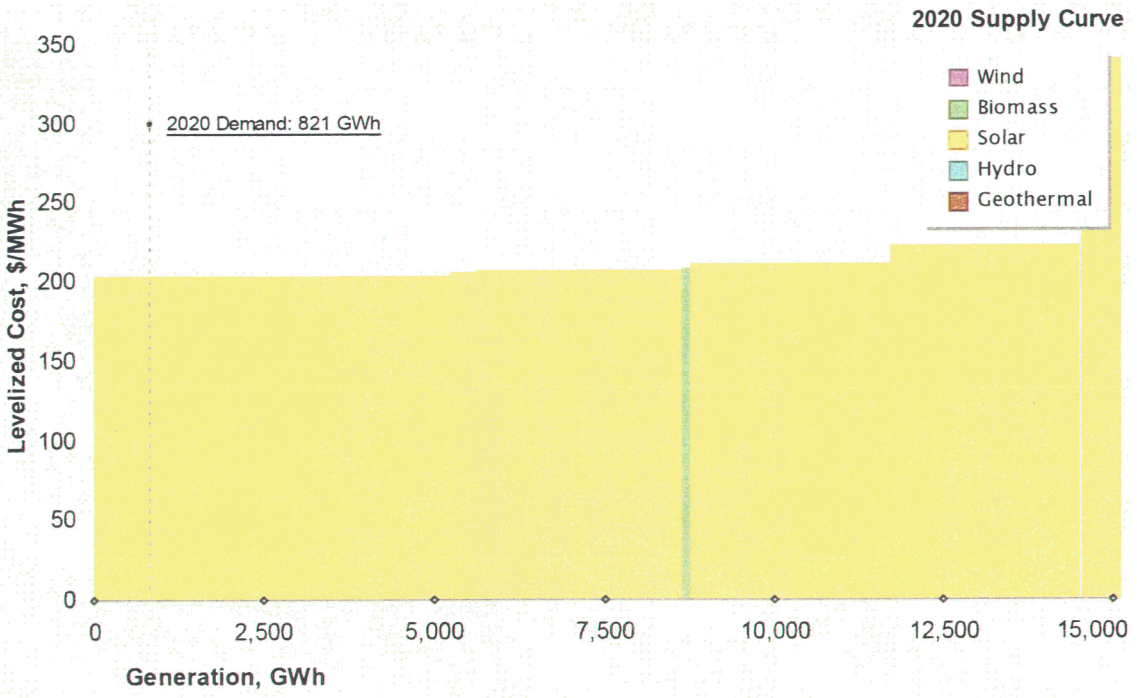

2015 Supply Curve
Wind
Biomass
Solar
Hydro
Geothermal
2015 Demand: 123 GWh
Levelized Cost, $/MWh
350
300
250
200
150
100
50
0
0
2,500
5,000
7,500
10,000
12,500
15,000
Generation, GWh

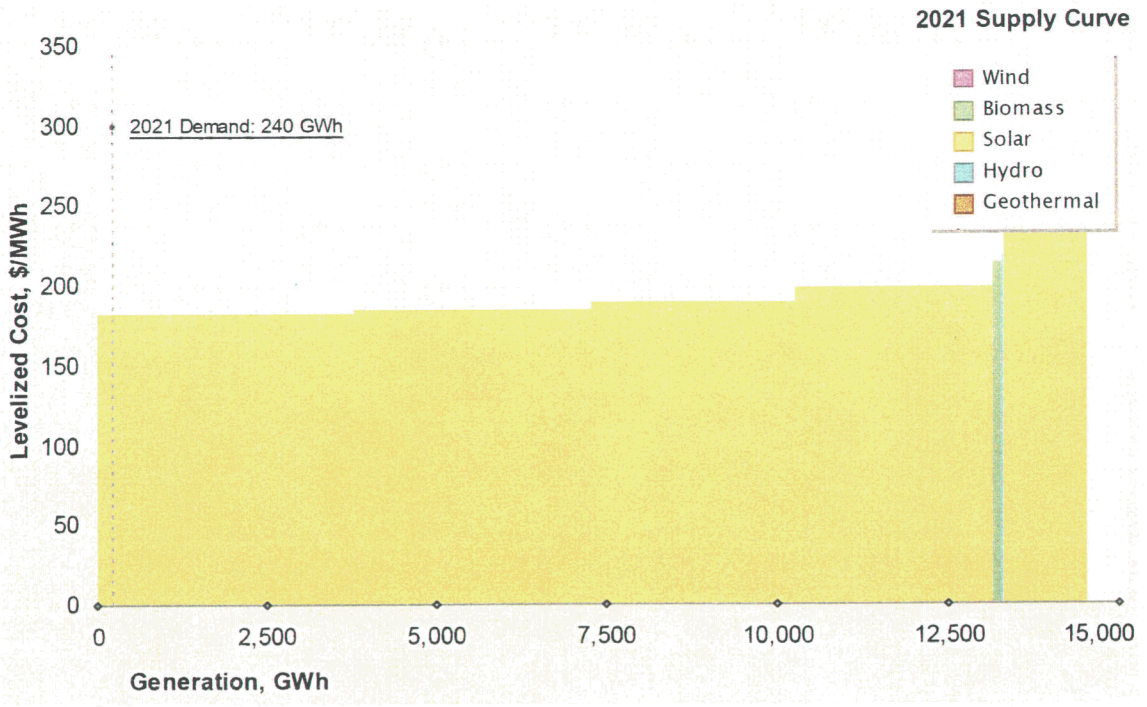

2016 Supply Curve
Wind
Biomass
Solar
Hydro
Geothermal
2016 Demand: 528 GWh
Levelized Cost, $/MWh
350
300
250
200
150
100
50
0
0
2,500
5,000
7,500
10,000
12,500
15,000
Generation, GWh

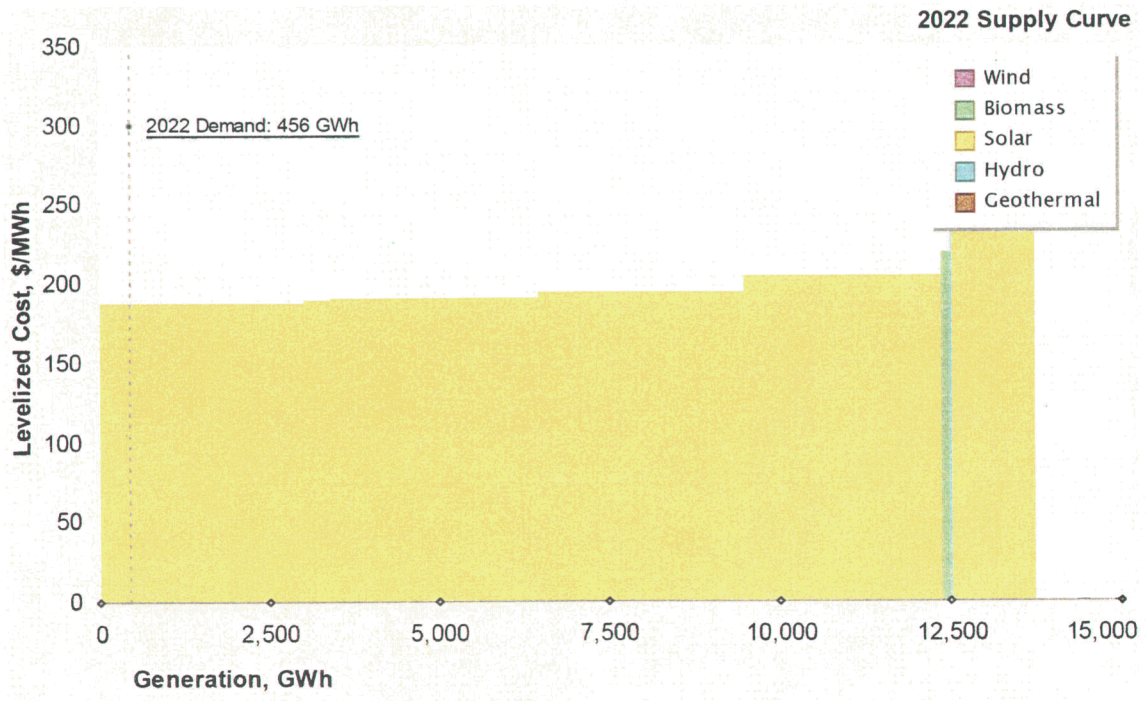

2017 Supply Curve
Wind
Biomass
Solar
Hydro
Geothermal
2017 Demand: 553 GWh
Levelized Cost, $/MWh
350
300
250
200
150
100
50
0
0
2,500
5,000
7,500
10,000
12,500
15,000
Generation, GWh

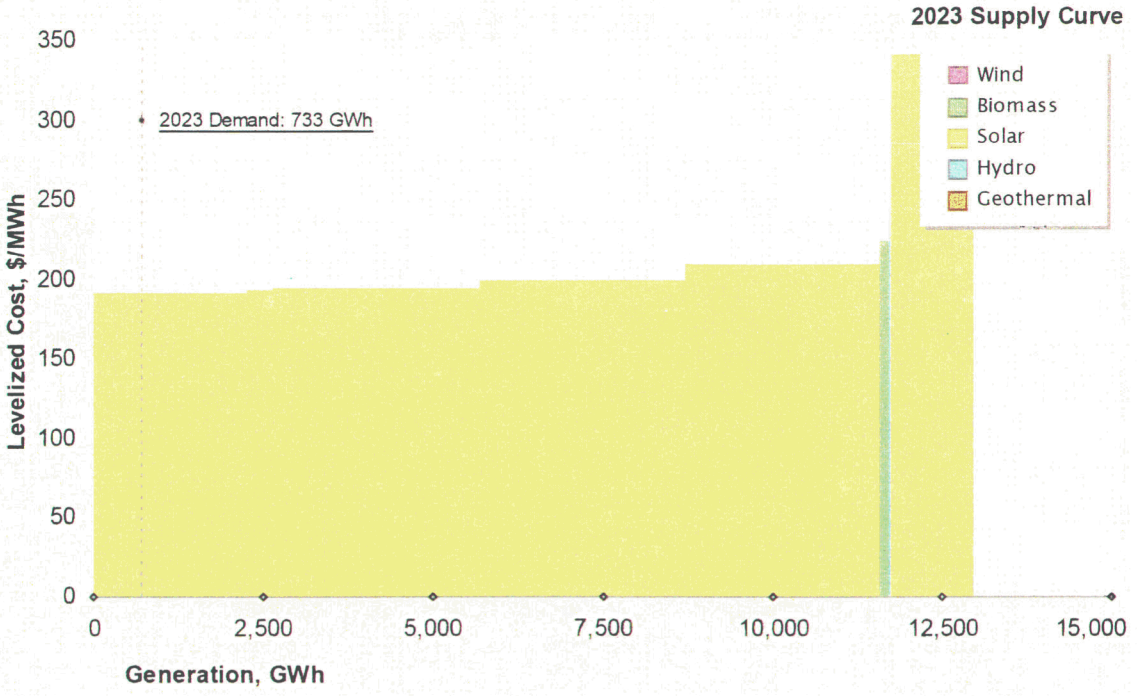

2018 Supply Curve
Wind
Biomass
Solar
Hydro
Geothermal
2018 Demand: 779 GWh
Levelized Cost, $/MWh
350
300
250
200
150
100
50
0
0
2,500
5,000
7,500
10,000
12,500
15,000
Generation, GWh

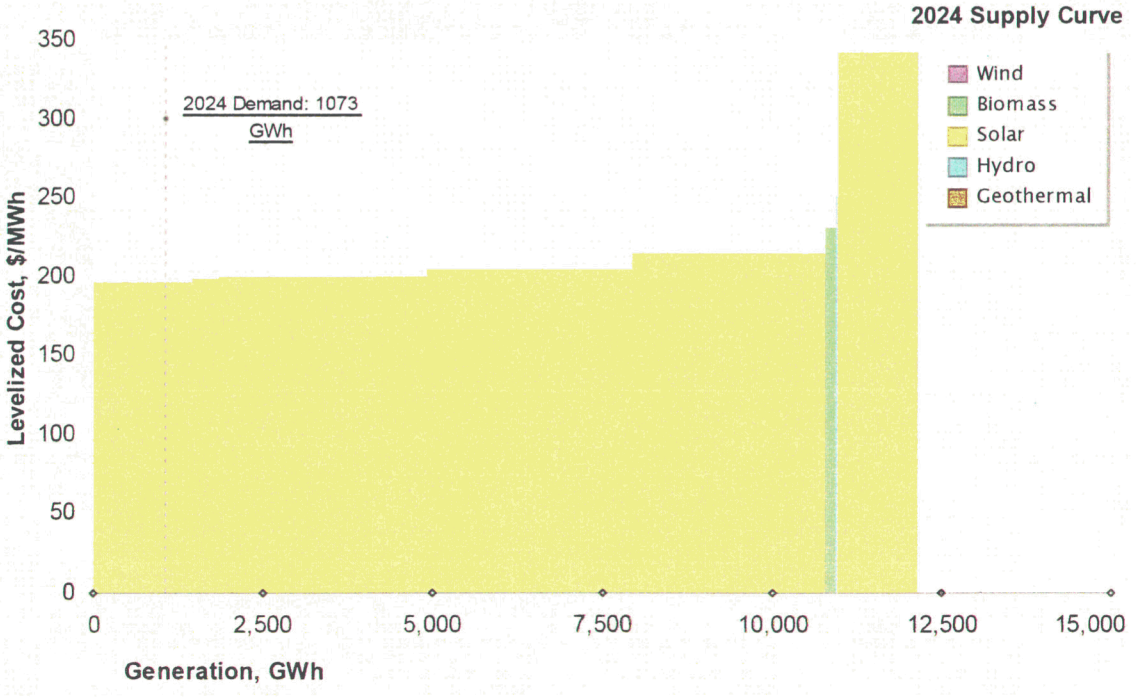

2019 Supply Curve
Wind
Biomass
Solar
Hydro
Geothermal
2019 Demand: 699 GWh
Levelized Cost, $/MWh
350
300
250
200
150
100
50
0
0
2,500
5,000
7,500
10,000
12,500
15,000
Generation, GWh

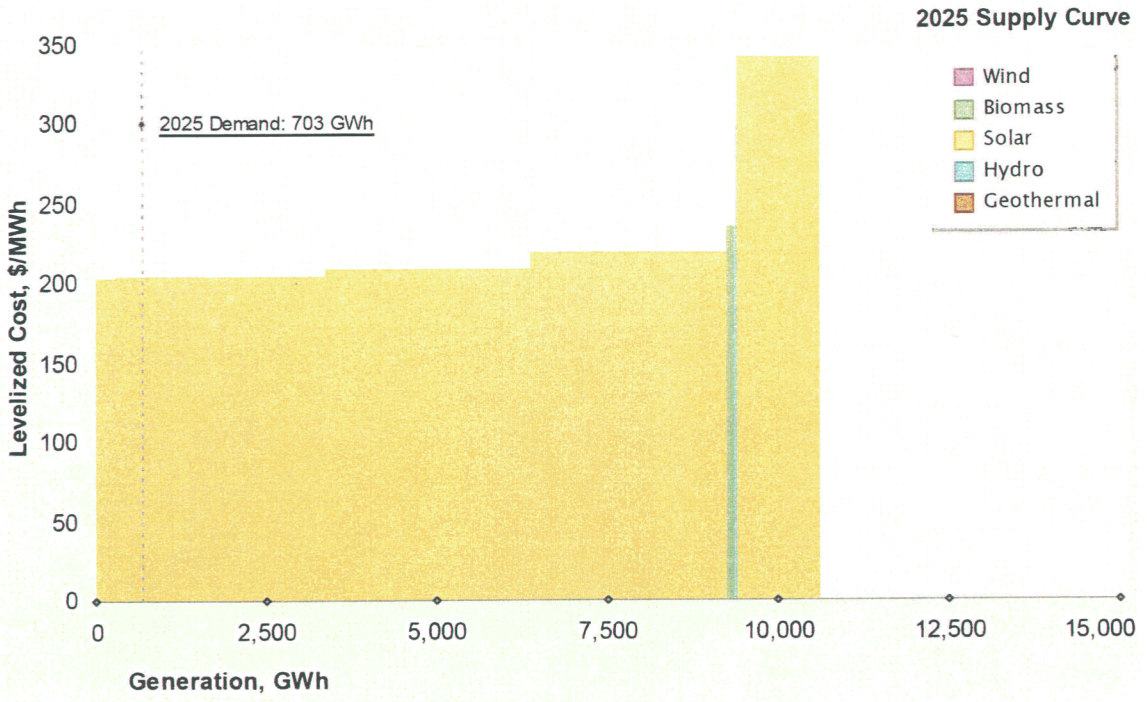

2020 Supply Curve
Wind
Biomass
Solar
Hydro
Geothermal
2020 Demand: 821 GWh
Levelized Cost, $/MWh
350
300
250
200
150
100
50
0
0
2,500
5,000
7,500
10,000
12,500
15,000
Generation, GWh


2021 Supply Curve
Wind
Biomass
Solar
Hydro
Geothermal
2021 Demand: 240 GWh
Levelized Cost, $/MWh
350
300
250
200
150
100
50
0
0
2,500
5,000
7,500
10,000
12,500
15,000
Generation, GWh


2022 Supply Curve
Wind
Biomass
Solar
Hydro
Geothermal
2022 Demand: 456 GWh
Levelized Cost, $/MWh
350
300
250
200
150
100
50
0
0
2,500
5,000
7,500
10,000
12,500
15,000
Generation, GWh


2023 Supply Curve
Wind
Biomass
Solar
Hydro
Geothermal
2023 Demand: 733 GWh
Levelized Cost, $/MWh
350
300
250
200
150
100
50
0
0
2,500
5,000
7,500
10,000
12,500
15,000
Generation, GWh


2024 Supply Curve
Wind
Biomass
Solar
Hydro
Geothermal
2024 Demand: 1073 GWh
Levelized Cost, $/MWh
350
300
250
200
150
100
50
0
0
2,500
5,000
7,500
10,000
12,500
15,000
Generation, GWh


2025 Supply Curve
Wind
Biomass
Solar
Hydro
Geothermal
2025 Demand: 703 GWh
Levelized Cost, $/MWh
350
300
250
200
150
100
50
0
0
2,500
5,000
7,500
10,000
12,500
15,000
Generation, GWh

ATTACHMENT 2

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Building a world of difference.

Arizona Public Service Company
Arizona Renewable Resource Transmission

B&V Project 162351.0010
25 July 2008

Attn: Peter Krzykos
Arizona Public Service Company
502 S. 2ndAvenue, M.S. 2259
Phoenix, AZ 85003

Subject: Assessment of Arizona Renewable Transmission Task Force, BTA Response Submittal

Dear Mr. Krzykos:

Black & Veatch is pleased to submit this Assessment of Arizona Renewable Transmission Task Force, BTA Response to Arizona Public Service Company.

We trust that this submittal meets your expectations and needs. Should you have any comments, please feel free to contact me at (913) 458-9543.

Very truly yours,

BLACK & VEATCH CORPORATION

Tim Mason
Renewable Energy Project Manager

tmm
Enclosure[s]

Assessment of Arizona Renewable Transmission Task Force, BTA Response

Commissioned by Arizona Public Service Company on behalf of the Arizona Transmission Providers (Arizona Public Service Company, Tucson Electric Power Company, Salt River Project and Southwest Transmission Cooperative, Inc.)

REPORT
B&V Project Number: 162351.0010
Project Manager: Tim Mason

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1.0 Executive Summary

Pursuant to A.R.S. § 40-360.02.E, the Arizona Corporation Commission ("ACC" or "Commission") is required to biennially review and issue a decision on the adequacy of existing and planned transmission facilities to meet energy requirements. To implement this requirement the Commission has developed the Biennial Transmission Assessment ("BTA") proceeding, requiring regulated electric utilities ("respondents") to prepare 10-year plan detailing the transmission requirements necessary to reliably serve electric demand. In adopting the fourth BTA[1], the Commission ordered respondents to provide an assessment of the transmission requirements necessary to connect proposed renewable resource generation located in Arizona to the grid for the fifth BTA. This order specified that the assessment include identification of the available transfer capability (ATC) on the existing transmission system, and a plan to connect the proposed renewable resources to the grid, including a description of the amount and location of the transmission required.

The respondents, working jointly with the Southwest Area Transmission (SWAT) planning group's Renewable Transmission Task Force (RETTF), developed an assessment of the current transmission capability and projected requirements detailed in the Commission Order. The respondents presented this assessment at the ACC's 5th Biennial Transmission Assessment Workshop on May 22, 2008.[2]

Black & Veatch has reviewed the SWAT-RETTF assessment to determine if it properly characterizes the ATC, adequately identifies renewable resource transmission requirements, and the conceptual plan is adequate to provide renewable resources the transmission necessary to deliver the energy to load. This report presents Black & Veatch's summary of the joint assessment. The report also provides a discussion of regional transmission planning efforts that will impact Arizona's transmission development for renewable resources, as well as provide recommendations on issues that APS should consider in planning transmission for renewable resources.

[1] Arizona Corporation Commission Decision No. 69389, March 22, 2007.

[2] http://www.azcc.gov/Divisions/Utilities/Electric/Biennial/2008%20BTA/Response%20on%20Renewables%20FINALl_4.ppt

Summary of Findings

As detailed in the following sections, Black & Veatch finds that the renewable resource transmission assessment completed by the SWAT-RETTF adequately identifies ATC in Arizona, appropriately considers anticipated system requirements, and provides a reasonable schematic plan to connect renewable resources to the Arizona transmission system. Specific observations on the assessment include:

- Developing a joint transmission assessment through SWAT–RETTF is superior to having each respondent develop discrete assessments and transmission plans. The transmission system in Arizona is fully integrated, and adding resources to the system will impact all entities, hence it is appropriate to conduct a regional analysis for the transmission system.
- Projected Available Transfer Capability (ATC) ratings were developed in accordance with current Western Energy Coordinating Committee (WECC) guidelines for calculating transfer capability. The ATC values provided in the assessment appropriately reflect Arizona ATC for system planning purposes.
- Renewable generation capacity identified in the SWAT assessment adequately reflects anticipated development, taking into consideration the inherent uncertainties in developing such an assessment.
- The SWAT-RETTF conceptual transmission configuration is appropriate for BTA purposes. Detailed transmission studies will be required for interconnecting specific resources, but this is premature given the level of current renewable resource development in Arizona.

Regarding the planning process for transmission to interconnect renewable resources in Arizona, Black & Veatch makes the following recommendations:

- Transmission studies should consider regional transmission initiatives designed to access renewable generation and deliver this energy to loads. Several interstate transmission lines have been proposed that may impact Arizona's renewable resource market potential, as well as impact Arizona's bulk transmission requirements.
- Renewable resource planning should be integrated with all system planning activities. A substantial quantity of renewable resources is currently proposed for construction in Arizona and, if constructed, would impact the current operation of the transmission system.

2.0 Introduction

Black & Veatch has prepared this review of the SWAT-RETTF transmission analysis prepared for the Fifth Biannual Transmission Assessment (BTA) on behalf of the Arizona Transmission Providers (Arizona Public Service Company, Tucson Electric Power Company, Salt River Project, and Southwest Transmission Cooperative, Inc. The purpose of this review is to (1) assess the methodology, data and results included in the SWAT-RTTP analysis, (2) consider how western regional transmission planning activities may impact Arizona transmission requirements, and (3) provide recommendations on issues that APS should consider in planning transmission for renewable resources.

2.1 Background

In response to increasing public demand and government policy goals to develop a cleaner, less carbon intensive electric energy infrastructure, there is unprecedented demand for renewable energy. To meet this demand, developers are proposing the construction of substantial quantities of renewable generating facilities to take advantage of Arizona's abundant natural resources, namely wind and solar.

A major hurdle to integrating these resources into the current Arizona electric system is the time and cost required to develop transmission to access these resources. Renewable resources tend to be located in remote areas away from existing infrastructure and the development and siting of transmission is often a long and involved process, particularly in areas of environmentally sensitive habitat. Transmission is also very costly, requiring large up-front capital expenditures by project developers, who are often unwilling or unable to finance this development. Recognizing these barriers, the ACC directed transmission providers in Arizona to detail the transmission requirements necessary to allow these resources to deliver energy to the grid. In Decision No. 69389 accepting the fourth BTA, the ACC specified:

> It is further ordered that in the next BTA, Commission regulated utilities, in consultation with stakeholders, should prepare an assessment of ATC for renewable energy and prep[are a plan, including a description of the location, amount of transmission needs of renewable resources in Arizona, and bring available renewable resources to load.[3]

The respondents, working jointly with the Southwest Area Transmission (SWAT) planning group's Renewable Transmission Task Force (RETTF), developed an assessment of the

[3] Arizona Corporation Commission, Decision No. 69389, March 22, 2007, p.8.

current transmission capability and projected requirements detailed in the Commission Order. The respondents presented this assessment at the ACC's 5th Biennial Transmission Assessment Workshop on May 22, 2008.

2.2 Report Organization

This report is organized into the following sections:

- **Section 3** – Review of SWAT-RETTF Assessment. This section details the methodology, data and results included in the SWAT-RTTP assessment and include Black & Veatch's conclusions on the planning process.
- **Section 4** – Regional Transmission Planning in Western U.S. This section discusses regional initiatives to develop transmission to access renewable generation.
- **Section 5** – Recommendations on Arizona Transmission Planning. Black & Veatch has provided several recommendations for Arizona planning for integrating renewable generation into the transmission system.

3.0 Review of SWAT-RETTF Assessment

In accordance with Commission requirements discussed in Section 2, the respondents completed a joint transmission assessment, renewable identification and renewable transmission plan. This was developed under the auspices of the SWAT-RETTF regional planning group rather than individual studies by each transmission provider. During October and November, 2007 the RETTF conducted public workshops to solicit input of interested parties on the assessment, which were attended by a range of utilities, generators and other interested parties. Additional workshops were held in early 2008 where the proposed plan was initially presented.

During the workshops SWAT provided information to stakeholders regarding ATC, an assessment of renewable resource potential and, ultimately, the proposed transmission schematic that identifies renewable resource areas that would likely require additional transmission development. The only format comment received at the workshops was the identification of a potential 100-MW wind generation facility proposed for the Navajo nation.

This section reviews the analytical approached employed by SWAT in the transmission analysis and presents Black & Veatch's conclusions on the process. First, Black & Veatch discusses the role of SWAT in the assessment.

3.1 SWAT Regional Transmission Planning

The respondents prepared a joint renewable transmission assessment under the SWAT. SWAT is a collaboration of utilities and transmission providers that conducts transmission planning in the Arizona and New Mexico region of the Western Energy Coordinating Committee (WECC) region.[4] SWAT is part of WestConnect, an umbrella transmission organization that focuses on transmission activities in the entire Southwestern U.S. WestConnect and SWAT provide a valuable function to Arizona in transmission planning, as the western electric grid is wholly interconnected and the actions of one participant in the system, such as adding resources in New Mexico, will impact all participants in the system to some extent. Participating in SWAT and WestConnect allows Arizona transmission providers to identify these issues. In 2006 SWAT created the Renewable Transmission Task Force, designed to focus on identifying and addressing the transmission requirements associated with renewable resource development in the SWAT region.

[4] A description of the SWAT located at http://www.westconnect.com/planning_swat_anm.php

Developing transmission assessments on a regional level is necessary to accurately identify ATC and identify the transmission requirements of an individual transmission owner. The transmission grid is an interconnected network, and Arizona's transmission system is impacted by the operation of the grid in neighboring areas. This is beneficial for Arizona, as it allows for the economic flow of energy in and out of Arizona to meet customer requirements most efficiently. While individual transmission owners propose and develop transmission necessary to interconnect resources located in their own territory, and to serve load within their own system, understanding the long-term requirements of the electric grid require the broader, regional view of resource supply and demand.

Conclusion

Developing the joint transmission assessment and plan for the BTA as part of SWAT is both logical and beneficial. Detailed in Section 3.3, a substantial amount of new renewable generation is currently proposed in Arizona, and putting all or a portion of this capacity on the electric system will impact the operation of all transmission providers in the state. It would be difficult to fully measure the impact of this if each utility were to develop transmission plans in isolation. Further, there are potential transmission cost savings and efficiencies by planning for renewable resource on a system-wide basis. An individual utility may not have visibility to the resources being included by other utilities, hence would not be capable of measuring the impact of these resources on its system. This would likely result in operational inefficiencies, where each utility may require different network requirements or remediation activities that may be unnecessary if the resource additions are coordinated. For these reasons it is appropriate that the transmission plan provided to the BTA was developed by the SWAT-RETTF.

3.2 Assessment of ATC in Arizona

The assessment of available transfer capability (ATC) for the existing transmission system was developed by the SWAT - RETTF in late 2007, using June 2007 data. ATC measures the usable transfer capability remaining in the transmission network over and above existing commitments. The WECC defines ATC as:

> A measure of the transfer capability remaining in the physical transmission network for further commercial activity over and above already committed uses. It is defined as Total

Transfer Capability less existing transmission commitments -- including retail customer service, less a Capacity Benefit Margin, less a Transmission Reliability Margin.[5]

Where:

Total Transfer Capability - The amount of electric power that can be transferred over the interconnected transmission network in a reliable manner while meeting all of a specific set of defined pre- and post-contingency system conditions.

Transmission Customer (Existing) - 1. Any eligible customer (or its designated agent) that can or does execute a transmission service agreement or can or does receive transmission service. 2. Any of the following responsible entities: Generator Owner, Load-Serving Entity, or Purchasing-Selling Entity.

Capacity Benefit Margin – CBM The amount of firm transmission transfer capability preserved by the transmission provider for Load-Serving Entities, whose loads are located on that Transmission Service Provider's system, to enable access by the LSEs to generation from interconnected systems to meet generation reliability requirements. Preservation of CBM for an LSE allows that entity to reduce its installed generating capacity below that which may otherwise have been necessary without interconnections to meet its generation reliability requirements. The transmission transfer capability preserved as CBM is intended to be used by the LSE only in times of emergency generation deficiencies.

Transmission Reliability Margin - The amount of transmission transfer capability necessary to provide reasonable assurance that the interconnected transmission network will be secure. TRM accounts for the inherent uncertainty in system conditions and the need for operating flexibility to ensure reliable system operation as system conditions change.

Developing a reliable and robust value for ATC is elusive, as ATC is highly dynamic. Transfer capability varies on an hourly basis, and at different times of the day and year the ATC on a given transmission path will vary widely depending on load requirements and operating resources. The ATC rating of a line does not represent an absolute limitation on the incremental transfer capability of a line, rather it reflects the quantity of resources that may be added while ensuring reliable delivery. Resources may be added to a transmission line with a nominal capacity rating that exceeds of the line's ATC, as long as if the energy delivered by these resources does not cause reliability concerns or result in transmission constraints. For instance, a line with a nominal ATC of 100 MW may not be able to accommodate 150 MW of baseload energy resources, but may be capable of transmitting 120 MW of off-peak energy generation.

The customary way to calculate ATC in the WECC is the rated system path methodology, and this method has been used by SWAT-RETTF in this analysis. This methodology considers the firm transfer potential of a line under a variety of conditions. A description of the ATC calculation is included in Appendix A. In addition to the rated system

[5] http://www.wecc.biz/wrap.php?glossary/index.php

path methodology, the North American Electric Reliability Council (NERC) has identified two alternative methods of calculating the ATC of a line, including the area interchange methodology and the flowgate methodology. Where the rated system path methodology considers the maximum capacity of a line, the alternative approaches determine the ATC based on the energy flow of a line. NERC is currently in the process of revising its ATC measurement methodologies for all of these approaches.[6]

Conclusion

The ATC ratings presented by the SWAT-RETTF were developed in accordance with current guidelines for calculating transfer capability, and the rated system path method for developing ATC is appropriate for use at this time for the BTA. In future BTA assessments SWAT should review the revised NERC ATC methodologies to determine if an alternative approach is more appropriate.

3.3 Renewable Resource Identification

Central to the development of a transmission plan to access renewable resources is identifying the resources that will be connected to the system, including type, quantity, location, and development timing. The SWAP-RETTF estimates 7,757 MW of renewable resources will be developed in Arizona within the BTA ten year planning horizon.[7] The majority of the resources are solar, and are projected to be built primarily in southern Arizona. Wind resources, which represent most of the remaining capacity, are expected to be developed in central and northern portions of the state. Small amounts of biomass and geothermal are also anticipated to be developed. The SWAT –RETTF assessment identified renewable energy zones (REZ) where there are high concentrations of renewable potential and proposed renewable projects.

Creating a reliable estimate of renewable resource development is challenging, as the ultimate quantity of resources developed will depend on several factors including public demand, government policies regarding renewable generation requirements, and the cost of renewable energy, both the direct cost and relative to the cost of conventional generation. Discussed in greater detail in Section 4, demand for renewable energy from Arizonians and other western U.S.

[6] ftp://www.nerc.com/pub/sys/all_updl/standards/sar/MOD-001-1_Project2006-07_clean_30-day_Pre-ballot_18Jun08.pdf

[7] Arizona Renewable Transmission Task Force BTA Response presentation by Chairman of SWAT RETTF Peter Krzykos, BTA Workshop, May 22-23 2008

energy customers is driving ever-increasing amounts of renewable generation to be proposed. Given that the Arizona renewable resource potential is vast and high quality, this may increase the demand for Arizona renewable energy and the transmission require to deliver this energy.

Equally difficult is quantifying how may, and which, of the proposed and potential facilities will be constructed. Discussed below, there are currently 29 applications for BLM land leases, but it is highly unlikely that all of these facilities will be developed. Developers often lease land in anticipation of future development rather than specific planned development. Further, a 2006 KEMA, Inc. study concluded that approximately 40% of all renewable resources with contracts for energy sales fail to get developed. (The study, which details why contracts fail, is included as Appendix B). Finally, many of the currently proposed resources are expected to be located of U.S. Bureau of Land Management (BLM) property, and BLM has recently announced that it is conducting Programmatic Environmental Impact Statement (PEIS) assessments of solar and geothermal resources.[8] It is unknown how this may affect currently-proposed facilities. That said, there remains a substantial quantity of proposed renewable projects proposed in Arizona. Black & Veatch reviewed the data on these proposed renewable developments to assess whether the SWAT-RETTF projection was appropriate for the BTA. This data is provided and discussed below.

Transmission Owner Queues: Each transmission owner maintains a list of resources that have applied for transmission interconnection to the transmission owner's system. Having a project in a transmission queue does not mean the project will be developed, but it is a strong indication of commercial interest in developing a project. As of April 18, 2008, there are approximately 7,500 MW of resources in transmission queues in Arizona. Table 3-1 summarizes the resources in the transmission queues by type. Appendix C details information on projects in each transmission owner queue.

Resource Type	Capacity (MW)
Biomass	22
Solar	3350
Wind	4203
Grand Total	7575

Table 3-1. Arizona Transmission Queue Capacity

[8] http://solareis.anl.gov/index.cfm, http://www.blm.gov/wo/st/en/prog/energy/geothermal/geothermal_nationwide.html

Arizona Renewable Energy Assessment, Black & Veatch: In September 2007 Black & Veatch published the Arizona Renewable Energy Assessment, which identified renewable resources located in Arizona that were suitable for development within the next 20 years.[9] The report concluded that over 100 projects, with an aggregate generating capacity of approximately 5,500 MW, could be cost-effectively developed in Arizona. These resources are summarized on Table 3-2 below, and detailed in Appendix D. Further, the report noted the potential for more solar, stating "The solar potential is vast, and the [report] only includes projects sufficient for meeting Arizona's forecast renewable energy demands through 2025."[10]

Arizona Renewable Energy Resources

Technology	Location	Capacity (MW)	Generation (GWh/yr)
Direct Fired Biomass	Maricopa	20	140
Biomass Cofiring	2 potential sites: TEP's Sringerville generating station and APS's Cholla generating station	20	140
Landfill Gas	15 potential small projects identified across the state	10	68
Anaerobic Digestion	Snowflake, Buckeye, Chandler, and Maricopa	10	69
Solar Thermal Electric	100 MW project in 2011. 2–4 200 MW sites per year after 2012	4,300[a]	10,940[a]
Hydroelectric	7 potential sites[b]	82	320
Wind	6 potential sites near Kingman and the White Mountains[c]	991	2551
Geothermal	Clifton Hot Springs and Gillard Hot Springs	35	215
Total		**5,468**	**14,443**

Notes:
[a] The solar potential is vast, and this only includes projects sufficient for meeting Arizona's forecast renewable energy demands through 2025.
[b] Glen Canyon compromises 90 percent of total potential.
[c] 500 MW of planned wind generation not included.

Table 3-2 Black & Veatch Assessment of Arizona Renewable Energy Resources

U.S. Bureau of Land Management Applications: The BLM maintains a listing of all applications for land leases on BLM property. There are currently 28 land lease applications to develop renewable generating facilities on BLM land in Arizona, with most of these applications

[9] http://www.bv.com/resources/energy_brochures/renewables/rsrc_AZ_RenewableEnergyAssessment.pdf
[10] Ibid, p.1-2, Table 1-1 note.

for solar thermal generation. Black & Veatch estimates the total potential generating capacity of these resources to be over 12,000 MW.[11] These resources are summarized on Table 3-3 below, and detailed in Appendix E. Mentioned above, BLM is currently conducting PEIS assessments of solar and geothermal resources, which together represent the vast majority ducting of resources in the BLM land lease application pool. The results of these assessments may substantially impact the development of energy facilities on BLM land in Arizona.

The solar PEIS review is being conducted jointly by the Department of Energy's Office of Energy Efficiency and Renewable Energy and BLM. The PEIS will "evaluate utility-scale solar energy development, to develop and implement Agency-specific programs that would establish environmental policies and mitigation strategies for solar energy projects, and to amend relevant Agency land use plans with the consideration of establishing a new BLM solar energy development program."[12] The geothermal PEIS, which is being developed jointly by the U.S. Forest Service and BLM, will consider the leasing of lands in eleven western states for geothermal energy resources.

Resource Type	Estimated Capacity (MW)
Solar Thermal	10,700
Solar Photovoltaic	600
Wind	830
Geothermal	30
Total	**12,160**

Table 3-3. BLM Applications for Renewable Energy Development in Arizona

Conclusion

Developing a reliable estimate of renewable resource development, and identifying the transmission requirements to access these resources, over the BTA ten year planning horizon is challenging. Increasing demand for renewable energy will certainly result in the addition of a substantial amount of new renewable generation, though it is difficult to determine how much additional capacity will be added. The SWAT-RETTF estimate of 7,757 MW represents a plausible amount of development given the demand for renewable energy and he expressed interest in developing renewable generation in Arizona. This would allow Arizona to generate

[11] BLM applications for wind facilities do not include estimates of generating capacity. Black & Veatch estimates are based on the total acreage and wind quality of the proposed site.

sufficient energy to satisfy its anticipated renewable energy demand, and allow for development of additional resources that could satisfy either increased Arizona renewable energy demand or provide energy for other western U.S. renewable energy demand.

3.4 Transmission Configuration

Based on the renewable resources and REZs discussed in Section 3-3, SWAT-RETTF designed a conceptual transmission configuration to allow resources in these areas to interconnect to the grid. This configuration would require eleven new high voltage (230 kV and 500 kV) substations and approximately 700 miles of new transmission lines. Transmission additions would be required for all utilities in Arizona.

Transmission planning is a long process that requires many iterations of increasingly refined analysis. The first step in the process is to develop a conceptual plan to meet the requirements (in this case is the addition of renewable generation to the existing system) and identify alternatives to meet the requirements. This may require several iterations to design plans with different attributes and costs. The most promising of these plans are selected to conduct more detailed analyses to determine transmission line size, timing, and siting. Once potential line(s) and transmission alignments have been identified, load-flow simulation modeling is conducted to assess the impact on energy flows in the entire grid. An important consideration in transmission development is siting and construction requirements, as the transmission design must also consider the feasibility of siting and permitting the proposed facilities as well.

Conclusion

The conceptual transmission design by SWAT-RETTF reflects an appropriate level of planning detail for the BTA analysis. Discussed in the renewable resource assessment, it is difficult to identify the renewable resources that will ultimately be developed, but there is a high probability that many, if not most, will be located in the REZ areas identified by SWAT-RETTF. This transmission assessment provides a good basis for conducting additional transmission analyses. As renewable resources move through the development process, the transmission plans to connect these resources should become more refined.

[12] http://solareis.anl.gov/index.cfm

4.0 Regional Transmission Planning in Western U.S.

The goal of the BTA is to insure that Arizona's electric utilities have appropriate infrastructure to provide reliable electric service, and the ACC ordered respondents to identify transmission requirements within Arizona. In developing transmission plans for Arizona renewables, Arizona should consider current activities in the WECC that may impact Arizona's access to renewable resources and to its transmission capability. Just as the Arizona utilities transmission systems are integrated, the Arizona transmission system is fully integrated into the western U.S. electricity grid, and the activities of other entities in the western U.S. grid will impact Arizona. Similar to the BTA, there are several planning initiatives underway to promote the development of renewable resources in the southwestern U.S. and to identify the transmission necessary to access these resources. These are described below. In addition to the regional planning initiatives, there several transmission lines have been proposed that would facilitate the transfer of renewable energy fin the region. Development of these lines would allow Arizona to access additional renewable generation, and may additionally provide additional transfer capability to the Arizona transmission system.

4.1 WestConnect & SWAT

WestConnect is a regional transmission planning organization composed of southwestern U.S. utilities providing electric transmission service and includes Arizona transmission providers. The goal of WestConnect is to coordinate transmission operation and development among its members. Members work collaboratively to assess stakeholder and market needs and to develop cost-effective enhancements to the western wholesale electricity market. WestConnect has several sub-groups, including the Arizona/New Mexico Sub-regional Planning Group, comprised of transmission regulators/governmental entities, transmission users, transmission owners, transmission operators and environmental entities in the desert southwest.

4.2 Western Governors Association – WREZ

The Western Governors Association (WGA) had developed the Western Renewable Energy Zone (WREZ) initiative to encourage the development of clean and renewable energy resources in support of its goal to develop 30,000 MW of clean energy resources by 2015. Central

to achieving this goal, the WREZ will identify where transmission is necessary to access renewable resources. The WREZ initiative is composed of a consortium of 11 states, British Columbia, Canada and Northern Baja, Mexico.

The expressed goals of the WREZ initiative include:

1) [Provide] reliable information for use by decision-makers that supports the cost-effective and environmentally sensitive development of renewable energy in specified zones, and
2) [Develop] conceptual transmission plans for delivering that energy to load centers within the Western Interconnection. A number of factors will be considered, including the potential for development, timeframes, common transmission needs and costs.

4.3 Proposed Western Transmission Development

Several large transmission projects have been proposed to allow for the long-distance movement of renewable energy from generation areas to load centers transmission in the west, specifically to southern Nevada, Arizona and California. The development of this transmission may impact Arizona in several ways. First, the proposed transmission may allow Arizona utilities to access additional renewable resources to meet its demand. Second, this may provide renewable developers in Arizona access to other markets. Finally, the development of transmission will alter the flow of energy on the grid even without additional energy development. Below is a brief description of the proposed transmission lines that are most relevant to Arizona.

4.3.1 SunZia

The SunZia Southwest Transmission Project is a 500-mile transmission line project from New Mexico to Arizona that will provide an expected 3,000 megawatts of new transmission capacity. A specific route has not yet been determined. The goal in developing the project is to increase renewable energy deliver capability to Arizona, as well as increase transmission reliability as described by SunZia's Project manager:

> "In addition to promoting development of wind, solar and geothermal energy production, by creating regional access to these renewable resources, SunZia increases the reliability of the underlying extra high-voltage transmission system in southern New Mexico and southern Arizona", said Tom Wray of SWPG and SunZia's project manager. "SunZia will help create a critical link between existing and planned transmission and generation facilities, while providing new

opportunities for the efficient delivery of new resources to meet growing power demands in the southwest."[13]

4.3.2 TransWest Express

The TransWest Express transmission line is a 900 mile line from Wyoming to Nevada that would allow the transfer of approximately 300 MW of resources. It is proposed to be in services in 2013.[14]

4.3.3 High Plains Express

The High Plains Express Transmission Project (HPX) would connect Arizona, New Mexico, Colorado and Wyoming using two 1,250 miles, 500 kV lines, with a total transfer capability of approximately 4,000 MW.

4.3.4 Gateway Projects

The Gateway projects are a combination of transmission lines. In total the project would result in the development of 1,000 miles of 500-kV transmission in six western states, significantly improving transfer capability throughout the west.

[13] http://www.sunzia.net/news.php

[14] http://www.wyia.org/projects/ProjectFiles/TRANSWEST%20EXPRESS%20%26%20GATEWAY%20SOUTH%20TRANSMISSION%20PROJECTS/03%5FPresentations%2DStudies/Studies/2008%2D0528%5FFinal%20WECC%20Regional%20Planning%20Project%20Report%20for%20GWS%20dated%20May%2028%2C%202008%2Epdf

5.0 Recommendations on Arizona Transmission Planning

Black & Veatch makes the following recommendations regarding the Arizona renewable transmission planning process.

5.1 Regional Planning for Renewable Transmission

In planning transmission for renewable resources, Arizona should continue to actively participate in regional transmission planning processes. Regional transmission development may allow Arizona to access inexpensive renewable resources and increase the diversity of resources used by utilities in the state. Further, transmission development may allow generators in Arizona to market power beyond Arizona,

5.2 Integration of Renewable Resource and Transmission Planning

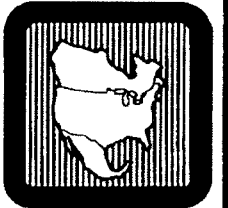
Planning transmission for renewables is somewhat different than planning for conventional resources. Many renewable resources (such as geothermal and wind) are site-specific, and insuring the transmission necessary to access these resources is available requires integration of resource and transmission planning.

An additional consideration regarding solar and wind resources is that they are intermittent resources, generating on an "as available" basis, providing energy but with limited capacity benefit. Intermittent resources must be "firmed up" with dispatchable generation, in order to insure that system reliability is maintained. Further, the integration if intermittent resources in the system may require that the system include additional ancillary services such as regulation and replacement capacity.

Appendix A.
Available Transfer Capability Definitions and Determination

Available Transfer Capability Definitions and Determination

A Framework for Determining Available Transfer Capabilities of the Interconnected Transmission Networks for a Commercially Viable Electricity Market



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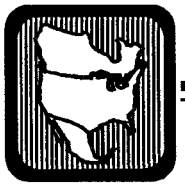
Council

Available Transfer Capability Definitions and Determination

A framework for determining available transfer capabilities of the interconnected transmission networks for a commercially viable electricity market



North American Electric Reliability Council

June 1996

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EXECUTIVE SUMMARY

This report, *Available Transfer Capability Definitions and Determination*, is in response to a NERC Strategic Initiative to "develop uniform definitions for determining Available (Transmission) Transfer Capability (ATC) and related terms that satisfy both [Federal Energy Regulatory Commission] FERC and electric industry needs, and which are to be implemented throughout the industry." The NERC Board of Trustees at its May 13–14, 1996 meeting approved this report and endorsed its use by all segments of the electric industry.

The report establishes a framework for determining ATCs of the interconnected transmission networks for a commercially viable wholesale electricity market. The report also defines the ATC Principles under which ATC values are to be calculated. It is non-prescriptive in that it permits individual systems, power pools, subregions, and Regions to develop their own procedures for determining or coordinating ATCs based on a regional or wide-area approach in accordance with the Principles defined herein. The proposed ATC calculation framework is based on the physical and electrical characteristics and capabilities of the interconnected networks as applicable under NERC, Regional, subregional, power pool, and individual system reliability planning and operating policies, criteria, or guides.

This report provides an initial framework on ATC that will likely be expanded and modified as experience is gained in its use and as more is learned about how the competitive electric power market will function. The U.S. Federal Energy Regulatory Commission's final rules, Orders No. 888 and No. 889 pertaining to promoting wholesale competition through open access non-discriminatory transmission services by public utilities and an open access same-time information system, respectively, were issued April 24, 1996. The framework for the determination of ATC as outlined in this report is in accord with the key provisions of these rulemakings.

ATC PRINCIPLES

The following Available Transfer Capability (ATC) Principles govern the development of the definition and determination of ATC and related terms. All transmission provider and user entities are expected to abide by these Principles.

1. ATC calculations must produce commercially viable results. ATCs produced by the calculations must give a reasonable and dependable indication of transfer capabilities available to the electric power market.

2. ATC calculations must recognize time-variant power flow conditions on the entire interconnected transmission network. In addition, the effects of simultaneous transfers and parallel path flows throughout the network must be addressed from a reliability viewpoint.

3. ATC calculations must recognize the dependency of ATC on the points of electric power injection, the directions of transfers across the interconnected transmission network, and the points of power extraction. All entities must provide sufficient information necessary for the calculation of ATC.

4. Regional or wide-area coordination is necessary to develop and post information that reasonably reflects the ATCs of the interconnected transmission network.

5. ATC calculations must conform to NERC, Regional, subregional, power pool, and individual system reliability planning and operating policies, criteria, or guides.

6. The determination of ATC must accommodate reasonable uncertainties in system conditions and provide operating flexibility to ensure the secure operation of the interconnected network.

The calculation of transfer capability is generally based on computer simulations of the operation of the interconnected transmission network under a specific set of assumed operating conditions. These simulations are typically performed "off line," well before the systems approach that operational state. Each simulation represents a single "snapshot" of the operation of the interconnected network based on the projections of many factors. As such, they are viewed as reasonable indicators of network performance and available transfer capability.

ATC DEFINITIONS

Available Transfer Capability (ATC) is a measure of the transfer capability remaining in the physical transmission network for further commercial activity over and above already committed uses. Mathematically, ATC is defined as the Total Transfer Capability (TTC) less the Transmission Reliability Margin (TRM), less the sum of existing transmission commitments (which includes retail customer service) and the Capacity Benefit Margin (CBM).

> **Total Transfer Capability (TTC)** is defined as the amount of electric power that can be transferred over the interconnected transmission network in a *reliable* manner while meeting *all* of a specific set of defined pre- and post-contingency system conditions.
>
> **Transmission Reliability Margin (TRM)** is defined as that amount of transmission transfer capability necessary to ensure that the interconnected transmission network is secure under a reasonable range of uncertainties in system conditions.
>
> **Capacity Benefit Margin (CBM)** is defined as that amount of transmission transfer capability reserved by load serving entities to ensure access to generation from interconnected systems to meet generation reliability requirements.

Curtailability is defined as the right of a transmission provider to interrupt all or part of a transmission service due to constraints that reduce the capability of the transmission network to provide that transmission service. Transmission service is to be curtailed only in cases where system reliability is threatened or emergency conditions exist.

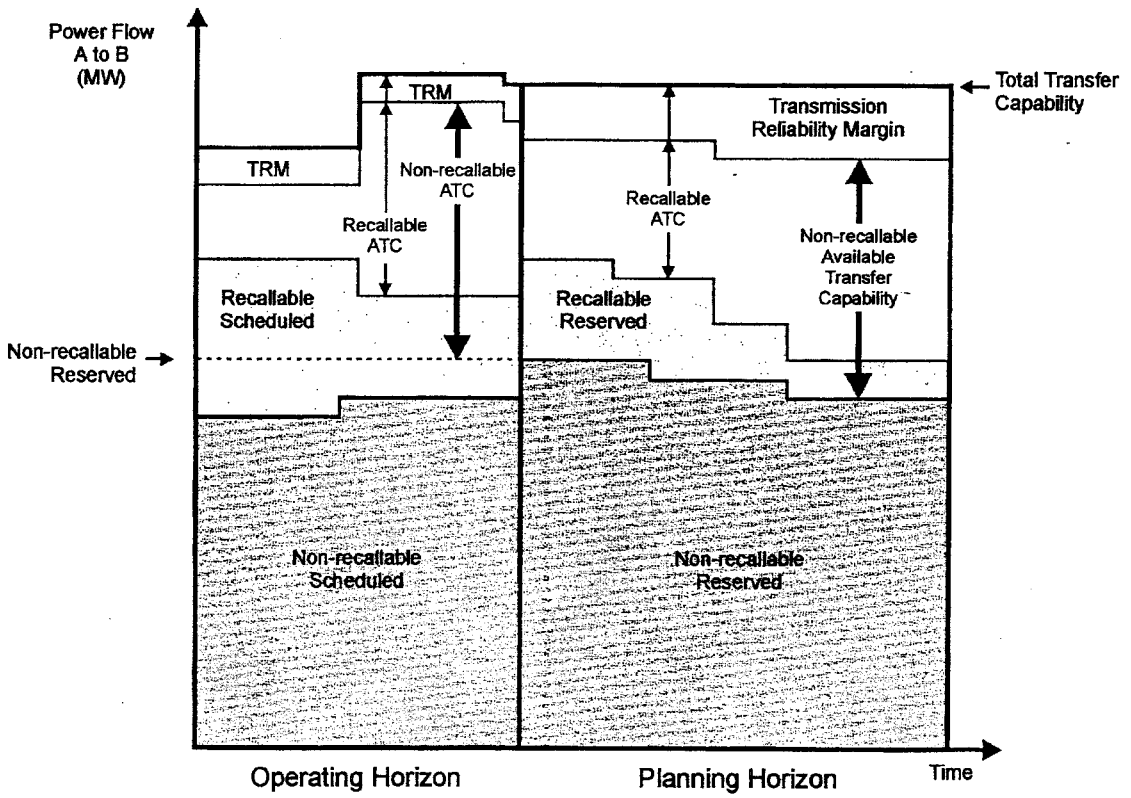
Recallability is defined as the right of a transmission provider to interrupt all or part of a transmission service for any reason, including economic, that is consistent with FERC policy and the transmission provider's transmission service tariffs or contract provisions.

Non-recallable ATC (NATC) is defined as TTC less TRM, less non-recallable reserved transmission service (including CBM).

Recallable ATC (RATC) is defined as TTC less TRM, less recallable transmission service, less non-recallable transmission service (including CBM). RATC must be considered differently in the planning and operating horizons. In the planning horizon, the only data available are recallable and non-recallable transmission service reservations, whereas in the operating horizon transmission schedules are known.

ATC AND RELATED TERMS

ATC and related terms are depicted graphically below. They form the basis of a transmission service reservation system that will be used to reserve and schedule transmission services in the new, competitive electricity market.



TTC, ATC, and Related Terms in the Transmission Service Reservation System

INTRODUCTION

BACKGROUND

Available Transmission Capacity as described in the U.S. Federal Energy Regulatory Commission's (FERC) March 29, 1995 Notice of Proposed Rulemaking (NOPR), Docket RM95-8-000, Section III-E4f, is a new term that has not been universally defined or used by the electric industry. The electric industry has historically used other standard terms, techniques, and methodologies to define and calculate meaningful measures of the transmission transfer capability of the interconnected transmission networks. These terms, which include First Contingency Total Transfer Capability (FCTTC) and First Contingency Incremental Transfer Capability (FCITC) as defined in NERC's May 1995 *Transmission Transfer Capability* reference document, are still applicable measures in an open transmission access environment. FERC's term Available Transmission Capacity and its definition and relationship to the industry's terminology need to be further clarified.

In its NOPR, FERC also requires that Available Transmission Capacity information be made available on a publicly accessible Real-time Information Network (RIN). Definitions of Available Transmission Capacity in the report of the industry's Electronic Information Network "What" Working Group, which was filed with FERC on October 16, 1995, are only considered to be assumptions to support the Working Group's effort in determining what information should be included on RINs. This report further refines those definitions.

It must be noted early in this report that electric systems in Canada and the northern portion of Baja California, Mexico, which are electrically interconnected with electric systems in the United States, are active members in NERC and the Regional Councils and are committed to promoting and maintaining interconnected electric system reliability. These non-U.S. systems are not, however, subject to FERC jurisdiction, and the commercial aspects of the definitions contained herein are not necessarily applicable to the operation of their internal transmission systems.

TERMINOLOGY CONVENTION

FERC used the term Available Transmission Capacity in its NOPR to label the information that is to be made accessible to all transmission users as an indication of the available capability of the interconnected transmission networks to support additional transmission service. To avoid confusion with individual transmission line capacities or ratings, all references to "ATC" throughout this report will refer to Available (Transmission) Transfer Capability and its related terms as defined in this report.

NERC STRATEGIC INITIATIVE

One of several *Strategic Initiatives for NERC*, approved by the NERC Board of Trustees on October 3, 1995, is to "develop uniform definitions for determining Available (Transmission) Transfer Capability and related terms that satisfy both FERC and electric industry needs, and which are to be implemented throughout the industry." The then existing NERC Transmission Transfer Capability Task Force, with expanded membership to include all segments of the electric industry, was assigned this responsibility for completion in May 1996.

INTRODUCTION

PURPOSE OF THIS REPORT

This report is the response to NERC's Strategic Initiative on ATC and defines ATC and related terms. From a commercial perspective, the key element in the development of uniform definitions for transmission transfer capability is the amount of transfer capability that is available at a given time for purchase or sale in the electric power market under various system conditions. Open access to the transmission systems places a new emphasis on the use of the interconnected networks. As such, future electric power transfers are anticipated to increase over a wide range of system conditions, making the reliable operation of the transmission networks more complex. To effectively maintain system reliability, those who calculate, report, post, and use this information must all have the same understanding of its meaning for commercial use. To accomplish this purpose, this report will answer the following questions:

- What is ATC?
- How does ATC relate to industry standard terminology?
- What physical factors need to be considered in determining ATC?
- What reliability issues must be considered in determining ATC?
- How is ATC calculated?
- How will ATC be commercially used?

The report establishes a framework for determining the ATCs of the interconnected transmission networks for a commercially viable electricity market. Although the report defines the ATC Principles under which ATCs are to be calculated, it is non-prescriptive in that it permits individual systems, power pools, sub-regions, and Regions to develop their own procedures for determining or coordinating ATCs based on a regional or wide-area approach in accordance with these Principles.

The report does not address transmission ownership and equity issues, nor does it address the allocation of transmission services or ATC values. The calculation of ATC is based strictly on the physical and electrical characteristics and capabilities of the interconnected networks as applicable under NERC, Regional, subregional, power pool, and individual system reliability planning and operating policies, criteria, or guides.

As the competitive electric power market develops, more will be learned on how these markets will function and how the definitions of ATC will be used. This report provides an initial framework on ATC, which will likely be expanded and modified as experience is gained in its use. The U.S. Federal Energy Regulatory Commission's final rules, Orders No. 888 and No. 889 pertaining to promoting wholesale competition through open access non-discriminatory transmission services by public utilities and an open access same-time information system, respectively, were issued April 24, 1996. The framework for the determination of ATC as outlined in this report is in accord with the key provisions of these rulemakings.

AVAILABLE TRANSFER CAPABILITY PRINCIPLES

ATC PRINCIPLES

Available Transfer Capability (ATC) is a measure of the transfer capability remaining in the physical transmission network for further commercial activity over and above already committed uses. As a measure bridging the technical characteristics of how interconnected transmission networks perform to the commercial requirements associated with transmission service requests, ATC must satisfy certain principles balancing both technical and commercial issues. ATC must accurately reflect the physical realities of the transmission network, while not being so complicated that it unduly constrains commerce. The following principles identify the requirements for the calculation and application of ATCs.

1. ***ATC calculations must produce commercially viable results. ATCs produced by the calculations must give a reasonable and dependable indication of transfer capabilities available to the electric power market.*** The frequency and detail of individual ATC calculations must be consistent with the level of commercial activity and congestion.

2. ***ATC calculations must recognize time-variant power flow conditions on the entire interconnected transmission network. In addition, the effects of simultaneous transfers and parallel path flows throughout the network must be addressed from a reliability viewpoint.*** Regardless of the desire for commercial simplification, the laws of physics govern how the transmission network will react to customer demand and generation supply. Electrical demand and supply cannot, in general, be treated independently of one another. All system conditions, uses, and limits must be considered to accurately assess the capabilities of the transmission network.

3. ***ATC calculations must recognize the dependency of ATC on the points of electric power injection, the directions of transfers across the interconnected transmission network, and the points of power extraction. All entities must provide sufficient information necessary for the calculation of ATC.*** Electric power flows resulting from each power transfer use the entire network and are not governed by the commercial terms of the transfer.

4. ***Regional or wide-area coordination is necessary to develop and post information that reasonably reflects the ATCs of the interconnected transmission network.*** ATC calculations must use a regional or wide-area approach to capture the interactions of electric power flows among individual, subregional, Regional, and multiregional systems.

5. ***ATC calculations must conform to NERC, Regional, subregional, power pool, and individual system reliability planning and operating policies, criteria, or guides.*** Appropriate system contingencies must be considered.

6. ***The determination of ATC must accommodate reasonable uncertainties in system conditions and provide operating flexibility to ensure the secure operation of the interconnected network.*** A Transmission Reliability Margin (TRM) may be necessary to apply this Principle. Additionally, transmission capability (defined as Capacity Benefit Margin or CBM) may need to be reserved to meet generation reliability requirements.

TRANSMISSION TRANSFER CAPABILITY CONCEPTS

The key basic concepts of transmission transfer capability are described below. Numerous other terms related to transfer capability are explored in detail in NERC's May 1995 *Transmission Transfer Capability* reference document. The concepts and terms in that document are still applicable in an open transmission environment.

TRANSFER CAPABILITY

Transfer capability is the measure of the ability of interconnected electric systems to *reliably* move or transfer power from one area to another over all transmission lines (or paths) between those areas under specified system conditions. The units of transfer capability are in terms of electric power, generally expressed in megawatts (MW). In this context, "area" may be an individual electric system, power pool, control area, subregion, or NERC Region, or a portion of any of these. Transfer capability is also directional in nature. That is, the transfer capability from Area A to Area B is *not* generally equal to the transfer capability from Area B to Area A.

TRANSFER CAPABILITY VERSUS TRANSMISSION CAPACITY

Electric systems throughout NERC have agreed to use common terminology to calculate and report transmission transfer limits to maintain the reliability of the interconnected transmission networks. These transfer values are called "capabilities" (differentiating them from "capacities") because they are highly dependent on the generation, customer demand, and transmission system conditions assumed during the time period analyzed. The electric industry generally uses the term "capacity" as a specific limit or rating of power system equipment. In transmission, capacity usually refers to the thermal limit or rating of a particular transmission element or component. The ability of a single transmission line to transfer electric power, when operated as part of the interconnected network, is a function of the physical relationship of that line to the other elements of the transmission network.

Individual transmission line capacities or ratings *cannot* be added to determine the transfer capability of a transmission path or interface (transmission circuits between two or more areas within an electric system or between two or more systems). Such aggregated capacity values may be vastly different from the transmission transfer capability of the network. Often, the aggregated capacity of the individual circuits of a specific transmission interface between two areas of the network is greater than the actual transfer capability of that interface. In summary, the aggregated transmission line capacities of a path or interface do not represent the transfer capabilities between two areas.

DETERMINATION OF TRANSFER CAPABILITY

The calculation of transfer capability is generally based on computer simulations of the operation of the interconnected transmission network under a specific set of assumed operating conditions. These simulations are typically performed "off line," well before the systems approach that operational state. Each simulation represents a single "snapshot" of the operation of the interconnected network based on the projections of many factors. As such, they are viewed as reasonable indicators of network performance and available transfer capability. Among the factors considered in these simulations are:

- Projected Customer Demands — Base case demand levels should be appropriate to the system conditions and customer demand levels under study and may be representative of peak, off-peak or shoulder, or light demand conditions.

- Generation Dispatch — Utility and nonutility generators should be realistically dispatched for the system conditions being simulated.

- System Configuration — The base case configuration of the interconnected systems should be representative of the conditions being simulated, including any generation and transmission outages that are expected. The activation of any operating procedures normally expected to be in effect should also be included in the simulations.

- Base Scheduled Transfers — The scheduled electric power transfers that should be modeled are those that are generally considered to be representative of the base system conditions being analyzed and which are agreed upon by the parties involved.

- System Contingencies — A significant number of generation and transmission system contingencies should be screened, consistent with individual electric system, power pool, subregional, and Regional planning criteria or guides, to ensure that the facility outage most restrictive to the transfer being studied is identified and analyzed. The contingencies evaluated may in some instances include multiple contingencies where deemed to be appropriate.

The conditions on the interconnected network continuously vary in real time. Therefore, the transfer capability of the network will also vary from one instant to the next. For this reason, transfer capability calculations may need to be updated periodically for application in the operation of the network. In addition, depending on actual network conditions, transfer capabilities can often be higher or lower than those determined in the off-line studies. The farther into the future that simulations are projected, the greater is the uncertainty in assumed conditions. However, transfer capabilities determined from simulation studies are generally viewed as reasonable indicators of actual network capability.

LIMITS TO TRANSFER CAPABILITY

The ability of interconnected transmission networks to *reliably* transfer electric power may be limited by the physical and electrical characteristics of the systems including any one or more of the following:

- Thermal Limits — Thermal limits establish the maximum amount of electrical current that a transmission line or electrical facility can conduct over a specified time period before it sustains permanent damage by overheating or before it violates public safety requirements.

- Voltage Limits — System voltages and changes in voltages must be maintained within the range of acceptable minimum and maximum limits. For example, minimum voltage limits can establish the maximum amount of electric power that can be transferred without causing damage to the electric system or customer facilities. A widespread collapse of system voltage can result in a blackout of portions or all of the interconnected network.

- Stability Limits — The transmission network must be capable of surviving disturbances through the transient and dynamic time periods (from milliseconds to several minutes, respectively) following the disturbance. All generators connected to ac interconnected transmission systems operate in synchronism with each other at the same frequency (nominally 60 Hertz). Immediately following a system disturbance, generators begin to oscillate relative to each other, causing fluctuations in system frequency, line loadings, and system voltages. For the system to be stable, the oscillations must diminish as the electric systems attain a new, stable operating point. If a new, stable operating point is not quickly established, the generators will likely lose synchronism with one another, and all or a portion of the interconnected electric systems may become unstable. The results of generator instability may damage equipment and cause uncontrolled, widespread interruption of electric supply to customers.

The limiting condition on some portions of the transmission network can shift among thermal, voltage, and stability limits as the network operating conditions change over time. Such variations further complicate the determination of transfer capability limits.

USES OF TRANSMISSION SYSTEMS

The interconnected transmission networks tie together major electric system facilities, generation resources, and customer demand centers. They are planned, designed, and constructed to operate reliably within thermal, voltage, and stability limits for the following purposes:

- To Deliver Electric Power to Customers — Transmission networks must provide for the reliable transfer of the electric power output from generation resources to customers under a wide variety of operating conditions.

- To Provide Flexibility for Changing System Conditions — Transmission capability must be available on the interconnected network to provide flexibility to reliably handle the shift in transmission facility loadings caused by maintenance and forced outages of generation and transmission equipment, and a wide range of variable system conditions, such as higher than expected customer demands, or construction delays of new facilities.

- To Reduce the Need for Installed Generating Capacity — Transmission interconnections between neighboring systems provide for the sharing of installed generating capacity, taking advantage of the diversity in customer demands and generation availability over a wide area, thereby reducing the amount of installed generating capacity necessary to meet generation reliability requirements in each of the interconnecting systems.

- To Allow Economic Exchange of Electric Power Among Systems — Transmission interconnections between systems, coupled with internal system transmission facilities, allow for the economic exchange of electric power among neighboring systems. Such economy transfers help reduce the overall cost of electricity to customers.

TTC DEFINITION AND DETERMINATION

DEFINITION OF TOTAL TRANSFER CAPABILITY

The Total Transfer Capability (TTC) between any two areas or across particular paths or interfaces is direction specific and consistent with the First Contingency Total Transfer Capability (FCTTC) as defined in NERC's May 1995 *Transmission Transfer Capability* reference document.

TTC is the amount of electric power that can be transferred over the interconnected transmission network in a *reliable* manner based on *all* of the following conditions:

1. For the existing or planned system configuration, and with normal (pre-contingency) operating procedures in effect, all facility loadings are within normal ratings and all voltages are within normal limits.

2. The electric systems are capable of absorbing the dynamic power swings, and remaining stable, following a disturbance that results in the loss of any single electric system element, such as a transmission line, transformer, or generating unit.

3. After the dynamic power swings subside following a disturbance that results in the loss of any single electric system element as described in 2 above, and after the operation of any automatic operating systems, but before any post-contingency operator-initiated system adjustments are implemented, all transmission facility loadings are within emergency ratings and all voltages are within emergency limits.

4. With reference to condition 1 above, in the case where pre-contingency facility loadings reach normal thermal ratings at a transfer level below that at which any first contingency transfer limits are reached, the transfer capability is defined as that transfer level at which such normal ratings are reached.

5. In some cases, individual system, power pool, subregional, or Regional planning criteria or guides may require consideration of specified multiple contingencies, such as the outage of transmission circuits using common towers or rights-of-way, in the determination of transfer capability limits. If the resulting transfer limits for these multiple contingencies are more restrictive than the single contingency considerations described above, the more restrictive reliability criteria or guides must be observed.

DETERMINATION OF TOTAL TRANSFER CAPABILITY

The concepts for determining transfer capability described in NERC's *Transmission Transfer Capability* reference document are still valid and do not change with the advent of open transmission access or the need to determine ATCs. The major points contained therein are briefly outlined below.

System Conditions

Base system conditions are identified and modeled for the period being analyzed, including projected customer demands, generation dispatch, system configuration, and base scheduled transfers. As system conditions change, the base system conditions under which TTC is calculated may also need to be modified.

Critical Contingencies

During transfer capability studies, many generation and transmission system contingencies throughout the network are evaluated to determine which facility outages are most restrictive to the transfer being analyzed. The types of contingencies evaluated are consistent with individual system, power pool, subregional, and Regional planning criteria or guides. The evaluation process should include a variety of system operating conditions because as those conditions vary, the most critical system contingencies and their resulting limiting system elements could also vary.

System Limits

As discussed earlier, the transfer capability of the transmission network may be limited by the physical and electrical characteristics of the systems including thermal, voltage, and stability considerations. Once the critical contingencies are identified, their impact on the network must be evaluated to determine the most restrictive of those limitations. Therefore, the TTC becomes:

$$TTC = \text{Minimum of } \{\text{Thermal Limit, Voltage Limit, Stability Limit}\}$$

As system operating conditions vary, the most restrictive limit on TTC may move from one facility or system limit to another as illustrated in Figure 1.

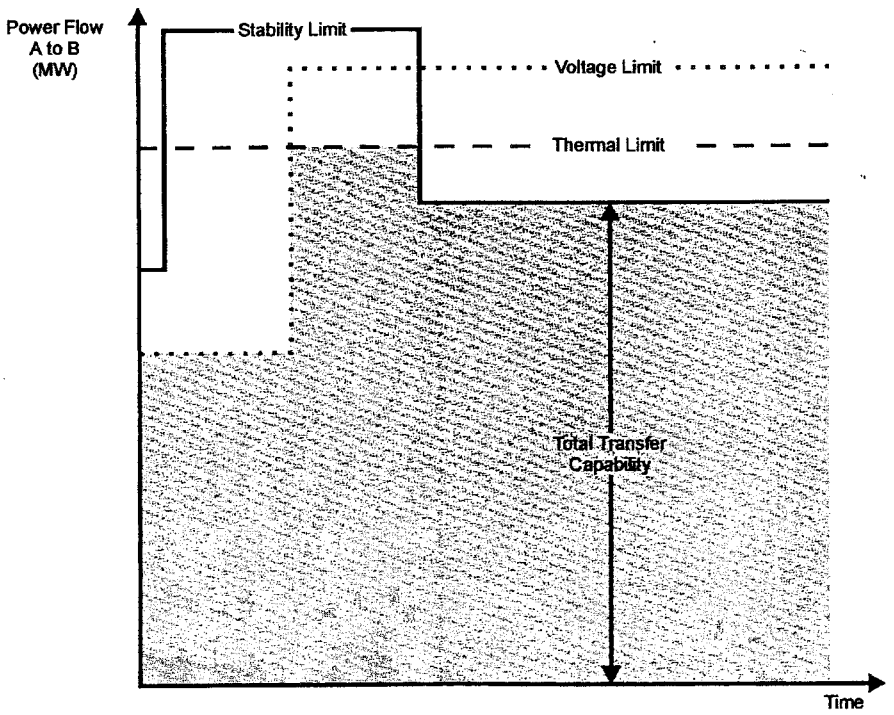


Figure 1: Limits to Total Transfer Capability

Parallel Path Flows

When electric power is transferred across the network, parallel path flows occur. This complex electric transmission network phenomenon can affect all systems of an interconnected network, especially those systems electrically near the transacting systems. As a result, transfer capability determinations must be sufficient in scope to ensure that limits throughout the interconnected network are addressed. In some cases, the parallel path flows may result in transmission limitations in systems other than the transacting systems, which can limit the transfer capability between the two contracting areas.

Non-Simultaneous and Simultaneous Transfers

Transfer capability can be determined by simulating transfers from one area to another independently and non-concurrently with other area transfers. These capabilities are referred to as "non-simultaneous" transfers. Another type of transfer capability reflects simultaneous or multiple transfers concurrently. These capabilities are developed in a manner similar to that used for non-simultaneous capability, except that the interdependency of transfers among the other areas is taken into account. These interdependent capabilities are referred to as "simultaneous" transfers. No simple relationship exists between non-simultaneous and simultaneous transfer capabilities. The simultaneous transfer capability may be lower than the sum of the individual non-simultaneous transfer capabilities.

TRANSMISSION TRANSFER CAPABILITY MARGINS

Two types of transmission transfer capability margins include:

- Transmission Reliability Margin (TRM) — to ensure the secure operation of the interconnected transmission network to accommodate uncertainties in system conditions.
- Capacity Benefit Margin (CBM) — to ensure access to generation from interconnected systems to meet generation reliability requirements.

Individual systems, power pools, subregions, and Regions should identify their TRM and CBM procedures used to establish such transmission transfer capability margins as necessary. TRM and CBM should be developed and applied as separate and independent components of transfer capability margin. The specific methodologies for determining and identifying necessary margins may vary among Regions, subregions, power pools, individual systems, and load serving entities. However, these methodologies must be well documented and consistently applied.

TECHNICAL BASIS

Electric systems historically have recognized the need for and benefits of transfer capability margins in the planning and operation of the interconnected transmission networks. In addition to meeting obligations for service to native load customers and deliveries for third-party transmission users, some reserve transmission transfer capability is required to ensure that the interconnected network is secure under a wide range of uncertain operational parameters. Also, systems have relied upon transmission import capability, through interconnections with neighboring systems, to reduce their installed generating capacity necessary to meet generation reliability requirements and provide reliable service to native load. With the introduction of mandatory, non-discriminatory access, and the resulting need to identify and provide current and projected ATCs to the competitive electric power market, a need now exists to formally address these two types of transmission transfer capability margins.

This report provides a framework to support the development of transfer capability margin procedures. TRM and CBM are concepts that may need to be further developed for general applicability while allowing for tailoring to specific Regional, subregional, power pool, and individual system conditions. As these margin concepts are developed and applied, NERC will review their implementation and consider the need for further guidance.

DEFINITION OF TRANSMISSION RELIABILITY MARGIN

Transmission Reliability Margin (TRM) is defined as that amount of transmission transfer capability necessary to ensure that the interconnected transmission network is secure under a reasonable range of uncertainties in system conditions.

TRM provides a reserve of transfer capability that ensures the reliability of the interconnected transmission network. All transmission system users benefit from the assurance that transmission services will be reliable under a broad range of potential system conditions. TRM accounts for the inherent uncertainty in system conditions and their associated effects on TTC and ATC calculations, and the need for operating flexibility to ensure reliable system operation as system conditions change.

Uncertainty in TTC and ATC Calculations

TTC and ATC determinations depend upon a myriad of assumptions and projections of system conditions, which may include such items as transmission system topology, projected customer demand and its distribution, generation dispatch, location of future generators, future weather conditions, available transmission facilities, and existing and future electric power transactions. Such parameters are assembled to produce a scenario to be used to project transfer capabilities under a reasonable range of transmission contingencies as specified in Regional, subregional, power pool, and individual system reliability operating and planning policies, criteria, or guides. Therefore, calculations of future TTCs and ATCs must consider the inherent uncertainties in projecting such system parameters over longer time periods. Generally, the uncertainties of TTC and ATC projections increase for longer term projections due to greater difficulty in being able to predict the various system assumptions and parameters over longer time periods. For instance, locations of future customer demands and generation sources are often quite uncertain, and these parameters have a potentially large impact on transfer capabilities. Similarly, future electric power transactions are inherently uncertain and can have significant impacts on transmission loadings. Therefore, the amount of TRM required is time dependent generally with a larger amount necessary for longer time projections than for near-term conditions. TRM must also have wide-area coordination.

Need for Operating Flexibility

TTC and ATC calculations must recognize that actual system conditions may change considerably in short periods of time due to changing operating conditions, and cannot be definitively projected without the provision of a transfer capability margin. These operational conditions include changes in dispatch of generating units, simultaneous transfers scheduled by other systems that impact the particular area being studied, parallel path flows, maintenance outages, and the dynamic response of the interconnected systems to contingencies (including the sudden loss of generating units).

DEFINITION OF CAPACITY BENEFIT MARGIN

Capacity Benefit Margin (CBM) is defined as that amount of transmission transfer capability reserved by load serving entities to ensure access to generation from interconnected systems to meet generation reliability requirements. Reservation of CBM by a load serving entity allows that entity to reduce its installed generating capacity below that which may otherwise have been necessary without interconnections to meet its generation reliability requirements.

The CBM is a more locally applied margin than TRM, which is more of a network margin. As such, to the extent a load serving entity maintains policies and procedures to reserve transfer capability for generation reliability purposes, the CBM should be included in the reserved or committed system uses in the calculation of ATC. These CBMs should continue to be a consideration in transmission system development. It is anticipated that individual load serving entities and regional planning groups will continue to address CBMs and that the NERC and Regional reviews of generation adequacy will continue to consider this capability. It is also anticipated that load serving entities will develop additional procedures for reserving transfer capability for generation capacity purposes and include these procedures in Regional planning reviews and regulatory filings as appropriate.

ATC DEFINITION AND DETERMINATION

DEFINITION OF AVAILABLE TRANSFER CAPABILITY

Available Transfer Capability (ATC) is a measure of the transfer capability remaining in the physical transmission network for further commercial activity over and above already committed uses. Mathematically, ATC is defined as the Total Transfer Capability (TTC) less the Transmission Reliability Margin (TRM), less the sum of existing transmission commitments (which includes retail customer service) and the Capacity Benefit Margin (CBM). ATC can be expressed as:

$$ATC = TTC - TRM - \text{Existing Transmission Commitments (including CBM)}$$

The ATC between two areas provides an indication of the amount of additional electric power that can be transferred from one area to another for a specific time frame for a specific set of conditions. ATC can be a very dynamic quantity because it is a function of variable and interdependent parameters. These parameters are highly dependent upon the conditions of the network. Consequently, ATC calculations may need to be periodically updated. Because of the influence of conditions throughout the network, the accuracy of the ATC calculation is highly dependent on the completeness and accuracy of available network data.

DETERMINATION OF AVAILABLE TRANSFER CAPABILITY

The determination of ATCs and the relationship of electric power transactions and associated power flows on the transmission network are described in Appendixes A and B. The ATC calculation methodologies described in Appendixes A and B are not intended to prescribe a specific calculation procedure nor do they describe the only methods of calculating ATCs. Each Region, subregion, power pool, and individual system will have to consider the ATC Principles in this report and determine the best procedure for calculating ATCs based upon their respective circumstances.

Appendix A describes an ATC calculation approach that may be termed a "network response" method. This method is intended to be illustrative of a procedure that is applicable in highly dense, meshed transmission networks where customer demand, generation sources, and the transmission systems are tightly interconnected.

Appendix B describes another ATC calculation approach that may be referred to as a "rated system path" method. This method is intended to be illustrative of a procedure that is applicable in so-called sparse transmission networks where the critical transmission paths between areas of the network have been identified and rated as to their achievable transfer loading capabilities for a range of system conditions.

COMMERCIAL COMPONENTS OF AVAILABLE TRANSFER CAPABILITY

To more fully define ATC, specific commercial aspects of transmission service must be considered. Because the terms "firm" and "non-firm" are used somewhat loosely within the electric industry, confusion often exists when these terms are used to characterize the basic nature of transmission services. To create reasonably consistent expectations regarding the transmission services that are being offered, the concepts of curtailability and recallability are introduced.

Curtailability

Curtailability is defined as the right of a transmission provider to interrupt all or part of a transmission service due to constraints that reduce the capability of the transmission network to provide that transmission service. Transmission service is to be curtailed only in cases where system reliability is threatened or emergency conditions exist. Curtailment procedures, terms, and conditions will be identified in the transmission service tariffs. When such constraints no longer restrict the transfer capability of the transmission network, the transmission service may be resumed. Curtailment does not apply to situations in which transmission service is discontinued for economic reasons.

Recallability

Recallability is defined as the right of a transmission provider to interrupt all or part of a transmission service for any reason, including economic, that is consistent with FERC policy and the transmission provider's transmission service tariffs or contract provisions.

Based on the recallability concept, two commercial applications of ATC are defined below and depicted graphically in Figure 2. They are as follows:

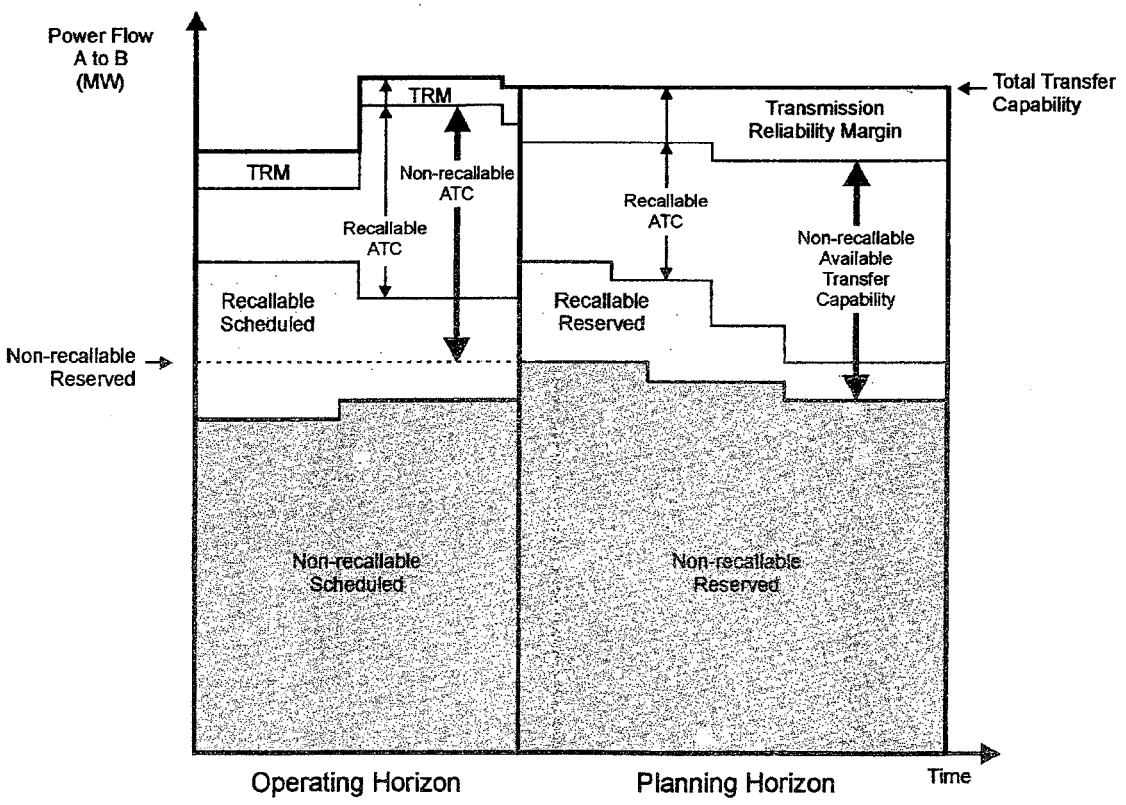


Figure 2: TTC, ATC, and Related Terms in the Transmission Service Reservation System

- Non-recallable Available Transfer Capability — Non-recallable ATC (NATC) is defined as TTC less TRM, less non-recallable reserved transmission service (including CBM). NATC has the highest priority use of the transmission network. The maximum amount of non-recallable service that can be reserved is determined based on what the network can reliably handle under normal operating conditions and during appropriate contingencies as defined in NERC, Regional, subregional, power pool, and individual system reliability operating and planning policies, criteria, or guides. Any lower priority service can be displaced by non-recallable service that is either new non-recallable service or non-recallable service that had been reserved but not scheduled.

  Mathematically, NATC can be expressed as:

  NATC = TTC – TRM – Non-recallable Reserved Transmission Service (including CBM)

- Recallable Available Transfer Capability — Recallable ATC (RATC) is defined as TTC less TRM, less recallable transmission service, less non-recallable transmission service (including CBM). Portions of the TRM may be made available by the transmission provider for recallable use, depending on the time frame under consideration for granting additional transmission service. To the extent load serving entities reserve transmission transfer capability for CBM, portions of CBM may be made available for recallable use, depending on the time frame under consideration for granting additional transmission service.

  RATC has the lowest priority use on the transmission network and is recallable subject to the notice provisions of the transmission service tariffs. Recallable reserved service may be recalled in favor of subsequent requests for non-recallable transmission service. However, recallable reserved service has precedence over subsequent requests for recallable transmission service, unless the tariff or contract provisions specify otherwise. Because RATC is recallable on short notice, it can use the transfer capability reserved for higher priority service that has been reserved but not scheduled.

  RATC must be considered differently in the planning and operating horizons. In the planning horizon, the only data available are recallable and non-recallable transmission service reservations, whereas in the operating horizon transmission schedules are known.

  Mathematically, RATC can be expressed as:

  a) Planning Horizon

  RATC = TTC
  – a(TRM)
  – Recallable Reserved Transmission Service
  – Non-recallable Reserved Transmission Service (including CBM)

  where $0 \leq a \leq 1$, value determined by individual transmission providers based on network reliability concerns.

b) Operating Horizon

RATC = TTC
- b(TRM)
- Recallable Scheduled Transmission Service
- Non-recallable Scheduled Transmission Service (including CBM)

where $0 \leq b \leq 1$, value determined by individual transmission providers based on network reliability concerns.

NATC and RATC are depicted graphically in Figure 2. TTC, ATC, and related terms in the transmission service reservation system are also shown in Figure 2. In general, the transition between the planning and operating horizons will be a function of available information about the system, the status of reserved and scheduled transmission services, and time considerations.

RECALLABLE AND NON-RECALLABLE RELATIONSHIPS AND PRIORITIES

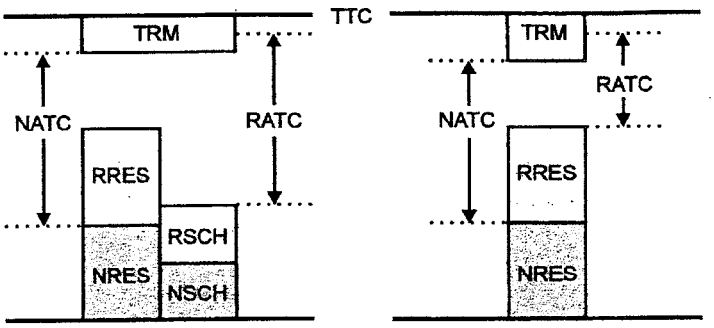
The relationships and priorities of recallable and non-recallable concepts as they apply to both scheduled and reserved transmission services are described below. In addition, the interaction between recallable and non-recallable transmission services and the effects on ATC values are discussed and illustrated.

Scheduled and Reserved Transmission Service

Reserved transmission service constitutes a reserved portion of the transmission network transfer capability, but the actual electric power transfer is not yet scheduled between areas. Scheduled transmission service indicates that an electric power transfer will be occurring on the transmission network for the time period for which the transmission service was reserved. Both terms can apply to either recallable or non-recallable transmission service, giving the following four transmission service terms:

- Non-recallable Reserved (NRES)
- Non-recallable Scheduled (NSCH)
- Recallable Reserved (RRES)
- Recallable Scheduled (RSCH)

The aggregate of the NSCH and RSCH must never exceed the TTC in the operational horizon. However, in the planning horizon, individual transmission providers may allow the aggregate of the NRES and RRES to exceed the TTC less TRM, to more fully utilize transmission assets, provided that NRES by itself never exceeds TTC less TRM. Such over-subscription of recallable reservations must be disclosed to the purchasers of RRES. These ATC relationships are shown in Figure 3.



NATC = TTC – TRM – NRES — Planning & Operating Horizon

RATC = TTC – a(TRM) – RRES – NRES — Planning Horizon
RATC = TTC – b(TRM) – RSCH – NSCH — Operating Horizon

where a and b are between 0 and 1

Constraints

$NSCH \leq NRES \leq TTC - TRM$

$NSCH + RSCH \leq TTC$

Transfer Capabilities		Transmission Services	
TTC	— Total Transfer Capability	NRES	— Non-recallable Reserved
ATC	— Available Transfer Capability	NSCH	— Non-recallable Scheduled
RATC	— Recallable ATC	RRES	— Recallable Reserved
NATC	— Non-recallable ATC	RSCH	— Recallable Scheduled

Figure 3: ATC Relationships

Transmission Service Priorities

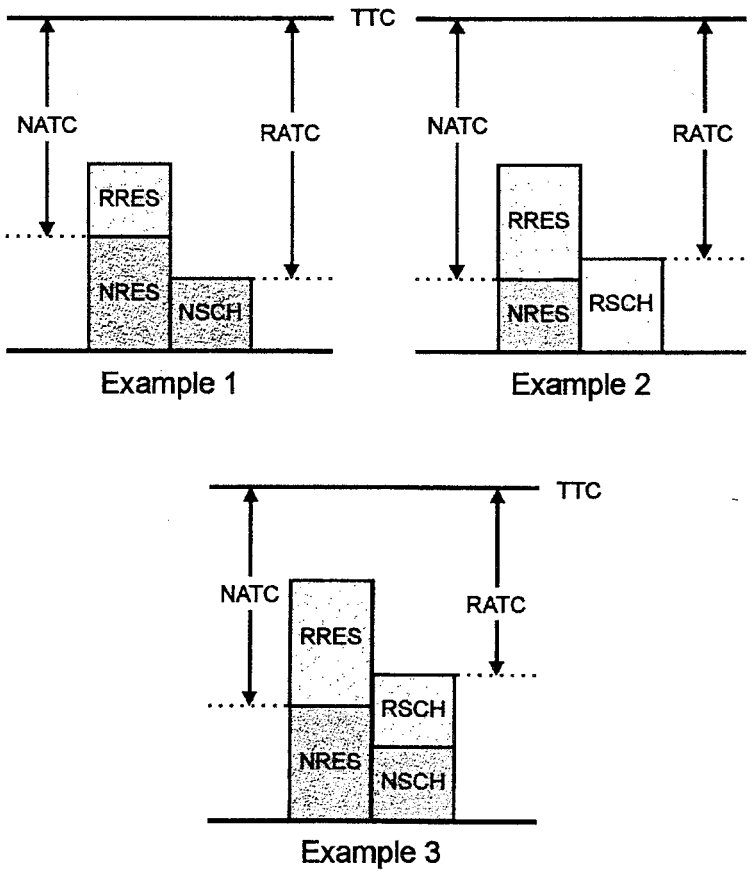
Non-recallable and recallable transmission service must adhere to a standard set of priorities universally applied throughout the electric power market to avoid confusion. These priorities are described below.

- Non-recallable service has priority over recallable service. Recallable transfers, reserved or scheduled, may be recalled for non-recallable requests. Recallability will generally be applied as needed only in areas of network constraint and not unilaterally over the entire network.

- All requests for transmission service will be evaluated in priority as established by applicable transmission service tariffs.

- Reserved transfer capability may be used by recallable scheduled transfers, provided that those scheduled transfers can be recalled if the reserved transfer requester wants to make use of the reserved transfer capability.

Several of the possible relationships of NATCs and RATCs to the different types of transfers that have been scheduled or reserved during a given time period are shown in Figure 4 and described below. These concepts apply to any time during the forecast period. Therefore, no time aspect is identified.



Transfer Capabilities	Transmission Services
TTC — Total Transfer Capability	NRES — Non-recallable Reserved
ATC — Available Transfer Capability	NSCH — Non-recallable Scheduled
RATC — Recallable ATC	RRES — Recallable Reserved
NATC — Non-recallable ATC	RSCH — Recallable Scheduled

Figure 4: ATC Relationships and Priorities

- Non-recallable scheduled (NSCH) transfers are of the highest priority (all Examples). NSCH transfers cannot be curtailed by the transmission provider except in cases where system reliability is threatened or an emergency exists. All NSCH transfers reduce the amount of ATC.

- Recallable ATC (RATC) can include transfer capability that is currently held by non-recallable reserved (NRES) transfers. However, the new transfers scheduled from the RATC may have to be interrupted if the NRES transfer requester wants to make use of the transmission network (Example 1).

- Non-recallable ATC (NATC) cannot include transfer capability that is currently held by non-recallable reserved (NRES) transfers because the reserved transfer would have priority over any new non-recallable transfer (Examples 1 and 3).

- Non-recallable ATC (NATC) can include transfer capability that is currently used by recallable scheduled (RSCH) transfers because a non-recallable transfer has priority over recallable transfers (Example 3).

- Recallable ATC (RATC) cannot include transfer capability that is currently used by recallable scheduled (RSCH) transfers because the scheduled transfer would have priority over any new transfers (Examples 2 and 3).

- Both non-recallable ATC (NATC) and recallable ATC (RATC) can include recallable reserved (RRES) transfers (all Examples). However, any new recallable transfers may have to be interrupted if the RRES requester wants to make use of the transmission network (Examples 2 and 3).

The Examples in Figures 3 and 4 illustrate how ATC may be applied in the conduct of commercial business. These definitions have no impact on the physical determination of how much additional transfers the network can support.

Appendix C further demonstrates the interaction between recallable and non-recallable transmission service and the effects on ATC values.

APPENDIX A. NETWORK RESPONSE METHOD FOR ATC DETERMINATION

The example in this Appendix describes an ATC calculation approach that may be termed a "network response" method. It demonstrates the ATC Principles described in this report and the physical impacts of electric power transfers on an interconnected transmission network. The method is intended to be illustrative of a procedure that is applicable in highly dense, meshed transmission networks where customer demand, generation sources, and the transmission systems are tightly interconnected. In such networks, transmission paths critical to a particular electric power transfer cannot generally be identified in advance. The critical path will be very much a function of the conditions that exist at the time the transfer is scheduled. The example does not introduce any concepts not covered in the front or main portion of this report.

PHYSICAL SYSTEM IMPACTS OF TRANSFERS

Determination of ATC requires some translation from the area to area transactions to the resultant electric power flows on the transmission network. This translation is done by stressing the system with appropriate transfers under critical contingencies to determine the characteristic response of the network. These network response characteristics, which are based on the line outage, power transfer, and outage transfer distribution factors of NERC's May 1995 NERC *Transmission Transfer Capability* reference document, can be determined by transfer capability studies either beforehand, or on a transaction-by-transaction basis.

When electric power is transferred between two areas such as Area A to Area F in Figure A1, the entire network responds to the transaction. The power flow on each transmission path will change in proportion to the response of the path to the transfer. Similarly, the power flow on each path will change depending on network topology, generation dispatches, customer demand levels, other transactions through the area, and other transactions that the path responds to which may be scheduled between other areas.

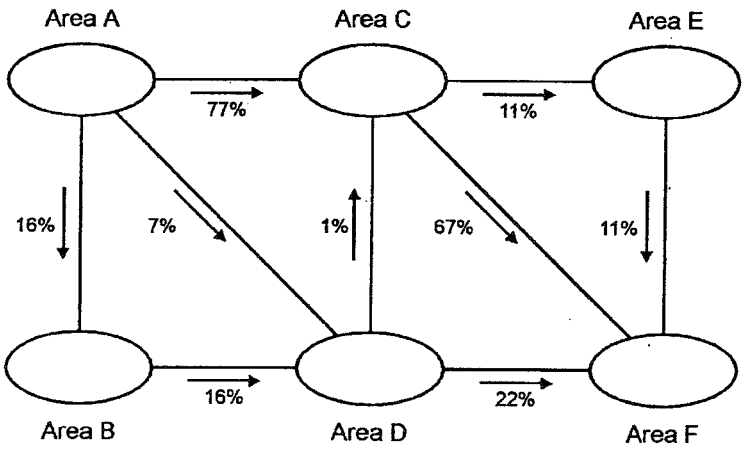


Figure A1: Network Response Characteristics for Area A to Area F Transfers

To illustrate this, computer simulation studies are performed to determine the transfer capability from Area A to Area F. During that process, it is determined that 77% of electric power transfers from Area A to Area F will flow on the transmission path between Area A and Area C (Figure A1).

Through application of those response characteristics, the impact on the path between Area A and Area C for a 500 MW transfer from Area A to Area F is graphically described in Figure A2. In this example, a pre-existing 160 MW power flow exists from Area A to Area C due to a generation dispatch and the location of customer demand centers on the modeled network. When a 500 MW transfer is scheduled from Area A to Area F, an additional 385 MW (77% of 500 MW) flows on the transmission path from Area A to Area C, resulting in a 545 MW power flow from Area A to Area C.

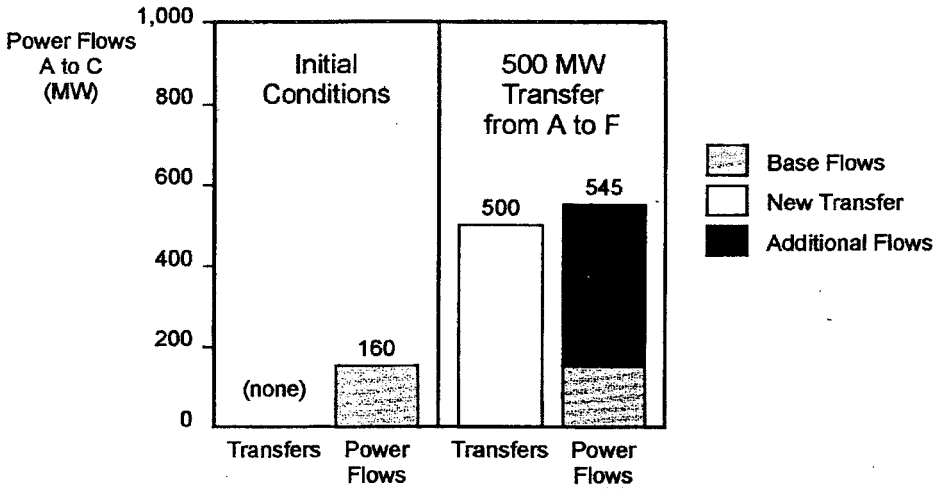


Figure A2: Existing vs. Resultant Power Flows on Path A to C for a 500 MW Transfer from Area A to Area F

To determine the ability of the network to transfer electric power from Area A to Area F, additional potential impacts within the individual areas must also be recognized. The network responses shown in Figure A1 must be expanded to consider possible transmission limits within each area.

The response characteristics of limiting facilities within the individual areas for an Area A to Area F transfer are shown in Figure A3. For simplicity, the flows within each area are not shown. Rather, the figures within each area represent the percentage of the transfer from Area A to Area F that flows on the most limiting facility within each area. Recognition of the limiting path responses within the individual areas for Area A to Area F transfers increases the complexity of determining the Area A to Area F ATC.

APPENDIX A. NETWORK RESPONSE METHOD FOR ATC DETERMINATION

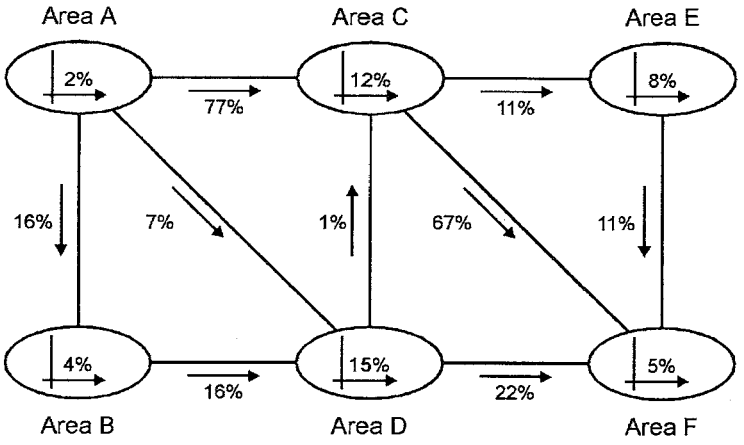


Figure A3: Internal and Interconnection Responses to Area A to Area F Transfers

TRANSLATION OF SYSTEM IMPACTS TO ATC

The ATC of the network depends on the existing loading conditions on the limiting transmission facility, wherever it may be, taking into account contingency criteria (i.e., outage of the most critical line or generator or multiple lines and generators, as appropriate).

ATC is a function of how much unused or unloaded capacity is available on the most limiting transmission facility, allowing for single and, in some cases, multiple contingencies. The translation of the unused capability of the transmission network to ATC determination for a particular direction is illustrated in Table 1, which refers to the transmission network shown in Figure A3 for an Area A to Area F transfer. The unused capacity of individual facilities in the transmission network, which is the difference between a facility's rating and its current power flow loading or its "available loading capacity," is divided by the response characteristic of the path facility to an Area A to Area F transfer. This procedure provides the individual critical path ATCs (in a system or between systems) from which the ATC from Area A to Area F is then determined by considering the most limiting path ATC. In this case, the limiting path is in Area D and the Area A to Area F ATC is 1,200 MW.

For a different electric power transfer, a new set of network responses and a new set of available capacity on limiting facilities would need to be determined to define the ATC for that transfer.

Electric power transfers have historically been scheduled between control areas on a contract path or area interchange basis. However, in the determination of ATCs, the actual flows on the network must be considered regardless of the scheduling methodology. In the preceding example, an electric power transfer may be scheduled from Area A to Area F, using a contract path from Area A to Area C to Area F. However, the reality of alternating current electrical systems is that the electric power would flow from Area A to Area F over the entire network, governed by the laws of physics. The electric power flowing on portions of the network other than the scheduled contract path is known as parallel path

APPENDIX A. NETWORK RESPONSE METHOD FOR ATC DETERMINATION

System or Path	Network Response (%)	Available Loading Capacity (ALC) on Limiting Facility (MW)	System or Path ATC (MW)	Area A to Area F ATC (MW)
Area A	2	35	1,750	
Area B	4	92	2,300	
Area C	12	454	3,780	
Area D	15	180	1,200	1,200
Area E	8	200	2,500	
Area F	5	250	5,000	
A – C	77	1,000	1,300	
A – D	7	157	2,240	
A – B	16	440	2,750	
B – D	16	512	3,200	
C – E	11	198	1,800	
C – D	1	18	1,800	
C – F	67	1,072	1,600	
D – F	22	385	1,750	
E – F	11	214	1,945	

Table 1: Available Transfer Capability Matrix for Transfers from Area A to Area F

flows, and can affect many systems in an interconnected network. In this particular example, the transmission limit in Area D limits the Area A to Area F transfers to 1,200 MW.

ATC TIME VARIATION AND NETWORK DEPENDENCY

Network conditions will vary over time, changing line loading conditions, and causing the ATC of the network to change. Also, the most limiting facility in determining the network's ATC can change from one time period to another, particularly in highly meshed networks. Therefore, the ATC of the network is time dependent.

This characteristic is illustrated conceptually in Figure A4. The first group of graphs on the left-hand side of the figure presents the available loading capacity at different points in time (T_1, T_2, T_3) for several lines in an interconnected network. If an Area A to Area B transfer is to be scheduled at T_1, each of the lines (line 1 in Area A, line 3 in Area B, line 7 in Area B, and line 16 in Area D) will respond to the transfer in accordance with its network response factor. This factor is used to determine an ATC as limited by each individual facility. The results are shown on the middle set of diagrams of Figure A4. The ATC for the network as a whole represents the minimum of the ATCs as defined by each facility at each time frame. These minimum ATCs are schematically illustrated in the right side of Figure A4. As demonstrated, the ATC is different for each time period and is determined by a different facility in each period.

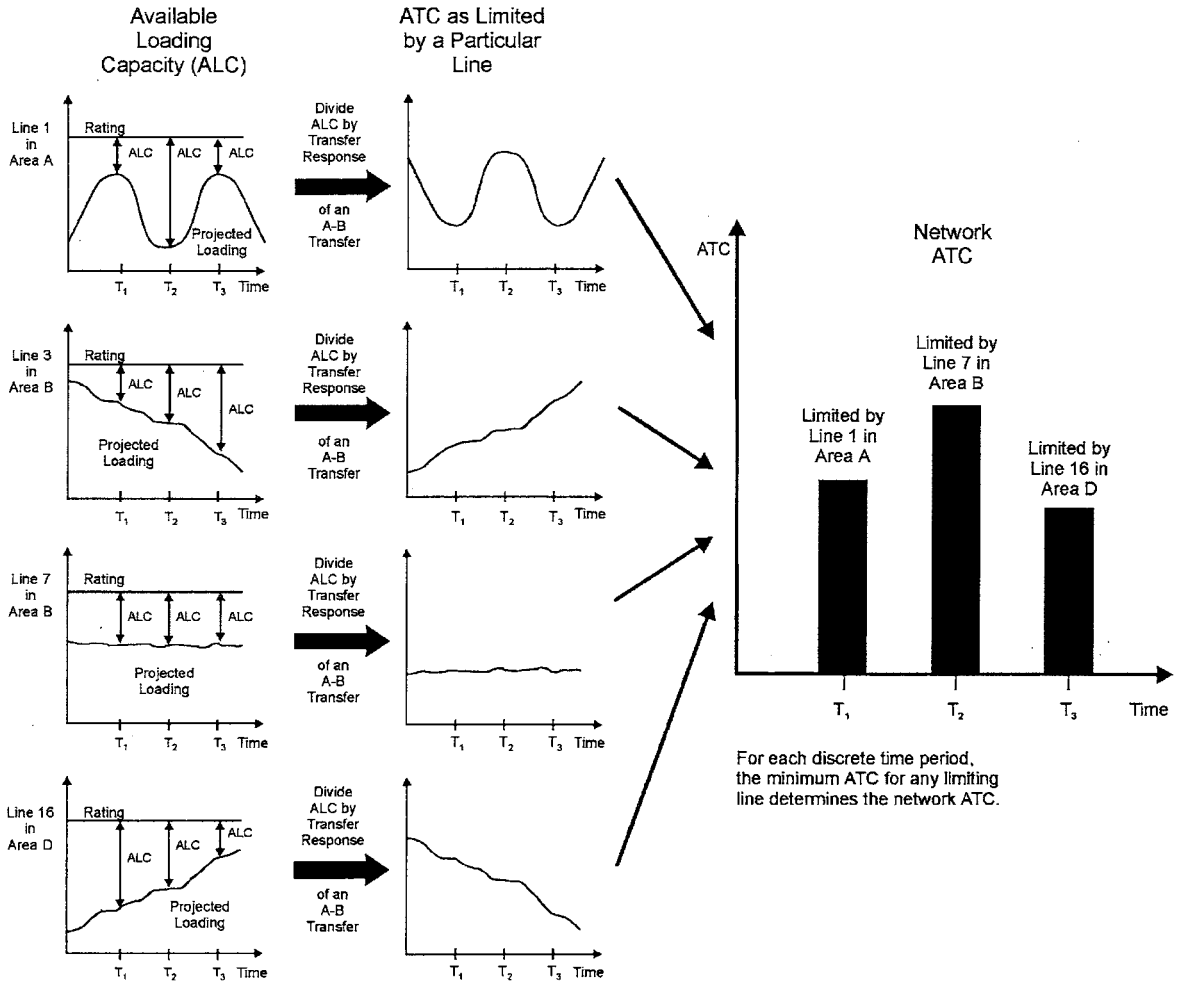


Figure A4: ATC Variance

APPENDIX A. NETWORK RESPONSE METHOD FOR ATC DETERMINATION

The determination of ATC and the difference between simultaneous and non-simultaneous transfers are demonstrated in Tables 2 and 3. These ATC demonstrations are based on the sample six system network shown in Figure A3.

Area	Facility	Network Response (%)	ALC* on Limiting Facility (MW)	Area to Area ATC (MW)
Area A to Area F Transfer				
D	D1	15	180	1,200
Area B to Area E Transfer				
B	B1	5	25	500
Area E to Area A Transfer				
A	A2	7	103	1,470

*Available Loading Capacity

Table 2: Non-Simultaneous ATC Analyses

Table 2 presents the non-simultaneous ATC analyses for three representative transfer conditions: Area A to Area F, Area B to Area E, and Area E to Area A. For each transfer direction, the area to area ATC is determined by the most critical system contingency and the resultant limiting system element, varying from 500 MW for an Area B to Area E transfer (limited by line B1 in Area B) to 1,470 MW for an Area E to Area A transfer (limited by line A2 in Area A).

Area	Facility	Network Response (%)	ALC* on Limiting Facility (MW)	Area to Area ATC (MW)
Area A to Area F ATC Analysis With a Pre-existing Area B to Area E 500 MW Transfer				
B	B1	3.5	0	0
Area A to Area F ATC Analysis With a Pre-existing Area B to Area E 500 MW Transfer and a Pre-existing Area E to Area A 1,470 MW Transfer				
B	B1	3.5	40	1,140

*Available Loading Capacity

Table 3: Simultaneous ATC Analyses

APPENDIX A. NETWORK RESPONSE METHOD FOR ATC DETERMINATION

The first section of Table 3 shows a determination of ATC for an Area A to Area F transfer, assuming that an Area B to Area E 500 MW transfer schedule is already in effect. Under this condition, the Area A to Area F ATC is now reduced from 1,200 MW (Table 2) to zero. This change is due to the increased loading on line B1 due to the previously scheduled 500 MW transfer from Area B to Area E, making it the limiting network facility. Note that the Area A to Area F transfer limiting facility was line D1 in Area D in the non-simultaneous analysis (Table 2).

The second portion of Table 3 is another determination of ATC for an Area A to Area F transfer. In this example, pre-existing transfers are in place from Area B to Area E of 500 MW and Area E to Area A of 1,470 MW. Under these conditions, the ATC for an Area A to Area F transfer is found to be 1,140 MW. This transfer is a slight reduction from the 1,200 MW ATC determination in the non-simultaneous case (Table 2), but is a significant increase from the zero ATC found in the previous case (first part of Table 3). This increased transfer is due to the offsetting effect of the flows caused by the pre-existing Area E to Area A transfer, which reduced the line loading on the critical facility B1, thus increasing the ATC for the Area A to Area F transfer direction.

These examples demonstrate that the determination of ATC in a tightly interconnected network is very much a function of system conditions that exist on the network at the time the transfer is to be scheduled. In addition, ATC is a function of the specifics of the electric power transfer being considered in terms of its direction, amount, and duration. To be able to properly appraise the performance of tightly interconnected networks to support contemplated transfers (i.e., what is the ATC), a regional or wide-area approach must be considered so that all network conditions are properly taken into account.

APPENDIX B. RATED SYSTEM PATH METHOD FOR ATC DETERMINATION

OVERVIEW

The rated system path (RSP) method for ATC determination is typically used for transmission systems that are characterized by sparse networks with customer demand and generation centers distant from one another. Generally in this approach, paths between areas of the network are identified and appropriate system constraints determined. ATC is computed for these identified paths and interconnections between transmission providers.

The RSP method involves three steps: 1) determining the path's Total Transfer Capability (TTC), 2) allocating the TTC among owners in a multi-owned path to determine the owners' rights, and 3) calculating ATC for each right-holder by subtracting each of their uses from each of their individual TTC rights. Wide-area coordination is achieved by developing the TTC in a manner that follows a regional review process. This process assures individual, power pool, subregional, and Regional coordination and the necessary consideration of the interconnection network's constraints and conditions.

The RSP method includes a procedure for allocating TTC, and in turn ATC, among the owners of the transmission path(s). It should be noted that the RSP method of allocation is not the only procedure that may be followed in allocating transmission services.

UNSCHEDULED FLOW OR PARALLEL PATH FLOW

The RSP approach accounts for the effects of unscheduled flow (parallel path flow) on interconnected systems through the modeling of realistic customer demand and generation patterns in advance of real-time operations, and uses a maximum power flow test to ensure that the transfer path is capable of carrying power flows up to its rated transfer capability or TTC.

The rating process begins by modeling the interconnected network with the actual flow that will occur on the path and its parallel paths under realistically stressed conditions. The lines comprising the path may be rated and operated as a single path. The network is tested under a wide range of generation, customer demand, and facility outage conditions to determine a reliability-based TTC. When determined this way, the TTC rating usually remains fairly constant except for system configuration changes such as a line outage situation. To implement the RSP ATC method, consistent path rating methods and procedures must be agreed upon and followed within the Interconnection.

Non-simultaneous ratings are normally used as the basis for calculating ATC. If, however, two rated paths have a simultaneous effect on each other, the rating process identifies the simultaneous capabilities or establishes nomograms that govern the simultaneous operation of the paths. Applicable operating procedures are negotiated to ensure reliable network operation. Where simultaneous operation is necessary, operator control is used to ensure safe and reliable operation of the transmission network.

APPENDIX B. RATED SYSTEM PATH METHOD FOR ATC DETERMINATION

CAPACITY ALLOCATION

The reliability-based TTC of a transfer path (its reliability rating) is allocated among the right-holders based upon their negotiated agreement. This determination of the property rights through the allocation process is critical to the RSP implementation of ATC. The rights in the path are negotiated for each of the individual transmission providers. Except for deratings based upon system operating (e.g., emergency) conditions, these allocations become rights that the right-holder may use or resell to others as non-recallable or recallable service.

Although the actual flows from each right-holder's schedule will flow on all parallel lines, the advance allocation of rights on a path makes it possible for right-holders to determine ATC and sell service within their rights independent of others. If the rating is determined using appropriate path rating procedures, including a maximum power flow test, the potential for adverse unscheduled power flow effects is minimized.

In real time, neither the total of the schedules, nor the actual power flow on a path may exceed the path TTC. Although the potential for adverse unscheduled power flow is minimized as a result of the modeling and rating process, some acceptable or mitigatable unscheduled flows will usually occur during real-time operation. Regions that use RSP to calculate ATC should adopt an unscheduled flow mitigation plan which addresses such flows, if they adversely affect system operation. The adverse flows can be managed through schedule changes, installing controllable devices such as phase shifters, or including this uncertainty as part of the reliability margin.

ATC CALCULATION APPROACH

1. Each path for which ATC must be calculated is identified, and then a reliability-based TTC is determined as described above. This TTC is then allocated among the owners by negotiated agreement.

2. Deratings for outages, nomograms, maintenance, or unscheduled flow are allocated, if necessary, to the right-holders based on prearranged agreements or tariffs.

3. Right-holders take their respective allocated shares of the TTC for a path and subtract the existing commitments to determine the appropriate ATC.

4. Right-holders update and repost their ATC calculations as new commitments impact their ATC. A transfer from one area to another involving several transmission owners requires locating and reserving capacity across multiple paths and potentially multiple right-holders.

EXAMPLE OF ATC DETERMINATION

The following example illustrates the application of the RSP method for determining ATC in a sparse network. The example transmission network is shown in Figure B1. All paths that connect the various areas have transfer capabilities that were individually developed in coordination with all areas giving consideration to unscheduled flow and interconnection interactions and effects. The TTCs portrayed in

Figure B2 are shown for each path and are directional, but are not necessarily the same for each direction.

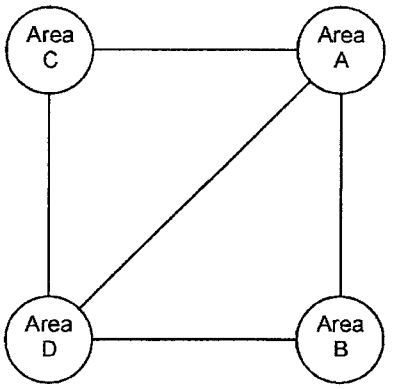


Figure B1: Sparse Network Model

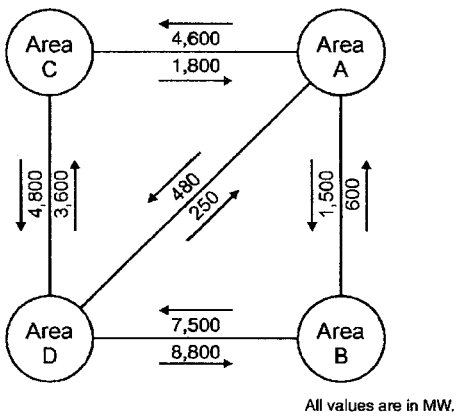


Figure B2: Total Transfer Capabilities

Each path may consist of several transmission lines that can also have different owners. In this example, the path between Areas B and D is comprised of five lines as shown in Figure B3. The TTC from Area B to Area D is 7,500 MW and, in the reverse direction, 8,800 MW. Line 1 is owned by a single entity and has an allocated portion of the TTC equal to 1,300 MW in either direction.

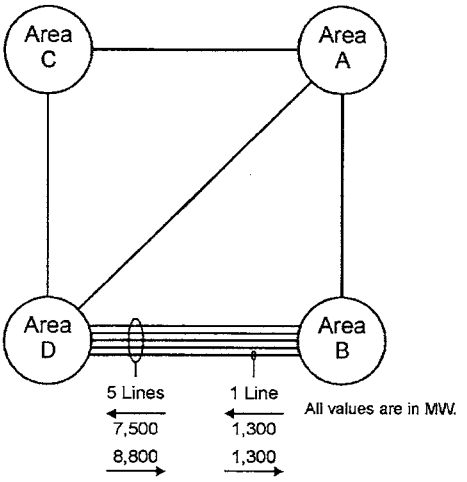


Figure B3: TTCs of Path B to D and Allocation of TTCs to Line 1

This example reflects a snapshot in time during the planning horizon. Initial transmission service reservations, all assumed to be non-recallable, are shown for each path in Figure B4. The corresponding ATC for each path has been calculated by subtracting the non-recallable service from the TTC. Because all the transmission service reservations are assumed on each path to be in one direction, the path ATC is only calculated for that direction.

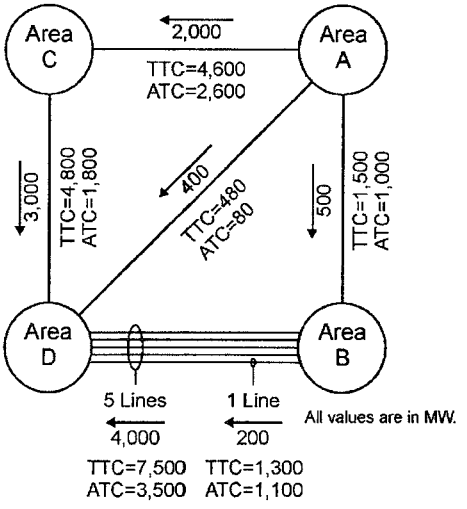


Figure B4: Initial Transmission Service Reservations

For example, referring to Figure B4, the ATC from Area B to Area D is calculated as 7,500 MW less 4,000 MW or 3,500 MW. For line 1 of the B to D path, the ATC is 1,300 MW less 200 MW or 1,100 MW. In the next case, as shown in Figure B5, 1,000 MW of non-recallable transmission service is acquired from Area A to Area B to Area D. No other changes occur. The total transmission service reserved from Area A to Area B is 1,500 MW, and the resulting ATC goes to zero. The ATC from Area B to Area D reduces to 2,500 MW (7,500 MW TTC less 5,000 MW reserved transmission service). It is assumed the 1,000 MW of the new reserved transmission service was obtained from the owner of line 1, resulting in the total reserved transmission service on this line being 1,200 MW. The new ATC for line 1 is 100 MW (1,300 MW TTC less 1,200 MW reserved transmission service).

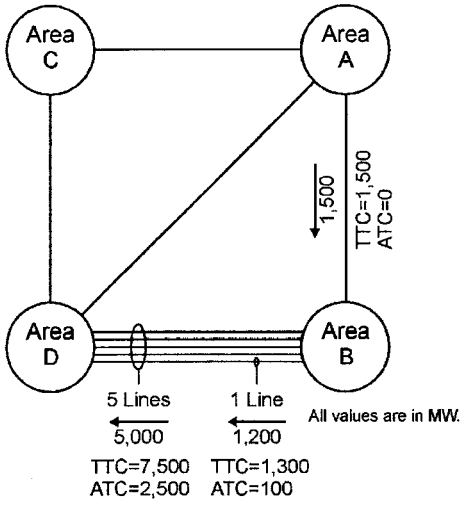


Figure B5: New Transmission Service Reservation on Path A to B to D

The non-recallable transmission service reserved for a path in each direction may not exceed the path's transfer capability in either direction under any circumstances. These limits are consistent with NERC Operating Policies.

Unscheduled flow may at times preclude scheduling to a path's full transfer capability or TTC. If an internal limit is encountered in any system as a result of the transaction from Area A to Area D, for example in Area D, Area D's system operator must respond to relieve the limitation such as by redis-patching generation or using phase shifter control. An unscheduled flow mitigation plan might also be implemented to relieve excessive unscheduled flow problems. Additional relief may be achieved by curtailing schedules that are contributing to the unscheduled flow on the path or by increasing schedules that would create unscheduled flow in the opposite direction. In this example, if path A to D were limiting, unscheduled flow mitigation procedures could be implemented to initiate coordinated operation of controllable devices such as phase-shifting transformers to relieve the limitation.

APPENDIX B. RATED SYSTEM PATH METHOD FOR ATC DETERMINATION

There will probably be times in the operating horizon when the use of the transmission network results in actual flows on a transmission path being less than the transmission scheduled on the path. During these periods, if the transmission path is fully scheduled, additional electric power may be scheduled to Area D from Area A by reserving transmission service over a different transmission path. In this case, transmission service could be obtained from either the owners of the direct path between Area A and Area D or the owners of the transmission system from Area A to Area C to Area D.

For the RSP method, the transmission rights to be reserved and scheduled by all transmission users are consistent with the rating of the transmission paths. If determined through a coordinated process using models that capture the major effects of the interconnected network, these ratings will create limits that result in the reliable operation of the regional electric system. The owners of the transmission paths, through a negotiated allocation process, will know their transmission service rights and the resulting use of these rights will be consistent with the physical capability and limitations of the transmission network. This RSP method assures efficient use and reliable operation of the interconnected transmission network.

APPENDIX C. TRANSMISSION SERVICE RESERVATIONS AND SCHEDULING

OVERVIEW

The following scenarios demonstrate how the 1,200 MW ATC quantity from Area A to Area F in the example in Appendix A may be commercially employed. The interplay between recallable and non-recallable transmission service and the resulting effects upon calculated ATCs are demonstrated using the equations presented in the "ATC Definition and Determination" section of this report. They clearly demonstrate that, although both recallable and non-recallable ATC are offered simultaneously, the combined total of recallable and non-recallable service does not exceed the TTC at any time.

For the purpose of this illustration, assume that conditions on the interconnected network are as described in Tables 1 and 2 of Appendix A. Under this scenario, the network ATC from Area A to Area F for this time period in the operating horizon is 1,200 MW. Also, for simplicity, assume that previous transmission commitments are zero. Thus, TTC in the following cases is 1,200 MW. Lastly, assume that TRM is zero. The resulting relevant simplified ATC equations for the operating horizon are:

$$NATC = TTC - NRES$$

$$RATC = TTC - RSCH - NSCH$$

The equations that describe the TTC constraints during this time frame are:

$$NRES \leq TTC$$

$$RSCH + NSCH \leq TTC$$

ATC DEMONSTRATION — SCENARIO 1

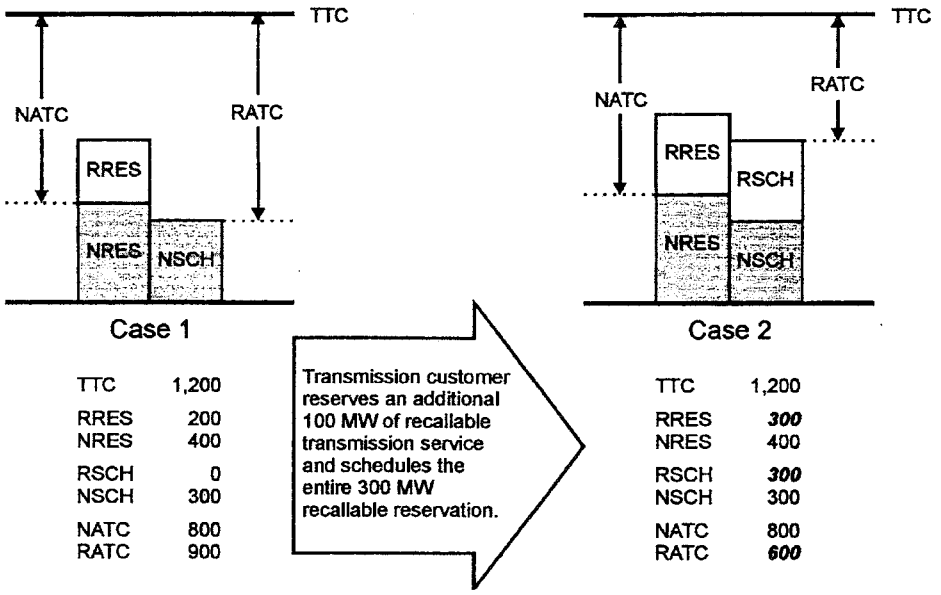
Consider the initial case identified in Figure C1 as Case 1. Reservations for 200 MW of recallable and 400 MW of non-recallable transmission service have been reserved against the 1,200 MW TTC.

Case 1 includes schedules for only 300 MW of non-recallable transmission service. Thus:

$$\begin{aligned} NATC &= TTC - NRES \\ &= 1{,}200 - 400 \\ &= 800 \text{ MW} \end{aligned}$$

$$\begin{aligned} RATC &= TTC - RSCH - NSCH \\ &= 1{,}200 - 0 - 300 \\ &= 900 \text{ MW} \end{aligned}$$

APPENDIX C. TRANSMISSION SERVICE RESERVATIONS AND SCHEDULING

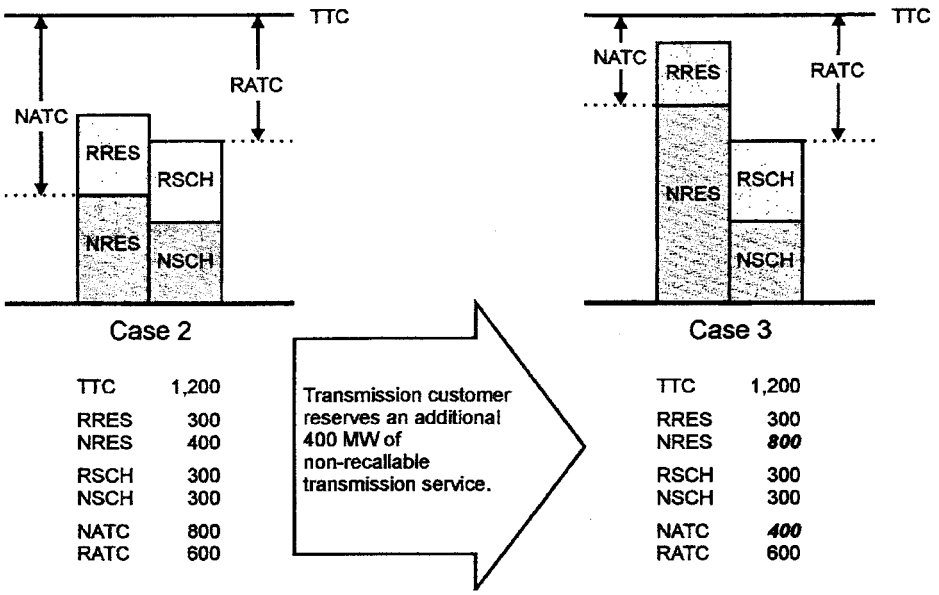


Transfer Capabilities		Transmission Services	
TTC	— Total Transfer Capability	NRES	— Non-recallable Reserved
ATC	— Available Transfer Capability	NSCH	— Non-recallable Scheduled
RATC	— Recallable ATC	RRES	— Recallable Reserved
NATC	— Non-recallable ATC	RSCH	— Recallable Scheduled

Figure C1: ATC Demonstration — Scenario 1

In Scenario 1, the transmission customer reserves an additional 100 MW of recallable transmission service and schedules the entire 300 MW recallable reservation. The results are shown in Figure C1 as Case 2. (Note that changed values are shown in bold italic type.) Non-recallable ATC is unchanged, but recallable ATC is changed as follows:

$$\begin{aligned} RATC &= TTC - RSCH - NSCH \\ &= 1{,}200 - 300 - 300 \\ &= 600 \text{ MW} \end{aligned}$$



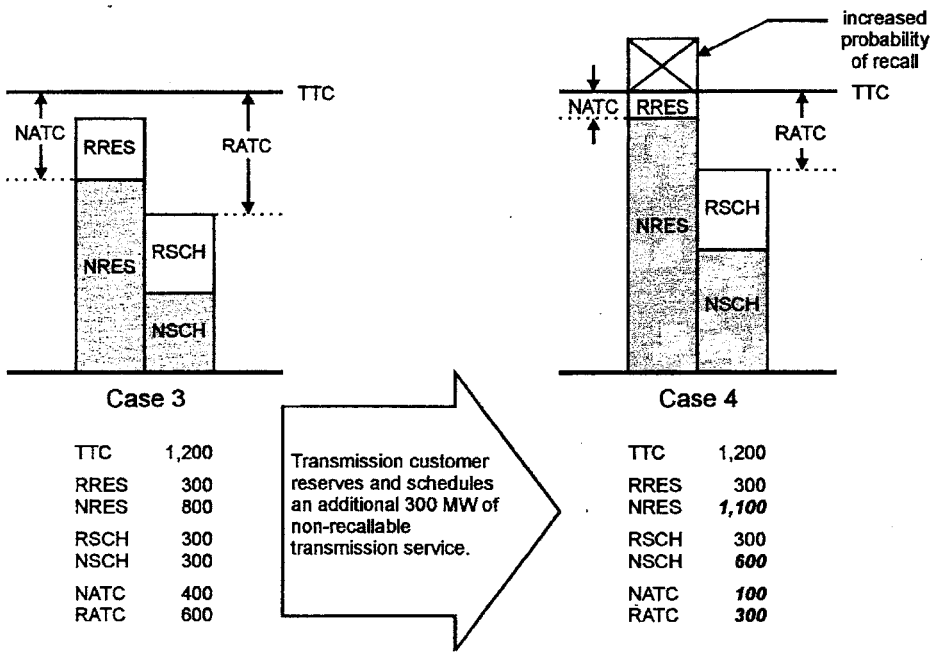
Transfer Capabilities		Transmission Services	
TTC	— Total Transfer Capability	NRES	— Non-recallable Reserved
ATC	— Available Transfer Capability	NSCH	— Non-recallable Scheduled
RATC	— Recallable ATC	RRES	— Recallable Reserved
NATC	— Non-recallable ATC	RSCH	— Recallable Scheduled

Figure C2: ATC Demonstration — Scenario 2

ATC DEMONSTRATION — SCENARIO 2

In Scenario 2 of Figure C2, the transmission customer reserves an additional 400 MW of non-recallable transmission service. The results are shown in Figure C2 as Case 3. Recallable ATC is unchanged in this scenario, but non-recallable ATC is changed as follows:

$$\begin{aligned} NATC &= TTC - NRES \\ &= 1{,}200 - 800 \\ &= 400 \text{ MW} \end{aligned}$$



Transfer Capabilities		Transmission Services	
TTC	— Total Transfer Capability	NRES	— Non-recallable Reserved
ATC	— Available Transfer Capability	NSCH	— Non-recallable Scheduled
RATC	— Recallable ATC	RRES	— Recallable Reserved
NATC	— Non-recallable ATC	RSCH	— Recallable Scheduled

Figure C3: ATC Demonstration — Scenario 3

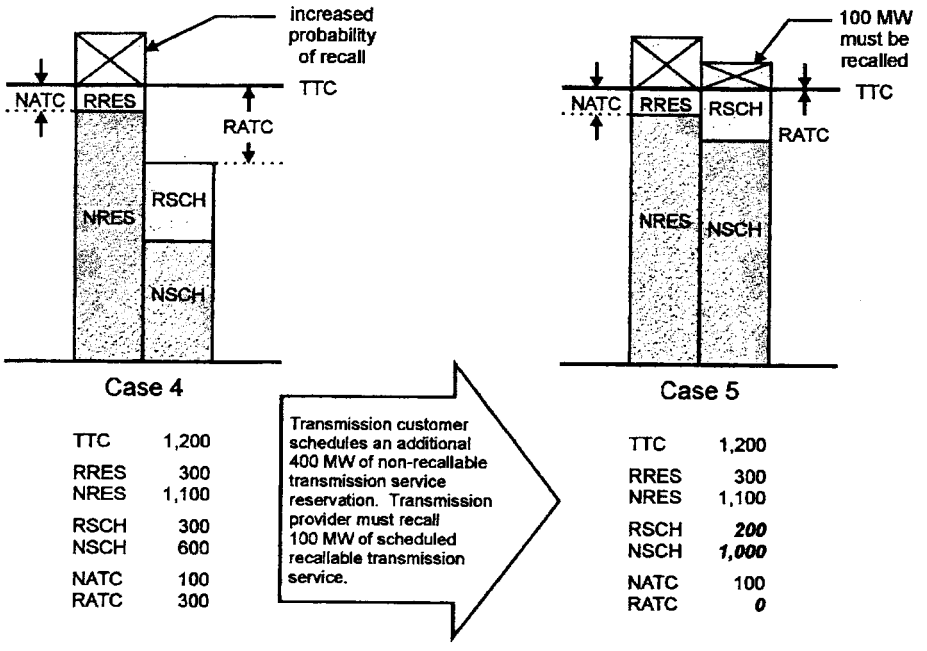
ATC DEMONSTRATION — SCENARIO 3

In Scenario 3 of Figure C3, the transmission customer reserves and schedules an additional 300 MW of non-recallable transmission service. The results are shown in Figure C3 as Case 4. In this scenario, both recallable and non-recallable ATCs are changed as follows:

$$\begin{aligned} NATC &= TTC - NRES \\ &= 1{,}200 - 1{,}100 \\ &= 100 \text{ MW} \end{aligned}$$

$$\begin{aligned} RATC &= TTC - RSCH - NSCH \\ &= 1{,}200 - 300 - 600 \\ &= 300 \text{ MW} \end{aligned}$$

Transmission customers holding the 200 MW of recallable transmission service reservations "above the TTC line" should be advised that they have a high probability of having their transmission service recalled.



Transfer Capabilities	Transmission Services
TTC — Total Transfer Capability	NRES — Non-recallable Reserved
ATC — Available Transfer Capability	NSCH — Non-recallable Scheduled
RATC — Recallable ATC	RRES — Recallable Reserved
NATC — Non-recallable ATC	RSCH — Recallable Scheduled

Figure C4: ATC Demonstration — Scenario 4

ATC DEMONSTRATION — SCENARIO 4

In Scenario 4 of Figure C4, the transmission customer schedules an additional 400 MW of non-recallable transmission service. The results are shown in Figure C4 as Case 5. Non-recallable ATC remains unchanged at 100 MW. Unless 100 MW of recallable transmission service schedules are recalled, the total schedules violate the TTC constraint. The transmission provider must recall 100 MW of scheduled recallable transmission service. The recallable ATC calculation is then:

$$\begin{aligned} RATC &= TTC - RSCH - NSCH \\ &= 1{,}200 - 200 - 1{,}000 \\ &= 0 \text{ MW} \end{aligned}$$

As this demonstration has shown, recallable transmission services may be reduced as non-recallable transmission services are reserved and scheduled, approaching the TTC limit.

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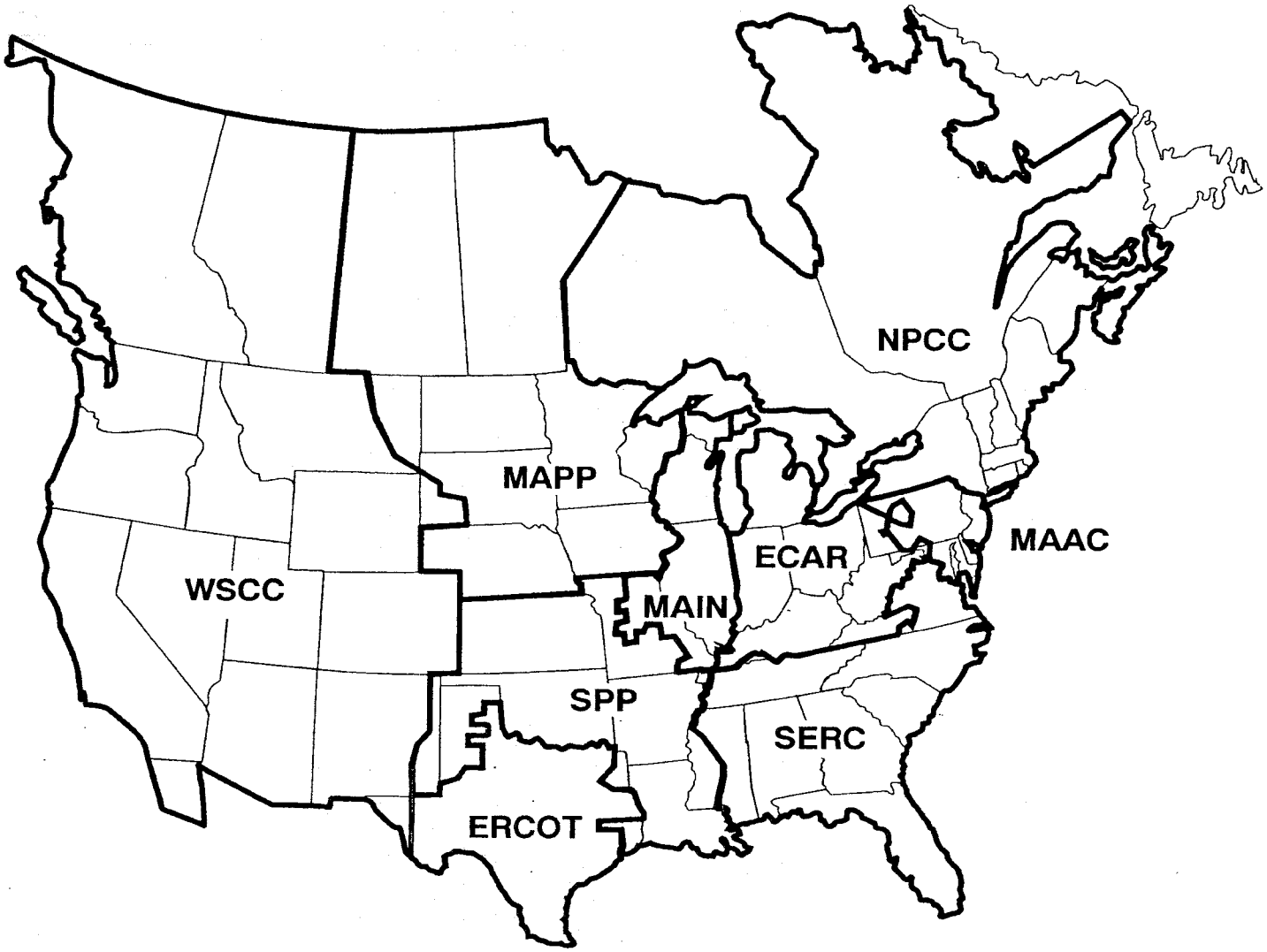

ECAR
East Central Area Reliability Coordination Agreement

ERCOT
Electric Reliability Council of Texas

MAAC
Mid-Atlantic Area Council

MAIN
Mid-America Interconnected Network

MAPP
Mid-Continent Area Power Pool

NPCC
Northeast Power Coordinating Council

SERC
Southeastern Electric Reliability Council

SPP
Southwest Power Pool

WSCC
Western Systems Coordinating Council

AFFILIATE

ASCC
Alaska Systems Coordinating Council

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Appendix B.
Building a "Margin of Safety" into Renewable Energy Procurements: A Review of Experience with Contract Failure

Building a "Margin of Safety" Into Renewable Energy Procurements:

A Review of Experience with Contract Failure

CONSULTANT REPORT

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California Energy Commission

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January 2006
CEC-300-2006-004

ABSTRACT

In implementing state renewables portfolio standards, utility purchasers and electricity regulators must confront the reality that signed renewable energy contracts will not always yield operational projects on the timeline given in the contracts themselves. Renewable energy projects may fail to achieve scheduled commercial operations for a variety of reasons, some of which are outside the control of both the purchasing utility and the renewable developer. If not addressed, this risk of *contract failure* could cause individual load-serving entities, or entire states, to fall short of their renewable energy targets. Based on a variety of data sources, this report summarizes potentially relevant experience with renewable energy contract failure from historical experience in California within the major investor-owned utilities' service territories; from a broad group of other North American electric utilities; and from government renewable energy contract and incentive auctions. The resulting sample is extensive, consisting of over 21,500 MW of renewable energy contracts. The report finds that contract failure rates vary considerably among utilities, across situations, and by technology. Though some of this experience is not entirely relevant to the contracting practices of today's electric utilities, the data suggest that a *minimum* overall contract failure rate of 20 to 30 percent should generally be expected for large solicitations conducted over multiple years. Failure rates much higher than these levels are supported by historical experience. Ongoing monitoring of contract failure is recommended. Moreover, as additional contracting experience is gained, it may be helpful to scrutinize the different approaches used by utility purchasers to mitigate contract failure, document early experience with those measures, and compare in some detail the approaches used in various jurisdictions.

KEYWORDS

renewable energy, power purchase agreement, contract failure, renewables portfolio standard, wind power, project status

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CHAPTER 1: INTRODUCTION

Policy Background

The California Renewables Portfolio Standard (RPS), established by Senate Bill 1078 (SB 1078, Chapter 516, Statutes of 2002, Sher) in 2002, calls for the state's investor-owned utilities (IOUs), energy service providers (ESPs), and community choice aggregators (CCAs) to meet 20 percent of their electricity load with eligible sources of renewable energy by 2017. The state's energy agencies have committed to an acceleration of the RPS such that the 20 percent goal is met seven years early, by 2010. Governor Schwarzenegger has endorsed this accelerated schedule and has set a goal of achieving a 33 percent renewable energy share by 2020 for the state as a whole; the California Energy Commission (Energy Commission) and the California Public Utilities Commission (CPUC) also support this aggressive target.

Much has already been accomplished under the state's RPS, and the state's three major IOUs – Pacific Gas and Electric Company (PG&E), Southern California Edison (SCE), and San Diego Gas and Electric (SDG&E) – have recently signed a large number of contracts for renewable energy capacity. Through interim renewable solicitations in 2002, bilateral contracts, and 2003-04 requests for offers (RFOs), these three utilities have signed contracts for roughly 1,700 – 3,000 MW of new or repowered renewables capacity, depending on the exercise of expansion options.[1] If each of these new projects achieves commercial operations, total deliveries could equate to 3.1 to 5.4 percent of the IOUs' combined 2004 electricity load.[2] All three IOUs are now proceeding with their 2005 RFOs.

Nonetheless, the state as a whole has fallen behind schedule in meeting its aggressive renewable energy targets, and few new renewable energy projects have achieved commercial operations over the last several years.[3] The recent and ongoing contracting efforts of the state's utilities may help overcome this shortfall, but it takes time for new renewables projects to be built, and concerns have been raised that some – perhaps many – of these contracts may not yield operational renewable energy projects on the timeline given in the contracts themselves.

Projects may fail to achieve scheduled commercial operations for a myriad of reasons, many of which are outside the control of the purchasing utility and some of which are outside the control of the renewable developer. If not addressed, this risk of *contract failure* could cause individual load-serving entities, and the state as a whole, to fall short of their renewable energy targets. Though a number of procurement strategies can be used to reduce the risk of contract failure, even these strategies cannot eliminate the possibility of unfulfilled contracts, and some of these strategies may have the unfortunate effect of reducing the number of renewable energy bids and raising bid prices.

The possibility of contract failure was raised as a serious concern of RPS stakeholders in a report commissioned by the Energy Commission[4] and was recently reiterated in a report prepared for the CPUC.[5] To accommodate this risk, the Energy Commission's 2005 Integrated Energy Policy Report recommends that the CPUC require that the state's IOUs procure a prudent contract-risk margin, noting that a 30 percent over-procurement margin might be an appropriate starting point but that the margin should be revised over time to reflect actual experience.[6] In its report to the CPUC, the Center for Resource Solutions recommended additional clarification of the state's rules for flexible compliance and penalties in the event of contract failure and that the CPUC consider encouraging or even requiring some level over-contracting.[7]

In requiring the IOUs to submit supplements to their long-term renewable procurement plans (D.05-10-014, October 6, 2005), the CPUC decided that a margin of safety in procurements was needed to guard against the possibility of contract failure and other contingencies (for example, attrition of the baseline, load uncertainty, and so forth). The CPUC therefore required the utilities to make an initial quantification of their "margin of safety" in RPS procurement. More recently, the CPUC established the requirements for the IOUs' 2006 procurement plans (R.04-04-026, November 9, 2005), mandating that these plans include an analysis of contracting above the 1 percent incremental procurement target (IPT) and presumptively instituting a 20 percent over-contracting target for 2006. The ruling also allows the utilities to provide analytic justification for proposing a different contracting level.

The major IOUs agree that there is some risk that not all renewable energy contracts will come to fruition and that there is therefore a need for some over-procurement but generally believe that such over-procurement should be at the discretion of utility management. In its supplemental long-term renewable procurement plan, SDG&E explains that it has a strategy of trying to meet 24 percent of its load with renewable energy by 2010 to account for this risk. SCE argues that mandated over-procurement is neither necessary nor appropriate, noting in part that little data on the appropriate level of over-procurement has been provided, that any margin of safety should be utility- and project-specific, and that SCE is fully capable of applying its own acumen to analyze and account for this risk on a going-forward basis (SCE also notes that transmission is likely to be the major cause for project delay and that addressing this issue should be the top priority). Similarly, PG&E maintains that it should be allowed to use reasonable judgment in deciding how much to over-procure, arguing that more flexibility is needed and that each RFO is unique and therefore that over-procurement should be based on the design and results of each individual solicitation.[8]

Objectives

Based on a variety of data sources, including a large number of interviews, this report summarizes potentially relevant experience with renewable energy contracts and contract failure from: (1) historical experience in California within the major

IOUs' service territories; (2) other North American electric utilities; and (3) government auctions of renewable energy contracts or incentives. Though available data are somewhat spotty in places, our sample is nonetheless extensive, consisting of more than ***21,500 MW*** of renewable energy contracts.

The purpose of this report is to provide data and context that may help the Energy Commission, CPUC, load-serving entities, and other RPS stakeholders in further deliberations on contract failure. More specifically, the goal is to provide data that may help inform the development of appropriate over-procurement margins, as well as possible approaches to lessen the risk of contract failure. This report does not offer specific policy or procurement recommendations. Instead, we seek to impartially report the experiences of other utilities and entities in contracting for renewable energy in the hope that California's IOUs and energy agencies can learn from these experiences.

We acknowledge that this report presents data that, while informative, do not represent the last word on those matters. We place particular emphasis on data that may be relevant to the present California IOU procurement processes but recognize that each procurement and project is different, and that much of the data presented here may not be directly relevant to the solicitation approaches currently being used by the state's IOUs. Additionally, time and budget constraints required that we not dig too deep into the experiences reported here; so though we are able to offer summary information, we are not able to provide detailed reviews of the failure rates, mitigation strategies, and experiences of individual utilities. Similarly, we are unable to link specific mitigation strategies with lower failure rates, to separate the influences of solicitation design and overall market conditions on failure rates, or to provide specific recommendations on which of the mitigation approaches might be most effective. We encourage readers of this report to identify inaccuracies in the data or interpretations that are presented in the pages that follow.

The remainder of this report is organized as follows:

- **Chapter 2** describes the methodology used to collect data, the specific sources and types of data that we sought, and the categorization that we use to identify the types of, sources of, and mitigation options for contract failure.
- **Chapter 3** summarizes the results of the various data collection efforts, reporting on experience from California, from other North American utilities, and from government-run auctions for renewable energy.
- **Chapter 4** draws some limited conclusions based on the data we were able to collect.
- **Appendix A** reproduces the rough interview guide used to collect data from other North American utilities.

CHAPTER 2: METHODOLOGY

Scope and Sources of Data Collection

Any attempt to apply experiences in renewable energy contracting from outside California to the present practices of the state's IOUs is fraught with difficulty because of the unique attributes of the California market and utility RFOs. California has a long history with renewable energy, a large installed base of renewables capacity, and a wide diversity of renewable resources. It also has perhaps the most aggressive RPS policy in the nation in terms of new capacity and contracting requirements, and faces more stringent siting and permitting processes than many other jurisdictions. The specific design of recent and ongoing utility renewable energy RFOs in the state also differ, to some degree, both among themselves and with the procurement practices used elsewhere.

We sought information on renewable energy contract failure from as many potentially relevant experiences as possible, recognizing that some of these are more germane than others. Data that we collected can be categorized as follows:

1. **California IOU Experience:** This includes historical experience with Qualifying Facilities (QF) in the state, the Energy Commission's production incentive auctions, and early experience from the three major IOUs' recent renewables contracting efforts. Data were obtained from a variety of publicly available reports and regulatory filings, as well as brief interviews with PG&E and SCE.[9]
2. **Other North American Utility Experience:** We interviewed 25 other electric utilities known to be active in renewable energy contracting. Utilities were selected based on known activity, geographic and commercial diversity, and ease of contact. This group included IOUs from other states, publicly owned utilities (POUs) from across the country (including California), federal power agencies, and a government utility in Canada. Data were obtained primarily from telephone interviews with utility staff or employees, but were augmented with public documents in several cases. Where not unduly difficult, we also sought publicly available data to confirm interview responses. Information was typically obtained about the utilities' contracting efforts in the 1999 to 2004 timeframe because more recent contracts will not have had a chance to fail, and earlier contracts are fewer in number and potentially less relevant. Nonetheless, we did identify a source of information on earlier contracts, and we do report data from that source. See Table 1 for a list of utilities (and other entities) that we interviewed.
3. **Government Contract Tenders and Incentive Auctions:** Though somewhat less relevant, we collected data from government entities in the United Kingdom, Ireland, and France that have run tenders for long-term renewable energy contracts. We also collected information on certain solicitations administered by state renewable energy funds that have offered incentive funding to renewable

energy projects, including those in New York, Pennsylvania, New Jersey, and Massachusetts. Data were collected from public reports and from e-mail and telephone contacts with the organizations administering the programs.

Table 1. Other North American Utilities Surveyed

Utility	Type
California and Nevada	
Sacramento Municipal Utility District (SMUD)	POU
Los Angeles Department of Water and Power (LADWP)	POU
Sierra Pacific/Nevada Power	IOU
Midwest/Mountain West	
We Energies	IOU
Alliant	IOU
Mid-American	IOU
Wisconsin Public Service	IOU
Xcel Energy	IOU
Great River Energy	POU
East/Southeast	
New England Power Company	IOU
Jacksonville Electric Authority (JEA)	POU
Texas	
TXU	IOU
Reliant	IOU
CPS Energy (San Antonio)	POU
Austin Energy	POU
Southwest	
Arizona Public Service (APS)	IOU
Public Service Company of New Mexico (PNM)	IOU
Tuscon Electric Power (TEP)	IOU
Salt River Project (SRP)	POU
Pacific Northwest	
PacifiCorp	IOU
Bonneville Power Administration (BPA)	Government
Portland General Electric (PGE)	IOU
Hawaii	
Hawaiian Electric Company (HECO)	IOU
Kauai Island Utility	POU
Canada	
Province of Ontario, Ministry of Energy	Government

Type of Data Sought

The data collection focused on information about renewable energy contracts, or power purchase agreements (PPAs). Regardless of the approach to data collection (whether via telephone interviews or public reports), we generally sought four basic types of information:

1) motivation and context for the renewable energy contracting effort;
2) renewable energy project and contract status, and contract failure rates, by resource type and by failure type;
3) reasons for contract failure; and
4) approaches used to reduce the risk of contract failure.

The interviews with North American utilities followed a loose interview guide that allowed us to systematically collect, aggregate, and present these data (see Appendix A).[10] Where public reports and filings were used, however, we were often unable to assemble comprehensive information on each of these issues and instead sometimes rely on qualitative and selective descriptions.

Categorizing Project Status and Types of Contract Failure

For the purpose of data collection and presentation (and as reflected in the interview guide presented in Appendix A), it is important to classify project status and define different types of contract failure. Five different types of project status are used here:

- Currently on-line and performing as expected (Online)
- Not currently on-line, but still on schedule to come on-line (Scheduled)
- Currently on-line but not performing to contract terms (Default)
- Significantly delayed, but may still come on-line at some point (Delayed)[11]
- Contract canceled altogether (Canceled)

In defining contract failure, the first two categories (Online and Scheduled) are typically considered *successful* contracts. Note that this approach may overestimate project success rates (and underestimate failure rates) in that some scheduled projects may face unforeseen difficulties.

The next three categories (Default, Delayed, and Canceled) are considered *failed* contracts, but they represent distinctly different types of contract failure with very different ramifications for the purchasing utility. Canceled projects never result in deliveries, while delayed projects may ultimately yield deliveries, and projects in default may simply be delivering less than that which was contracted. Because of these important distinctions, where possible we report data on all three types of contract failure. We were unable to track, due to lack of data, past delays in projects that are currently on-line.

Categorizing the Causes of Contract Failure

Where possible, we also sought information on the causes of contract failure. Systematic information on the causes of contract failure was consistently collected only through our utility interviews, though qualitative information on this subject is reported elsewhere as well. Recognizing that projects (and their contracts) can fail for more than one reason, we allowed utilities to identify multiple causes.

Although we allowed for other responses, in the interviews we specifically asked which of the following failure causes were more significant:

- **Failure to site or permit the project** (Site and Permit): This may include local opposition to the project, failure to obtain site control (leases or ownership) of the project location, or failure to obtain appropriate permits.
- **Interconnection or transmission problems** (Transmission): Many developers underestimate the complexity, cost, or time required to address transmission and interconnection issues.
- **Financial failure of generator/developer** (Developer Finance): A developer may be unable to obtain financing for a project or may need to walk away from a project because the cost of financing has increased or because of the bankruptcy or other financial problems of the developer.
- **Lack of credit-worthy purchaser** (Utility Finance): In some instances, the utility (or other entity) responsible for purchasing power from the project may not be creditworthy, making project financing more difficult and costly, and putting the project at risk of failure.
- **Availability and/or cost of resource** (Resource Availability): Lack of verified resource availability can yield contract failures, as can an escalation in the expected cost of the fuel supply.
- **Increases in capital costs** (Capital Costs Increase): Recent wind turbine price increases are often mentioned as a prime contributor to contract failure. Other technologies can also suffer from increased capital costs after contract signature.
- **Technology issues** (Technology): This category covers any sort of technology issue that can lead to contract failure.
- **Project delay results in loss of subsidy** (Subsidy Issues): The on again/off again nature of the Production Tax Credit (PTC) for the past few years has made the availability of subsidies a serious problem for the wind industry. A delay could mean loss of subsidies, leading to contract cancellation.

Of course, in many cases these failure categories can interact with each other. A developer could have a delay brought on by transmission issues (or permitting), for example, resulting in not being able to secure a turbine order as scheduled. Turbine prices may then rise, leading to project cancellation due to price increases.

Categorizing Mitigation Strategies

One would expect that the degree of contract failure would be heavily influenced by the procurement strategies of the purchasing party. If that party uses extreme

measures to ensure project success, then success rates will increase and failure rates will fall.

The final step of our data collection was therefore to describe, qualitatively at least, the approaches used to lessen contract failure. Though we again allowed for other responses, the strategies that we pre-identified for data collection purposes are listed below:

- **Strict pre-conditions for proposal submission** (Strict Pre-Conditions): The purchasing party could impose strict pre-conditions for proposal submission in order to ensure that only viable projects bid. These could include (for example) a demonstration of complete site control, wind turbine availability, having all permits in hand, or use of a technology with a proven track record.
- **Proposal submission fees** (Submission Fees): These are fees required upon proposal submission, or upon selection for the short list. Similar to pre-conditions, the purpose is typically to ensure that only serious proposals are submitted.
- **Request for qualifications** (RFQ Process): An RFQ process, like submission fees and pre-conditions, is intended to ensure serious bidders. The RFQ imposes an additional step on developers, as they must first demonstrate their qualifications before being allowed to bid.
- **Due diligence**: Due diligence involves evaluating projects on non-economic terms, and can range from a cursory review of an application to an extremely in-depth evaluation of the likelihood of a project meeting its obligations if offered a contract.
- **Waiting list**: By keeping a few proposals in reserve as "backups" in case one of the signed contracts fails, the use of a waiting list can lessen the effects of contract failure.
- **Pre-operation milestones with deposit** (Pre-operation Milestones): The purchasing party may impose deposit requirements on the developer upon contract signature or at some other point, with the deposit forfeited if the project fails to achieve certain pre-operation milestones (for example, obtaining permits, ordering major capital equipment, construction start, and so forth.).
- **Operational performance guarantees** (Performance Guarantees): These are contractual terms that force the developer to pay the utility damages if the project fails to perform as specified in the contract, either by failing to achieve commercial operations on schedule or by not meeting production expectations.
- **Project ownership options** (Ownership Options): This strategy involves contractual language that allows the utility to step in and assume ownership of a project that is in trouble, or RFOs that solicit utility ownership options in addition to PPAs.

Confidentiality

Telephone interviewees were told that the report would be made public, and that they should therefore not divulge confidential or sensitive information. To further reduce the potential release of sensitive information, in this report we provide

aggregate data and anecdotal information from each utility interview and not detailed data specific to individual utilities. Two respondents were not comfortable providing details about their renewable contracts, even when assured that their data would be displayed only in aggregate form. The vast majority of respondents were forthcoming and generously gave of their time, information, and opinions.

Data Rounding

Through the remainder of the report, data contained in Tables and Figures includes rounding resulting in minor discrepancies where totals may not add correctly.

CHAPTER 3: SUMMARY AND ANALYSIS OF DATA COLLECTED

This chapter comprehensively presents the data that we were able to collect. We start by reviewing the experience of California's IOUs with renewable energy contracting and contract failure, including Qualifying Facilities during the 1980s and 1990s, the Energy Commission's production incentive auctions, and the IOUs' recent contracting efforts. We then turn to a summary of experience from other North American utilities, which is arguably the most relevant of the data presented in this report. We end by highlighting experience with government-run renewable energy tenders and incentive solicitations.

Historical California IOU Experience

As historical leaders in renewable energy development, California's major IOUs possess a wealth of experience with renewable energy contracting and contract failure. Despite that fact, California's experience is, by and large, either dated or too recent to yield conclusive results or otherwise bears little resemblance to the present contracting practices of the state's IOUs. Though we present potentially useful data here, we emphasize that the more relevant experience arguably comes from the contracting practices of other utilities (presented in the next major subsection).

PURPA QF Experience

California aggressively implemented the Public Utility Regulatory Policies Act of 1978 (PURPA) through a variety of standard offer contracts offered by the state's IOUs in the 1980s. By 1986, roughly 16,000 MW of eligible QF projects had received contracts under these programs (primarily Standard Offer #2 and Interim Standard Offer #4, which were suspended in March 1986 and April 1985, respectively). This 16,000 MW included fossil cogeneration facilities, as well as renewable facilities. Many of the facilities receiving contracts under PURPA were required to come on-line within five years, though some extensions were offered.

According to the Energy Commission's 1994 Electricity Report[12], on-line QF and self-generation capacity at that time was roughly 11,100 MW, equating to an overall success rate of 69 percent (and a failure rate of 31 percent). Some of the operational projects had faced delays, however, and the overall success rate would be lower (and the failure rate higher) were those delays taken into consideration.

Focusing just on the renewable energy QF capacity under contract to the state's three largest IOUs, success rates were even lower (and, correspondingly, failure rates were higher). Table 2 presents data on renewable QF capacity under contract to these utilities in the first quarter of 1987 and operational as of the third quarter of 1995. Of nearly 9,000 MW of renewable QF contracts, about 4,100 MW were operational as of 1995, a success rate of just 45 percent. Geothermal and solar projects had relatively higher success rates, at 84 percent and 58 percent

respectively, while hydro, biomass, and wind had lower success rates of 40 percent or less. Even among those projects that did achieve commercial operations, a number of projects – especially biomass facilities – were unable to maintain operations as originally expected due to technical issues and fuel unavailability.

Table 2. Success Rates for California Renewable Energy QF Contracts[13]

Technology	Signed Contracts (MW) [1st Quarter 1987]	On-line Projects (MW) [3rd Quarter 1995]	Success Rate (%)
Wind	4,120	1,641	40%
Biomass/Biogas/Solid Waste	2,098	829	40%
Geothermal	999	841	84%
Hydro	1,127	391	35%
Solar	636	368	58%
TOTAL	**8,980**	**4,070**	**45%**

Throughout the late 1980s and early 1990s, the Energy Commission, as well as other parties, used a variety of approaches to predict what fraction of the QF contracts would likely result in operating projects, and over what timeframe. The Energy Commission used, in part, statistical analysis of past completion rates to predict future success. Though we did not seek information on the specific nature of those calculations, it is clear that the Energy Commission, the state's IOUs, and the state's independent power producers all recognized that many projects with signed QF contracts would not ultimately succeed.

Though informative, we do not believe this experience is altogether relevant in today's market conditions. The QF contract rush occurred at the very beginnings of the renewable energy industry in the state, and developers were sometimes poorly capitalized and ill-equipped to develop commercial projects. The contract rush also resulted from high and profitable power purchase agreements available from the state's IOUs on a "first-come" basis with few qualifications or barriers. Unlike the present contracting efforts of the state's IOUs, few attempts were made to reduce the risk of contract failure (the QF projects at the time did not face extensive due diligence, bid deposits, performance guarantees and so forth). These factors suggest that the failure rate of the QF contracts may be higher than one would expect today.

On the other hand, the QF contracts were attractively priced, ensuring that developers would have every reason to push their projects to completion. In addition, projects at the time did not always face the same siting, permitting, and resource supply competition issues faced by renewable energy developers today. These factors suggest that historical QF failure rates could in fact be *lower* than might be expected in the present contracting environment. Because of these opposing influences, one cannot say *definitively* whether this historical experience

documents failure rates that are likely to be lower or higher than might be experienced today.

California Production Incentive Auctions

To support utility-scale, grid-supply renewable energy projects in California, the California Energy Commission held three auctions of five-year production incentives between March 1998 and June 2001, awarding a total of approximately $242 million to 81 projects representing about 1,300 MW of capacity. Twelve projects (15 percent) were subsequently canceled due to an inability to meet funding milestones, while 47 projects (58 percent) have come on-line, leaving 22 projects (27 percent) still pending. In capacity terms, 38 MW (3 percent) have been canceled, and 488 MW (37 percent) have come on-line, with 777 MW (60 percent) still pending. Table 3 breaks down project status by technology.

Table 3. Status of Energy Commission's New Renewable Facilities Program, through June 2005[14]

Technology	Total		On-line		Canceled		Delayed/Pending	
	Projects	MW	Projects	MW	Projects	MW	Projects	MW
Biomass	3	19	2	11	1	8	0	0
Digester Gas	1	2	1	2	0	0	0	0
Geothermal	4	157	2	59	0	0	2	98
Landfill Gas	27	77	14	36	10	27	3	13
Small Hydro	5	33	3	31	0	0	2	2
Waste Tire	1	30	0	0	0	0	1	30
Wind	40	986	25	348	1	3	14	635
TOTAL	**81**	**1306**	**47**	**488**	**12**	**38**	**22**	**777**

To receive the full five-year production incentive, projects from the first auction were originally required to be on-line before the end of 2002, projects from the second auction prior to the end of 2001, and projects from the third auction by July 2003. Though legislation subsequently extended those deadlines for projects that could demonstrate that the delays resulted from circumstances beyond their control, it is nevertheless clear that those projects that are still pending (i.e., 27 percent of all projects, representing 60 percent of all capacity) are well behind schedule. The principal reason for the delays is that projects have been unable to secure power purchase agreements that would allow the projects to proceed.[15] This situation was greatly exacerbated by the electricity crisis that roiled the market in 2000-01 and pushed the state's largest investor-owned utility into bankruptcy. Looking ahead, at least some of these pending projects will likely be built to supply California's RPS; these projects will then choose between receipt of their production incentive award or any available supplemental energy payments.

Although the highly abnormal market conditions that appeared in 2000-01 would have inhibited the development of many of these projects regardless of the stringency of the auction process, it is worth noting that the Energy Commission auctions were not intended to guarantee project completion. Instead, they were price-oriented auctions open to any eligible renewable technology, with relatively lenient milestones and relatively lenient measures to reduce the risk of contract failure.[16] For this reason, and because production incentives by their nature offer only a portion of the overall revenue requirements of a renewable facility (unlike PPAs), we believe that the degree of project success/failure under this Energy Commission program offers relatively little guidance for the future of utility renewable energy RFOs in the state.

Recent IOU Contracting Efforts

California's IOUs have recently embarked on one of the most aggressive renewable energy contracting efforts witnessed internationally since California's experience with QFs in the mid-1980s. Some experience with contract failure is now available from these early efforts, and a significant level of project delay and possibly failure appears likely. Experience is limited, however, and much more data will be available in the coming years.

PG&E

PG&E has signed renewable energy contracts through its 2002 interim solicitation, its 2004 renewable energy RFO, and through bilateral negotiations. PG&E's most recent contracting experience includes three new and one repowered wind projects from its 2004 RFO (195-233 MW) and two pre-existing but currently inoperable biomass projects (18 MW). Because contracts for these projects have only recently been signed, and all but one have on-line dates of 2006 or later, it is too early to know whether they will all succeed in achieving commercial operations without delay.[17]

PG&E also signed contracts under its 2002 interim solicitation and via bilateral negotiations in 2003 and 2004. With the exception of two wind repowers, these contracts were with existing renewable generators for which the risk of contract failure should be near zero. Of the two wind repowering contracts, one 18 MW project is now on-line, and the other 37.6 MW contract has been cancelled (though the associated project won a new contract under PG&E's 2004 RFO).

More generally, PG&E reports that biomass fuel availability and wind turbine availability and cost appear to be the most significant risks for their current projects, and that a key challenge is to walk the fine line between making contract terms stringent enough to reduce the risk of contract failure, but not so stringent as to reduce competition and inflate prices.

SCE

SCE aggressively signed contracts for new renewable generation based on its 2003 RFO, with eight contracts totaling 664 – 1,353 MW of capacity. These projects have had signed contracts for a brief period, and contract failure cannot yet be comprehensively assessed (when signed, the projects had expected on-line dates of late 2006, at the earliest). However, in its supplement to its long-term renewable procurement plan filed on December 7, 2005, SCE notes that *at least* six of these eight projects are unlikely to achieve commercial operations by 2010, due in large part to the time requirements for transmission expansion. This suggests that at least six of the eight contracts (75 percent) will, at a minimum, experience significant delay relative to originally planned on-line dates.[18]

SCE also signed four wind repowering contracts in 2005 (37 MW); SCE believes that all four are currently on-track. SCE's interim solicitation in 2002 yielded a number of additional contracts, four of which were for new renewable generation (the majority of the contract capacity was for existing geothermal capacity from the Geysers). Of those four contracts, two have subsequently failed: the 5 MW TrueSolar project, which ultimately failed to gain regulatory approval from the CPUC; and a large North American Power Group biomass facility, which apparently also failed to receive needed regulatory approvals from the CPUC for siting purposes. The other two projects are small (2.5 MW each) landfill gas facilities that are currently on-line. These data suggest, on a project basis, a failure rate of 50 percent.

In discussion, SCE reiterated the need for new transmission as its main concern. Of particular concern is that transmission upgrades have a four- to seven-year time horizon, while the PTC only has a two-year time horizon. SCE also noted that wind turbine prices have risen dramatically, in part due to the boom-and-bust cycles created by the PTC, putting wind projects at some risk. Finally, SCE mentioned that the acceleration of the RPS targets to 20 percent by 2010 could further aggravate contract failure rates, as utilities are required to go deep into the pool of possible projects and potentially sign up projects that are earlier in the development cycle.

SDG&E

Under its 2004 RFO, SDG&E signed contracts with 524 – 1,124 MW of new renewable generation capacity. Because contracts for these projects have only recently been signed, and most presumably have commercial operation dates of 2006 and later, it is too early to know whether they will succeed in achieving commercial operations without delay. In 2004, SDG&E also signed contracts through bilateral negotiations with a 4.5 MW hydro facility, a 45 MW biomass project, and a 51 MW wind project, with expected on-line dates late-2005, late-2006, and mid-2006, respectively. We understand the 51 MW wind project to be on schedule but that the biomass project now has a projected on-line date of mid-2007; we are not aware of the status of the hydropower project.

Of more relevance, SDG&E signed 15 renewable energy contracts under its 2002 interim renewable energy solicitation, many of which called for the construction of

new renewable generation facilities (CPUC Resolution E-3867). Though details on each of these contracts are not publicly available (and SDG&E did not respond to our interview attempts), some information can be gleaned from public sources. According to an October 19, 2004, factsheet provided on SDG&E's Web site[19], for example, only 12 of these contracts were apparently still in force as of that date, of which only six are clearly identified as new projects. Assuming that three projects did indeed fail, that those projects were to be newly constructed, and that the other six projects have achieved commercial operations, SDG&E's overall success rate for new project contracts under its 2002 RFO was apparently 67 percent on a project basis (six out of nine; information on the capacity of the failed contracts is not public). Five of the six new projects did, however, experience delays before achieving commercial operations (CPUC Resolution R-3867 and R-3883), representing 102 MW of the 110 MW of new capacity under contract at that time (83 percent of the new projects and 93 percent of the capacity experienced delays).[20] All six projects are apparently now operational.[21]

The result of these delays and failures was that SDG&E's actual incremental deliveries contributed 70 percent and 50 percent of the predicted amount for 2003 and 2004 had all projects operated as originally scheduled.[22] According to SDG&E's latest RPS compliance filing, 2005 incremental deliveries are expected to be approximately 70 percent of the projected level had all of the contracts from its 2002 interim solicitation resulted in on-schedule deliveries.

Summary

Each of the state's IOUs is making efforts to reduce the risk of contract failure. Due diligence is conducted by each utility, proposal submission (or short-list) fees of various forms have been required, credit requirements are imposed, pre-operation deposits and milestones have been established, and operational performance guarantees are in place. Many of the details of these requirements are not made public, however, and are often subject to private negotiation among the parties. Additionally, the state's utilities do not take a uniform approach to these requirements and evaluation protocols, and the level of stringency applied is the subject of significant utility discretion.

What is clear is that the tools used by the state's IOUs to date to reduce the risk of contract failure have not been altogether successful. It may be useful in the future to more carefully scrutinize the different approaches used by the state's IOUs to reduce contract failure, document early experience with those various measures, and compare in some detail the approaches used in California with those applied in utility solicitations elsewhere in North America. Given that measures to combat contract failure may often have the unfortunate effect of restricting competition and raising bid prices (both of which would be to the detriment of the state's ratepayers), we strongly recommend that any further efforts to explore the practices of the state's IOUs to reduce contract failure consider these countervailing influences as well.

Other North American Utility Experience

Other North American utilities have considerable recent experience with renewable energy contracting, and contract failure. Before conducting our own interviews with these utilities (listed in Table 1), we performed a limited literature search to assess whether similar information had been gathered previously.

We identified one dated, but relevant, study that was completed on behalf of Hydro-Quebec in 1994.[23] The author of this paper completed a utility survey quite similar to our own. Excluding utility "pioneers" (which include the California IOUs, reported earlier, and Maine), data for that study came from 21 utilities that had procured renewable energy through competitive (and often all-source) solicitations and standard offer contracts in the late 1980s and early 1990s. A total of 318 renewable energy contracts representing 2,333 MW of renewable capacity are included in the sample; contract success rates are summarized in Table 4. Success rates, as defined by on-line projects at the time of the survey, averaged 83 percent on a project basis and 60 percent on a capacity basis. Considering on-line projects and those still under development, success rates are even higher: 93 percent on a project basis and 92 percent on a capacity basis.

Table 4. Success Rates for Historical Utility Renewable Energy Contracts

Technology	Signed Contracts		On-line Project Success Rate (%)		On-line and Under Development Project Success Rate (%)	
	Projects	MW	Projects	MW	Projects	MW
Biomass	46	898	57%	45%	85%	87%
MSW	33	815	76%	85%	88%	93%
Hydro	173	358	91%	83%	97%	99%
Wind	66	262	82%	4%	91%	94%
TOTAL	**318**	**2333**	**83%**	**60%**	**93%**	**92%**

Though a relatively large sample, this early experience is not altogether relevant in today's market conditions, for the same reasons as presented earlier for the California PURPA QF results. Because of this, we chose to conduct our own survey of more recent utility experience with renewable energy contracting.

Utility Respondents and Contracting Context

Fifteen IOUs, eight POUs, and two government entities were interviewed for this report. Of those, four IOUs are not included in the data presented below because they either own their renewable assets or had only contracted with *existing* renewable energy plants, leaving a total pool of twenty-one respondents.

Each interview started by asking how many distinct renewable energy RFOs the respondent utility had issued in recent years. Where more than one RFO had been

issued, data were entered separately for each RFO. This explains why 21 respondents produced 29 separate data points in some of the results that follow (each data point represents a distinct RFO, or in the event that a utility did not use an RFO process, the utility's entire renewable contracting experience).

As shown in Table 5, in all, nineteen utilities report that they have issued twenty-five distinct RFOs for renewable energy; five of these RFOs resulted in no signed PPAs[24], but are included in the present study because they provide additional data on approaches used to mitigate the risk of contract failure. The other four data points came from utilities that had chosen to purchase some of their renewable energy through processes other than an RFO (i.e., bilateral negotiations). Utility respondents reported that they had signed 74 power purchase contracts for renewable energy, 81 percent of which derived from an RFO process. These contracts represent 2,857 MW of renewable energy capacity, 76 percent of which came through RFOs.

Eighteen utility respondents were seeking only PPAs with renewable energy developers, while one respondent was looking only for projects to own, and one other was seeking to purchase only unbundled RECs. One utility was seeking either PPAs or project ownership.

Table 5. Summary Information on Utility Respondents and Renewable Energy Contracting

Number of usable utility respondents	21
Number of utilities that relied upon at least one RFO	19
Number of distinct renewable energy RFOs	25
Number of non-RFO contracting efforts	4
Number of total renewable energy contracting "data points"	29
Number of RFOs that resulted in no PPAs	5
Number of utilities only seeking renewable energy PPAs	18
Number of utilities only seeking project ownership	1
Number of utilities only seeking unbundled RECs	1
Number of utilities seeking PPAs or project ownership	1
Number of signed renewable energy contracts	74
Megawatts of signed renewable energy contracts	2,857

Motivation for Renewable Energy Contracting

The dominant motive for renewable energy contracting among our sample is RPS requirements (16 data points, representing 1,938 MW of capacity). Internal utility

renewable energy targets (five data points, representing 459 MW of capacity),[25] integrated resource plans (five data points, representing 285 MW), and voluntary renewable energy demand (three data points, representing 175 MW) were also identified. Table 6 shows the contract motives.

Table 6. Contract Motives

Motive	Number of Data Points	Percentage of Data Points	Capacity (MW)	Percentage of Capacity
RPS	16	55%	1938	68%
Internal Target	5	17%	459	16%
IRP	5	17%	285	10%
Green Power	3	10%	175	6%

Technology Selection

Of the 74 renewable energy contracts, wind power was the overwhelming technology of choice, representing roughly half of all of the contracts and 85 percent of the renewable energy capacity under contract. Wind was followed by landfill gas, with 20 percent of the projects and 3 percent of the capacity. Geothermal, biomass, solar, hydropower, and other[26] all had three to five signed contracts each, and 1 to 5 percent of the contracted capacity. (See Figure 1 and Figure 2). The dominance of wind in our sample makes it somewhat difficult to extrapolate the results of our research to technologies other than wind.

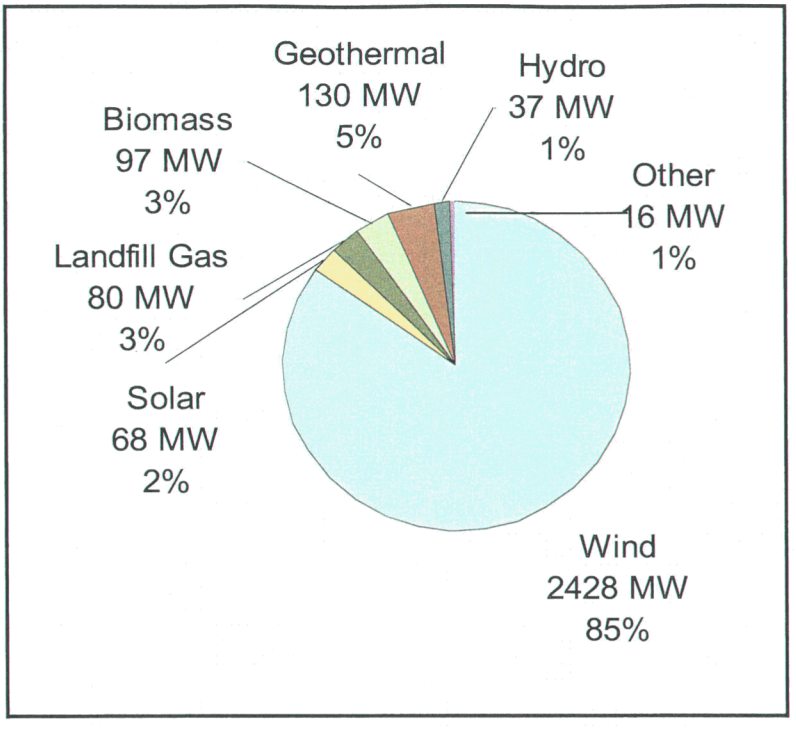

Figure 1. Total Contract Capacity (MW), by Technology

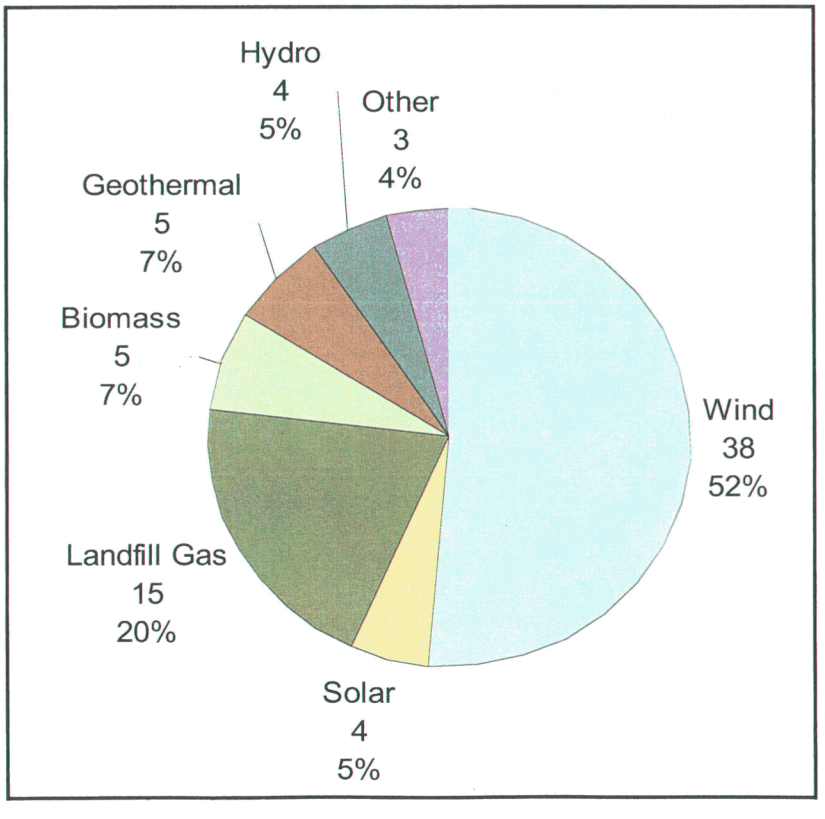

Figure 2. Total Number of Contracts, by Technology

Aggregate Contract Status and Success Rates

Just over *half* of the seventy-four renewable energy contracts in our overall sample can be categorized as successful (defined as projects that are either on-line or are scheduled to come on-line on schedule), whether represented by capacity (53 percent; 1,521 MW out of a total of 2,857 MW) or by number of projects (51 percent; 38 out of 74 projects). These results are shown graphically in Figure 3 and Figure 4. This success rate may drop to the extent that currently on-schedule projects ultimately fail to meet their schedules, or are unable to come on-line. On the other hand, if projects that are currently experiencing significant delays or are in default, achieve commercial operations at expected production levels, then the success rate could rise.

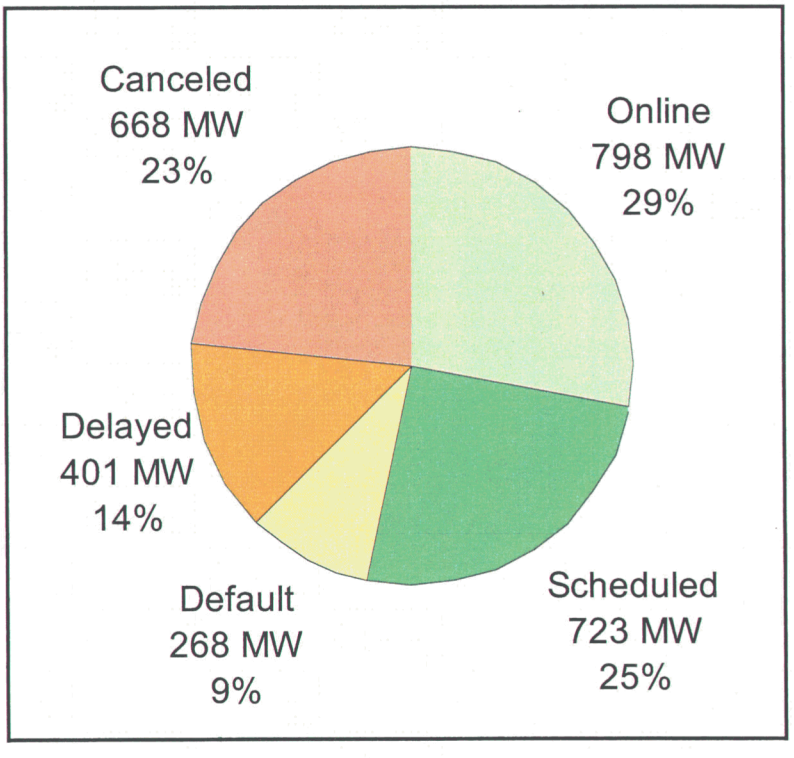

Figure 3. Contract Status, by Capacity (MW)

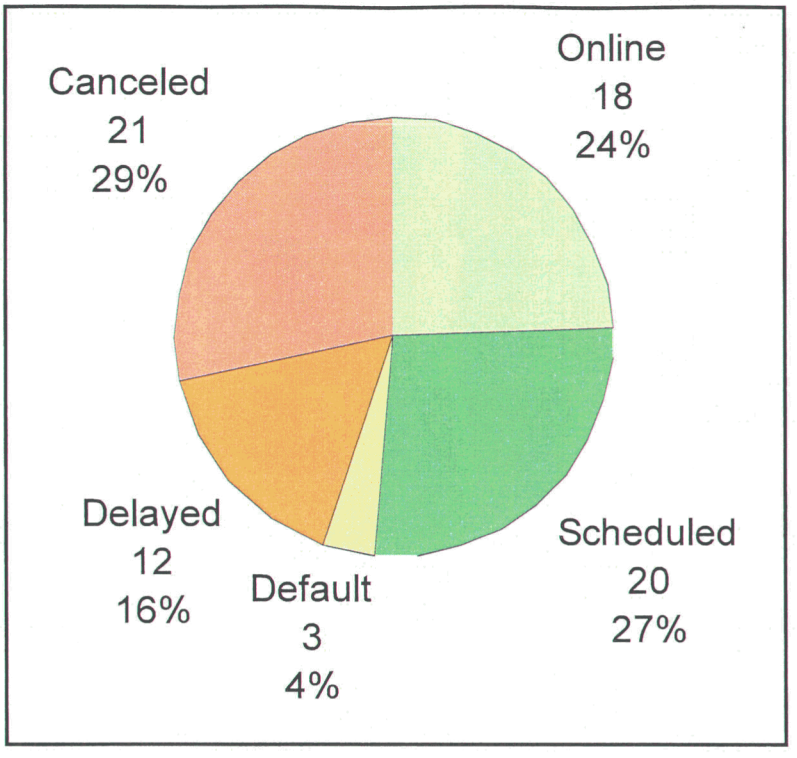

Figure 4. Contract Status, by Number of Projects

The data also provide information on the various types of contract failure. Absolute project cancellation rates are at 23 percent and 29 percent on a contract and capacity basis, respectively. We expect these figures to rise as projects that are now delayed or are scheduled to come on-line encounter difficulties. Projects that are significantly delayed constitute 14 percent (capacity basis) and 16 percent (project basis) of our sample, while projects that are on-line but are not maintaining contracted production levels (in default) equal 9 percent (capacity basis) and 4 percent (project basis).[27]

Contract Success by Technology Type

Figure 5 and Figure 6 show contract status by renewable technology type, in an attempt to discern whether certain kinds of renewable technologies witness higher levels of contract success, on average. Of the 38 wind contracts, 47 percent appear to be succeeding at this time, while 73 percent of the fifteen landfill-gas projects appear to be succeeding. On a capacity basis, success rates were 57 percent for wind (1,372 MW of 2,428 MW) and 87 percent for landfill gas (70 MW of 80 MW). Based on these results, it appears as if contract success rates for wind power are significant lower than those for landfill gas.

For each of the other technologies in our sample, including solar, hydro, biomass, and geothermal, there were too few data points to meaningfully evaluate technology-specific success rates. When combined into one category, however, this category

experienced lower success rates than wind or landfill gas: 43 percent of projects (9 of 21) and just 23 percent of capacity (80 MW of 349 MW). Project delays appear particularly problematic for these projects. Based on our overall sample, we are left to conclude that landfill gas projects have (on average) generally experienced the fewest problems in achieving commercial operations, while wind projects have encountered more significant problems and other renewable technologies have fared even worse.

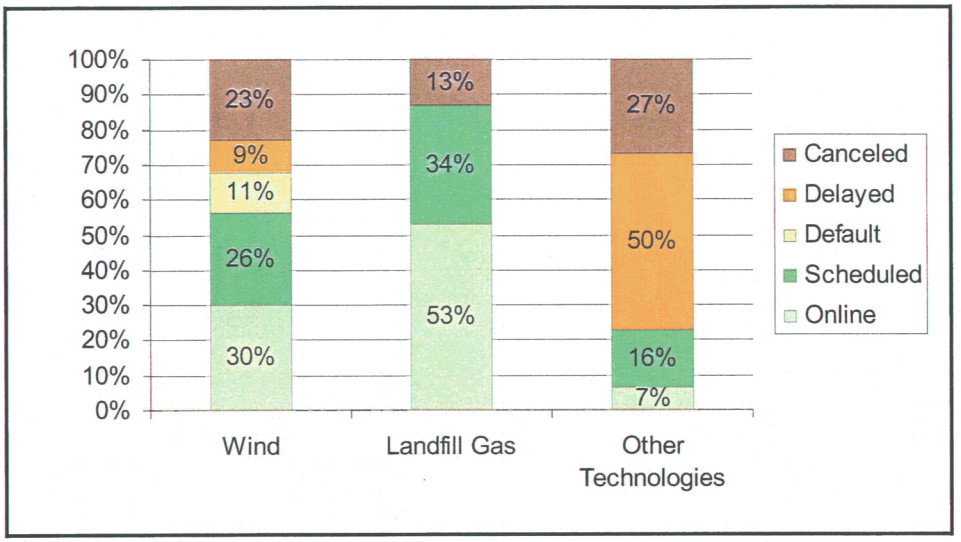

Figure 5. Success and Failure Rates by Technology (by Capacity, MW)

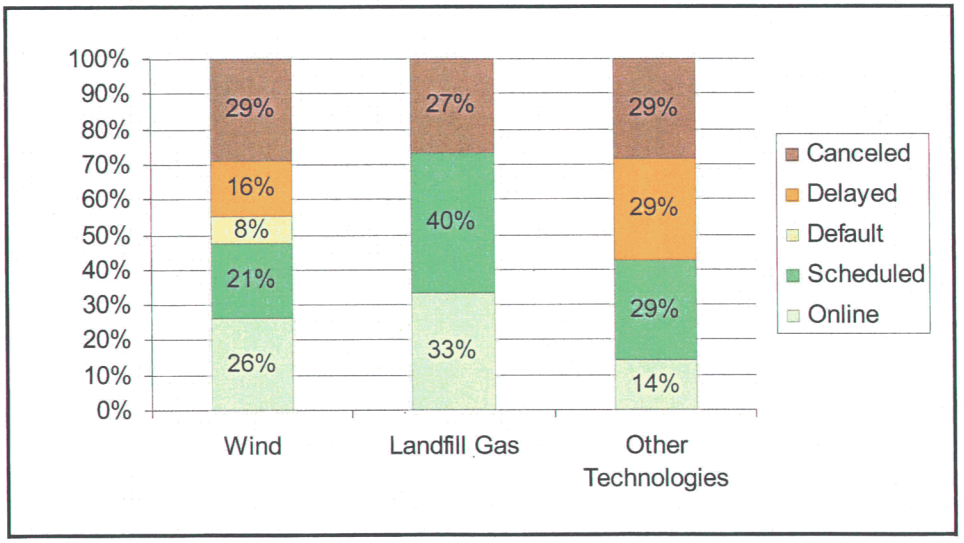

Figure 6. Success and Failure Rates by Technology (by Number of Projects)

Contract Success Rates by Utility RFO

The degree of contract success varies not only by technology, but also by utility and solicitation. Specifically, 12 of the RFOs in our sample and all four non-RFO contracting efforts have experienced some degree of contract failure, while 8 RFOs had 100 percent contract success rates. Figure 7 shows the contract success rates for these 24 RFOs and contracting efforts in histogram form.

These data illustrate that contract failure rates are far from uniform across utilities and solicitations, and appear bimodal, with many utilities experiencing low or no failures, and many others experiencing extraordinarily high rates of contract failure. Some of this disparity reflects the fact that many of the utilities in our sample have only signed one or two renewable energy contracts. If the data are restricted to only larger RFOs (specifically, those that resulted in two or more contracts with a combined capacity of 50 MW or more), the number of data points drops from 24 to 9, and the distribution becomes less bimodal, as shown in Figure 8. There remains, however, a considerable degree of disparity across solicitations.

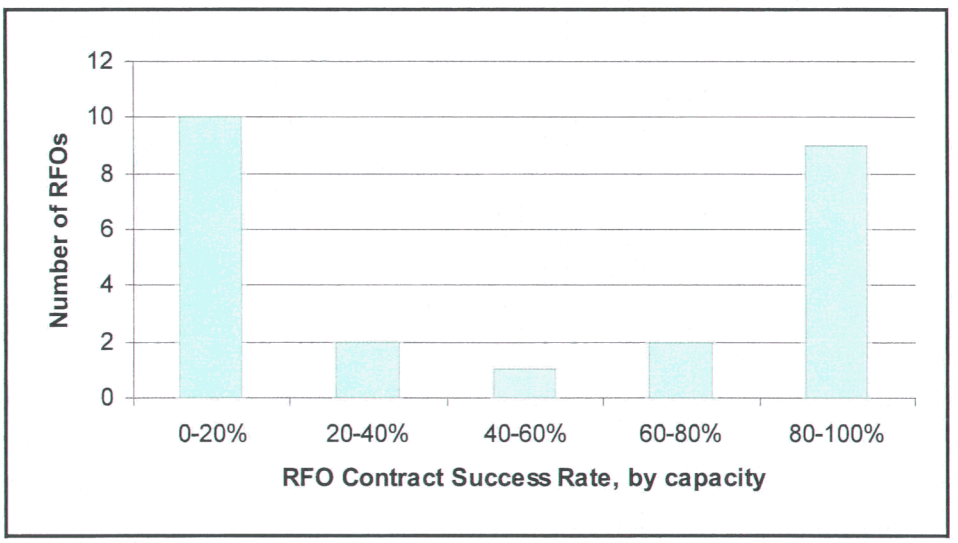

Figure 7. Contract Success Histogram (All RFOs)

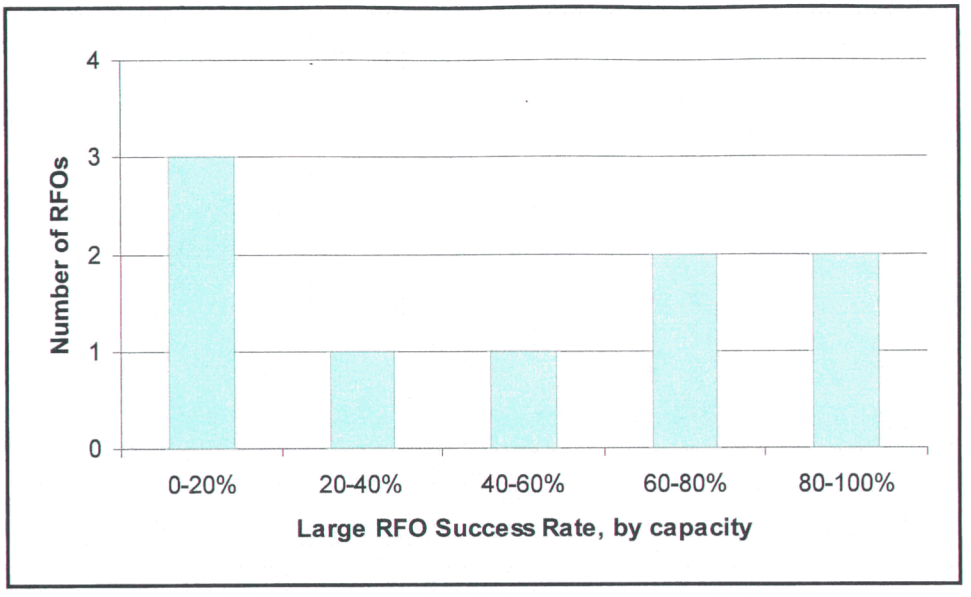

Figure 8. Contract Success Histogram (Larger RFOs)

Some of the remaining variation in contract success should reflect the degree to which a variety of procurement strategies are used to reduce the risk of contract failure. The specific approaches used by utilities in our sample are described later. Here we simply note that from our data, at least, we were unable to discern a strong correlation between the contract success rate of RFOs and either the number of mitigation strategies employed by the utility or the level of due diligence performed. This may simply reflect data limitations, or it may reflect the fact that many other factors also come into play in determining the fate of individual contracts and that overall market conditions can have a significant effect on contract status. With the data collected for this project, we are unable to tease apart these various influences.

Failure Causes

The causes of contract failure vary. Figure 9 shows the number of times particular failure causes were cited by respondents as an issue for contracts that they had signed. It is important to note that this information was not consistently collected on a project-by-project basis and is instead presented for each of the 12 RFOs that experienced some degree of contract failure in combination with four utilities that experienced contract failure outside of an RFO setting.

The top causes of contract failure include siting and permitting issues, developer financing troubles, capital cost increases, and transmission and interconnection issues. Many respondents specifically commented on the recent rise in wind turbine costs as being particularly problematic. Biomass projects, on the other hand, appear to be more significantly constrained by resource availability. Interestingly, only one respondent noted problems with technology as being a factor in project failure; this may be a result of the dominance in our sample of wind power, a relatively mature technology. Issues associated with the credit quality of the purchaser (utility finance)

were only identified in the two Nevada RFOs, where the state's major utility has faced significant credit concerns in recent years. In addition to financing challenges, the Nevada utilities (in their December RPS compliance plan filing to the Nevada utilities commission) also note as problematic the tendency for developers to propose speculative projects, the lack of experience by some of the sellers, and the inability of suppliers to negotiate with subcontractors necessary to develop their projects. In fact, the Nevada utilities observe that the lowest-price bids that they have received have often come from the developers with modest or non-existent track records, while more experienced developers have tended to offer the highest prices. Other utilities confirmed this view.

Not surprisingly, many of the failure causes are interrelated. One respondent, for example, noted that a developer it was working with did not understand the complexity of transmission issues, and the resulting delay meant wind turbine prices had increased, making the project uneconomic. Other examples included developers having difficulties securing a site and incurring delays that then made the project unable to receive the PTC or unable to obtain a turbine order. The most unusual anecdote was of a Midwest wind farm that had experienced delays due to PTC and turbine availability but ultimately failed because the project's funding dried up when its Japanese investor became spooked by possible bat deaths.

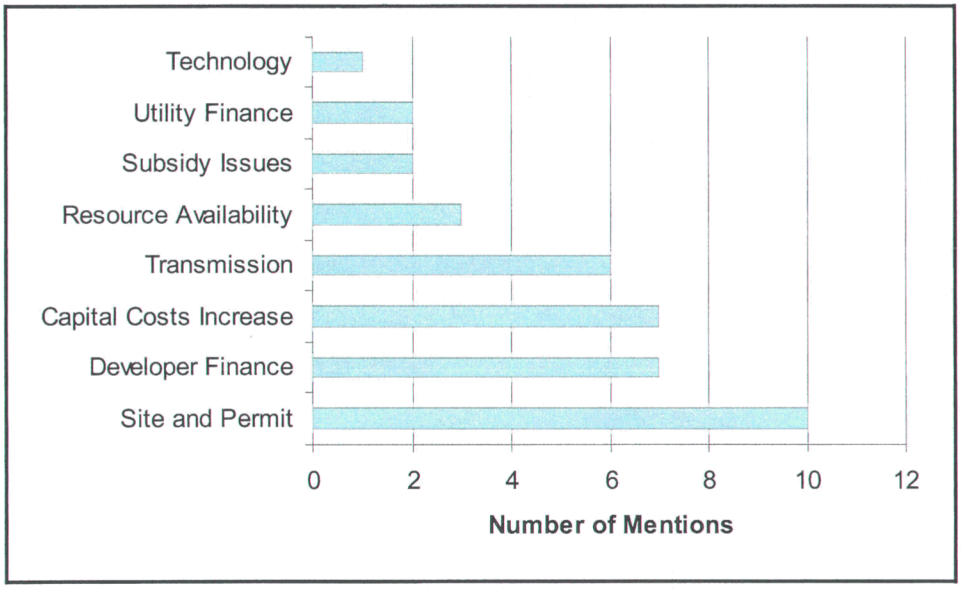

Figure 9. Causes of Contract Failure

Mitigation Strategies

A variety of procurement strategies can be used to reduce the risk of contract failure. A persistent theme that emerged from the interviews was that contracting for renewables has often been a delicate balancing act: requirements in the PPAs or the RFO process that are unduly stringent can seriously limit the number of developers willing to enter into contracts (increasing prices), but requirements that

are too loose can easily result in high rates of project attrition and contract failure. It was also recognized that even with stringent requirements that seek to ensure project success, overall market conditions can still result in contract failure.

Ultimately, each utility has had to choose what level of stringency to apply, and utilities have sometimes altered these requirements over time. Our interview respondents disagree on these various strategies, with some choosing to be more stringent over time as experience has been gained, and others moving in the opposite direction. There also does not appear to be a consistent view about which of the various strategies are optimal, and a great deal of experimentation is therefore still taking place.

Though each mitigation strategy can itself vary in its level of stringency (for example, due diligence might be limited or extensive, and performance requirements can be strict or somewhat more lenient), we had neither the budget nor time to exhaustively collect these details; in future work, it may be useful to seek additional information in this area. Here we simply report the number of respondents who indicated that their utility had used various mitigation strategies in their renewable energy procurement and contracting efforts.

Figure 10 presents the mitigation strategies used by our utility respondents. The most commonly cited approaches include due diligence, operational performance guarantees, and pre-operation milestones/bid deposits. Experience with each of these approaches is discussed in more detail below.

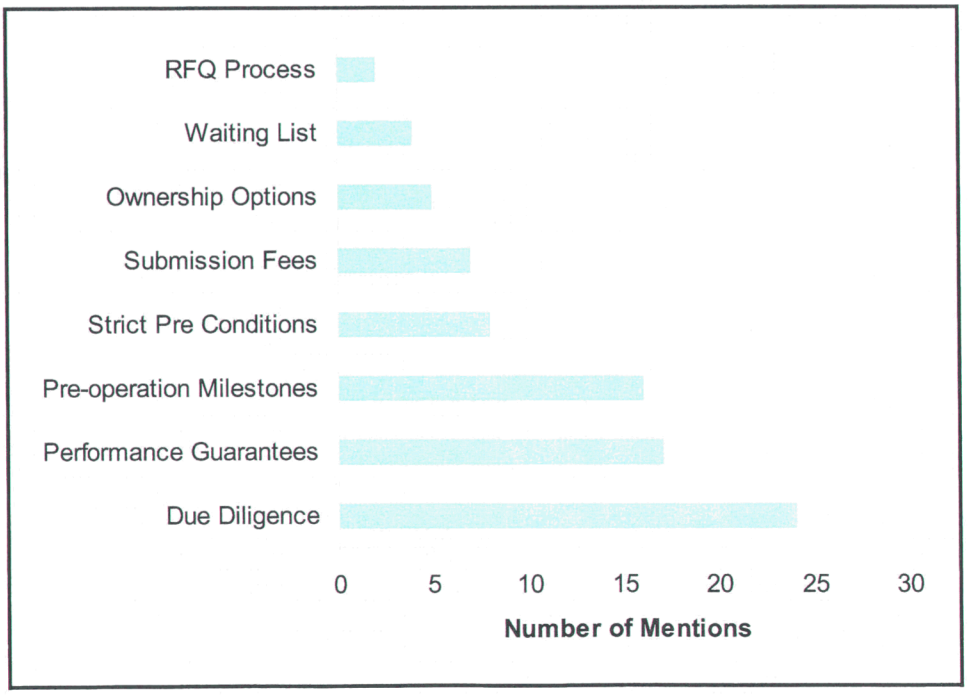

Figure 10. Use of Mitigation Strategies

Request for Qualifications

Two utilities specifically mentioned working only with developers that the utility had worked with in the past or came highly recommended. This "pre-vetting" process gave these utilities confidence that the projects so selected would be successful and helped the utilities avoid the time and expense of negotiating with developers who may ultimately not be able to complete projects. These two utilities effectively bypassed the RFO process altogether and simply approached trusted developers (or vice versa) when they needed projects. Though only these two utilities in our sample used a Request for Qualifications (RFQ)-like process, a few additional utilities were contemplating using a more formal RFQ approach in the future. For example, Nevada's IOUs have experienced a high degree of renewable energy contract failure and have proposed to address this (in part) by using an RFQ process or by more heavily weighing non-price considerations in bid evaluation. Other utilities expressed the view that inclusiveness would increase competition and drive down prices and that an open RFO process was likely to achieve better results than one in which an RFQ narrowed the list of eligible bidders.

Waiting List

The three utilities (one utility had two RFOs, resulting in a total count of four in Figure 10) that specifically mentioned using a waiting list said it was more of an informal "second tier" of short-listed projects that could be contacted if PPA negotiations broke down with the first-tier of projects, or if a contracted project failed early in the development process. Waiting lists do not help avoid contract failure, but they can provide a backup pool of possible projects in the event that projects do fail and a utility does not want to go back to the market with a new RFO.

Ownership Options

Two utilities issued RFOs that specifically allowed utility ownership options, and two others mentioned considering ownership as a mitigation strategy that they might use in the future. One utility, faced with two failing wind projects, chose to purchase the development rights from these projects and plans to build and operate the plants themselves. Another utility uses a unique structure where an unregulated subsidiary takes a passive equity investment in renewable projects once they have a signed PPA and PUC approval. Though this structure allegedly aligns the interests of the developer and the utility, it does not appear to have increased contract success rates for this particular utility.

Submission Fees

Submission fees have been employed by five utilities (two utilities had two RFOs each, resulting in a total count of seven), though the stringency of these fees likely varies considerably. Many others commented that such fees are particularly disliked by developers. To partially accommodate this concern, some utilities have applied submission fees only once projects make the shortlist. Other utilities stated that they have so far chosen not to use submission fees to ensure that as many projects as possible bid into their RFOs.

Strict Pre-Conditions

Strict pre-conditions for proposal submission have also been used by five utilities (some utilities had multiple RFOs, hence a total count of eight). One utility, for example, required that project proposals include clear commitments from equity partners and that projects identify potential lenders and submit letters from those lenders indicating that (1) they had read the RFO, (2) they had reviewed the proponent's financial model, and (3) they were either highly confident that they would finance the project or already had agreements in place to do so. Such strict requirements ensured that only viable projects would bid, and all projects selected under this RFO are on schedule. Not surprisingly, many developers did not like these requirements and expressed concern that competitive prices were to some degree sacrificed in the name of ensuring project viability and that smaller developers were disadvantaged relative to their larger competitors. In another case, a utility made a firm wind turbine order a pre-condition for submitting a bid under its latest (2005) RFO as a result of the recent shortage of wind turbines. The Nevada IOUs, meanwhile, are considering the development of strict pre-conditions for developer financial strength and experience that are scaled to the size of the project bid (larger projects would be required to meet a higher threshold). Proffering the opposing view on strict pre-conditions, one utility respondent said that it was more efficient to cull proposals based on various evaluation criteria than to rigidly require all projects to meet certain strict pre-conditions, especially when each project is unique.

Pre-Operation Milestones

Pre-operational milestones with deposits were among the most popular of the mitigation strategies, though the nature and stringency of the milestones and the level of possible deposit forfeiture varies considerably. Future work should seek to collect these details more systematically. One utility respondent noted that it is planning to increase the pre-operation security requirements for its next RFO, as it has found this mechanism to be a helpful way of screening projects. Another expressed the view that stepped increases in milestone security as a project gets closer to commercial operations can be a very useful tool to ensure that maximum effort is being applied to meet pre-defined milestones. Though many respondents advocated stringent deposit requirements and milestones, others argued that this approach can easily drive up the cost of renewable projects and drive away developers, further eroding competition. One utility said that it had established milestones and deposits but had chosen not to rigidly enforce these contract provisions in a number of instances in which the project was still making (delayed) progress towards commercial operations out of fear that strict enforcement could have severely reduced the ability of the projects to come on-line at all.

Performance Guarantees

Operational performance guarantees (taking the form of electrical production guarantees of various forms, or liquidated damages for construction delays) were possibly the most controversial topic. Though performance guarantees are clearly

common, there is less agreement on the appropriate level of stringency. Many of the utility respondents felt that making damages too high would drastically reduce the pool of developers, while others felt that without some sort of performance guarantee they would get "burned" by developers.

Due Diligence

Some form of due diligence was used by the vast majority of utility respondents. Many of these utilities reported that they placed a great deal of emphasis on due diligence and that their evaluation processes were extensive, all of this to help ensure that only truly viable projects would earn contracts. Though this approach has reportedly worked well for many utilities, some of the smaller utilities noted that they simply lacked the time and expertise to engage in such extensive due diligence. In collecting data, we categorized due diligence as either "low" – meaning a cursory review of developers' history and financing, "average" – a more in depth look at the technology, developer financing and experience, as well as site control; and finally "extensive" – a thorough investigation of all aspects of the proposed project. Of the 24 data points for due diligence, 3 utilities practiced "extensive" due diligence, 4 were rated "low", and the rest were "average." One respondent specifically hoped that extensive due diligence could help reduce the risk of contract failure and replace the need for restrictive security and performance guarantees. A different respondent, on the other hand, noted with concern that extensive due diligence can take a considerable amount of time, yielding delays and potentially leading to lost projects. A final utility reported that it hoped to limit the degree of due diligence in future solicitations and instead rely more heavily on pre-operation milestones and deposit requirements.

Other Strategies

Several other strategies, not otherwise included in the categories above, were mentioned by one or more of the interview respondents.

- Utility finance: In response to concerns about the impaired credit of the state's utility and the resulting difficulty for developers in accessing financing, Nevada has created its Temporary Renewable Energy Development (TRED) program. Through this program, a predetermined allocation of funds collected by the state's electric utilities are placed in a third-party trust that will disburse payments to renewable energy developers for the electricity sold to the utilities. By creating a separate trust, project financiers are guaranteed payment regardless of the financial situation of the utility. The Nevada utilities, however, feel that "TRED is not the panacea that everyone thought it would be," because some financiers are still uncomfortable with the poor credit of the utility purchasers.
- Over-contracting: Though not yet approved by the state's regulatory commission, Nevada's major electric utilities have proposed the concept of "design reserves" through which the utilities would agree to over-contract with renewable generators in order to build a procurement cushion of 15 percent above the annual RPS obligation; this extra supply of renewable energy

certificates could then be used in the event of an undersupply of renewable generation in future years.

- Marketing and noticing: At least one utility indicated that it planned to use a more thorough marketing and noticing strategy in the future to ensure that developers were aware of and had adequate time to respond to its RFOs.
- Regulatory approval: Another utility indicated that it was going to seek assurances from the state regulatory commission that the commission's approval of renewable energy contracts (and disallowance of recovery) would not be decided purely on the basis of price.
- PTC availability: One utility respondent specifically noted that it had taken on PTC risk to help ensure project success. In particular, the utility agreed to pay the developer the value of the PTC, if the PTC was not renewed or accessible to the project.
- Transmission and integration: One respondent noted that it had a separate, unregulated business to assist developers with integrating wind into the transmission grid to reduce transmission problems.

Government Contract Tenders and Incentive Auctions

This section presents renewable energy success rates under government bidding programs. Two types of programs are considered: (1) those that provide successful bidders with a long-term contract for a project's full output, and (2) those that provide successful bidders with more limited forms of financial support – for example, a grant or production incentive. The former type of program has been prevalent in Europe (experience in the United Kingdom, Ireland, and France is covered here), while the latter has been more common in the United States (experience from New Jersey, New York, Pennsylvania, and Massachusetts is covered here; the California Energy Commission's use of this approach was discussed earlier[28]).

Although one might think that the states covered below would provide the closest analogy to California's present contracting activities, the European experience may be more relevant for the purpose at hand – for example, determining contract failure rates. This is because the state programs have provided only partial aid to projects in the form of grants or production incentives and have therefore typically not replaced the need for a long-term power purchase contract for electricity production. The European programs, in contrast, have provided a complete, long-term contract for the project's full output – similar to the PPAs offered by electric utilities covered in the previous section. That said, even the European experience is not as relevant as the US utility experience covered previously in part because market conditions in Europe may be quite different than in the US.

Perhaps of most importance, relatively few steps have been taken by the European or state programs to reduce the risk of contract failure. As discussed in more detail below, certain aspects (either unintended or by design) of the UK and French programs actually *encouraged* speculative projects with a potentially high likelihood of failure. Ireland learned from this experience (and its own), and in later rounds not only over-contracted for capacity, but also required that bidders secure planning and

permitting permission, as well as site control, before bidding. Among the US programs covered here, mitigation strategies have ranged from nonexistent on one end of the spectrum to detailed due diligence, bid bonds, and development and construction milestones on the other.

The United Kingdom

During the 1990s, the UK supported utility-scale renewables primarily through multiple rounds of competitive tenders for long-term contracts. This bidding process was known as the Non-Fossil Fuel Obligation (NFFO) in the UK and Northern Ireland (NI) and the Scottish Renewables Obligation (SRO) in Scotland. All told, there were five rounds of UK-NFFO tenders, two rounds of NI-NFFO tenders, and three rounds of SRO tenders. Table 7 reports aggregate results of this process by technology, updated through the first half of 2005.

In total, the NFFO/SRO tenders have yielded an overall completion/success rate of 50 percent on a project basis and just 33 percent on a capacity basis. The two technologies with the largest shares of capacity under contract – municipal and industrial waste (MIW) and wind – have generally fared the worst, with capacity completion rates of around 20 percent.

Table 7. Combined Status of UK-NFFO, NI-NFFO, and SRO as of June 30, 2005[29]

Technology	Total		On-line		Pending or Canceled	
	Projects	MW*	Projects	MW*	Projects	MW*
Biomass	32	256	9	107	23	149
Hydro	146	95	70	49	76	46
LFG	329	700	242	510	87	190
MIW**	90	1,398	22	261	68	1,137
Sewage Gas	31	34	24	25	7	9
Wave	3	2	1	0.2	2	1.8
Wind	302	1,154	100	246	202	908
TOTAL	**933**	**3,639**	**468**	**1,198**	**465**	**2,441**

* MW are expressed in terms of Declared Net Capacity (DNC), which is the amount of baseload capacity required to produce an equivalent amount of energy over a year (sometimes called an "average MW"). Thus, a 4 MW wind farm with a 25% capacity factor would have a DNC of 1 MW.
**MIW = Municipal and Industrial Waste

There are a number of reasons for the relatively poor success rate in the United Kingdom.[30] First, the UK government was intensely focused on reducing costs, with a stated commitment to reduce the average price per kWh of each successive tender. This practice effectively set the average price for a given technology in the previous tender as a benchmark that all bidders seeking contracts in the following tender must beat. This focus on declining costs, along with the complete lack of a

non-performance penalty, little due diligence, and a lengthy allowed development period (four years for third round of the UK-NFFO, and five years for the fourth and fifth rounds of the UK-NFFO),[31] encouraged generators to bid speculatively based on expectations of declining technology costs. To further increase their chance of securing a contract, developers naturally looked to sites with the strongest renewable resources – which in the United Kingdom often coincide with sensitive areas not always appropriate for development. As a result, many projects were ultimately refused planning and permitting permission.

Ireland

Similar to the United Kingdom, Ireland has also, until recently, supported utility-scale renewables through a process of competitive bidding for long-term (15-year) contracts, known as the Alternative Energy Requirement (AER). Between 1995 and 2003, there were six rounds of AER tenders. Like the NFFO, the AER was a competitive process, with the lowest bids in each technology band being offered contracts, generally (at least in AER I-IV) without regard to qualitative considerations, such as the financial strength of the project or the likelihood of completion.

Table 8 conveys the aggregate results of all six AER tenders, as of June 2005. Out of 1,081 MW awarded contracts, 233 MW have so far come on-line – a success rate of just 22 percent. Though expected commercial operation dates obviously vary by AER round, all AER VI projects (except for offshore wind and biomass-CHP projects, which have until the end of 2006) were expected to be on-line and selling electricity by December 31, 2004. Since AER VI was the last tender, any project (except offshore wind and biomass CHP) not yet indicated as "on-line" in Table 8 can be considered to be experiencing delays, at a minimum.

Table 8. Aggregate Results from AER Rounds I-VI (as of June 2005)[32]

Technology	Total		On-line	
	Projects	MW	Projects	MW
Fossil CHP	27	80	9	29
Biomass CHP	3	27	1	3
Landfill Gas	16	42	>6	22
Digester Gas	9	2	0	0
Waste to Energy	1	30	0	0
Onshore Wind	93	840	>13	175
Offshore Wind	2	50	0	0
Small Hydro	29	10	>10	4
TOTAL	**180**	**1081**	**>39**	**233**

Starting with AER III in 1997, allowances were made for possible contract failure. For example, AER III had a target of 100 MW but awarded contracts to 159 MW to provide a cushion (of 59 percent) in the event of project failure. Similarly, AER V had a target of 255 MW but contracted with 363 MW to provide a 42 percent cushion. More importantly, to try and mitigate relatively poor completion rates in early rounds, the government eventually (for AER V and VI) required that bidders demonstrate site control, as well as full planning and permitting permission.[33] Results of these mitigation strategies are so far mixed – as of June 2005, AER V and VI's overall capacity completion rates were just 12 percent and 16 percent, respectively, though projects reportedly in construction at that time will, if completed, push AER VI's success rate up to 61 percent.

France

In February 1996, France launched the "EOLE 2005" program, with an objective of bringing 250-500 MW of new wind power capacity on-line by 2005. As in the United Kingdom and Ireland, the "EOLE 2005" program was based on a series of competitive tenders for long-term contracts. Price was the primary criteria, though other factors were considered as well. Successful applicants were awarded a contract with EDF (France's electric utility), and had three years to come on-line (or else risk a penalty equal to 1 percent of the cost of the project).

Contracts were awarded through several stages of tenders, with sub-tranches targeting specific types of projects.[34] In aggregate, 55 projects adding up to 362 MW were awarded long-term contracts before the program was discontinued in early 2000. At the end of 2000, only 49 MW of the 362 MW had been built (success rate of 13 percent).[35] This number reportedly increased to 115 MW at the end of 2001 (success rate of 32 percent); we have been unable to obtain more recent data, which would be needed to provide a final, updated success rate.[36]

Though more recent data is not available to gauge project completion post-2001, the EOLE 2005 program is generally considered to have been unsuccessful. Turbine supply problems (one French turbine manufacturer delayed the introduction of its turbines to the market, while a Dutch turbine supplier favored by several projects went bankrupt) and permitting problems reportedly contributed to project delays and low completion rates. Furthermore, a number of the projects awarded contracts were clearly speculative in nature, not yet having measured the wind resource at the time of the tender. The preliminary nature of these projects complicated financing and often resulted in project economics that were ultimately considered to be unviable once further due diligence occurred.[37]

New Jersey

In July 2002, the New Jersey Board of Public Utilities (NJBPU) announced that it had competitively awarded $11.3 million in funding (through a combination of grants and production incentives) to four "grid supply" renewable energy projects: two involving wind power, one involving landfill gas, and one involving photovoltaics (PV). As shown in Table 9, the smaller wind project is in construction and is

scheduled for completion in 2005, the landfill gas project is still in development, and the PV and larger wind projects have been canceled.[38] This solicitation therefore currently has a project completion rate of 25 percent (22 percent in capacity terms), with 50 percent of projects (66 percent in capacity terms) canceled and the remaining 25 percent (12 percent in capacity terms) pending.

Table 9. Status of NJBPU 2001 Grid Supply Solicitation

Technology	Total		On-line		Canceled		Pending	
	Projects	MW	Projects	MW	Projects	MW	Projects	MW
Wind	2	29	1	8	1	21	0	0
LFG	1	4	0	0	0	0	1	4
PV	1	1	0	0	1	1	0	0
TOTAL	**4**	**34**	**1**	**8**	**2**	**22**	**1**	**4**

This relatively poor success rate is reflective, in part, of the lenient nature of the solicitation. Projects were essentially allowed to dictate their own development schedule (as long as it did not exceed one year for design, one year for permitting, and two to three years for construction), and there were no bid bonds or other financial commitments to discourage speculative bids. Proposals were, however, evaluated by an independent advisory committee of industry experts, in part for viability.

New York

Through the New York State Energy Research and Development Authority (NYSERDA), New York has conducted three solicitations supporting grid-supply renewable generation facilities, including two exclusively supporting wind projects, and one that supported landfill gas generation projects.[39] NYSERDA also helps administer the state's RPS and has conducted one solicitation under the RPS. Each is summarized below and in Table 10.

Program Opportunity Notice (PON) 498 Wind Project Development. Under this program, NYSERDA ultimately awarded in 1998 a total of $7 million to two wind projects totaling 41.5 MW. Both ultimately came on-line, the smaller project in 2000 and the larger one in 2001. A third wind power project of 10.5 MW was initially selected and awarded $4 million in support. However, the contact was never executed, and the proponent eventually withdrew. The reason for withdrawal of the third project was that permitting was proving to be more challenging than the proponent had appetite for, and ultimately the proponent could not make the economics work and lost interest, to focus on bigger and more-profitable projects in regulated markets where a 20-year PPA with a creditworthy entity was more likely than in New York's deregulated market. The form of support under this program was a mixture of up-front grants (25 percent of incentive dollars) and three years of

quarterly incentive payments made based on project availability (75 percent of incentive dollars).[40]

PON 672 Wind Project Development. Under this program, $17 million of five-year production incentives were awarded in 2002 to five wind power projects totaling 315 MW. These wind projects ranged in *proposed* capacity from 40 to 100 MW. The outcome, however, has evolved due to the adoption of the New York RPS. Specifically, all incentive-based contracts have now been terminated by mutual consent, freeing the proposed projects to compete under NYSERDA's more attractive RPS solicitations (New York's RPS rules require forfeiture of incentive-based payments to be eligible for RPS support). Of the original five projects, one project (the Maple Ridge Wind Farm) is nearing completion (January 31, 2006) at a much larger size of 231 MW (the original proposal was for 100 MW) and now has a contract with NYSERDA under the New York RPS. The other four projects have experienced delays, for a variety of reasons. One project has missed development milestones due to avian impact issues and is behind schedule by more than a year. Another project missed contract milestones because of general local opposition, and the developer refocused its efforts on the larger Maple Ridge project and other prospects. A forth project missed contract milestones because of general local opposition, and the developer ultimately refocused its efforts on its second project under PON 672. This last project is in the midst of an Environmental Impact Statement (EIS) and faces local opposition, and is competing with another project for limited transmission.

PON 732 Alternative Fuels, Power Generation and Energy Storage. Under this program, three landfill gas generation projects totaling 5.2 MW received a total of $1.5 million in support in 2003 and 2004. The structure of the funding consists of 25 percent spread over milestones that end with construction and 75% based on performance over four years. All three projects are still pending.

RFP 916 RPS Solicitation. NYSERDA also serves as the central procurement agent under New York's RPS and in that role will conduct periodic procurements for renewable energy attributes. NYSERDA prepared a standard purchase agreement for RECs and released its first formal Request for Proposals, RFP 916, on December 20, 2004. Contracts were to be a maximum of 10 years in duration and payment for RECs was to be at a fixed $/MWh price. Sealed-bids were submitted for consideration on January 18, 2005, and the initial award group was announced just three business days later. NYSERDA ultimately awarded contracts to seven projects for the rights to environmental attributes (RECs) associated with 281.45 MW of incremental generation. The seven contracts included the full output from two wind projects, a portion of the output from two other wind projects, and incremental generation from three repowered/upgraded hydroelectric projects. By the end of 2005, the three hydroelectric upgrades were already online; two wind projects had been fully commissioned; and a third wind project (the largest at 231 MW) had commissioned 69.3 MW with the remainder under construction. One of the wind farms (21.5 MW under contract) is apparently experiencing some delays. The

contract durations vary considerably, with the shortest term being one year, and the other contracts being either four or ten years.

The results of PON 672 complicate calculations of project success rates. However, assuming that the 100 MW project (slated to come fully on-line in early 2006, at 231 MW) would have achieved commercial operations under PON 672 at 100 MW absent RPS-related contract cancellation, but that the other four projects were not meeting their milestones and are therefore considered unsuccessful, then NYSERDA's combined success rate under PON 672, 498, and 732 has been 38 percent (39 percent if the 5.2 MW of pending landfill gas projects are considered likely to achieve commercial operations). NYSERDA's more recent RPS solicitation will have a much higher success rate: assuming that only the 21.5 MW wind project is ultimately delayed or unsuccessful, NYSERDA's success rate with RFP 916 will be 92 percent. Combining all of the solicitations, an overall success rate of roughly 63 percent has been achieved.

NYSERDA has employed several mechanisms to reduce the risk of contract failure in these programs. Under PON 672, 498, and 732, NYSERDA included performance milestones in the contracts, made performance incentives only available at or after commercial operation, and limited such incentives to no more than five years in duration. Projects were ranked for selection based on incentive levels per kW installed as well as other subjective development criteria. Though these mechanisms are not as stringent as one is likely to see in a utility PPA, they were used to improve the chances of project success. NYSERDA's RPS contracts are more stringent and include performance security and milestones, with security forfeited in the event a project does not reach fruition by a specified milestone. This is likely to be one of the reasons that NYSERDA's contracting success rate has been higher under its most recent RPS solicitation than under earlier PONs.

Table 10. Status of NYSERDA's Renewable Energy Support PONs								
Technology	Total		On-line		Canceled		Pending	
	Projects	MW	Projects	MW	Projects	MW	Projects	MW
Wind: PON 498	3	52	2	41.5	1	10.5	0	0
Wind: PON 672	5	315	0	0	5	315	0	0
Landfill Gas: PON 732	3	5.2	0	0	0	0	3	5.2
Hydro: RFP 916	3	3.2	3	3.2	0	0	0	0
Wind: RFP 916	4	278.25	2 + part of another	95.05	0	0	1 + part of another	183.2
TOTAL	**18**	**653.7**	**7+**	**139.8**	**6**	**325.5**	**4+**	**188.4**

Pennsylvania

In Pennsylvania, the Sustainable Development Fund (SDF) serving PECO's service territory has issued, as part of the Pennsylvania Wind Development Program, several rounds of competitive solicitations to provide a total of $12 million of support to utility-scale wind projects throughout the state. Through this program, SDF support has typically taken the form of $/MWh production incentives, though other forms of financial support (for example, debt financing) have also been available.

Phase I supported two projects, one of which eventually had to relinquish its award due to delays caused by local opposition and legal action, which prevented the project from meeting its contractual milestones. That same project, however, successfully re-applied for incentives under Phase III of the program and eventually came on-line.[41] Three other projects also received funds under Phase III; one of these lost its funding due to an inability to meet contractual milestones. In Phase IV, SDF negotiated a funding award with a single wind project but never actually consummated an agreement because the developer decided to deploy the turbines to a different wind project in another state.

Table 11. Results from the Pennsylvania Wind Development Program							
Program Phase	Year	Total		On-line		Canceled	
		Projects	MW	Projects	MW	Projects	MW
Phase I	2000	2	80	1	15	1	65
Phase III	2002	4	159	3	119	1	40
Phase IV	2005	1	35	0	0	1	35
TOTAL		**7**	**273**	**4**	**134**	**3**	**139**

In summary, a total of seven funding awards have led to four successful project completions (57 percent success rate) and three funding terminations (43 percent cancellation rate). In capacity terms, 49 percent of funded capacity has come on-line, while 51 percent has been cancelled. As mentioned above, one of the three terminated projects eventually came on-line through a subsequent phase of the program. The other two terminated projects are still being developed, though do not currently have access to SDF funding.

SDF has attempted to ensure a high success rate through several means. First, SDF enlisted a team of experts to conduct detailed due diligence on all proposals. Second, SDF used its discretion to fund only those projects most likely to come on-line within the time frame specified by each solicitation (rather than focusing exclusively on the level of the incentive requested, as often occurs in an auction format). Finally, modest application fees and a forfeitable performance security fee (equal to $1,500/MW of capacity) helped to discourage speculative or immature projects.

Massachusetts

In the fall of 2003, the Massachusetts Technology Collaborative (MTC) announced the award of $32 million in funding through the first round of its Massachusetts Green Power Partnership (MGPP) Program to support the financing and construction of new renewable projects.[42] This novel solicitation offered support in the form of either long-term renewable energy certificate (REC) purchase commitments or price supports in the form of REC option agreements. Round 1 awards were made to six projects totaling 98.6 MW of total capacity, including two wind projects, a biomass repowering of a former coal plant, a landfill gas generator, a hydroelectric generator and a grid-supply PV plant. A summary of the awards and their status is shown in Table 12 below.

Table 12. Status of MTC's MGPP Round 1 Supply Solicitation								
Technology	Total		On-line		Canceled		Pending	
	Projects	MW	Projects	MW	Projects	MW	Projects	MW
Wind	2	43.5	0	0	0	0	2	43.5
Biomass	1	50	0	0	0	0	1	50
Landfill Gas	1	3.3	1	3.3	0	0	0	0
Hydroelectric	1	1.3	0	0	0	0	1	1.3
Photovoltaic	1	0.5	0	0	0	0	1	0.5
TOTAL	**6**	**98.6**	**1**	**3.3**	**0**	**0**	**5**	**95.3**

Of the projects securing awards, the landfill gas plant has completed construction; the hydroelectric and biomass plants are under construction and expected to be on-line in 2006. One wind plant is permitted but is still seeking to secure wind turbines in a scarce market; the other wind generator has had its primary permit appealed, with the appeal underway and expected to be resolved one way or the other in the next several months. Finally, the PV project has just secured key financing support and is now set to move forward.

At this juncture, no projects have been cancelled. However, every project not yet completed is moving forward more slowly than initially envisioned, with the exception of the biomass plant, which is still moving according to its contractual timetable. Both wind projects were initially expected to come on-line in late 2004. Their delays were caused by similar events: first by a protracted permitting process, and subsequently by uncertainty in the extension of PTC. The smaller project is now experiencing further delays due to the subsequent shift in the global wind turbine market; the larger project must resolve a legal appeal to its primary permit before proceeding. Finally, the PV project necessitated special legislation for the host community to own the power generation asset, introducing a delay.

Though some uncertainty remains as to what fraction of the projects may ultimately fail, the MTC's process tried to limit the risk of contract failure. First, a panel of industry experts was used to help select projects, with project viability an important evaluation criterion. Second, while all MGPP contracts allow the generator a one-time, nine-month extension without repercussion to the generator, thereafter, all contracts have milestones after which MTC has the opportunity to reconsider the funding. Some contracts also have security or penalty payments that *could* be collected upon failure to meet the milestones, if MTC chooses to enforce them. To date, MTC has not yet elected to enforce penalty provisions or reconsider awards as milestones have been missed. Extensions have been granted because MTC ultimately wants the projects to succeed, and because each has made satisfactory forward progress. No further extensions are guaranteed, but extensions will be considered on a case-by-case basis.

CHAPTER 4: CONCLUSIONS

This report has presented the experiences of electric utilities and others in contracting with renewable energy projects. A key purpose of this report has been to collect and present success and failure rates for renewable energy contracts.

We were successful in collecting information from California (PURPA QFs, Energy Commission production-incentive auctions, and recent IOU experience), from 21 other North American utilities and from government solicitations in support of renewable energy. Some of these experiences are considerably more relevant to the contracting efforts of California's IOUs than are others. Though available data are somewhat spotty in places, our sample is nonetheless extensive, consisting more than ***21,500 MW*** of renewable energy contracts. Table 13 presents in summary form some of the key findings of our efforts.

We find some weak evidence that capacity-based success and failure rates have changed somewhat over time. Though capacity-based success rates among California QF contracts from the 1980s averaged only 45 percent, for example, contracting success rates were seemingly on the rise in the late1980s and early 1990s (up to 60 – 92 percent nationwide). Data collected on recent utility experience shows a capacity-based success rate of just 53 percent (considering on-line and on-schedule projects). If projects that are not achieving their performance goals are also included as successful projects, however (leaving only cancelled projects and those that are significantly delayed and not yet on-line as failures), then the success rate jumps to 62 percent.

We also find that success rates vary considerably among utilities and across situations. Within our sample of recent North American utility experience, we find that landfill gas projects have experienced the least amount of failures, while the attrition rate for wind power and other renewable technologies has been higher. European experience also shows greater levels of project success among landfill and sewage gas facilities than from traditional biomass and wind power projects. Experience from other renewable energy contracting efforts suggests some variation in failure rates among different technology types as well, but those relationships are not always consistent among the examples presented in this report.

The experience of government-run auctions for renewable energy contracts in Europe and incentive solicitations in the United States bear less relevance to California's current contracting practices. In large part as a result of their design, success rates among these programs are often lower than for utility solicitations in which: (1) a full revenue-requirements contract is being offered, and (2) procurement mechanisms are typically used to reduce the risk of contract failure. Specifically, project success rates have ranged from 22 to 33 percent in Europe, from 22 to 63 percent in the states of New Jersey, New York, Pennsylvania, and Massachusetts,

and 37 percent for the California Energy Commission's production incentive auctions.

Table 13. Summary of Information on Contract Success Rates

Context	Signed Contracts (MW)	Success Rate (MW Basis)	Notes
Recent North American Utility Experience	2857	53-62%	Includes 29% on-line and 25% on schedule; range reflects whether projects in default are considered successful or not. Does not include 14% that have been significantly delayed. Overall project cancellation rate equals 23%, but this will increase over time.
Historical North American Utility Experience	2333	60-92%	60% reflects on-line capacity at the time of the survey (1994), while 92% includes contracted capacity that was still under development at that time.
California PURPA QFs	8980	45%	Relevance to current IOU contracting practices is weak.
European Contract Tenders	5082	22-33%	Combines tenders in UK (33%), Ireland (22%), and France (32%, but expected to be higher if more recent data were available). More projects may come on-line with time, though such projects will generally have experienced delays. Signed capacity underestimates total because uses "declared net capacity" ratings for the UK. Experience not altogether relevant because, with some exceptions, little was done to mitigate contract failure.
US State Incentive Auctions	1060	22-63%	Combines incentive auctions from NJ (22-35% depending on whether pending projects are counted as successful), NY (63%, based on assumptions presented earlier and including all solicitations combined), PA (49%), and MA (55%; successful projects assumed to include projects currently on-line or under construction). Experience not altogether relevant because programs offered incentives, not full revenue requirements.
California Energy Commission Auctions	1306	37%	An additional 60% of projects are still pending, but have experienced substantial delays. Relevance to current IOU contracting practices is weak.

Project success and failure rates, at least among other North American utilities, appear bimodal, with many utilities experiencing low or no failures, and many others experiencing extraordinarily high rates of contract failure. Some of this disparity may be due to the varying degree to which utilities use a variety of procurement strategies to reduce the risk of contract failure. It also reflects the fact that many of the utilities in our sample have signed only one or two renewable energy contracts. In any case, the disparity of experiences further complicates the development of a single, uniform target for over-procurement at this stage of the California RPS. Moreover, given the scope of this project, we were unable to link specific mitigation strategies with lower failure rates, to separate the influences of solicitation design and overall market conditions on failure rates, or to provide specific recommendations on which of the mitigation approaches might be most effective.

Though there is considerable variation among utilities with contract failure, and data limitations prevent robust conclusions, the experience presented in this report suggests that an overall failure rate of 20 to 30 percent should likely be considered the *minimum* level of expected failure for large RFOs conducted over multiple years (any individual RFO may well be able to beat these failure rates). In fact, failure rates much higher than these levels (50 percent, or even greater in some cases) are supported by historical experience, especially for projects that use pre-commercial technologies or that (like many projects in California) are likely to face siting, permitting, resource supply, transmission, or other barriers to development. Somewhat supportive of failure rates at these or higher levels is recent experience with renewable energy contracting by California's IOUs, which shows what appears to be a healthy degree of contract failure; we have no reason to believe that this will not continue in future RFO cycles, especially as the state's utilities dig deeper into the pool of possible projects.

There is a clear need to carefully monitor the ongoing status of renewable energy contracting in California. California's renewable energy contracting efforts are unique in their scale and design, and each RFO is different. A single uniform over-procurement target gleaned from the experiences described in this paper and held constant for years would not be appropriate. Ongoing and more systematic monitoring of contract failure in the state will help inform the appropriate level of (and changes to) any over-contracting target that might be established. We note that at the present time, the amount of information made public by the state's IOUs makes it difficult to accurately track contract status and project failure rates.

As experience is gained in the state with renewable energy contracting, it may also be helpful to more carefully scrutinize the different approaches used by the state's IOUs to lessen contract failure, document early experience with those various measures, and compare in some detail the approaches used in California with those applied in utility solicitations elsewhere in North America. It may also be helpful to evaluate the causes of contact failure in California and analyze the extent to which those failures could have been cost-effectively reduced through procurement design (compared to failures caused by market conditions that could not have easily been

anticipated). Because measures to combat contract failure may have the unfortunate effect of restricting competition and raising bid prices, such analyses should take care to evaluate the advantages *and* disadvantages of these various procurement strategies.

APPENDIX A: INTERVIEW GUIDE

Renewable Energy Contract Failure Study

Utility:

Contact Person: Phone Number:

Date Called:

General Notes:

Context:

Was there a traditional RFO process?	
If so, when was your RFO issued?	
Were you looking for a PPA, RECs, or to own the project(s)?	
What was the timeframe of the project?	
Time to respond to RFO?	
PPA signup date?	
Project start date?	
Term of the PPA?	
What was the motivation of the project? (RPS, Green power, IRP, etc.)	
What was the target (e.g. 100MW, 5,000 MWhrs, % of generation)?	
Was the target technology specific? (i.e. Solar, Wind, etc)	

Project information:

Number of projects that responded to RFO:	
Number of projects shortlisted:	
Number and MW of projects with signed/announced PPAs:	

Projects with PPA's by technology:

Tech	Wind	Solar	LFG	Biomass	Geotherm.	Hydro	Other?
#							
MW							

On-line and failure information for projects:

Number and MW of projects now on-line by technology

Tech	Wind	Solar	LFG	Biomass	Geotherm.	Hydro	Other?
#							
MW							

Of those on-line, number and MW that have experienced delays (and how long).	
Of those on-line, number and MW that have failed to meet production targets or have defaulted.	
Of those not yet on-line, number and MW that are on schedule to come on-line as per PPA.	
Of those not yet on-line, number and MW that are delayed but still may come on-line.	
Of those not yet on-line, number and MW that have been cancelled altogether.	
Number of projects with cost increases after signed PPA.	
Other cancellations or delays?	

Cause(s) for projects that were cancelled, delayed, or underperformed:

REASON	Proj	Proj	Proj	Proj
Failure to site and/or permit				
Interconnection or transmission				
Financial failure of generator				
Lack of creditworthy purchaser				
Availability and/or cost of resource				
Changes in capital prices				
Technology issues				
Project delay results in loss of subsidy (e.g. PTC)				
In-eligibility under state program				
Other (please clarify)				

Mitigation strategies:

Strict pre-conditions	
Due diligence	
Proposal submission Fees	
Pre-operation milestones with deposit	
Operational performance guarantees (liquidated damages)	
Use of waiting list	
Profitable PPAs	
RFQ process	
Change project ownership	
Future/other strategies?	

ENDNOTES

[1] The utilities have also signed new contracts with existing renewable energy generators.
[2] Center for Resource Solutions. "Achieving a 33% Renewable Energy Target." Prepared for the California Public Utilities Commission, November 1, 2005.
[3] California Energy Commission. "Implementing California's Loading Order for Electricity Resources." CEC-400-2005-043, July 2005.
[4] Ryan Wiser, Kevin Porter and Mark Bolinger. "Preliminary Stakeholder Evaluation of the California Renewables Portfolio Standard." CEC-300-2005-011, June 2005.
[5] Center for Resource Solutions. "Achieving a 33% Renewable Energy Target." Prepared for the California Public Utilities Commission, November 1, 2005.
[6] California Energy Commission. "2005 Integrated Energy Policy Report." CEC-100-2005-005-CTF, November 2005.
[7] Center for Resource Solutions. "Achieving a 33% Renewable Energy Target." Prepared for the California Public Utilities Commission, November 1, 2005.
[8] In their 2006 renewable energy procurement plans, SCE and PG&E also note that presumptively increasing the IPT to 1.2 percent is not appropriate at least in part because the IPT represents a *delivery* requirement, not a *contracting* requirement.
[9] Despite several attempts, we were unable to contact SDG&E.
[10] This was not always possible, however, due to confidentiality constraints, lack of institutional memory, or a lack of time on the part of the respondent.
[11] Delayed is defined not as a simple delay of a few months in construction, but as significant delays in the project coming on-line coupled in many cases with uncertainty of the project ever becoming successful.
[12] California Energy Commission. "1994 Electricity Report." P300-95-002, November 2005.
[13] PG&E, SCE and SDG&E 1st Quarter 1987 and 3rd Quarter 1995 Cogeneration and Small Power Production Quarterly Reports.
[14] California Energy Commission. "Renewable Energy Program: 2005 Annual Report to the Legislature." CEC-300-2005-020, November 2005.
[15] Individual projects, of course, have experienced delays as a result of a number of other factors as well, including permitting and siting barriers, resource supply, and overall market uncertainty. Project cancellations, meanwhile, have been primarily caused by lack of PPAs, siting and permitting challenges, interconnection costs, equipment failures, legal challenges, and inadequate fuel supplies.
[16] To increase the likelihood of serious bids, the Energy Commission required the submission of bid bonds to provide a guarantee of performance in the auction and indicate that the bidder was proposing a serious, viable project. However, the bid bond was never intended to guarantee performance throughout the construction or during the operation of the project. Full refunds of the bid bond were provided when projects filed permit applications, the rationale being that filing for permits could involve a significant expenditure of funds by the developer that would not be made unless the developer intended to develop the project. In the second two auctions, the Energy Commission supplemented the bid bond requirement by also instituting a series of bonuses and penalties to encourage early project completion. For more information, see Mark Bolinger and Ryan Wiser, "Production Incentive Auctions to Support Large-Scale Renewables Projects in Pennsylvania and California." Lawrence Berkeley National Laboratory, September 2002.
[17] Based on PG&E's supplement to its long-term renewables procurement plan, filed December 7, 2005, it appears as if PG&E's contract with a repowered Altamont wind project may be significantly delayed beyond its 2006-2008 originally projected on-line date.
[18] SCE also notes that many of the projects have delayed submitting their interconnection applications to the CA ISO and that further delays may be caused by the required timelines for environmental studies. What is clear is that a number of the projects under contract with SCE are at an early stage of development. Delay and project cancellation are significant risks for these projects. Concerns have also been raised about the viability of SCE and SDG&E's massive solar-thermal

contracts, which rely on a technology and cost projections that have not yet been commercially proven. How SCE and SDG&E have attempted to mitigate this risk is not publicly known at this time.

[19] http://www.sdge.com/regulatory/renewablesFactSheet.doc.

[20] As a condition for approving the delays, SDG&E was able to garner certain concessions from the project developers.

[21] To our knowledge, the specific causes of the delays and apparent failures have not been made public, with one exception. An Oasis Power 60 MW wind project was apparently delayed due to: (1) PPA revisions needed to accommodate the project's financiers; (2) uncertainty on the operations of the CA ISO's PIRP program; (3) delays with the interconnection facilities agreement; and (4) uncertainty over the extension of the PTC (CPUC Resolution E-3883). In all cases, however, the CPUC found that project delays were not caused by SDG&E's actions.

[22] In its original advice letter filings, SDG&E predicted that the 15 signed contracts would result in 4 percent and 7 percent incremental deliveries in 2003 and 2004, respectively.

[23] Gregg Morris. "Utility Experiences with Private, Renewable Energy Generating Sources." Prepared for Hydro-Quebec, March 18, 1994.

[24] One of these RFOs actually resulted in signed PPAs, but the utility was unwilling to share any details about the contracts (number, capacity, technology, or status).

[25] These internal targets have often been established either in anticipation of future regulation, or as a result of regulation that requires municipal utilities to implement an internal RPS.

[26] This "other" category comes from the New England Power 1991 renewable RFO and includes waste to energy and waste heat.

[27] The three projects in default are all wind projects located in Texas that have been transmission-constrained and have therefore significantly under-performed. All three contracts have apparently resulted in lawsuits; at issue is whether the generator is responsible for transmission curtailments.

[28] Other states have also provided incentive support to utility-scale renewable energy projects. Here we focus on those states that have more extensive recent experience.

[29] Source: http://www.dti.gov.uk/renewables/policy_pdfs/nffofs11June2005.pdf

[30] These reasons are described in Mitchell, C. "The England and Wales Non-Fossil Fuel Obligation: History and Lessons." *Annual Review of Energy and Environment.* Stanford University, California, USA, 2005.

[31] Although there were no explicit penalties for exceeding the four- and five-year development periods, a project that did so would begin to cut into the length of the NFFO contract. As such, the NFFO process created incentives to bid low (to secure a contract), wait as long as possible to construct the project (hoping for technology cost reductions), and then bring the project on-line just prior to the end of the allowed development period (in order to capture the full series of contract payments).

[32] Data synthesized from documents found at http://www.dcmnr.gov.ie/NR/rdonlyres/2E9CE305-4C9D-4CE2-87E2-2FB8DF13A6AD/0/AERProgramme2005.doc.

[33] For example, see http://www.dcmnr.gov.ie/NR/rdonlyres/F070739C-0716-41AF-8A4E-DEBC1F8A99F5/0/AERVIdraft9dcmnrPrintersFinalVersion.pdf. In the future (under a different type of policy support), Ireland will impose even stricter assurances, including a valid interconnection agreement from the relevant grid operator.

[34] For example, in the first stage, there were two sub-tenders: one for developers that had already measured the wind resource, and another for those that had not. The second stage also had two sub-tenders: one for projects on the continent, and another for projects in overseas French territories.

[35] ADEME, May 2001 Quarterly News Bulletin of the ToTem Project. http://translate.google.com/translate?hl=en&sl=fr&u=http://www.ademe.fr/travail/totem/ContexteProjet.htm&prev=/search%3Fq%3DEOLE%2B2005%26hl%3Den%26lr%3D

[36] http://www.renewable-energy-policy.info/relec/france/policy/bidding.html

[37] See: http://translate.google.com/translate?hl=en&sl=fr&u=http://e2phy.in2p3.fr/2001/bal2/sld005.htm&prev=/search%3Fq%3DEOLE%2B2005%26hl%3Den%26lr%3D

[38] The 21 MW wind project was cancelled when the completed wind resource study revealed a resource that was considered unviable, even given the NJBPU support.

[39] NYSERDA has also offered two programs supporting wind prospecting.

[40] 92 percent availability earned the full incentive, and the incentive declined linearly to zero at 42 percent availability.

[41] Phase II of the program did not offer production incentives but rather other forms of financing, such as subordinated debt. Perhaps in part due to the less-attractive nature of such incentives (relative to a production incentive), there were no viable respondents to Phase II, and no funding awards were made.

[42] Round 2 of MGPP is now underway, offering $39 million. The RFP was issued in January 2005, with responses due in March 2005. The results are expected to be announced shortly.

Appendix C. Arizona Transmission Queue Resources

Arizona Transmission Queue Resources As of 4/18/2008					
Company	**COD**	**Capacity (MW)**	**Point of Interconnection**	**County**	**Resource Type**
TEP	2005	80	Dolan Springs Sub	Mohave	Wind
TEP	2008	15	Dolan Springs Sub	Mohave	Wind
TEP	2005	15	Dolan Springs Sub	Mohave	Wind
TEP	2007	95	Co-Spr	St Johns	Wind
APS	2008	60	Cholla - Coconino	Coconino	Wind
APS	2008	128	Cholla Show	Coconino	Wind
APS	2007	22	Cholla zeniff	Navajo	Biomass
APS	2008	270	Ashofork - Pollock	Yavapai	Wind
APS	2009	125	cholla - show	Coconino	Wind
APS	2010	100	Adams - Mural	Cochise	Wind
APS	2011	110	Harquahala Jnc	Maricopa	Solar
APS	2011	110	Panda Liberty line	Maricopa	Solar
APS	2010	400	North Gila Sub	Yuma	Solar
APS	2010	1000	Moenkopi 500 kV	Coconino	Wind
APS	2010	300	Cholla-Pinnacle Peak 345 kV	Navajo	Wind
APS	2012	400	Proposed Harquahala Junction	Maricopa	Solar
APS	2012	800	Proposed Harquahala Junction	Maricopa	Solar
APS	2010	500	Moenkopi-Eldorado Line 500 kV	Coconino	Wind
APS	2008	250	North Gila Sub	Yuma	Solar
APS	2012	500	Proposed Harquahala Junction	Maricopa	Solar
APS	2013	500	Proposed PV-NG2 500 kV line	Yuma	Solar
APS	2011	280	Gila Bend 230 kV Sub	Maricopa	Solar
SRP	2007	150	CO-CH, CO-SK 500 kV	Navajo	Wind
WAPA	2008	500	Tap on 345kV Glen Canyon-Pinnacle Peak	Coconino	Wind
WAPA	2008	300	Mead - Davis 230 kV Line	Mohave	Wind
WAPA	2008	65.1	Goldmine Tap Substation	Imperial	Wind
WAPA	2008	500	Peacock Substation	Mohave	Wind

Appendix D. Arizona Renewable Energy Assessment

A UniSource Energy Company

Arizona Public Service Company
Salt River Project
Tucson Electric Power Corporation

Arizona Renewable Energy Assessment

FINAL REPORT
B&V Project Number 145888

September 2007

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1.0 Executive Summary

Black & Veatch Corporation has prepared this report for Arizona Public Service Company, Salt River Project, and Tucson Electric Power Company (APS/SRP/TEP). The purpose of this report is to assess the prospects for significant renewable energy development in Arizona. The scope of the study is limited to Arizona projects that would export power to the grid (that is, not distributed energy projects). This study includes a review of the current status of renewable energy in Arizona, characterization of renewable power generation technologies, assessment of Arizona's renewable resources, and an assessment of key risk factors. This section summarizes the key findings in these areas.

1.1 Background and Objective

Electricity produced in Arizona is mostly from traditional natural gas, coal, and nuclear resources. Hydroelectric contributes about 6 percent, while non-hydro renewable resources are currently very small (0.07 percent). To stimulate further development of renewable energy, the Arizona Corporation Commission adopted final rules in 2006 to substantially increase Arizona's Renewable Energy Standard (RES). The new RES mandates that impacted utilities (including TEP and APS) obtain 15 percent of their energy from renewable resources by 2025. SRP has also adopted a renewable energy goal similar to the RES.

The objective of this report is to assess the full potential of Arizona renewable energy resources while accounting for the economics of developing those resources. Large scale renewable energy development will be necessary to meet the renewable mandates set forth in the Southwest. Although Arizona is well known for its solar resources, solar is currently the most expensive renewable energy resource. By comparison, Arizona is thought by many to have relatively limited opportunities for comparatively lower cost renewables, such as wind, biomass, geothermal and hydroelectric. This study assesses the relative potential of all resources and forecasts which are most likely to be developed over the next 20 years. It is important to note that this report concentrates on the potential of the renewable energy resources themselves. It does not, beyond the inclusion of transmission interconnection costs, address the potential cost or availability of transmission capacity needed to deliver these resources to load. Further, out-of-state resources and their impact on the Arizona renewable energy market are not included in the scope of this review.

This study was undertaken in two phases. The Interim Report (Section 3, 4 and 6 of this Final Report) reviewed a broad range of renewable energy technologies and

concluded with recommendations for further study in Phase 2. Phase 2 of the project (the remainder of this Final Report) characterizes the most promising options in greater detail and identifies potential projects for possible implementation.

1.2 Renewable Energy Technology Options

Nineteen renewable and advanced energy technologies were assessed in Phase 1. The technologies were split into eight categories as shown below. Each technology was described with respect to its principles of operation, applications, resource characteristics, cost and performance, environmental impacts, and outlook for Arizona applications.

Technologies that are **bold and underlined** in the list below were recommended for further study in Phase 2 due to their large potential and/or low cost.

1. Solid biomass
   - **1.1 Direct fired**
   - 1.2 Biomass Gasification and IGCC
   - **1.3 Cofiring**
   - 1.4 Plasma Arc Gasification
2. Biogas
   - **2.1 Anaerobic digestion**
   - **2.2 Landfill gas**
3. Solar Electric
   - 3.1 Solar thermal electric
     - **3.1.1 Parabolic Trough**
     - **3.1.2 Parabolic dish engine**
     - 3.1.3 Power Tower
     - 3.1.4 Compact Lens Fresnel Reflector
   - 3.2 Solar photovoltaic
     - 3.2.1 Residential
     - **3.2.2 Commercial**
     - **3.2.3 Utility-scale**
4. Hydroelectric
   - **4.1 Conventional Hydroelectric**
   - **4.2 Pumped Storage**
5. **Wind**
6. **Geothermal**
7. Fuel Cells Using Renewable Fuels
8. Compressed Air Energy Storage

1.3 Renewable Resource Assessment

Additional research was performed for technologies that were recommended in the first phase of the project. The objective was to assess the renewable energy resources that are suitable for development in the near- to mid-term (next 20 years). Potential development prospects were identified, levelized generation costs were calculated, and supply curves were developed for each resource. An end result of this process was the identification of a list of over 100 hypothetical renewable energy projects that might be developed to meet demands for renewable energy in Arizona (Appendix A and B contain lists of these projects). Table 1-1 and Figure 1-1 summarize the renewable energy

resources in Arizona potentially developable over the near- to mid-term (through 2025). The table and figure do not include existing (24 MW) or planned projects (504 MW), which are shown in Table 3-2.

General findings from the resource assessment are described in the following sections.

Table 1-1. Arizona Renewable Energy Resources Available in the Near- to Mid-Term.

Technology	Location	Cost (2007$/ MWh)	Capacity (MW)	Generation (GWh/yr)
Direct Fired Biomass	Maricopa	143	20	140
Biomass Cofiring	2 potential sites: TEP's Sringerville generating station and APS's Cholla generating station	58 - 63	20	140
Landfill Gas	15 potential small projects identified across the state	82 - 99	10	68
Anaerobic Digestion	Snowflake, Buckeye, Chandler, and Maricopa	62 - 128	10	69
Solar Thermal Electric	100 MW project in 2011. 2–4 200 MW sites per year after 2012	161- 176	4,300[a]	10,940[a]
Hydroelectric	7 potential sites[b]	32 - 215	82	320
Wind	6 potential sites near Kingman and the White Mountains[c]	75 - 141	991	2551
Geothermal	Clifton Hot Springs and Gillard Hot Springs	110 - 122	35	215
Total			**5468**	**14,443**

Notes:

[a] The solar potential is vast, and this only includes projects sufficient for meeting Arizona's forecast renewable energy demands through 2025.

[b] Glen Canyon compromises 90 percent of total potential.

[c] 500 MW of planned wind generation not included.

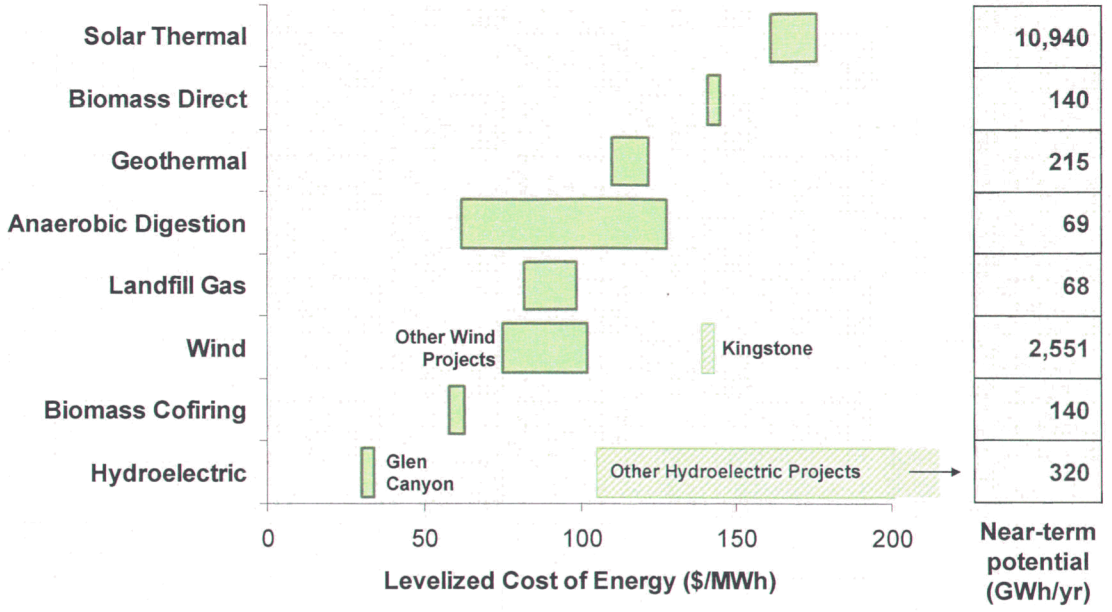


Figure 1-1. Summary Cost and Potential of Arizona Renewable Resources.

1.3.1 Direct Fired and Cofired Biomass

Although biomass resources are limited, direct-fired biomass and cofired biomass technologies were identified as promising technologies in the first stage of the analysis. Sufficient resource was identified in central Arizona to support a 20 MW direct-fired combustion plant in the vicinity of Maricopa. This facility would be a low emission, fuel-flexible fluidized bed that would burn a variety of biomass fuels, including mill residues, urban wood waste from Phoenix and Tucson, and agricultural residues. The two potential cofiring projects are a 10 MW facility located at TEP's Springerville Generating Station and a 10 MW facility located at APS's Cholla Generating Station. To counter potential negative impacts on the boilers, the cofiring projects were assumed to use a gasification system close-coupled to the existing boiler. The cofiring projects would utilize forest and mill residues.

Considering the other renewable energy options evaluated in this study, the costs of the two cofiring projects are relatively low (about $60/MWh in 2010), and the costs of cofiring are certainly lower than the direct fired project (about $162/MWh in 2012). In general, the costs of biomass in Arizona are high compared to other states due to limited available low cost biomass and the small scale of the potential projects.

While cofiring is lower cost than direct fired biomass plants, there are a couple of significant barriers to its implementation. Initiating a biomass cofiring project may require the host coal plant to reopen existing air permits, even though cofiring generally

reduces emissions. The risk and cost of reopening existing permits is not included in the cofiring cost estimate, but it may be a significant deterrent to cofiring projects. Further, electricity demand in Arizona is increasing faster than any other state (600 MW increase per year). Biomass cofiring converts capacity to a renewable source rather than adds capacity, and thus may be less attractive than new capacity additions.

If the cofiring projects face too many obstacles, an additional direct fired biomass facility could be developed in Northern Arizona in lieu of the cofiring projects.

1.3.2 Landfill Gas

Black & Veatch utilized the Environmental Protection Agency Landfill Methane Outreach Program (LMOP) database of landfills in Arizona to assess 25 potential sites. Black & Veatch attempted to contact each of the landfills to verify data and assess the suitability for power development. Based on this review, fifteen potential projects were identified, totaling 9.7 MW of capacity and 68 GWh of annual generation. This capacity is much smaller than what would be expected for similar sized landfills in other states due to Arizona's dry climate. Most of these projects could be available by 2010 if development were prioritized. Projects costs vary, but most projects are projected to generate power for around $90/MWh.

The overall prospects for landfill gas generation are small. Landfill gas projects can take less time to develop than large solar or wind projects, so landfill gas may play a more significant role in the near term.

1.3.3 Anaerobic Digestion

The utilization of biogas generated from anaerobic digestion of animal manure was identified as a technically feasible option in the first stage of the analysis. Potential anaerobic digestion projects were identified based on large concentrations of livestock (swine, dairy, and poultry) operations within an area. Four anaerobic digestion projects were identified, ranging from 1.5 to 3.5 MW. The projects total 9.9 MW of capacity and 69 GWh of annual generation. The costs for the anaerobic digestion projects range from $70/MWh to $140/MWh (in 2010), largely dependent on project scale.

While this resource has a relatively limited generation potential, anaerobic digestion projects could be executed relatively quickly and with low levels of risk.

1.3.4 Solar Thermal Electric

There is large potential for solar thermal development in Arizona. The review focused on the only commercially proven technology: parabolic trough. Parabolic dish

Stirling systems are promising, but unproven; their costs were assessed in a side scenario study (section 8).

The potential for solar thermal was characterized in a different manner than other technologies. Rather than being limited by resource availability, the technology is limited by equipment availability, development timelines, and ultimately economics. Due to supplier constraints, it was assumed that the first 100 MW trough plant in Arizona would not be completed until 2011. It is assumed that the near term supply chain constraints in the industry will be alleviated by 2013, and two to four 200 MW plants could be constructed per year thereafter. Generic projects were characterized in four areas of the state: Phoenix, Yuma, Stoval, and Tucson.

Unlike most other technologies evaluated for this study, it is expected that significant technical and cost advances will be realized for solar thermal trough plants. In addition, parabolic dish engine technology may also be deployed on a commercial level, and this technology could become competitive over the term of this study (through 2025).

The supply curve for solar thermal trough plants is relatively flat with the lowest cost projects generating power for about $160/MWh (hypothetical 2007 project, includes 30 percent investment tax credit). The flat supply curve means that a lot of solar thermal can be developed for about the same cost. This cost is substantially higher than non-solar resources profiled in this study. The potential supply of solar thermal potential is vast, and exceeds the near-term demands for renewable energy in Arizona.

1.3.5 Solar Photovoltaic

As with solar thermal technologies, constraints on the deployment of solar photovoltaic projects are not related to resource; the constraints are mainly capital costs and equipment availability. The review focused on deployment of larger photovoltaic systems (5-10 MW). Concentrating photovoltaic technology was also addressed as a possible future technology.

Even with significant cost reductions, costs for solar photovoltaic and concentrating photovoltaic projects are too high (greater than $240/MWh) to compete with the other renewable energy technologies surveyed. However, an advantage of solar photovoltaics is that smaller projects may be able to come online in the very near-term (2008 and 2009). As such, they are one of the few in-state technologies available to meet near-term renewable energy demand.

Alternative project and cost structures for solar PV projects are currently being refined, and they have the potential to substantially lower the "all-in" cost of energy from solar PV. Given the high capital costs for PV, any improvement in capital structure or

financing costs has a relatively strong impact on the final levelized cost. These structures have not been modeled in this report.

1.3.6 Hydroelectric

Seven hydroelectric projects were identified as potentially promising. The total combined capacity of the seven projects identified is 81.8 MW, with an energy generation potential of 320 GWh/yr. A single project, adding generation at Glen Canyon dam, makes up about 90 percent of this total. The projects were identified based on government information, and details were difficult to verify. Of the seven projects, Glen Canyon, Tucson and Waddell are the only projects that could be reasonably located. Glen Canyon and Waddell have the most head and flow available compared to other sites. They also have existing hydropower installed and therefore show the most potential for further study. The Glen Canyon project is the lowest cost project of all the renewable energy projects surveyed for this study. It is forecast to cost about $50/MWh in 2015, the year it is projected to be available. The other hydroelectric projects are all projected to be much more expensive, at costs over $150/MWh in 2013, the first year they are projected to be available.

Drought conditions of recent years have reduced water resources throughout the Western US in recent years, including Lake Powell. Continued drought conditions may decrease the actual statewide hydroelectric potential.

1.3.7 Wind Power

While the wind resource is generally less attractive in Arizona compared to surrounding states, wind was identified as one of the more promising resources in the first phase of the study. To identify specific areas conducive to the development of a utility-scale wind energy projects, information was gathered on Arizona's estimated wind resource, transmission infrastructure, environmental restrictions, and federal land areas. After reviewing many potential sites for constructability, transmission proximity, wind resource, and other constraints, six sites were chosen as the most promising for near-term development. While it is possible that other wind sites could be developed in Arizona, these sites are less attractive based on this analysis.

The total combined capacity of the six sites identified is 990 MW, with an energy generation potential of 2,550 GWh/yr. (The 500 MW of already planned wind projects are not included in this total). Costs for most projects are estimated to be about $75 to $100/MWh in 2010, which is the year when wind is first expected to be available. While the wind resources in Arizona are modest when judged against many other states, compared to other renewable energy options in Arizona, prospects for wind are good due

to the relatively low cost. Arizona wind resources, however, are stronger in the winter when electricity demand is low, and weaker in the summer when demand is higher. Assessment of the seasonal value of energy (or avoided cost, more generally) was not included in the scope of this study.

1.3.8 Geothermal

Geothermal was identified as a relatively unknown, but potentially promising resource in the first phase of this study. The two known geothermal resources with the highest temperatures are located in the eastern part of the state: the Clifton Hot Springs and the Gillard Hot Springs projects. Interpretation of preliminary data suggests that resource temperatures may enable binary power generation.

Because the projects are still in their early exploratory state, there is not enough data available to accurately characterize the geothermal projects with a high degree of precision. Even identifying the potential project size is still speculative. For this reason, generic 20 and 15 MW projects were assumed. At best, these assumptions identify "place-holder" projects that must be further defined as more information about the true potential of each site is discovered. Because of their small-scale and long lead time (which places them after the assumed expiration of the production tax credit), costs for the two projects are relatively high ($149/MWh and $163/MWh in 2014). Nevertheless, this cost is still competitive with solar resources that are expected to be developed in the same timeframe.

1.4 Forecasted Renewable Energy Development

Black & Veatch has developed a model to help utilities, states, and other entities develop renewable energy plans. For the utilities represented in this study, Black & Veatch evaluated Arizona's renewable energy development potential in light of increased demand for renewable energy stimulated, in part, by the Renewable Energy Standard. The model was then used to forecast renewable energy development in the state through 2025.

The model evaluates the total lifecycle cost of renewable energy projects, including capital and operating costs, performance, and transmission system interconnection. Projections are made for future changes in technology cost and performance based on Black & Veatch's experience. By allowing the model to consider all possible renewable energy resources in Arizona, the study assesses the full potential of all renewable energy resources while accounting for the economics of developing those resources. The model does not include transmission system upgrades (other than interconnection costs) or system integration costs for intermittent resources (e.g. wind).

The model also does not assess value (i.e., avoided cost) of the resource as determined by its degree of firmness or time of delivery (e.g. on-peak vs. off-peak). In selecting projects, utilities may consider these factors, which may result in a different order of resource/project development. Further, although long term transmission constraints have not been reviewed, a long term analysis should include a transmission development plan.

Figure 1-2 shows the total renewable energy supply curve for Arizona in the year 2025. Costs are in nominal dollars (that is, 2025 costs) without tax credits. This curve shows all new projects identified in the study. The curve also shows a demand line indicating the projected 2025 renewable energy demand of 11,210 GWh (this already accounts for planned projects). If development of renewables in Arizona were economically optimum (again, not considering transmission upgrades and avoided costs), then all of the projects to the left side of the demand line would be built by 2025. It should be noted that there are additional higher cost resources that would extend the potential supply of renewables further to the right than indicated on this chart. However, once sufficient projects were identified to meet demand, Black & Veatch did not continue to identify higher cost projects.

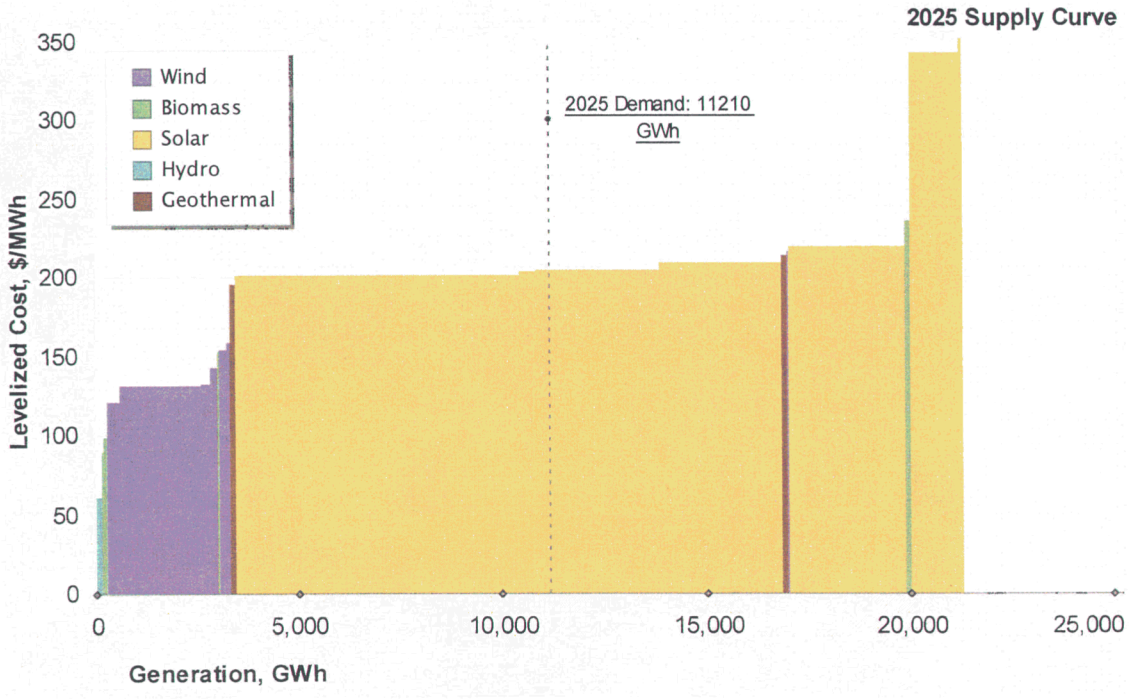


Figure 1-2. Total Arizona Renewable Supply Potential in 2025.

The supply curve shows that a portion of Arizona's renewable energy demands can be met with lower cost non-solar resources, especially wind. However, by 2017, it is

projected that lower cost non-solar resources will be exhausted and large-scale solar thermal plants will then be built at a rate of 200 to 400 MW per year through 2025. Other insights from the model include:

- **Non-solar resources limited** – Arizona has a variety of renewable energy resources that could be developed; however, other than solar, these resources appear relatively limited. In the mid to near-term, developable potential for new biomass, geothermal, and hydroelectric projects combined could contribute about 952 GWh/yr, or 1 percent of the electricity that was generated in Arizona in 2005. Wind could contribute about 2.5 percent. With energy storage, solar could theoretically supply the entire electricity needs of the state. (Note that these totals exclude 825 GWh/yr of additional existing and already planned projects, most of which is wind).
- **Non-solar resources important** – Despite the relatively limited potential of wind, biomass, geothermal and hydroelectric resources, they serve an important role in forestalling the need to install expensive solar. However, the relatively limited potential of these resources compared to surrounding states may serve as a deterrent for large, out-of-state renewable energy project developers.
- **Regional renewable energy markets** – This study did not include an assessment of regional renewable energy supply and demand. Neighboring states, namely California, New Mexico, and Nevada, also have aggressive renewable energy standards. These states may have more economical renewable energy sources than Arizona (for example, Salton Sea geothermal resources and New Mexico wind); however, given their own aggressive in-state demands and transmission limitations, they may not be a dependable source for Arizona. While the importation of renewable energy may help to defer Arizona's needs, it is not likely to fully satisfy them.
- **Lowest cost resources** – The most promising project opportunities from an economic perspective involve enhancements to existing facilities: adding a unit at the existing Glen Canyon hydroelectric project and biomass cofiring at the Cholla and Springerville coal plants. These projects are around $60/MWh or less.
- **Solar about twice cost of other resources** – Solar is the most expensive of the renewable resources profiled in this study. The lower cost solar resources (about $161-176/MWh in 2007) are about twice as expensive as the bulk of the non-solar resources (about $70-110/MWh in 2007). The base case model included only proven, fully commercial solar technologies such as solar

photovoltaics and solar thermal trough. If forecasted technology improvements are realized, dish engine technologies have the potential to be cost competitive with conventional parabolic trough systems.

- **Arizona's reliance on solar is unique** – Arizona appears unique in the U.S. in its dependence on in-state solar energy to meet its renewable energy demands. It is estimated that 65 percent of the Arizona renewable demand in 2025 will be met by solar. Generally speaking, other states in the Southwest U.S. will likely be less reliant on solar to meet their renewable energy requirements. This is because other states generally have a larger base of non-solar renewables that they can rely on for near-term needs. By comparison, Arizona's non-solar resources are relatively limited. Solar technologies will play a key part of renewable's future in Arizona.
- **Consideration of avoided costs is important and necessary** – This project did not assess the differential value (i.e., avoided cost) of renewable resources. Avoided cost is typically determined by assessing a resource's capacity value (based on degree of "firmness" at the time of a utility's system peak demand) and its energy value (based on time of delivery). In selecting projects to develop or procure, utilities may consider these factors, which may result in a different order of resource/project development than shown in the supply curves in this report. This is important when comparing resources such as wind and solar. For example, wind energy projects only provide fractional capacity value (often estimated at 20 percent of the nameplate capacity) and are more likely to offset low cost energy resources during the winter and spring. Solar resources can readily provide firm capacity with gas hybridization or thermal storage. Further, solar is generally coincident with times of higher capacity needs. There are numerous methods to calculate avoided cost, and costs are specific to individual utility systems.

1.5 Assessment of Key Risk Factors

Black & Veatch analyzed some of the risk factors of interest to utilities in Arizona to determine how sensitive the supply curve results would be to changing situations. These factors include tax credit changes, implementation of advanced solar technologies, delayed technical advances, escalating construction costs, manufacturing/supply chain constraints, near term performance learning curve, and competition for limited resources.

1.5.1 Tax Credit Changes

Most renewable resources benefit from either production tax credits (PTCs) or investment tax credits (ITCs). The base case model assumed tax credits expire in 2012. In the long term, whether tax credits expire in 2008 or 2012 has little impact on the cumulative average cost of meeting renewable energy demand in Arizona (less than 1 percent by 2025). This is because many of the most expensive, large solar projects would likely be built after 2012. If tax credits never expire, the impact is a significant reduction in cumulative portfolio costs (25 percent reduction).

1.5.2 Advanced Solar Technologies

There are pre-commercial advanced solar technologies that may reduce the cost of solar energy. Two of these technologies include concentrating solar photovoltaic (CPV) and parabolic dish engine. These technologies were not included in the base case model, but were modeled in a sensitivity analysis. Based on Black & Veatch's assumptions, technology advancements in CPV will not make that technology competitive with conventional solar parabolic trough technologies for utility scale applications. However, there does appear to be potential for dish engine technologies to become competitive with solar trough technology.

1.5.3 Delayed Technical Advances

Advances are expected in wind and solar technologies, resulting in lower costs and higher capacity factors. However, there is a risk that such advancement may be delayed or not realized, and this was investigated in a sensitivity analysis. When technology advances were delayed, wind and solar thermal projects had lower capacity factors compared to the base case, which required development of more projects to meet the same demand. Because of lack of advancement, solar projects, particularly in the later years, are higher cost than the base case. The reduced technical advances will make levelized costs for wind and solar higher, which will make other technologies (biomass and geothermal) comparatively more attractive in early years. The cumulative effect on the total renewable energy cost will likely be an increase of 15 to 20 percent by 2025.

1.5.4 Escalating Construction Costs

The model base case has a capital cost escalation of 2.5 percent per year, which is meant to track close to general inflation. There is a risk that construction costs will escalate at a higher rate, depending on future markets for materials and labor. A sensitivity analysis was performed assuming 5 percent escalation. The results are pronounced. At year 2025, levelized costs are about 37 percent higher than the base case.

1.5.5 Manufacturing and Supply Chain Constraints

Manufacturing and supply chain constraints were assumed in the model. The projects most likely to be impacted by such constraints are solar and wind. For wind projects, there is currently a delay of up to two years between turbine order and turbine delivery because demand is greater than manufacturing capability. The wind projects identified for this project are assumed to be available to come online between 2010 and 2013. If there are additional constraints in the turbine supply chain, then it is likely that renewable energy demand would not be met in some years with in-state resources.

Solar projects were also modeled with manufacturing constraints in mind. Due to these constraints, it has been assumed that the first 100 MW trough plant in Arizona could not be completed until 2011. It is assumed that the near-term supply chain constraints in the industry will be alleviated by 2013, and two to four 200 MW plants could be constructed per year thereafter if deemed economical

1.5.6 Near-Term Performance Learning Curve / Project Failure

In the near-term, projects may under-deliver renewable energy as they gain experience during the initial operational and development learning period. Projects may also fail outright, and not supply any renewable energy. From a supply curve standpoint, contract failure shifts the supply curve to the left. When a project fails, its generation is removed from the supply curve, while all projects to the right (more expensive projects) shift left to fill in the space. As lower-priced projects fail, utilities will be forced to contract with more expensive renewable projects to procure the necessary amount of energy.

1.5.7 Competition for Limited Renewable Resources

As more and more renewable energy projects are developed, there will be fewer renewable resources to utilize in the future. There is a risk that utility competition for limited renewable resources will increase prices. This is particularly true in supply-constrained markets. For Arizona utilities, it is possible that renewable energy developers may set energy prices as high as possible while still beating the marginal cost of competing energy supplies. This would increase the total renewable energy cost, but it is uncertain to what extent.

2.0 Introduction

Black & Veatch Corporation has prepared this study of renewable energy for the three largest utilities in Arizona: Arizona Public Service Company, Salt River Project, and Tucson Electric Power Company (APS/SRP/TEP). The purpose of this report is to assess the prospects for significant renewable energy development in Arizona. The scope of the study is limited to Arizona projects that would export power to the grid (that is, not distributed generation projects).

This study includes a review of the current status of renewable energy in Arizona, characterization of renewable power generation technologies, assessment of Arizona's renewable resources, and an assessment of key risk factors.

2.1 Background

In response to increasing public interest in clean energy sources, concerns about energy security, and the environmental impacts of fossil fuels, numerous states have encouraged development of renewable energy sources. Renewable energy standards have been a popular mechanism used by other states and countries to mandate a certain percentage of electricity be generated from renewable energy resources.

Electricity in Arizona is largely produced from traditional natural gas, coal, and nuclear resources. Hydroelectric contributes about 6 percent, while non-hydro renewable resources are currently very small (0.07 percent). To stimulate development of renewables, Arizona was one of the earlier states to adopt a renewable energy standard. Arizona enacted its original Environmental Portfolio Standard (EPS) in March of 2001. The EPS required that investor owned utilities provide 1.1 percent of their power from renewables by 2007.

In November 2006, the Arizona Corporation Commission adopted final rules to substantially increase Arizona's Renewable Energy Standard (RES) such that some utilities would be required to obtain 15 percent of their energy from renewable resources by 2025. Such a standard places Arizona among the most aggressive in the nation. In addition, Arizona is surrounded by other states in the Southwest (California, Nevada, and New Mexico) that also have strong renewable energy standards. The combined effect of these standards is to substantially increase the demand for renewable energy in the region.

2.2 Objective

The objective of this report is to assess the full potential of all Arizona renewable energy resources while accounting for the economic variables of developing those

resources. Large scale renewable energy development will be necessary to meet the renewable mandates set forth in the Southwest. Although Arizona is well known for its solar resources, solar is the most expensive renewable energy resource. By comparison, Arizona is thought by many to have relatively limited opportunities for lower cost renewables, including wind, biomass, geothermal and hydroelectric. This study assesses the relative potential of all resources and forecasts which are most likely to be developed over the next 20 years.

2.3 Approach

Black & Veatch has developed an objective methodology to assess renewable energy potential based on sound utility generation planning fundamentals and the specific challenges inherent to analyzing renewable energy generation technologies. This study was undertaken in two phases. This final report is a comprehensive account of both. An Interim Report covered Phase 1. It described the current status of renewable energy in Arizona, characterized renewable power generation technologies and the general potential of the different resources, and reviewed available financial incentives for renewable energy. The Interim Report (Section 3, 4 and 6 of this Final Report) reviewed a broad range of renewable energy technologies and concluded with recommendations for further study in Phase 2. Phase 2 of the project (the remainder of this Final Report) characterizes the most promising options in greater detail and identifies potential projects for possible implementation.

This study began with an assessment of renewable energy generation technologies to identify the most promising technologies for Arizona. The following technologies were initially identified as potentially promising:

- Wind
- Solar Thermal (trough)
- Solar Thermal (dish)
- Solar Photovoltaics
- Direct Biomass Combustion
- Cofired Biomass
- Anaerobic Digestion
- Landfill Gas
- Hydroelectric
- Geothermal

Following identification of the most promising technologies, a resource assessment was performed to quantify the near-term developable potential of the promising renewable resources. In some cases, the assessment included new primary

research and initial siting activities to collect renewable energy resource data. This information was used to determine the size of the resources, geographic distribution, and technical feasibility of utilization. An end result of this process was the identification of a list of over 100 hypothetical renewable energy projects that might be developed to meet demands for renewable energy.

Following the resource assessment, the total lifecycle costs were calculated for each renewable energy project. Costs included capital and operating costs, performance, transmission system interconnection, and financial incentives. Transmission costs, which can be significant, have not been included at this stage of the analysis. Projections were also made for future changes in technology cost and performance based on Black & Veatch's experience in the field. Resource estimates were combined with technology characteristics to develop a set of economic supply curves showing the renewable energy available (MWh) at different levelized costs ($/MWh). The supply curves for the individual renewable energy technologies were then combined to generate statewide renewable energy supply curves. The supply curves can be used to identify a hypothetical least-cost set of renewable energy projects through 2025.

Once the base model was established, it was used to test the model results against various key risk factors.

2.4 Report Organization

Following this Introduction, this report is organized into the following sections:

- **Section 3 – Renewable Energy Overview:** This section provides an overview of renewable energy including the historical development of renewables in the US followed by the status of renewable energy in Arizona.
- **Section 4 – Assessment of Renewable Energy Technology Options:** This section reviews the general characteristics and costs of renewable energy technology options for Arizona. The section concludes with a short list of technologies recommended for further study.
- **Section 5 – Renewable Resource Assessment:** This section summarizes the renewable energy resources of Arizona that are suitable for development in the near- to mid-term (next 20 years). Potential development prospects are identified, levelized generation costs are calculated, and a set of supply curves is developed.
- **Section 6 – Renewable Energy Financial Incentives:** This section describes the existing and proposed incentives that are available to new renewable energy facilities.

- **Section 7 – Renewable Energy Development Model:** This section summarizes the supply curve model. The model is described, assumptions are outlined, and key results are presented.
- **Section 8 – Assessment of Key Risk Factors:** Black & Veatch analyzed some of the risk factors of interest to utilities in Arizona to determine how sensitive the supply curve results would be to changing situations. These factors include changes in tax law, delayed technical advances, escalating construction costs, manufacturing/supply chain constraints, near term performance learning curve, and competition for limited resources.

3.0 Renewable Energy Overview

This section provides an overview of renewable energy including the historical development of renewables in the US followed by the status of renewable energy in Arizona.

Renewable energy generation technologies are based on energy sources that are practically inexhaustible in that most are solar derivatives. Such technologies are often favored by the public over conventional fossil fuel technologies because of the perception that renewable technologies are more environmentally benign. Renewable energy options include wind, solar, biomass, biogas, geothermal, hydroelectric, and ocean energy. Table 3-1 shows the power conversion technologies that have been developed to harness these energy sources.

Table 3-1. Renewable Energy Conversion Technologies

Renewable Resource	Energy Conversion Technology
Solar	Photovoltaic Thermal electric (trough, dish, etc.) Thermal water heating Absorption chilling
Wind	Wind Turbines
Water	Hydroelectric Turbines Pumped Hydro Storage (also Compressed Air Storage)
Ocean	Wave Energy Devices Tidal/Current Energy Turbines Thermal Energy Conversion
Geothermal	Steam Turbines Direct Use Geothermal Heat Pumps
Biomass	Combustion (direct fired, cofiring with coal) Gasification / Pyrolysis
Biogas, Biodiesel, Ethanol	Engine generators Combustion turbines Microturbines Fuel cells

Renewable technologies have been developed to harvest energy from wind, solar radiation, biomass, water, and the earth's thermal energy. Although the potential resources are very large, non-hydro renewable energy currently only supplies about 2

percent of the electricity demand in the United States. Figure 3-1 is a summary of electricity generation for the United States in 2005, including a breakdown of the renewable energy portion of generation. The figure shows that renewable sources represent only a few percent of total electricity generation. The largest sources of renewable generation are hydroelectric followed by biomass, such as wood waste. Although increasing in popularity, other renewable energy sources, including wind and solar, make up much smaller portions of the total.

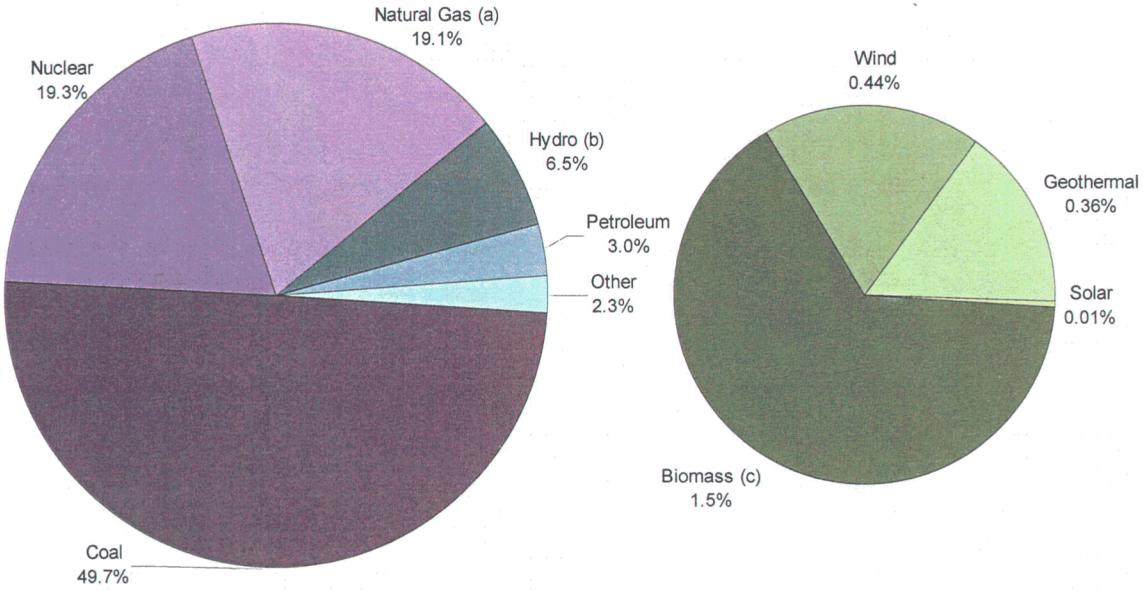


Figure 3-1. U.S. Electricity Generation by Source, 2005 (Source: EIA).

Recent natural disasters coupled with increased global demand and political instability led to sharp increases in oil and natural gas prices. Energy supply and security has become a topic of concern among policy makers and the public at large. In addition to their price volatility, fossil fuels emit pollutants and are often imported from other states or countries. Policy makers have historically looked to renewable energy to address these issues, and interest is resurging again.

3.1 Historical Development of Renewable Energy

Modern forms of non-hydro renewable energy technology have largely developed over the last thirty years. Industry growth has been uneven in response to abruptly shifting market forces, changing government policies, and evolving technology.

3.1.1 1978-1991: PURPA and Standard Offer Contracts

The modern era of renewable energy arose from the initial oil shortages of the 1970s. In 1978, the federal government passed the Public Utilities Regulatory Policy Act, which stimulated widespread development of renewable energy projects. Under PURPA, many biomass, wind, and geothermal plants came online and were allowed to sell excess power to the utility at an avoided cost or other negotiated rate. Some of these costs/rates, particularly in California, were tied to high forecasts of future fossil prices. The generous PURPA contracts combined with other financial incentives allowed California to lead the world in development of biomass, geothermal, wind and solar technologies. Ultimately, PURPA spurred the development of the independent power producer (IPP) industry. IPPs currently dominate ownership of renewable energy plants.

As shown in Figure 3-2 and Figure 3-3, growth of the renewable energy industry was faster during the 1980s than at any other time in recent history – with the possible exception of the current renewables "boom." During this period the predominant technologies implemented were biomass, waste to energy, and geothermal. In fact, up until 1999, biomass and waste accounted for approximately two-thirds of renewable generation capability installed in the US (nameplate basis). However, wind energy technology, which had matured in Europe, was to soon take over leadership.

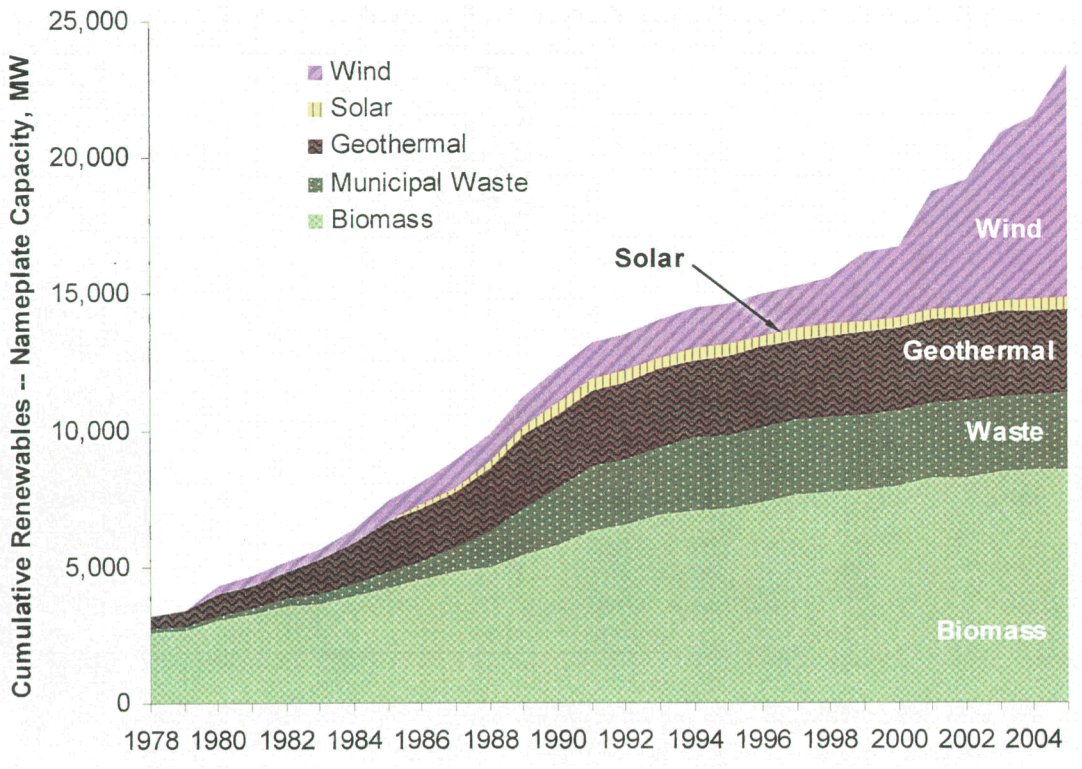


Figure 3-2. Cumulative Renewable Generation Capacity, MW (Data from GED[1]).

[1] Black & Veatch analysis of data from Global Energy Decisions' proprietary "Energy Velocity" database, May 2006.

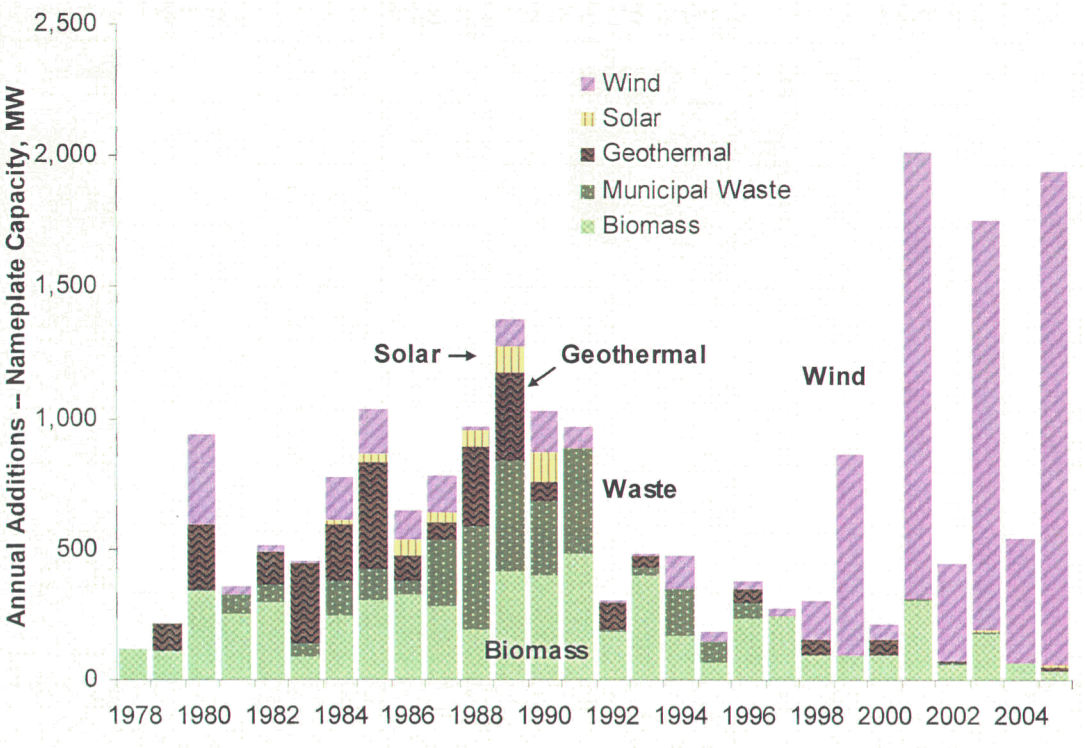


Figure 3-3. U.S. Annual Capacity Additions, MW (Data from GED).

3.1.2 1992-2004: The PTC and RPS Era

As the influence of PURPA waned with lower electricity costs in the 1990s, a new round of renewable energy development, mostly wind, was spurred by the Production Tax Credit (PTC) enacted in 1992. Despite the new incentive, development in the early 1990s was at a much slower pace than during the 1980s.

Near the latter half of the last decade, states began to implement Renewable Portfolio Standards (RPS) mandating that a certain percentage of electricity supply come from renewable sources. RPS programs accelerated the development of renewables (see Figure 3-2). To date, 22 states have implemented RPS policies mandating that a portion of power supplied to retail customers come from renewable energy sources. RPS goals vary greatly by state, as does the specific consideration for biomass energy. Notable state RPS programs include California (20 percent renewables by 2010), New York (24 percent by 2013), Massachusetts (4 percent by 2009), and Pennsylvania (18 percent by 2020). Figure 3-4 shows the various state renewable portfolio standards.

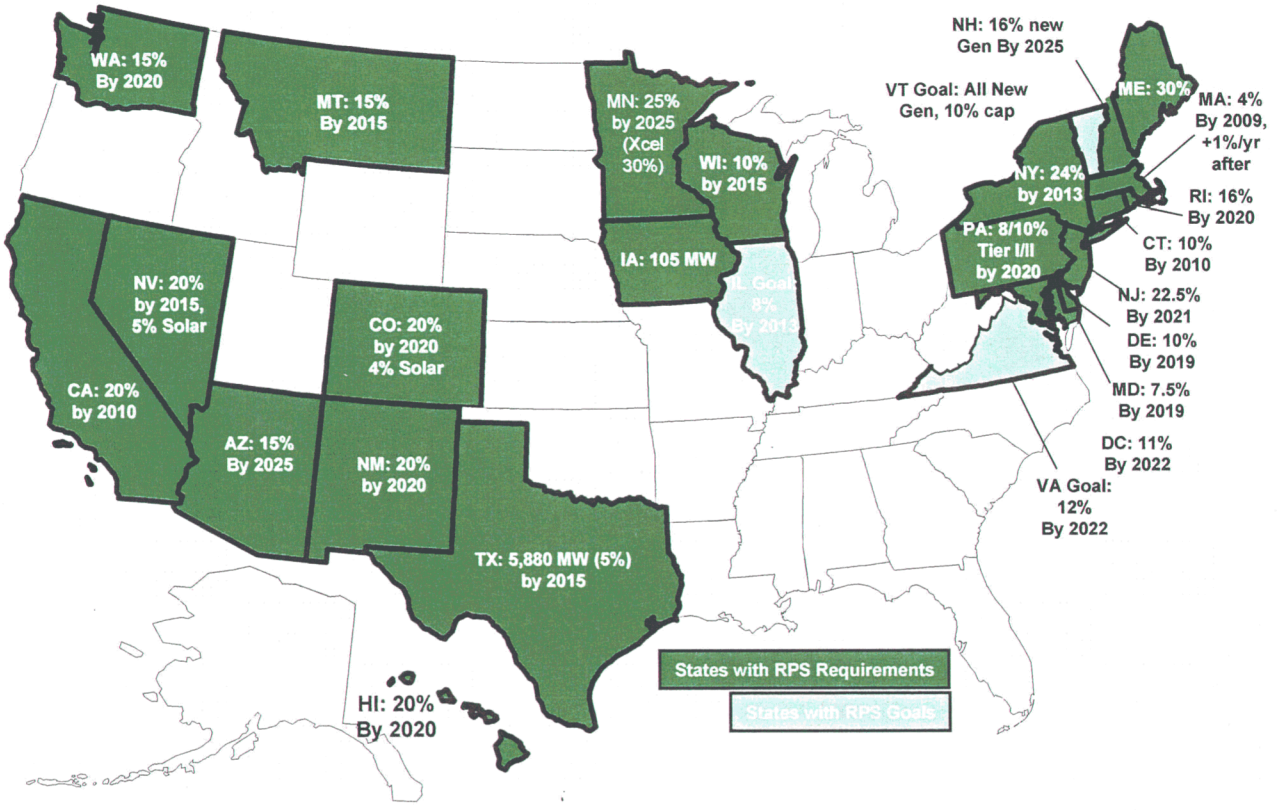


Figure 3-4. State Renewable Portfolio Standards (as of May 2007).

Based on developments in Europe, wind energy technology had also greatly improved from the designs of the 1980s. Wind benefited greatly from the combination of preferential PTC treatment, RPS programs, and improved technology. Since 1999, about 90 percent of all new renewable energy development has been wind (nameplate capacity basis). Prior to 1999, wind comprised about 10 percent of total renewables additions.

3.1.3 2005: Energy Policy Act

In the past year, changes in federal tax policy and a surge in demand for renewable energy have caused a new era in renewable energy development.

Federal involvement in the energy industry has traditionally been limited due to strong state regulation; however, the federal government is increasing its role, especially with respect to renewable energy. Recently, the government has significantly expanded tax and other incentives for renewable energy developers through the Energy Policy Act of 2005 (EPAct). The federal government has traditionally funded renewable research and development through the Department of Energy, and President Bush's recent state of the Union address called for more investment and spending on renewables.

The Energy Policy Act of 2005 included significant changes to renewable energy incentives, particularly related to the tax code. The changes in the tax code from the EPAct are significant: the PTC was extended to many new technologies and the Investment Tax Credit (ITC) was increased from 10 percent to 30 percent for solar.

The PTC provides a tax credit of 1.5 cents per kWh of eligible renewable generation for the first ten years of the project's life. The full credit is adjusted for inflation, and is worth $20/MWh as of 2007. Some resources receive half the PTC amount, currently $10/MWh. The PTC has gone through an "up and down" cycle of expiration and renewal over the past few years (see Figure 3-5). Originally enacted as part of the Energy Policy Act of 1992, the credit has expired numerous times before being renewed by Congress. The gaps in the PTC record have caused the wind market to cycle through boom and bust periods of development. Prior to October 2004, the PTC applied only to the production of electricity from wind and "closed-loop" biomass (and poultry waste for a brief period). Wind is the only technology that benefited significantly from the PTC during this timeframe.

Additional information on the ITC, PTC, and other renewable energy incentives is provided in Section 6 of this report.

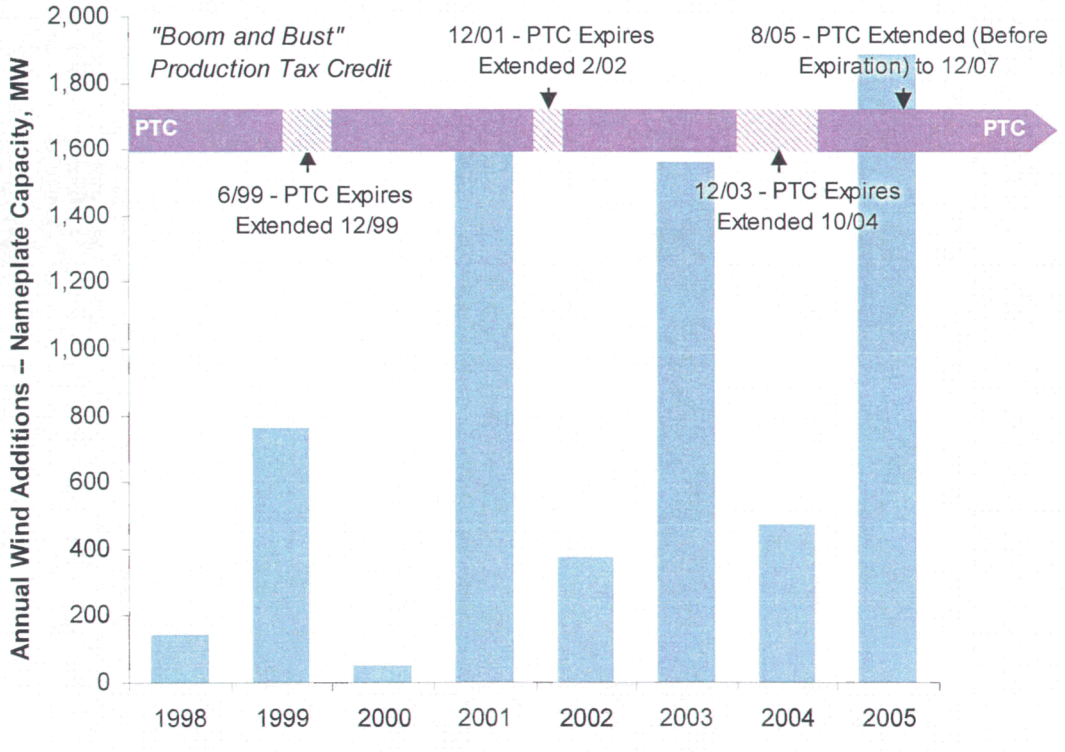


Figure 3-5. Production Tax Credit Cycle and Impact on Wind Installations (Data from GED).

The PTC again expired at the end of 2003 and was not renewed until October 4, 2004,[2] as part of the Working Families Tax Relief Act of 2004 (H.R. 1308). This Act extended the credit through December 31, 2005 and expanded it to include additional resources. The timing of this extension did little to spur new development of non-wind projects. The Energy Policy Act of 2005 modified the PTC and extended it through December 31, 2007. Another one year extension (Through December 31, 2008) was recently granted through the Tax Relief and Health Care Act of 2006. Due to the expanded timeframe and eligibility, the latest revisions have accelerated development of many different types of renewable energy. The PTC is now available for all the major renewable resources, with some receiving the "full" PTC and others the "half" credit (see Section 6 for details).

In the past, the PTC has been successful in encouraging development of wind energy but not other technologies. Closed-loop biomass (including poultry waste for a short time) was the only other technology eligible prior to 2004. Biomass was not developed due to restrictive definitions placed on fuel eligibility. However, the recent expansions and extensions of the PTC are now stimulating widespread development of all types of renewable energy technologies.

3.2 Renewable Energy Status in Arizona

Figure 3-6 shows the electricity generation data for Arizona in 2005. Current energy sources are comprised largely of traditional natural gas, coal, and nuclear resources. Hydroelectric contributes about 6 percent, while non-hydro renewable resources are currently very small (0.07 percent).

Figure 3-7 shows the historical generation data for Arizona from 1990 to 2005. Reviewing this information shows two key facts: (1) electricity generation in Arizona is increasing rapidly (over 60 percent growth from 1990 to 2005) and (2) the proportion of natural gas in Arizona's electricity supply has increased rapidly, from about 3 percent in 1997, to over 28 percent in 2005.

[2] Though when it was renewed, it applied retroactively so any project that went into operation received the PTC.

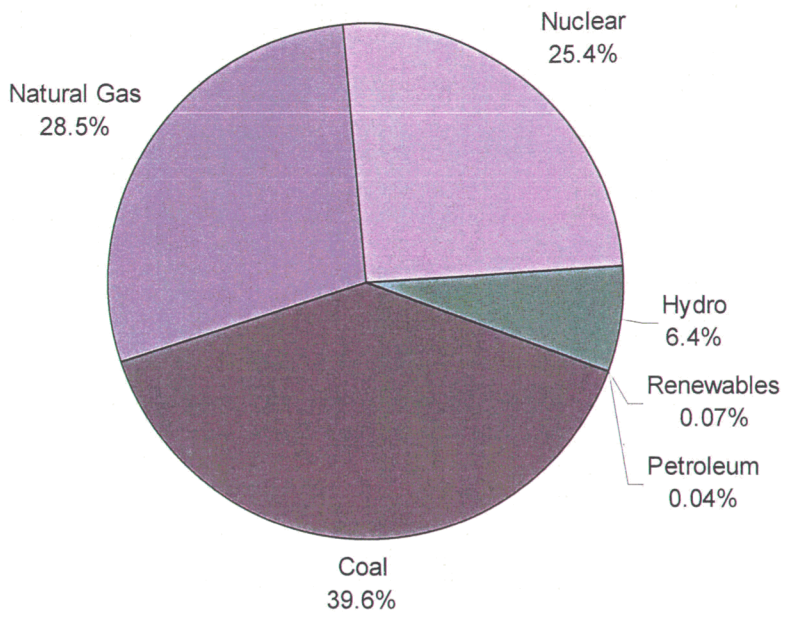


Figure 3-6. Electricity Generation in Arizona by Source, 2005 (Source: EIA).

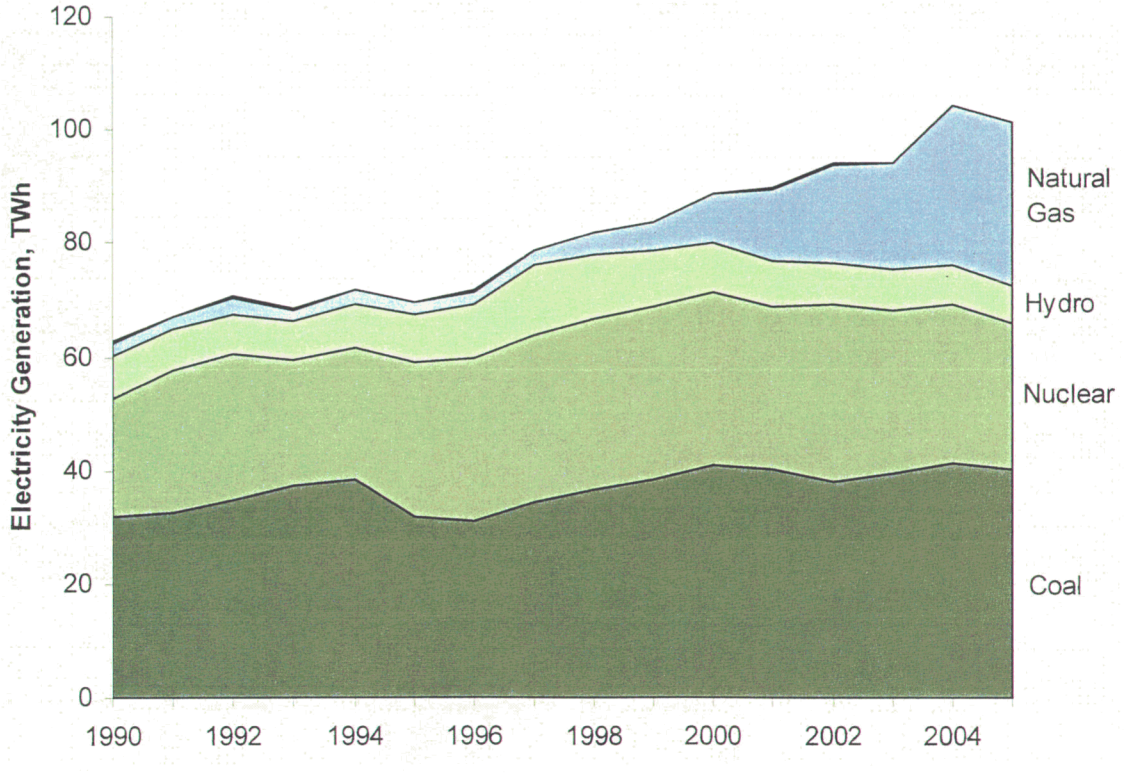


Figure 3-7. Electricity Generation in Arizona 1990-2005 (Source: EIA).

3.2.1 Existing and Announced Renewable Energy Projects

Although renewables currently only comprise a small fraction of the electricity in Arizona, this will likely change in the near future. Table 3-2 shows existing and announced renewable energy projects (excluding large hydroelectric projects). There are about 24 MW of renewable energy projects currently operating in Arizona, including 12 MW of biomass, 0.8 MW hydroelectric, and the remainder solar (11 MW). In addition, there are over 500 MW of projects in various stages of development throughout the state. The vast majority of these projects are based on wind resources, although there is a 20 MW biomass project under construction in eastern Arizona.

3.2.2 Arizona Renewable Energy Standard[3]

Arizona was one of the earlier states to adopt a renewable portfolio standard mandating that utilities source a portion of their energy from renewable energy sources. Arizona enacted its original Environmental Portfolio Standard (EPS) in March of 2001. The EPS required that investor owned utilities provide 1.1 percent of their power from renewables by 2007. The standard began with a requirement of 0.2 percent in 2002, increasing by 0.2 percent annually. Solar electric was to make up 50 percent of the standard in 2001, increasing to 60 percent for 2004 through 2012. Although the EPS was largely responsible for several of the projects identified in the previous section, many felt that the mandate needed to be revised.

After much deliberation, on November 14th, 2006 the Arizona Corporation Commission (ACC) adopted a new Renewable Energy Standard (RES) that requires utilities to meet higher targets for renewable energy sources. The requirement begins at 1.25 percent renewables in 2006 and stair-steps up to 15 percent renewable energy production by 2025 (see Table 3-3). A certain portion of the RES must be met with distributed renewable energy generation sources, such as small solar and wind. This is also known as a set-aside. The set-asides begin at 5 percent of the standard in 2007 and rise to 30 percent of the renewable standard percentage in 2012 and thereafter. At the full 15 percent standard in 2025, the set-aside would be 30 percent of total renewable requirement of 15 percent, or 4.5 percent of total electricity generation (10.5 is non-distributed resources). One half of the distributed resource requirement must come from residential installations, the other half must be from non-residential, non-utility applications. The purpose of the set-aside is to encourage renewable energy production from distributed sources such as small solar or wind equipment located on or near ratepayer property instead of larger, centralized renewable power plants.

[3] Source: ACC Decision No. 69127 (AAC R14-2-1801 et seq.), available at: http://www.cc.state.az.us/utility/electric/res.pdf, accessed January 2007.

Table 3-2. Renewable Energy Projects in Arizona.

Technology / Project Name	Owner	MW	COD
Biomass			
Los Reales Landfill Cofiring	TEP	4	1999
Tri Cities Landfill	SRP	5	2001
Eagar Biomass	Western Renewable Energy	3.7 to 4.7*	2008*
Skunk Creek Landfill	Ameresco	3	2008**
27th Ave. Landfill	Cambrian	3	2009**
Snowflake White Mountain Power	NZLegacy Energy LLC	24	2008**
Hydroelectric			
Arizona Falls	SRP	0.8	2003
Solar			
Santan Solar	SRP	0.097	1998
Santan Solar	SRP	0.097	1999
Star	APS	0.2	2000
Flagstaff	APS	0.08	1997
Ocotillo	APS	0.1	1998
Tempe	APS	0.18	1998
Gilbert (AZ)	APS	0.12	1999
Municipal Rooftops	APS	0.1	1999
Ocotillo	APS	0.1	1999
Scottsdale	APS	0.03	1999
Microelectronics Rooftop	APS	0.02	2000
Glendale	APS	0.2	2001
Prescott ERAU Solar	APS	0.2	2001
Agua Fria	SRP	0.2	2001
Yucca	APS	0.1	2001
Prescott Airport Solar Plant	APS	3.4	2002-06
Springerville Generating Station	TEP	5.1	2002-03
Saguaro	APS	1	2005
Wind* **			
Steel Park Wind	Western Wind Energy	15	2007**
Sunshine Wind Energy Park	Foresight Energy Co	60	2007**
Sunset Mountains Wind	Hopi Tribe (The)	100	2007**
Dry Lake Wind	PPM Energy Inc	99	2008**
Steel Park Wind	Western Wind Energy	100	2008**
Steel Park Wind	Western Wind Energy	100	2009**
Total Existing		**24**	
Total Proposed		**504**	

Source: Utilities, GED

Notes:

* Generator is 4.7MW, boiler damaged, was not capable of powering the generator at 4.7MW. May replace with larger boiler.

** Planned / Proposed Projects (COD subject to change).

*** None of the wind projects are currently under contract to sell power.

Table 3-3. Arizona Renewable Energy Standard Requirements.

Year	RES Total Requirement	Distributed Share of RES	Distributed Share of Total	Non-Distributed Share of Total
2006	1.25%	0.0%	0.0%	1.3%
2007	1.50%	5.0%	0.1%	1.4%
2008	1.75%	10.0%	0.2%	1.6%
2009	2.0%	15.0%	0.3%	1.7%
2010	2.5%	20.0%	0.5%	2.0%
2011	3.0%	25.0%	0.8%	2.3%
2012	3.5%	30.0%	1.1%	2.5%
2013	4.0%	30.0%	1.2%	2.8%
2014	4.5%	30.0%	1.4%	3.2%
2015	5.0%	30.0%	1.5%	3.5%
2016	6.0%	30.0%	1.8%	4.2%
2017	7.0%	30.0%	2.1%	4.9%
2018	8.0%	30.0%	2.4%	5.6%
2019	9.0%	30.0%	2.7%	6.3%
2020	10.0%	30.0%	3.0%	7.0%
2021	11.0%	30.0%	3.3%	7.7%
2022	12.0%	30.0%	3.6%	8.4%
2023	13.0%	30.0%	3.9%	9.1%
2024	14.0%	30.0%	4.2%	9.8%
2025	15.0%	30.0%	4.5%	10.5%

Eligible renewable resources include:

- Biogas electricity generator
- Biomass electricity generator
- Hydroelectric
  - Existing hydroelectric upgrades
  - Existing hydroelectric used to "firm" other eligible resources
  - New small hydroelectric (10 MW or less)
- Fuel cells that use only renewable fuels
- Geothermal generator
- Landfill gas generator
- Solar electricity resources

- Wind generator
- Hybrid wind and solar

In addition, various distributed generation technologies qualify for the distributed resource set-aside. These include solar daylighting, solar pool water heaters, solar HVAC, combined heat and power (CHP) and other on-site technologies. However, these technologies were not investigated in this report, since the focus is on the non-distributed share of the RES.

It should be noted that only the regulated utilities are covered by the ruling. This includes investor owned utilities (Arizona Public Service and Tucson Electric Power) and cooperatives. Salt River Project is not required to comply with the RES; however, SRP has adopted its own renewable energy goals. In 2004, SRP established a voluntary goal of achieving 15 percent of its energy from renewable energy and energy efficiency by 2025. Currently SRP has obtained 5 percent of its 15 percent goal (4 percent renewables, and 1 percent energy efficiency). The majority of the renewables share is from large hydroelectric.

4.0 Assessment of Renewable Energy Technology Options

This section reviews the general characteristics and costs of renewable energy technology options for Arizona.

The first step in the development of generation alternatives involves the identification of generic generation technologies whose technical and cost characteristics cause them to be worthwhile candidates for inclusion in portfolio plans. The objective of this section is to characterize the various renewable energy technologies suitable for application in Arizona. The information contained in this section will be used to screen technologies for further investigation later in the project.

4.1 Introduction

Technologies to harness renewable energy are diverse and include wind, solar, biomass, biogas, geothermal, hydroelectric, and ocean energy. Steady advances in equipment and operating experience spurred by government incentives have lead to many mature renewable technologies. The technical feasibility and cost of energy from nearly every form of renewable energy have improved since the early 1980s. However, most renewable energy technologies struggle to compete economically with conventional fossil fuel technologies, and in most countries the renewable fraction of total electricity generation remains small. This is true despite a huge resource base that has potential to provide many multiples of current electricity demand. Nevertheless, the field is rapidly expanding from niche markets to making meaningful contributions to the world's electricity supply.

4.1.1 Technologies Evaluated

This section provides an overview of the following renewable energy options:

1. Solid biomass
   - 1.1 Direct fired
   - 1.2 Cofiring
   - 1.3 Biomass gasification and IGCC
   - 1.4 Plasma arc gasification
2. Biogas
   - 2.1 Anaerobic digestion
   - 2.2 Landfill gas
3. Solar
   - 3.1 Solar photovoltaic
   - 3.2 Solar thermal electric

4. Hydroelectric
5. Wind
6. Geothermal
7. Fuel cells using renewable fuels

In addition, although it is not a renewable energy technology, compressed air energy storage can potentially help enable development of intermittent renewable energy sources, such as wind. The technology is briefly introduced at the end of this chapter.

4.1.2 General Approach to Characterization

Generally, each technology is described with respect to its principles of operation, applications, resource characteristics, cost and performance, environmental impacts, and a high level assessment (non-quantitative) of its development prospects for Arizona. The alternatives have been presented with a typical range for performance and cost, and the generic data provided should not be considered definitive estimates. A more detailed treatment of cost for promising technologies (including supply curves) is provided later in this report. The performance and costs are based on a representative size and installation in Arizona. Estimates are based on Black & Veatch project experience, vendor inquiries, and a literature review. In addition, an overall levelized cost range for the general technology type is provided. This levelized cost of energy accounts for capital cost (including direct and indirect costs), fuel, operations, maintenance, and other costs over the typical life expectancy of the unit. (See further description below.) A range of levelized costs is typically provided. In such cases, the low end of the levelized cost is based on the higher capacity factors and the lower capital and O&M costs. This approach is simple from a calculation perspective; however it must be noted that the low end of the costs represents and ideal "best case scenario", which is likely difficult to achieve in practice. The high end of the levelized cost is based on the lower capacity factors and the higher capital and O&M costs. Applicable financial incentives have been included in the levelized cost calculations, as indicated for each technology. These incentives are generally described in Section 6.

It should be noted that the characteristics provided in this section are general, and have been developed for the purposes of providing high-level screening information to identify the most promising technologies. Section 5 of this report provides estimates which are project-specific. These estimates are more accurate and representative of actual projects that could potentially be developed.

Although a few of the technologies are not commercially viable at this time, cost and performance data were assembled as available to provide a complete screening-level resource planning evaluation.

4.1.3 Levelized Cost of Energy Calculation Example

A levelized busbar cost model was constructed to evaluate the cost of each generating option. A levelized busbar analysis converts both fixed and variable costs to a single, all-inclusive cost per kilowatt-hour, assuming a given capacity factor[4].

Table 4-1 illustrates the calculation of a busbar cost at a 90 percent capacity factor for a 35 MW biomass plant based on the capital and operating characteristics developed in this section and the fixed charge rate assumptions described in Section 7. The columns of the table present the year-by-year costs in four categories (capital, fixed O&M, variable O&M, fuel) based on the input assumptions shown at the top of the table. Any applicable tax credits are also accounted for on a pre-tax basis. The total annual cost is determined by applying the levelized fixed charge rate to the initial capital cost. The fixed O&M is equal to the initial cost plus escalation; variable O&M is based on the escalated cost and unit production, fuel cost is based on the escalated fuel cost, output and the net plant heat rate. Busbar costs are equal to the total cost divided by output, and the present worth cost is based on a 10.1 percent discount rate. At a capacity factor of 90 percent, the table indicates that the busbar cost of the unit is $66/MWh over a 20 year period. This is a levelization of a 20 year nominal cost and has the following interpretation: if the busbar costs of the facility were $66/MWh every year of the 2007-2026 period, the present value of these costs would be the same as the present value of the variable, year-by-year costs listed in the "Busbar Cost" column of Table 4-1.

[4] Capacity factor is a significant assumption in the busbar cost calculation as it is the basis for determining the number of kilowatt hours a generating unit will produce, and the unit's all inclusive cost will be spread over, in a given time period.

Table 4-1. Biomass Levelized Cost of Energy Calculation.

Biomass Direct Combustion

Low Cost Case

Plant Input Data		Economic Input Data	Rate	Escalation
Capital Cost ($1,000)	96,250	First Year Fixed O&M ($1,000)	2,905.00	2.5%
Total Net Capacity (MW)	35.00	First Year Variable O&M ($1,000)	3,118.12	2.5%
Capacity Factor	90%	Fuel Rate ($/MBtu)	1.00	2.5%
Full Load Heat Rate, Btu/kWh (HHV)	13,500.00	Tax Credit ($/MWh)	16.56	2.5%
Debt Term	15			
Project Life	20			
		Present Worth Discount Rate	10.1%	
Hours per Year	8,760	Levelized Fixed Charge Rate	12.00%	

Year	Annual Capital Cost ($1,000)	Fixed O&M ($1,000)	Variable O&M ($1,000)	Tax Credit ($1,000)	Fuel Rate ($/MBtu)	Fuel Cost ($1,000)	Total Cost ($1,000)	PW Total Cost ($1,000)	Busbar Cost ($/MWh)	PW Cost ($/MWh)	Avoided Capacity Cost ($/kW)	Avoided Energy Cost ($/MWh)
2007	11,550	2,905	3,118	(4,570)	1.00	3,725	16,729	15,194	60.62	55.06	0.00	111.89
2008	11,550	2,978	3,196	(4,684)	1.03	3,818	16,858	13,907	61.09	50.40	0.00	121.46
2009	11,550	3,052	3,276	(4,801)	1.05	3,914	16,991	12,731	61.57	46.14	0.00	131.10
2010	11,550	3,128	3,358	(4,921)	1.08	4,012	17,127	11,655	62.07	42.24	0.00	133.40
2011	11,550	3,207	3,442	(5,044)	1.10	4,112	17,266	10,672	62.57	38.68	0.00	139.93
2012	11,550	3,287	3,528	(5,170)	1.13	4,215	17,409	9,774	63.09	35.42	160.34	146.48
2013	11,550	3,369	3,616	(5,299)	1.16	4,320	17,556	8,952	63.62	32.44	162.00	155.09
2014	11,550	3,453	3,706	(5,432)	1.19	4,428	17,706	8,200	64.17	29.72	160.15	159.54
2015	11,550	3,539	3,799	(5,568)	1.22	4,539	17,860	7,513	64.72	27.23	192.08	155.25
2016	11,550	3,628	3,894	(5,707)	1.25	4,652	18,018	6,884	65.30	24.95	192.80	164.57
2017	11,550	3,719	3,991		1.28	4,769	24,029	8,338	87.08	30.22	192.35	168.47
2018	11,550	3,812	4,091		1.31	4,888	24,341	7,672	88.21	27.80	183.14	166.80
2019	11,550	3,907	4,194		1.34	5,010	24,660	7,059	89.37	25.58	203.74	163.22
2020	11,550	4,005	4,298		1.38	5,135	24,988	6,497	90.56	23.54	200.11	168.86
2021	11,550	4,105	4,406		1.41	5,264	25,324	5,980	91.77	21.67	196.32	159.73
2022	-	4,207	4,516		1.45	5,395	14,118	3,028	51.16	10.97	214.88	164.41
2023	-	4,312	4,629		1.48	5,530	14,471	2,819	52.44	10.22	202.03	166.83
2024	-	4,420	4,745		1.52	5,668	14,833	2,625	53.76	9.51	206.07	170.16
2025	-	4,531	4,863		1.56	5,810	15,204	2,443	55.10	8.85	210.19	173.57
2026	-	4,644	4,985		1.60	5,955	15,584	2,275	56.48	8.24	214.40	177.04
2027	-	-	-		-	-	-	-	0.00	0.00	0.00	0.00
2028	-	-	-		-	-	-	-	0.00	0.00	0.00	0.00
2029	-	-	-		-	-	-	-	0.00	0.00	0.00	0.00
2030	-	-	-		-	-	-	-	0.00	0.00	0.00	0.00
2031	-	-	-		-	-	-	-	0.00	0.00	0.00	0.00
2032	-	-	-		-	-	-	-	0.00	0.00	0.00	0.00
2033	-	-	-		-	-	-	-	0.00	0.00	0.00	0.00
2034	-	-	-		-	-	-	-	0.00	0.00	0.00	0.00
2035	-	-	-		-	-	-	-	0.00	0.00	0.00	0.00
2036	-	-	-		-	-	-	-	0.00	0.00	0.00	0.00
2037	-	-	-		-	-	-	-	0.00	0.00	0.00	0.00
2038	-	-	-		-	-	-	-	0.00	0.00	0.00	0.00
2039	-	-	-		-	-	-	-	0.00	0.00	0.00	0.00
2040	-	-	-		-	-	-	-	0.00	0.00	0.00	0.00
2041	-	-	-		-	-	-	-	0.00	0.00	0.00	0.00
2042	-	-	-		-	-	-	-	0.00	0.00	0.00	0.00
2043	-	-	-		-	-	-	-	0.00	0.00	0.00	0.00
2044	-	-	-		-	-	-	-	0.00	0.00	0.00	0.00
2045	-	-	-		-	-	-	-	0.00	0.00	0.00	0.00
2046	-	-	-		-	-	-	-	0.00	0.00	0.00	0.00
2047	-	-	-		-	-	-	-	0.00	0.00	0.00	0.00
2048	-	-	-		-	-	-	-	0.00	0.00	0.00	0.00
2049	-	-	-		-	-	-	-	0.00	0.00	0.00	0.00
2050	-	-	-		-	-	-	-	0.00	0.00	0.00	0.00
2051	-	-	-		-	-	-	-	0.00	0.00	0.00	0.00
2052	-	-	-		-	-	-	-	0.00	0.00	0.00	0.00
2053	-	-	-		-	-	-	-	0.00	0.00	0.00	0.00
2054	-	-	-		-	-	-	-	0.00	0.00	0.00	0.00
2055	-	-	-		-	-	-	-	0.00	0.00	0.00	0.00
2056	-	-	-		-	-	-	-	0.00	0.00	0.00	0.00

Levelized Bus-bar Cost, $/MWh	66.09
Net Levelized Cost ($1,000)	18,238.23

Calculating the levelized cost of energy allows various technologies to be compared on an economic basis. However, it is important to note that busbar costs may not always be comparable between all options. For example, it is not appropriate to directly compare the levelized cost of an intermittent wind plant with dispatchable output from a peaking plant. This is because the economic value of the peaking plant is higher

than the time variant output from the wind plant. Additionally, transmission costs have not been included in the generalized levelized cost of energy calculations and these should be considered when comparing specific projects against one another.

4.2 Solid Biomass

Biomass is any material of recent biological origin; the most common form is wood. Electricity generation from biomass is the second most prolific source of renewable electric generation after hydroelectric power. Solid biomass power generation options include direct-fired biomass, biomass gasification, and cofired biomass, as described in the following subsections. This section concludes with a summary of development prospects for biomass in Arizona.

4.2.1 Direct-Fired Biomass

According to the US Department of Energy, there is about 35,000 MW of installed biomass combustion capacity worldwide. Combined heat and power applications in the pulp and paper industry comprise the majority of this capacity (Figure 4-1).

Figure 4-1. 35 MW Biomass Combustion Plant.

Operating Principles

Direct biomass combustion power plants in operation today use the same steam Rankine cycle that was introduced commercially 100 years ago. In many respects, biomass power plants are similar to coal plants. When burning biomass, pressurized steam is produced in a boiler and then expanded through a turbine to produce electricity. Prior to its combustion in the boiler, the biomass fuel may require processing to improve the physical and chemical properties of the feedstock. Furnaces used in biomass combustion include spreader stoker fired, suspension fired, fluidized bed, cyclone, and pile burners. Advanced technologies, such as integrated biomass gasification combined cycle (IGCC), Plasma Gasification and biomass pyrolysis, are currently under development.

Applications

Although wood is the most common biomass fuel, other biomass fuels include agricultural residues such as bagasse (sugar cane residues), dried manure and sewage sludge, black liquor from pulp mills, and dedicated fuel crops such as fast growing grasses and eucalyptus.

Biomass plants usually have a capacity of less than 50 MW because of the dispersed nature of the feedstock and the large quantities of fuel required. As a result of the smaller scale of the plants and lower heating values of the fuels, biomass plants are commonly less efficient than modern fossil fuel plants. In addition to being less efficient, biomass is generally more expensive than conventional fossil fuels on a $/MBtu basis because of added transportation costs. These factors usually limit the use of direct-fired biomass technology to inexpensive or waste biomass sources.

Resource Availability

To be economically feasible, dedicated biomass plants are located either at the source of a fuel supply (such as at a sawmill) or within 50 miles of numerous suppliers (up to 200 miles for a very high quantity, low cost supplier). Wood and wood waste are the primary biomass resources and are typically concentrated in areas of high forest-product industry activity. In rural areas, agricultural production can often yield significant fuel resources that can be collected and burned in biomass plants. These agricultural resources include bagasse, corn stover, rice hulls, wheat straw, and other residues. Energy crops, such as switchgrass and short rotation woody crops, have also been identified as potential biomass sources. In urban areas, biomass is typically composed of wood wastes such as construction debris, pallets, yard and tree trimmings, and railroad ties. Locally grown and collected biomass fuels are relatively labor intensive

and can provide substantial employment benefits to rural economies. In general, the availability of sufficient quantities of biomass is less of a feasibility concern than the high costs associated with transportation and delivery of the fuel.

Based on recent biomass resource assessments that Black & Veatch is familiar with, the expected cost of clean wood residues can vary as much as 100 percent depending on the type of residue, quantity, and hauling distance.

Cost and Performance Characteristics

Table 4-2 presents the typical characteristics of a 35 MW stoker boiler biomass plant with Rankine cycle using wood as fuel. Two fuel costs scenarios were evaluated: (1) a relatively lower cost ($1.00/MBtu) scenario which would be based primarily on urban wood waste sources in the major metropolitan areas, and (2) a moderate cost ($2.50/MBtu) scenario which would be more representative of a project using forest thinnings and forestry residues. Actual fuel cost could vary significantly from the values characterized here based on local supply and demand, and transportation distance. For example, Black & Veatch has previously estimated costs for biomass resources at greater than $3/MBtu in some parts of Arizona. In this case, transport distances were up to 200 miles. (Additional discussion is provided in Section 5.) Another possible biomass fuel is dedicated energy crops, which are grown specifically to provide feedstock for biomass plants. However, experience with energy crops is very limited in Arizona; further, costs for these fuels would likely approach $4.00/MBtu or greater. For these reasons, electricity costs for energy crops are not provided.

Table 4-2. Direct-Fired Biomass Combustion Technology Characteristics.	
Performance	
Typical Duty Cycle	Baseload
Net Plant Capacity (MW)	35
Net Plant Heat Rate (HHV, Btu/kWh)	13,500
Capacity Factor (percent)	70 to 90
Economics (2007$)	
Total Project Cost ($/kW)	2,750 to 3,500
Fixed O&M ($/kW-yr)	83
Variable O&M ($/MWh)	11.3
Levelized Cost, $1.00/MBtu ($/MWh)	66 to 94
Levelized Cost, $2.50/MBtu ($/MWh)	90 to 118
Applicable Incentives	Open loop: $10/MWh PTC, 5-yr MACRS Close loop: $20/MWh PTC, 5-yr MACRS
Technology Status	
Commercial Status	Commercial
Installed US Capacity (MW)	7,000

Environmental Impacts

Biomass power projects must maintain a careful balance to ensure long-term sustainability with minimal environmental impact. Most biomass projects target utilization of biomass waste material for energy production, saving valuable landfill space. Biomass projects that burn forestry or agricultural products must ensure that fuel harvesting and collection practices are both sustainable and do not adversely affect the environment. On the positive side, biomass projects that collect thin forests to reduce the risk of forest fires are increasingly seen as a way to restore a positive balance to forest ecosystems while avoiding catastrophic and polluting uncontrolled forest fires.

Unlike fossil fuels, biomass is viewed as a carbon-neutral power generation fuel. While carbon dioxide (CO_2) is emitted during biomass combustion, a nearly equal amount of carbon dioxide is absorbed from the atmosphere during the biomass growth phase. Further, biomass fuels contain little sulfur compared to coal and therefore produce less sulfur dioxide (SO_2). Finally, unlike coal, biomass fuels typically contain only trace amounts of toxic metals, such as cadmium and lead. However, biomass combustion still must include technologies to control emissions of nitrogen oxides (NO_x), particulate matter (PM), and carbon monoxide (CO) to maintain Best Available Control Technology (BACT) standards.

Arizona Biomass Combustion Outlook

The outlook for biomass combustion technologies is provided in Section 4.2.5 Biomass Technologies Development Prospects.

4.2.2 Biomass Gasification and IGCC

Biomass gasification is an emerging technology that converts solid biomass into a gaseous fuel which can then be combusted or otherwise utilized. There are numerous uses for the gas and many different gasifier technologies. Integrated gasification combined cycle (IGCC) is a developing application that combines a gasifier with a conventional combined cycle power plant (combustion turbine followed by a steam cycle). All of the 19 demonstration scale of IGCC plants constructed worldwide have been fossil-fueled. There are no integrated gasification combined cycle plants currently operating with biomass as a primary fuel.

Operating Principles

Biomass gasification is a process to convert solid biomass into a gaseous fuel. This is accomplished by heating the biomass in an environment low in oxygen ("fuel rich"). Gasification is a promising process for biomass conversion. By converting solid fuel to a combustible gas, gasification enables the use of more advanced, efficient and environmentally benign energy conversion processes such as gas turbines and fuel cells to produce power, and chemical synthesis to produce ethanol and other value added products. There is a huge variety of gasification technologies including updraft, downdraft, fixed grate, entrained flow, fluidized bed, and molten metal baths. The technology choice depends primarily on the fuel characteristics and the desired capacity of the plant.

Most biomass gasification systems are air blown. The primary product of air-blown gasification is a low heating value fuel gas, typically 15 to 20 percent (150-200 Btu/ft^3) of the heating value of natural gas (1,000 Btu/ft^3). Using oxygen, steam, or indirect heating results in a higher quality gas, although at higher costs.

Applications

The primary advantage of gasification over direct combustion is the versatility of the gasification product. Gasification expands the use of solid fuel to include practically all the uses of natural gas and petroleum, including close-coupled boilers, combustion engines and turbines, fuel cells, and chemical synthesis, and Stirling engines. The various fuel gas conversion options are illustrated in Figure 4-2.

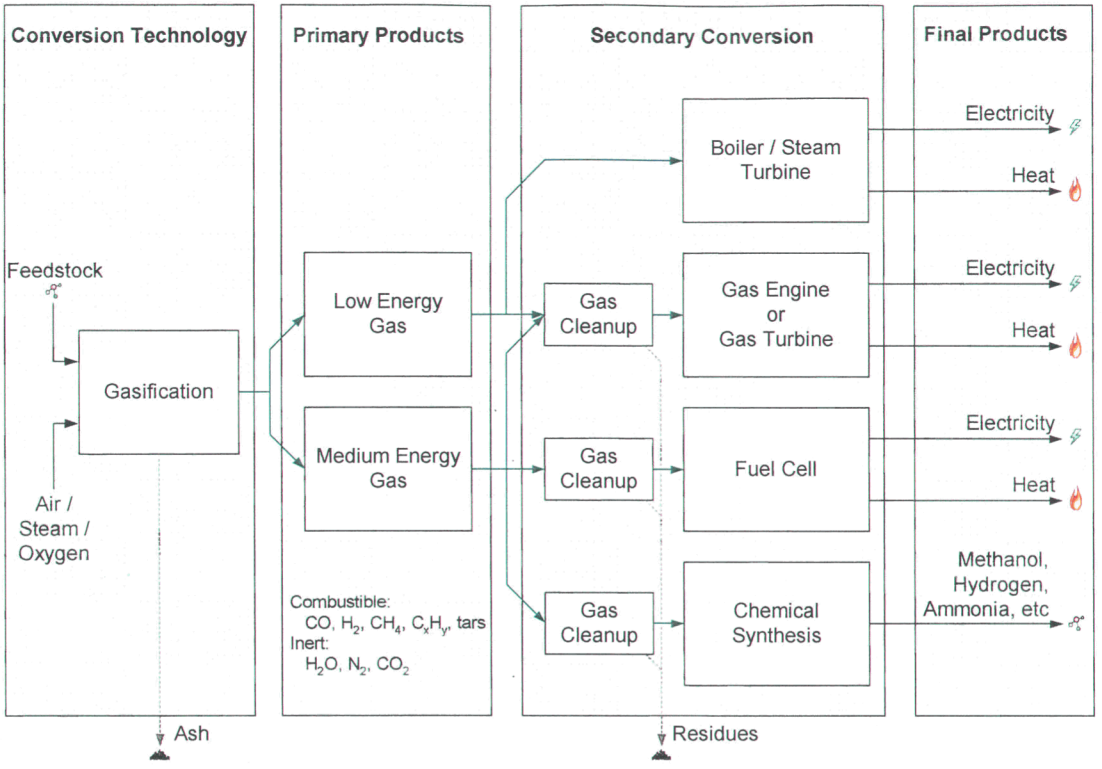


Figure 4-2. General Gasification Flow.

One of the principal focus areas for biomass gasification technology developers has been biomass IGCC. In an IGCC plant, the syngas exiting the gasifier is cleaned and combusted in a combustion turbine, generating power. Waste heat from the gas turbine is used to generate steam for use in a Rankine steam cycle. Net conversion to electricity for biomass IGCC plants is projected to be approximately 35 percent, compared to 20 to 25 percent for direct fired biomass plants. The potentially significant increase in efficiency makes biomass IGCC attractive; however, problems experienced with technology demonstration will need to be overcome. Although there are many gasifiers installed that produce fuel gas for close-coupled combustion in a boiler (essentially staged combustion), recent attempts to demonstrate more advanced processes, such as IGCC, have not been successful. Issues have been related partially to the gasification process itself, but also to supporting ancillary equipment, such as fuel handling and gas cleanup. Regardless, there are several biomass gasification equipment suppliers, including Foster Wheeler, Energy Products of Idaho, and Primenergy, which continue to develop biomass gasification technology for other applications.

Resource Availability

A biomass gasification or biomass IGCC plant would have similar resource availability issues as a direct-fired biomass plant. To be economically feasible it should be located either at the source of a fuel supply or within 50 to 75 miles of numerous suppliers. Wood, wood byproducts, agricultural residues, energy crops, and urban wood wastes are all suitable fuels for a biomass IGCC plant.

Like other biomass conversion technologies, an IGCC biomass plant would be limited in capacity by the amount of resource which could feasibly be delivered. A reasonable estimate for this limit is 30 MW to 75 MW, depending on location. Conversely, coal IGCC power plants are typically limited by the gas turbine capacity, not by fuel availability, and can be designed for much larger capacities similar to other fossil fuel power plants.

Cost and Performance Characteristics

Given the lack of commercial experience, cost and performance estimates for an IGCC biomass plant are uncertain. Since it would be limited to a size much smaller than an IGCC coal plant, an IGCC biomass plant would not benefit from the economies of scale of such plants. Table 4-3 presents projected characteristics for a biomass IGCC combustion plant for urban wood waste and forest residues.

Environmental Impacts

A biomass IGCC biomass project would have the same long-term sustainability concerns as other biomass conversion technologies. Biomass is viewed as a carbon-neutral power generation fuel. While CO_2 is emitted during biomass conversion, a nearly equal amount of CO_2 is absorbed from the atmosphere during the biomass growth phase. Further, biomass fuels contain little sulfur compared to coal and therefore produce less SO_2. Finally, unlike coal, biomass fuels typically contain only trace amounts of toxic metals, such as cadmium, and lead. Biomass gasification technologies will require equipment to control emissions of NO_x, PM, and CO to maintain air emission standards. It is important to note that given that biomass IGCC is expected to have higher efficiency than biomass combustion-based power plants, the pounds of pollution per MWh generated are substantially less.

Table 4-3. Biomass IGCC Technology Characteristics.	
Performance	
Typical Duty Cycle	Baseload
Net Plant Capacity (MW)	35
Net Plant Heat Rate (Btu/kWh)	10,000 to 11,500
Capacity Factor (percent)	70 to 90
Economics ($2007)	
Total Project Cost ($/kW)	3,000 to 4,000
Fixed O&M ($/kW-yr)	83
Variable O&M ($/MWh)	10.7
Levelized Cost, $1.00/MBtu ($/MWh)	65 to 99
Levelized Cost, $2.50/MBtu ($/MWh)	82 to 120
Applicable Incentives	Open loop: $10/MWh PTC, 5-yr MACRS Closed loop: $20/MWh PTC, 5-yr MACRS
Technology Status	
Commercial Status	Demonstration
Installed US Capacity (MW)	0

4.2.3 Biomass Cofiring

One of the most economical methods to burn biomass is to cofire it with coal in existing plants. Cofired projects are usually implemented by retrofitting a biomass fuel feed system to an existing coal plant, although greenfield facilities can also be designed to accept a variety of fuels.

As discussed in the previous section, a major challenge to biomass power is that the dispersed nature of the feedstock and high transportation costs generally preclude plants larger than 50 MW. By comparison, coal power plants rely on the same fundamental power conversion technology but can have much higher unit capacities, exceeding 1,000 MW. As a result of this larger capacity, modern coal plants are able to obtain higher efficiency at lower cost. Through cofiring, biomass benefits from this higher efficiency through a more competitive cost than a stand-alone, direct-fired biomass plant.

It should be noted that electricity demand in Arizona is increasing faster than any other state. Biomass cofiring converts capacity to a renewable source rather than adds capacity, and thus may be less attractive than alternatives to add capacity.

Applications

There are several methods of biomass cofiring that can be used to produce energy on a commercial scale. Provided that they were initially designed with some fuel flexibility, stoker and fluidized bed boilers generally require minimal modifications to accept biomass. For these types of boilers, simply mixing the fuel into the coal pile may be sufficient to cofire biomass.

Figure 4-3. Coal and Wood Mix.

Cyclone boilers and pulverized coal (PC) boilers (the most common in the utility industry) require smaller fuel sizes than stokers and fluidized beds and may necessitate processing of the biomass before combustion. There are two basic approaches to cofiring in this case: co-feeding the biomass through the coal processing equipment or separately processing and then injecting the biomass in the boiler. The first approach blends the fuels and feed them together to the coal processing equipment (crushers, pulverizers, etc.). In a cyclone boiler, up to 10 percent of the coal heat input can be replaced with biomass using this method. Pulverizers in a PC boiler are not designed to process relatively low density biomass, and fuel replacement is generally limited to around 2 or 3 percent if the fuels are mixed. The second approach (separate biomass processing and injection) allows higher cofiring percentages (10 to 15 percent) in a PC unit but costs more than processing a fuel blend.

Even at these limited cofiring rates, plant owners and operators have raised numerous concerns about the negative effects of cofiring on plant operations. These include the following:

- Reduced plant capacity.
- Reduced boiler efficiency.
- Ash contamination decreasing the quality of coal ash.
- Increased O&M costs.
- Minimal NOx reduction potential (usually proportional to biomass heat input).
- Boiler fouling/slagging because of the high alkali in biomass ash (more of a concern with fast growing biomass, such as energy crops).
- Potentially negative effects on SCR air pollution control equipment (catalyst poisoning).
- Reopening existing air permits.

These concerns have hampered the widespread adoption of biomass cofiring by electric utilities in the United States. However, these concerns can often be addressed through proper system design, fuel selection, and limits on the amount of cofiring.

Coal and biomass cofiring can also be considered in the design of new power plants. Designing the plant to accept a diverse fuel mix allows the boiler to incorporate biomass fuel, ensuring high efficiency with low O&M impacts. Fluidized bed technology is often the preferred boiler technology for cofiring since it has inherent fuel flexibility. There are many fluidized bed units around the world that burn a wide variety of fuels, including biomass. An example is a 240 MW circulating fluidized bed (CFB) in Finland, which burns a mixture of wood, peat, and lignite. This unit is capable of burning various fuels, ranging from 100 percent biomass to 100 percent coal.

Resource Availability

For viability, the candidate coal plant should be located within 100 miles of suitable biomass resources. The United States has a larger installed biomass power capacity than any other county in the world. The United States-based biomass power plants provide 7,000 MW of capacity to the national power grid. Coal power generation accounted for 2 trillion kWh in 2005, which comprised 49.7 percent of the total generation in the United States. Conversion of as little as 5 percent of this generation to biomass cofiring would increase electricity production from biomass by nearly 400 percent. It is important to note that biomass cofiring projects typically do not result in capacity increases as do other renewables. Instead, they offset fuel use at existing plants.

Cost and Performance Characteristics

Table 4-4 presents the typical characteristics for a biomass and coal cofired plant. The characteristics are based on cofiring 35 MW of biomass (separate injection) in a 400 MW pulverized coal power project. Except for fuel, the characteristics are provided on

an incremental basis (changes that would be expected compared to the coal plant). The primary capital cost for the project would be related to the biomass material handling system. As with direct fired biomass, biomass fuel cost is assumed to range from $1.00/MBtu for urban wood residues to $2.50/MBtu for forestry residues. To calculate the incremental fuel cost, coal has been assumed at a base cost of $1.50/MBtu. The incremental biomass cost is then ($0.50/MBtu) to $1.00/MBtu. Thus on the low-end, the biomass fuel cost is actually assumed to be $0.50/MBtu less expensive than coal.

Analysis of the range of incremental levelized costs presented in Table 4-4 indicates that the costs to cofire biomass with coal would be relatively small. The range of incremental levelized costs is between approximately $0/MWh (no increase) to $9/MWh for urban wood waste (assumed to cost $1/MBtu, which is $0.50/MBtu less than coal), and $18/MWh to $27/MWh for forest residues (assumed to cost $2.50/MBtu, which is $1/MBtu more than coal). This can be interpreted as the additional cost to produce one MWh of biomass energy, over the cost of coal power.

Table 4-4. Cofired Biomass Technology Characteristics.

Performance	
Typical Duty Cycle	Typically baseload, depends on host
Net Plant Capacity (MW)	35
Net Plant Heat Rate (Btu/kWh)	Increase 0.5 to 1.5 percent
Capacity Factor (percent)	Unchanged
Economics (Incremental Costs in 2007$)	
Total Project Cost ($/kW$_{biomass}$)	300 to 500
Fixed O&M ($/kW$_{biomass}$-yr)	5 to 15
Variable O&M ($/MWh$_{biomass}$)	Included with fixed
Levelized Cost, $1.00/MBtu ($/MWh$_{biomass}$)	0 to 9
Levelized Cost, $2.50/MBtu ($/MWh$_{biomass}$)	18 to 27
Applicable Incentives	None
Technology Status	
Commercial Status	Established, not fully commercial

Environmental Impacts

As with direct-fired biomass plants, the biomass fuel supply must be collected in a sustainable manner. Assuming this is the case, cofiring biomass in a coal plant generally has overall positive environmental effects. Clean biomass fuel typically reduces emissions of SO_2, CO_2, NO_x, and potentially heavy metals such as mercury. Further,

compared to other renewable resources, biomass co-firing directly offsets fossil fuel use. It may also provide an alternative to landfilling wastes, particularly wood wastes.

Arizona Biomass Cofiring Outlook

Arizona has several coal fired power plants that might be suitable candidates for biomass cofiring. A list of these is provided in Table 4-5. The outlook for biomass cofiring is further discussed in the next section.

Table 4-5. Arizona Utility Coal Fired Power Plants.

Plant Name	Primary Owner	Unit	Capacity, MW	County
Apache Station	Az Elec Power Coop	2	204	Cochise
Apache Station	Az Elec Power Coop	3	204	Cochise
Cholla	APS	1	113.6	Navajo
Cholla	APS	2	288.9	Navajo
Cholla	APS	3	312.3	Navajo
Cholla	APS	4	414	Navajo
Navajo	SRP	1	803.1	Coconino
Navajo	SRP	2	803.1	Coconino
Navajo	SRP	3	803.1	Coconino
Coronado	SRP	1	410.9	Apache
Coronado	SRP	2	410.9	Apache
H Wilson Sundt	TEP	4	120	Pima
Springerville	TEP	1	424.8	Apache
Springerville	TEP	2	424.8	Apache

Source: EIA

4.2.4 Plasma Arc Gasification

Plasma arc gasification is a combination of gasification with plasma arc technology. Both are mature technologies, but the integration of the two is relatively new.

Gasification is typically thought of as incomplete combustion of a fuel to produce a fuel gas with a low to medium heating value. Heat from partial combustion of the fuel is also generated, although this is not considered the primary useable product. The primary product of conventional air-blown gasification is a low heating value fuel, typically 15 to 20 percent (150 to 200 Btu/ft^3) of the heating value of natural gas (about 1,000 Btu/ft^3). Combustible components of the gas include carbon monoxide, hydrogen,

methane, higher hydrocarbons such as ethane and propane, and tar. The conventional use for this gas is combustion in a boiler to generate steam, although it could potentially be used in higher efficiency engines or combustion turbines if the gas is sufficiently clean.

There are two primary configurations for plasma torches: transferred and non transferred torches. Both configurations use a pair of electrodes across which a large current is applied. An arc, basically manmade lightning, is created when the electricity bridges the gap between the two electrodes. The arc generates temperatures of up to 30,000°F. The transferred torch directly contacts the arc with the material, or a conductor, in the reactor. The non-transferred torch blows a stream of air across the arc inside the torch to produce superheated gas, approximately 5,000°F. This gas provides the thermal input to the reactor that is required to decompose the material. The temperature in the reactor itself is generally around 2,000°F. Plasma arc torches require large amounts of electricity. Depending on the fuel being processed, the facility may not generate net electricity output.

Figure 4-4. Plasma Arc Torch Operating (Source: http://www.zeusgroup.org/applications.html).

Applications

The extreme temperatures produced by plasma torches makes them well-suited for waste remediation applications because the inorganic constituents in the waste that might normally be hazardous are literally melted to form a glassy slag which can be

captured in a solid form. This encapsulation of hazardous waste requires significant amounts of energy and has very specialized economical niche markets. Currently, some industry leaders feel that plasma arc disposal of municipal solid waste (MSW) is not economic. An alternate approach to strictly disposing of the MSW with plasma torches is to gasify the MSW and recover the combustible syngas that results from the thermal reaction. There are very few installations worldwide to benchmark against for economic evaluation. These are summarized in Table 4-6.

Table 4-6. Installed MSW Plasma Arc Gasification Projects.

Vendor - Project	Fuel	Commercial Status	Electrical Capacity, MW	Fuel Throughput, tpd
Westinghouse Plasma Corp.				
Yoshii, Japan	MSW	Pilot	--	25
Utashinai, Japan	ASR/MSW*	Commercial	8	165
Mihama, Japan	MSW	Commercial	--	28
Startech Environmental				
Bristol, Connecticut	Variety	Demonstration	--	5
Integrated Environmental Technologies				
APET, Hawaii	Medical waste	Commercial	--	24

Notes:
* Primary fuel intended to be auto shredder residue (ASR). Plant is capable of using MSW for up to 50 percent of volumetric throughput.

Resource Availability

Plasma arc gasification technologies can process the same basic resources as other biomass and waste to energy technologies. However, plasma arc is particularly well suited to handle difficult materials, such as hazardous waste, auto shredder residue, incinerator ash, low-level radioactive waste, and medical waste. The net power export potential (if any) of a plant depends heavily on the resource being processed.

Cost and Performance Characteristics

Because the technology is pre-commercial, objective cost and performance information for plasma arc systems was not obtainable for this study.

Environmental Impacts

Plasma arc technologies are well-suited for vitrification of waste materials. Extensive documentation of testing shows that the vitreous slag has very low leaching potential, effectively "locking up" contaminants in the solid material. Air emissions are not as well-documented. Technology suppliers claim that the extreme temperatures of the plasma system dissociate any harmful molecular emissions. However, very little discussion of emissions such as mercury can be found. It does not seem that mercury would be captured in the slag because it has such a low boiling point. Conventional waste to energy facilities seem to have achieved compliance with EPA's emissions limits for dioxins and furans; plasma arc gasification would not seem to offer substantial benefits over those technologies in that respect.

Arizona Plasma Gasification Development Prospects

Plasma arc gasification of waste is a developmental technology that has not gained widespread support, particularly as a power generation technology. There do seem to be some instances in which it can be cost effective, such as in highly land constrained areas with significant population density. Even in these favorable conditions, the economic viability of plasma arc projects is subject to technology risk. It is possible that plasma arc gasification of MSW may become commercial in a 10 to 20 year timeframe. In such case, it could be expected to generate approximately the same amount of electricity as other waste to energy options. Due to its pre-commercial nature, it is recommended that plasma arc gasification not be considered further for this study.

4.2.5 Biomass Technologies Development Prospects

There is some potential to develop biomass resources, although they are relatively limited compared to wind and solar resources in the state. Biomass potential is largely based on available resources; however, in the case of cofiring, a suitable host power plant in the vicinity is also necessary.

In December 2005, the National Renewable Energy Laboratory (NREL) published a new set of biomass resource data and documentation, including GIS data layers of major biomass resources on a county level. The data represents fairly uniform set of biomass resource data, and is the most current nation-wide, county level data source available. As described below, much of the resource data is based on statistical estimation. To determine the actual available quantities and suppliers of biomass material in the region, a more detailed resource assessment and supplier survey would be necessary. This survey would be carried out in the next phase of this project.

The NREL data is defined as follows:

- **Agricultural Residues** – This data includes residues from corn, wheat, soybeans, cotton, sorghum, barley, oats, rice, rye, canola, beans, peas, peanuts, potatoes, safflower, sunflower, sugarcane and flaxseed. Residue estimates were developed using the total grain production, crop-to-residue ratio, and moisture content. The total grain production data for each county in 2002 were as reported to the US Department of Agriculture. It was assumed that 35 percent of the total residue could be collected, accounting for residue left for soil protection, grazing, bedding, etc. Animal manures are discussed in the anaerobic digestion section of this report. Agricultural residues are relatively limited in Arizona due to the arid climate.
- **Forest Residues** – Forest residue data is adapted from the 2002 USDA Forest Service Timber Product Output Database. The quantities include commercial logging residues and other practices such as fire management (fuel reduction), pre-commercial thinnings, and land clearing. Since this data source is based on historical sector output, the NREL estimates have been augmented with an estimate of projected availability from fire management forest thinnings. A large portion of Arizona's forested land is located within National Forests. Until the early 1990s, much of this land was harvested for timber. The amount of timber harvested has declined substantially over the past 15 years. Currently, much of the wood removed from Arizona forests is due to fire management.
- **Primary Mill Residues** – Primary mill residue data is also taken from the 2002 USDA Forest Service Timber Product Output Database. The quantities include mill residues such as slabs, edgings, trimmings, sawdust, veneer clippings, and pulp screenings. This includes material that is already utilized as well as material that is disposed as waste. As the amount of timber harvested from Arizona forests declined due to environmental restrictions, the timber available to sawmills also declined. This caused many of the sawmills in Arizona to close their operations. In 1960, there were approximately 38 sawmills; in 1998 there were only 13.[5] In a recent Black & Veatch survey, even fewer mills were identified.

[5] Source: Keegan, Charles E. Arizona's Forest Products Industry: A Descriptive Analysis 1998. School of Business Administration, University of Montana

Figure 4-5. Large Wood Yard in Arizona (Source: SFP).

- **Secondary Mill Residues** – Secondary mill residue includes material from wood manufacturing facilities including pallet, truss, and furniture manufacturers. Data from the US Census Bureau was used to determine the number of businesses in each county. The size of the company was then used to estimate the amount of residue each company generates, using data from a previous NREL study which found that pallet and lumber companies generate about 300 tons per year, and a small woodworking company generates about 5 to 20 tons per year of wood waste.
- **Urban Wood Residues** – Includes municipal solid waste segregated wood (wood chips, pallets, and yard waste), tree trimming services, and construction and demolition (C&D) wood. Quantities were estimated using data from a previous NREL study, which found that approximately 3 to 5 percent of MSW is wood, one tree service generates about 1,000 tons per year of wood waste, and that C&D wood is proportionate to population. Urban wood waste is a promising source in Arizona, particularly around urban centers.

Table 4-7 summarizes the resource data by county, with estimates for the amount of potential generation (MW) possible from these resources. Figure 4-6 shows urban wood waste distribution in the state. It can be seen that this data represents a high-level assessment of the available resources. However, it is based on reasonable assumptions and draws from reliable data sources. Black & Veatch believes that this data provides a first-level representation of the relative quantities of each resource throughout Arizona.

If biomass is economically competitive, Black & Veatch recommends that a more detailed biomass resource assessment be performed.

Table 4-7. Estimated Biomass Resources in Arizona (Dry Tons/Year).

County	Agricult. Residue	Forest Residue	Primary Mill Residue	Secondary Mill Residue	Urban Wood Waste	Total	MW[a]
Apache	0	12,380[b]	0	498	7,403	20,280[b]	4[b]
Cochise	34,207	0	0	20	12,758	46,985	8
Coconino	0	16,125[b]	0	41	11,977	28,142[b]	5[b]
Gila	0	4,083	0	253	5,387	9,723	2
Graham	18,254	0	0	245	3,577	22,076	4
Greenlee	0	1,764	0	0	1,048	2,812	1
La Paz	18,110	0	0	0	2,090	20,200	4
Maricopa	69,267	0	0	28,679	312,337	410,283	74
Mohave	2,394	0	0	1,829	16,628	20,851	4
Navajo	0	24,769[b]	108,588	1,519	10,337	145,213[b]	26[b]
Pima	15,946	0	0	2,964	86,102	105,011	19
Pinal	126,526	0	0	1,025	18,497	146,048	26
Santa Cruz	0	0	0	738	4,073	4,812	1
Yavapai	0	11	0	1,870	17,077	18,958	3
Addl. Forest Thinnings[c]		300,000				300,000	54
TOTAL	**350,990**	**359,132**	**108,588**	**40,954**	**525,609**	**1,385,272**	**249**

Source: NREL (http://www.nrel.gov/gis, accessed 2006), except forest thinnings estimate.

Notes:

[a] Assumes an average biomass HHV of 8,500 Btu/lb, a heat rate of 13,500 Btu/kWh, and a capacity factor of 80 percent. A cofired project at 10,000 Btu/kWh would produce more power.

[b] Does not include supplemental forest thinnings, see note (c).

[c] Projected forest thinnings carried out for fuel reduction in Arizona National Forests, about 90 percent of which are in the Apache-Sitgreaves, Coconino, and Kaibab National Forests (Coconino, Navajo, and Apache counties). Based on thinning 35,000 acres per year with a yield of 10 dry tons per acre. Additional research resulted in a slightly lower estimate, see Section 5.1.

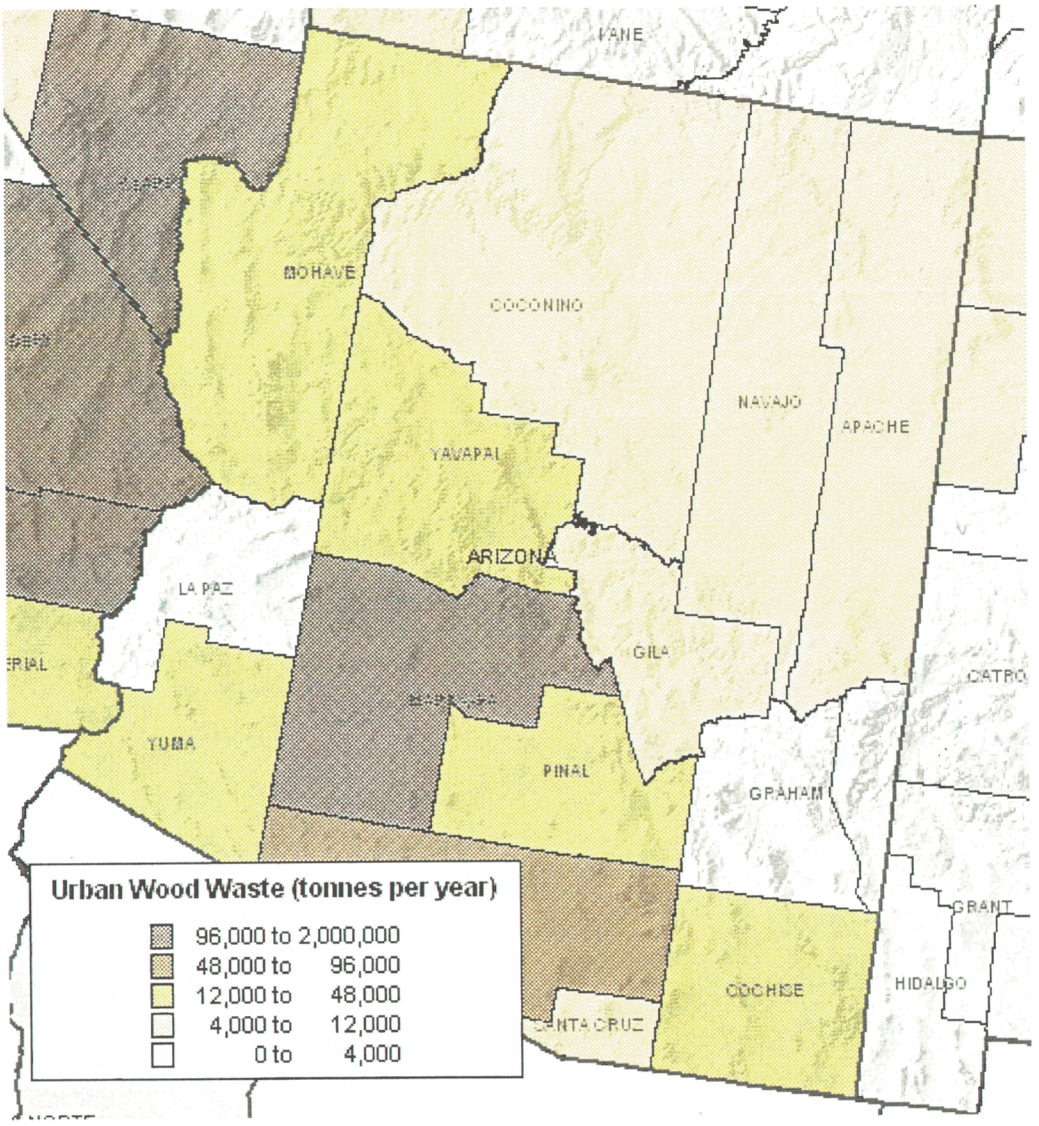


Figure 4-6. Arizona Urban Wood Waste Resource.

This table shows about 250 MW of stand-alone generation potential from biomass resources in Arizona. Different residues are available in different parts of the state. Various projects are conceivable based on these distributions.

- Maricopa County (Phoenix) has the largest potential (74 MW) of all counties, due primarily to the relatively large estimated quantities of urban wood waste. This quantity should be sufficient to support development of a stand-alone biomass plant in the Phoenix area. Permitting constraints and long-term sustainability of the wood supply may make a smaller facility more optimal. The nearest potential host for cofiring is TEP's 120 MW Sundt station.

- In Pinal County, between Phoenix and Tucson, agricultural residues are predominant (26 MW total). Combined with the 19 MW residues from Pima County (Tucson), another biomass plant could be sited. Alternatively, the biomass could be cofired with coal in TEP's Sundt station.
- As noted in the table, there may be 250,000 dry tons/year (45 MW) of forest thinnings from fuel reduction efforts in the Apache-Sitgreaves, Coconino, and Kaibab National Forests located in Coconino, Navajo, and Apache counties. In Navajo County alone there is a relatively large quantity of primary mill residues (20 MW worth). Much of this comes from a single source: the Fort Apache Timber Company's (FATCO) sawmill located in the extreme southern portion of the county. The total resource potential from all sources in Coconino, Navajo, and Apache counties is 89 MW. The proposed 24 MW Snowflake White Mountain Power project will also burn some of the available biomass.

Additional assessment and quantification of potential biomass resources is provided in Section 5 of this report.

4.3 Biogas

Biogas technology refers to the process of generating electricity with gas captured from the anaerobic digestion of manure or naturally occurring landfill gas (LFG). The following subsections describe the formation of these fuels and their ability to produce renewable energy.

4.3.1 Anaerobic Digestion

Anaerobic digestion is a natural process that occurs when bacteria decompose organic materials in the absence of oxygen. The byproduct of this decomposition is generally composed of 50 to 80 percent methane. The most common applications of anaerobic digestion use industrial wastewater, animal manure, or human sewage as feedstock. According to Bioenergy News, the publication of the Bioenergy Association of New Zealand, Inc., the projection of total installed capacity of anaerobic digestion will grow from 185 MW in 2004 to 575 MW in 2013. The projection is that 203 MW will be installed in Western Europe, 68 MW in North America, and 46 MW in Australia.[6]

[6]The World Biomass Report, *Bioenergy News*, December 2004, http://www.bioenergy.org.nz.

Applications

Anaerobic digestion is commonly used in municipal wastewater treatment as a first-stage treatment process for sewage sludge. Increasingly stringent agricultural manure and sewage treatment management regulations are the primary drivers for the heightened interest in anaerobic digestion technologies. Use of anaerobic digestion technologies in wastewater treatment applications results in a smaller quantity of biosolids residue compared to aerobic (digestion in the presence of oxygen) technologies Waste water treatment plants commonly use the biogas for process heating requirements. Power production from digestion facilities is typically a secondary consideration.

The Los Angeles Department of Water and Power has announced a new agreement to purchase power from a proposed 40 MW anaerobic digestion facility that will process 3,000 tons per day of municipal green waste, such as landscape trimmings and food waste to produce biogas for power production. The proposed facility would be the largest of its kind in the world. There are various other high-solids digestion systems installed worldwide, primarily in Europe and Japan.

Biogas produced by anaerobic digestion can be used for power generation, direct heat applications, and absorption chilling. Reciprocating engines are the most common power conversion device, although demonstrations with microturbines and fuel cells have been successful.

Resource Availability

For manure digestion on farms, the resource is readily accessible, and only minor modifications to existing manure management techniques are required to produce biogas suitable for power generation. In some cases, economies of scale may be realized by transporting manure from multiple farms to a central digestion facility. For central plant digestion of manure from several sources, the availability and proximity of a large number of livestock operations is necessary to provide sufficient manure feed rate to the facility. However, the larger size of regional facilities does not necessarily guarantee better economics, because of higher manure transportation costs. For anaerobic digestion of municipal sewage wastes, the resource is readily available at the wastewater treatment plant.

Cost and Performance Characteristics

Table 4-8 presents the typical characteristics of farm-scale dairy manure anaerobic digestion systems utilizing reciprocating engine technology. Costs for anaerobic digestion systems are very site specific. A photo of a dairy manure digester is shown on Figure 4-7.

Table 4-8. Farm-Scale Anaerobic Digestion Technology Characteristics.	
Performance	
Typical Duty Cycle	Baseload
Net Plant Capacity (MW)	0.150
Capacity Factor (percent)	70 to 90
Economics (2007$)	
Total Project Cost ($/kW)	4,000 to 6,000
Variable O&M ($/MWh)	17
Levelized Cost ($/MWh)	68 to 126
Applicable Incentives	$10/MWh PTC (>150 kW only)
Technology Status	
Commercial Status	Commercial
Installed Worldwide Capacity (MW)	185

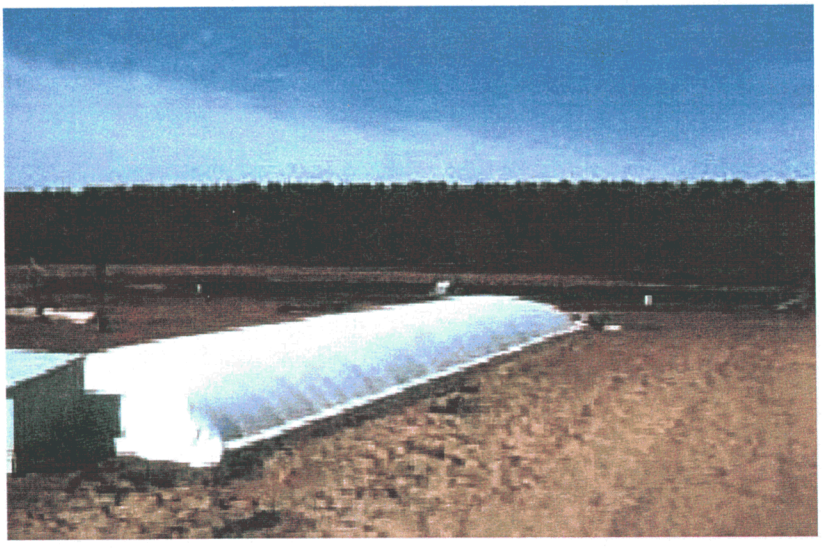


Figure 4-7. 135 kW Dairy Manure Digester.

Environmental Impacts

Anaerobic digesters have multiple positive environmental impacts: they reduce pathogens in the waste stream; they eliminate odor problems; they reduce methane emissions relative to atmospheric decomposition of manure, which are a significant contributor to greenhouse gas emissions; and they can help prevent nutrient overloading in the soil resulting from manure spreading.

Developmental Potential

The potential for power generation from anaerobic digestion depends on the feedstock: animal manures or sewage sludge. Combined, the potential is about 50-60 MW, with sewage sludge being significantly less expensive.

There are over 4 million farm animals in Arizona raised in concentrated animal feeding operations (CAFOs). Typically, farm digesters are installed at either dairy farms or pig farms. As shown in Table 4-9, there is theoretically the potential for about 27 MW of power produced from dairy and swine operations in Arizona. The dairy and swine concentration is heaviest in Maricopa counties, and to a lesser extent, Navajo, Pinal, and Yuma counties. Pinal and Yuma counties also have large concentrations of beef cattle. Because it is dry and dispersed, manure from beef cattle is generally not suitable for anaerobic digestion applications. However, it can be combusted if dry.

Table 4-9. Arizona Biogas Potential (MW) from Dairy and Swine Farms.

County	Dairy	Swine	Total
Cochise	0.1	0.05	0.1
Greenlee	0.1	0	0.1
Maricopa	15.2	0	15.2
Mohave	0.2	0	0.2
Navajo	0	5.2	5.3
Pima	0.2	0	0.2
Pinal	3.0	0	3.0
Yavapai	0.7	0	0.7
Yuma	2.3	0	2.3
Totals	21.8	5.3	27.0

Source: APS, Arizona Department of Environmental Quality, Black & Veatch

Human waste water treatment plants (WWTP) can also be a suitable source for biogas, particularly if anaerobic digestion systems are already installed. There are 13 WWPTs in Arizona with sewage sludge digesters. The largest plant, the 179 million gallon per day (MGD) 91st Avenue Wastewater Treatment Plant, has the potential to produce about 12 MW. There are three other plants between 10 and 100 MGD with a combined capacity of about 8 MW.[7]

Because the anaerobic digestion system is already installed, power generated from biogas at WWTPs can be as little as half the cost of animal manure digestion projects.

[7] Peter Johnston (APS), Daniel Musgrove (Universal Entech), "Biofuels", available at: http://www.cc.state.az.us/utility/electric/EPS-BBG.ppt.

However, it is usually the case that the power demands of the wastewater treatment process are larger than the biogas potential. Therefore the potential for grid export is limited.

4.3.2 Landfill Gas

LFG is produced by the decomposition of the organic portion of waste stored in landfills. LFG typically has methane content in the range of 45 to 55 percent and is considered an environmental risk. There is increased political and public pressure to reduce air and ground water pollution and to reduce the risk of explosion associated with LFG. From a generation perspective, LFG is a valuable resource that can be burned as fuel by reciprocating engines, small gas turbines, or other devices (Figure 4-8). LFG energy recovery is currently regarded as one of the more mature and successful waste-to-energy technologies. There are more than 600 LFG energy recovery systems installed in 20 countries.

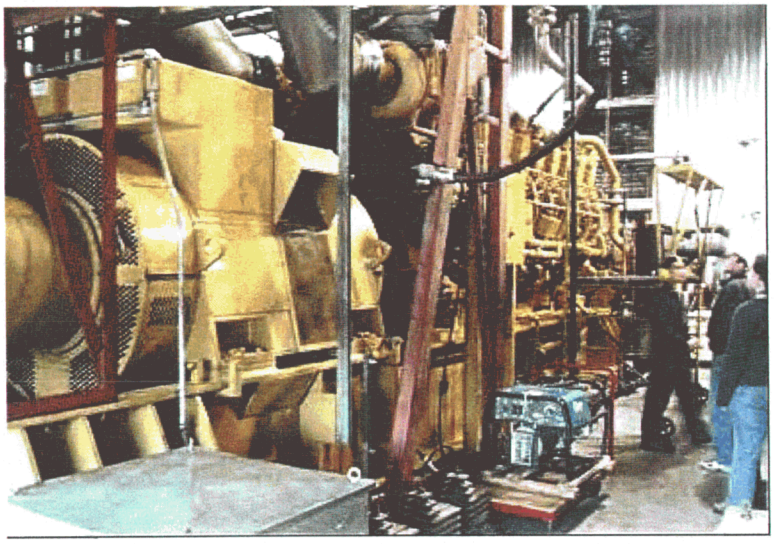


Figure 4-8. Reciprocating Engine Used to Generate Power from LFG.

Applications

LFG can be used to generate electricity and process heat, or can be upgraded for pipeline sales. Power production from an LFG facility is typically less than 10 MW. There are several types of commercial power generation technologies that can be easily modified to burn LFG. Internal combustion engines are by far the most common generating technology choice. About 75 percent of the landfills that generate electricity use internal combustion engines. Depending on the scale of the gas collection facility, it

may be feasible to generate power via a combustion turbine or a boiler and steam turbine. LFG co-firing in larger utility boilers is also in use; TEP currently operates a 5 MW co-fired LFG operation in Tucson. Nearly 35 percent of all landfill gas projects in the U.S. are co-fired.[8] Testing with microturbines and fuel cells is also under way, although these technologies do not appear to be economically viable for power generation.

Resource Availability

Gas production at a landfill is primarily dependent on the depth and age of waste in place and the amount of precipitation received by the landfill. In general, LFG recovery may be economically feasible at sites that have more than 1 million tons of waste in place, more than 30 acres available for gas recovery, a waste depth greater than 40 feet, and at least 25 inches of annual precipitation. The arid conditions in Arizona limit LFG productivity.

The economic life of an LFG resource is limited. After waste deliveries to a landfill cease and the landfill is capped, LFG production will decline, typically following a first order decay.

Cost and performance Characteristics

The economics of installing an LFG energy facility depend heavily on the characteristics of the candidate landfill. The payback period of an LFG energy facility at a landfill that has an existing gas collection system can be as short as 2 to 5 years, especially if environmental credits are available. However, the cost of installing a new gas collection system at a landfill can prohibit installing an LFG facility. Table 4-10 presents cost and performance estimates for typical LFG projects using reciprocating engines.

[8] Source: Tucson Electric Power

Table 4-10. Landfill Gas Technology Characteristics	
Performance	
Typical Duty Cycle	Baseload
Net Plant Capacity (MW)	2 to 10
Capacity Factor (percent)	70 to 90
Economics (2007$)	
Total Project Cost ($/kW)	1,500 to 2,000
Variable O&M ($/MWh)	17
Fuel Cost ($/MBtu)	1.00 to 3.00*
Levelized Cost ($/MWh)	40 to 80
Applicable Incentives	$10/MWh PTC
Technology Status	
Commercial Status	Commercial
Installed US Capacity (MW)	1,100

* Fuel cost is variable. The low end of this range is unlikely unless an existing gas purchase contract is in place, or responsibility for the gas collection system is assumed. .

Environmental Impacts

Combustion of LFG releases pollutants similar to those released by many other fuels, but the combustion of LFG is generally perceived as environmentally beneficial. Since LFG is principally composed of methane, if it is not combusted, LFG is released into the atmosphere as a greenhouse gas. As a greenhouse gas, methane is 23 times more harmful than CO_2. Collecting the gas and converting the methane to CO_2 through combustion greatly reduces the potency of LFG as a source of greenhouse gas emissions.

Arizona Landfill Gas Outlook

The potential for landfill gas project developments in Arizona is limited, although project economics are generally very competitive. Based on data acquired from the US Environmental Protection Agency's (EPA) Landfill Methane Outreach Program (LMOP) database, there are at least 25 candidate landfills with the potential for power generation from landfill gas. These projects are listed in Table 4-11. The estimated potential generation at the different locations ranges from a few kilowatts up to around 10 MW. In aggregate, 20 to 30 MW of potential may be possible. The actual amount of generation which is achievable at these locations will depend on the actual gas generation levels, landfill gas composition, the level of coverage of the collection system, and the net plant heat rate (NPHR) of the engine-generators or other appropriate conversion technology.

The potential for project development at these locations will depend on the gas availability and the details of any existing gas rights contracts.

Table 4-11. Candidate Landfill Gas Project Locations in Arizona.

Landfill Name	City	Waste in Place (tons)
Apache Junction LF	Apache Junction	1,000,000
Cinder Lake MSW LF	Flagstaff	2,150,000
City of Glendale Municipal Landfill	Glendale	5,000,000
Grey Wolf Landfill	Dewey	3,000,000
Huachuca City Landfill	Huachuca	1,200,000
North Center Street Landfill	Phoenix	2,000,000
Northwest Regional MSW Landfill	Phoenix	1,000,000
Painted Desert Landfill	Joseph City	1,500,000
Queen Creek MSW Landfill	Queen Creek	1,500,000
Rio Rico MSW Landfill	Rio Rico	1,000,000
Salt River Landfill	Phoenix	3,000,000
Skunk Creek Landfill	Phoenix	12,000,000
Cave Creek Landfill	Phoenix	NA
Cocopah Landfill	Somerton	2,200,000
Copper Mountain Landfill	Wellton	NA
Dudleyville Landfill	Winkelman	8,902
Harrison City Landfill	Tucson	2,250,000
Ironwood Landfill	Florence	286,464
La Paz County Landfill	Parker	NA
Lake Havasu Landfill	Lake Havasu City	NA
Mohave Valley Landfill	Mohave Valley	NA
Sierra Estrella Landfill	Maricopa	NA
Southwest Regional Landfill	Buckeye	NA
Tangerine Road MSW Landfill	Tucson	2,100,000
Vincent Mullins Landfill	Tucson	NA

Source: EPA Landfill Methane Outreach Program (LMOP) database

4.4 Solar Electric

Solar radiation can be captured in numerous ways with a variety of technologies. The two major groups of technologies are solar thermal and solar photovoltaics.

4.4.1 Solar Thermal Power

The performance, commercial readiness, cost, reliability, and technical risk of solar thermal power technology are characterized in this section. The technologies discussed include:

- Parabolic trough
- Parabolic dish
- Power tower
- Compact Linear Fresnel Reflector (CLFR)

Concentrating solar thermal power plants (CSP) produce electric power by converting the sun's energy into high temperature heat using various mirror or lens configurations. For solar thermal electric systems (trough, dish-Stirling, and power tower), the heat is transferred to a turbine or engine for power generation. Thermal plants consist of two major subsystems: a collector system that collects solar energy and converts it to heat, and a power block that converts heat energy to electricity.

All CSP systems make use of the direct normal insolation (DNI) component of solar radiation, that is, the radiation that comes directly from the sun. Global radiation, which is reflected radiation, is present on sunny and cloudy days but is unusable by CSP systems. Since all CSP systems use DNI and concentration of DNI allows a solar system to achieve a high working fluid temperature, there is a need for the collector systems to track the sun. Parabolic trough and CLFR systems use single-axis trackers to focus radiation onto a linear receiver while parabolic dish engine and power tower CSP systems use two-axis trackers.

Trough, power tower and CLFR systems collect heat to drive central turbine-generators making them best suited for relatively large plants—50 MW or larger. Trough, tower and CLFR plants, with their large central turbine generators and balance of plant equipment, have a cost advantage of economy of scale—that is, cost per kW goes down with increased size. Dish systems are modular in nature, with single units producing power in the range of 10 kW to 35 kW making them ideal for distributed or remote generation applications. Dish systems can also be sited as large plants by aggregating many units. Dish systems have the potential advantage of mass production of individual units, similar to the mass production of automobiles

Trough and tower systems have the potential advantage over dish systems in that an amount of dispatchability can be designed into the system with thermal storage or the use of hybrid fossil fuel. Storage for CLFR systems, while being explored in concept, has not been developed. Dispatchability allows the solar plant to generate electricity during short duration cloudy periods or to generate electricity into the evening after sunset. This gives the plant potential to receive capacity credit, and provides the ability to more closely match the utility peak load profile. At this time, dish engine systems have not been configured to provide hybrid fossil capability.

Parabolic Trough Systems

Parabolic trough solar thermal systems have been the dominant solar thermal technology installed to date. Parabolic trough systems concentrate DNI using single axis tracking, parabolic curved, trough-shaped reflectors onto a receiver pipe or heat collection element (HCE) located at the focal line of the parabolic surface. A high temperature heat transfer fluid (HTF) picks up the thermal energy in the HCE. Heat in the HCE is then used to make steam in the steam generator. The steam drives a conventional steam-Rankine power cycle to generate electricity. Figure 4-9 shows trough collectors. A collector field contains many parallel rows of troughs connected in series. Rows are typically placed on a north-south axis, allowing the single-axis troughs to track the sun from east to west during the day.

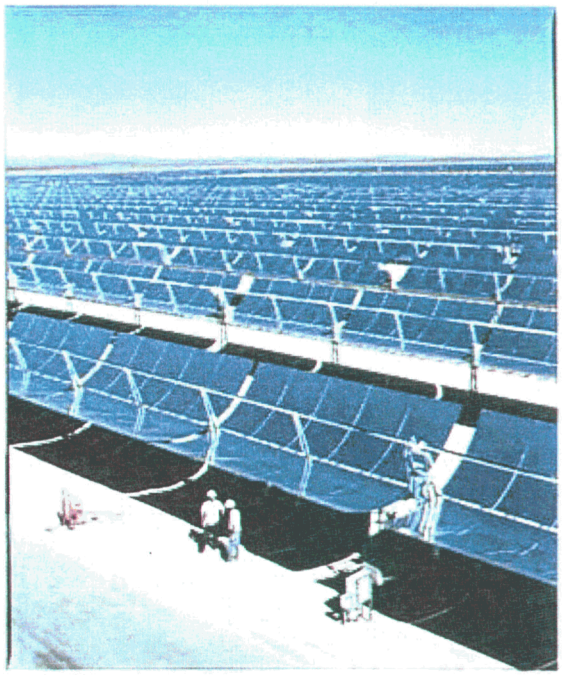


Figure 4-9. Kramer Junction Trough Plant (NREL).

The largest collection of parabolic systems in the world is the Solar Energy Generating Systems (SEGS) I through IX plants in the Mohave Desert in southern California. The SEGS plants were built in the 1985 to 1991 time frame. The Kramer Junction site has five 30 MW systems. The largest of the SEGS plants, SEGS IX, located at Harper Lake, is 80 MW. All of the SEGS plants are "hybrids," using fossil fuel to supplement the solar output during periods of low solar radiation. Each plant is allowed to generate 25 percent of its energy annually using fossil fuel.

There are several commercial parabolic trough projects in the planning or active project development stage. Solargenix, (now Acciona) constructed a 1 MW plant in Arizona, which became operational in spring 2006. There are several plants under construction, including Nevada Solar One, an Acciona 64 MW plant in Nevada, and several 50 MW plants in Spain. The Andasol Spanish plants will include 7 hours of thermal storage. Other projects in various stages of planning include integrated solar combined cycle system (ISCCS) in southern California, India, Egypt, Morocco, Mexico, and Algeria. In addition, there are plans for a series of SEGS type plants in Israel.

Parabolic trough systems are considered commercially available for industrial applications. The primary developers of this technology include Acciona, Solel Solar Systems, Solar Millennium and Solucar. Suppliers of components for trough systems include reflector supplier Flabeg and receiver suppliers Schott Glass and Solel Solar Systems. Other major glass companies have expressed interest in entering the trough mirror market. The currently planned technology, for thermal storage, is the molten salt two-tank system. This provides a feasible storage capacity of up to 12 hours and is considered to have a low-to-moderate associated technology risk.

Parabolic Dish-Engine Systems

A solar parabolic dish-engine system comprises of a solar concentrator (or "parabolic dish") and the power conversion unit (PCU). The concentrator consists of mirror facets which combine to form a parabolic dish. The dish redirects DNI to a receiver mounted on a boom at the dish's focal point. The system uses a two-axis tracker such that it points at the sun continuously.

A parabolic dish-engine system using a Stirling engine is shown on Figure 4-10. The PCU includes the thermal receiver and the engine-generator. In the solar receiver, radiant solar energy is converted to heat in a closed hydrogen loop which drives the Stirling engine-generator. Because the PCUs are air cooled, water cooling is not required. This is important because water cooling is necessary for the large, central power blocks associated with trough and power tower technologies. Thermal storage is not currently considered to be a viable option for dish engine systems.

Figure 4-10. Dish Engine System (NREL).

Relatively level land is preferable for construction and maintenance ease; however, siting requirements on slope are likely less significant than those for trough and tower systems.

Individual dish engine units range in size from 10 to 25 kW. Because they can operate independent of power grids, they can be used for remote applications as well as grid connected applications. With their high efficiency and modular construction, the cost of dish engine systems is expected to be competitive in distributed markets. Stirling Engine Systems (SES), the principal dish engine developer in the United States, projects that the cost of dishes will decrease dramatically with hundreds of MWs of central station, grid connected deployment.

At the present time, there are no operating commercial dish engine power plants. A six dish test deployment at Sandia National Laboratories (SNL) in Albuquerque, New Mexico, was completed in 2005. This development is under a joint agreement between SES and SNL. In 2005, Southern California Edison publicly announced the completion of negotiations on a 20 year power purchase agreement with SES for between 500 to 850 MW of capacity (producing 1,182 to 2,010 GWh/year) of dish engine units. Also in 2005, SES announced a contract with San Diego Gas & Electric to provide between 300 and 900 MW of solar power using the dish technology. If successful, this large deployment of dish engine systems is expected to drastically reduce capital and O&M costs and result in increased system reliability.

While pricing for these power purchase agreements remains confidential, based on stated claims it must be under the California Market Price Referent (MPR) which is roughly $110/MWh using solar time of day factors applied to the base MPR (of $75).

Other planned deployments of dish engine systems include contracted deployments of a 25 kW demonstration dish by SES at Eskom in South Africa and a 10 kW Schlaich Bergermann und Partner (SBP) dish providing power to the grid in Spain. Proposed or planned deployments include a 10 kW SBP dish in France and a 10 kW SBP dish in Italy.

Power Tower Systems

A power tower uses thousands of sun-tracking mirrors called heliostats to redirect DNI to a receiver at the top of a tower. In the most recent receiver deployment, a molten nitrate salt HTF heated in the receiver is used to generate steam, which in turn is used in a conventional turbine generator to produce electricity. An earlier power tower generated steam directly in the receiver; however, the current US design uses molten nitrate salt because of its superior heat transfer and energy storage capabilities. Systems with air as the working fluid in the receiver or power system have also been explored in international research and development programs. Commercial power tower plants can be sized to produce anywhere from 50 to 200 MW of electricity. Figure 4-11 is a photograph of the 10 MW Solar Two prototype molten salt system.

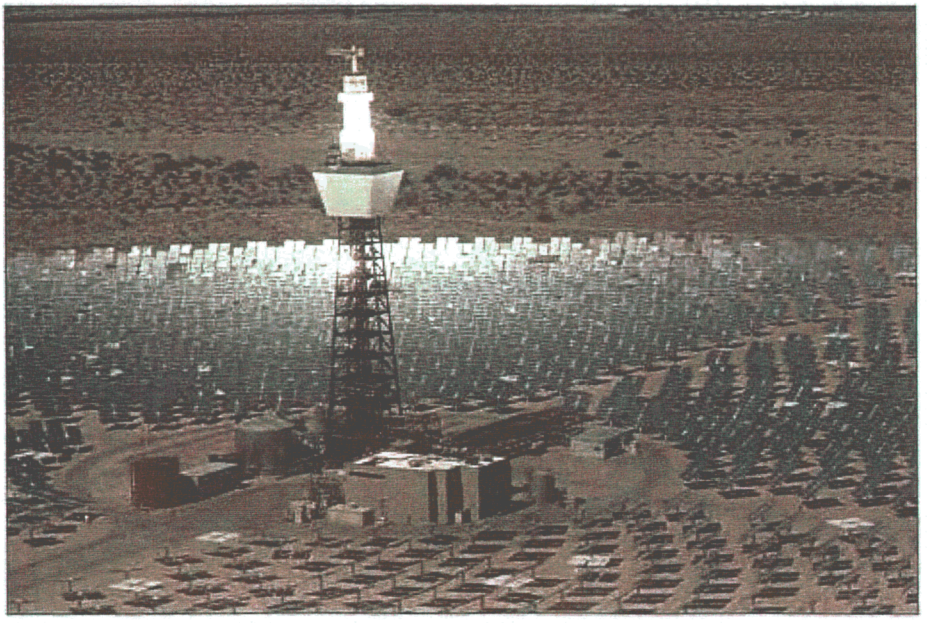


Figure 4-11. 10 MW Solar Two Power Tower System (NREL).

An advantage of power tower plants is that molten salt can be heated to 1,050°F, with steam generation at 1,000°F, which is utility-standard main steam temperature. This results in slightly higher cycle efficiency than is achievable with the lower temperature (about 735°F) steam produced in a trough system. Furthermore, power towers have the advantage that the molten salt is used both as the HTF and as the storage medium, unlike the trough system which uses high temperature oil as the HTF, and requires oil-to-salt and salt-back-to-oil heat exchange for thermal storage. The result is that storage is less costly and more efficient for power towers than for troughs.

There are no commercial power tower plants in operation today. In 1982, a 10 MW power tower plant, Solar One, located near Barstow, California, operated from 1982 to 1988 and produced over 38 million kilowatt-hours (kWh) of electricity. Solar One generated steam directly in the receiver. To implement improved heat transfer and thermal storage, the plant was retrofitted (and renamed Solar Two). Solar Two operated from 1998 to 1999. Although Solar Two successfully demonstrated efficient collection of solar energy and dispatch of electricity, including the ability to routinely produce electricity during cloudy weather and at night, the plant encountered various technical issues. Solutions to these issues have been identified; however, successful demonstration of certain improvements is required prior to commercial financing of a large-scale plant.

In addition to Solar One and Solar Two, experimental and prototype systems have operated in Spain, France, and Israel. Solucar Energia, S.A., an Abengoa company, recently announced the completion of an 11 MW solar power tower near Seville, Spain. Called PS 10, the power plant is the first tower-based solar power system to generate electricity commercially. PS 10 uses a water-steam receiver. Abengoa has plans for a second, 20 MW plant. In addition, ESKOM, the largest utility in South Africa, is considering a 100 MW molten-salt plant. A 17 MW molten salt plant in Spain, Solar Tres, is also being planned by Ghersa, Boeing, and Nexant. However, this plant appears unlikely to be built at this time. The primary developer of molten salt technology for power towers is United Technologies Corporation.

Compact Lens Fresnel Reflector (CLFR)

The compact linear Fresnel reflector (CLFR) is a solar thermal technology in which rows of mirrors reflect solar radiation on a linear receiver located on towers above the mirror field. Solar Heat & Power from Australia is developing a CLFR technology (Ausra is the US affiliate). Liddell 1, the first generation CLFR system is shown in Table 4-12. That system is located at the Macquarie Liddell Power Station near Singleton, New South Wales, Australia. Liddell 2 is under construction at the same site. Liddell 2 will supply steam to the Liddell Power Station for feedwater heating. Ausra is developing a

6.5 MWe solar electric demonstration plant in Portugal. The company is marketing large solar electric systems in the United States.

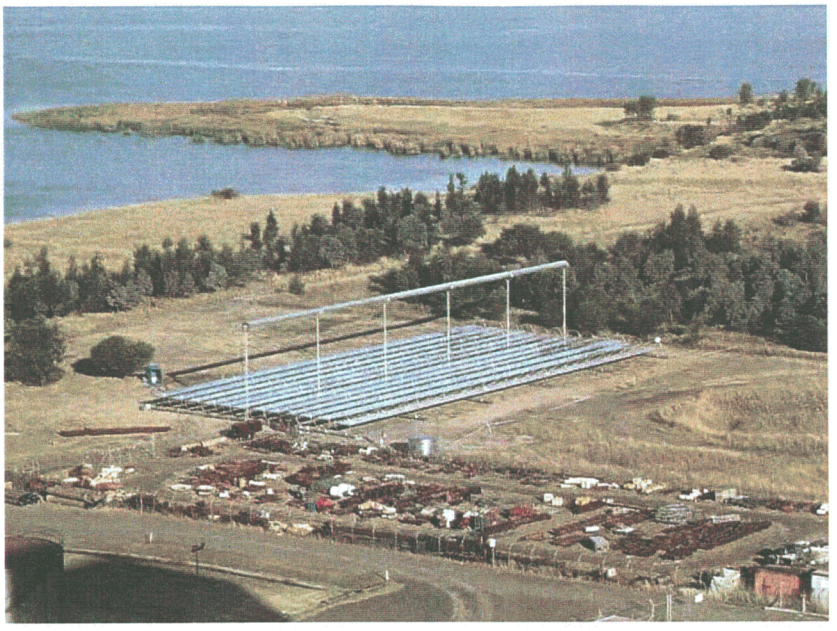


Figure 4-12. Liddell Phase 1 CLFR Demonstration System.

In the CLFR, collector mirrors rotate on the linear axis parallel to the receiver, following the sun's movement throughout the day. The CLFR is similar to the more commercially mature solar parabolic trough systems in that it uses one-axis tracking to focus solar radiation on a linear receiver. However, the CLFR has major difference from the trough system. These include several advantages.

- The CLFR optics are less stringent than optics of a trough. This allows a less expensive collector/receiver system.
- The CLFR receiver does not move, such that no flexible hoses or ball joints are required as in a trough system.
- The CLFR is more compact in terms of land use. A CLFR may have a ground cover ratio (GCR), which is the ratio of mirror area to land area, of about 70 percent versus a GCR of about 30 percent for a trough.

Disadvantages of the CLFR compared to the trough include the following.

- The CLFR is less mature in technical and commercial development.
- Trough cost and performance are fairly well known, whereas CLFR cost and performance are unproven.

- The saturated steam generated by the CLFR is relatively low temperature and being saturated, rather than superheated, results in less efficient power generation.
- The overall CLFR solar to steam efficiency is substantially lower than trough.

Cost and Performance Characteristics

While there are several solar thermal technologies being actively promoted, the most commercial technology is parabolic trough. Representative characteristics for a parabolic trough system with 6 hours of energy storage operating in Arizona are presented in Table 4-12. This table also includes cost estimates for a 14 MW solar dish system. Costs for 100 MW plus systems should be much lower (perhaps by as much as half) if technology development and large-scale manufacturing is successful. Further discussion of potential solar configurations and costs are provided in Section 5 of this report.

Table 4-12. Solar Thermal Technology Characteristics.

	Parabolic Trough	Parabolic Dish
Performance		
Typical Duty Cycle	Peaking - Intermediate	As Available, Peaking
Net Plant Capacity (MW)	100	14
Integrated Storage	6 hours	None
Capacity Factor (percent)	37 to 43	20 to 25
Economics ($2007)		
Total Project Cost ($/kW)	5400 to 6300	5,000 to 6,000
Variable O&M ($/MWh)	20 to 25	10 to 20
Levelized Cost ($/MWh)	132 to 176	184 to 281
Applicable Incentives	30% ITC	30% ITC
Technology Status		
Commercial Status	Commercial	Demonstration
Installed US Capacity (MW)	~350	< 1

4.4.2 Photovoltaics

Due to its high cost, intermittency, and low capacity factor, solar photovoltaics (PV) has had little penetration into the electricity market. While solar, in general, represents a very small portion of the overall electricity generated in the US, solar PV represents an even smaller fraction. However, there is recent strong growth being

observed in the PV industry. In the US in 2005, 70 MW of grid connected PV was installed, which is nearly double the installations in 2003. This section provides a background into the solar PV industry, the benefits of solar PV energy, and the incentives available to solar PV installations.

Operating Principles

Solar PV converts sunlight (also known as insolation) directly into electricity. The power produced depends on the material involved and the intensity of the solar radiation incident on the cell. Single or polycrystalline silicon cells are most widely used today. Single crystal cells are manufactured by growing single crystal ingots, which are sliced into thin cell-size material. The cost of the crystalline material is significant. The production of polycrystalline cells can cut material costs but with some reduction in cell efficiency. Thin film solar cells are made from layers of semiconductor materials only a few micrometers thick. These materials make applications more flexible, as thin film PV can be integrated into roofing tiles or windows. Thin film cells significantly reduce cost per unit area, but also result in lower efficiency cells. Gallium arsenide cells are among the most efficient solar cells and have other technical advantages, but they are also more costly and typically are used only where high efficiency is required even at a high cost, such as space applications or in concentrating PV applications. Additional advanced technologies are under development including dye sensitized solar cells (DSSC) and organic light emitting diodes (OLED). These technologies hope to achieve dramatic reductions in cell cost, but likely will have efficiencies on the lower end of the range for PV cells.

Markets

Currently, the commercial PV market is dominated by silicon-based cells, with about 90 percent market share including thin-film silicon cells. Recent shortages and cost increases of silicon have driven the market for new materials. The following chart shows production by technology type.

Table 4-13. 2005 World Cell Production by Technology Type (MW).

Technology	US	Japan	Europe	ROW	Total	%
Monocrystalline flat plate	58	179.4	149	100	486.4	28
Polycrystalline flat plate	23	495	277	196	991	56
Amorphous silicon	23	36.2	6.1	6	71.3	4
Silicon ribbon	27	-	26	-	53	3
Cadmium telluride	20	-	12	0	32	2
Copper indium diselenide	3	-	2	-	5	0
A-si/CZ slice	-	122	-	-	122	7
Total (all technologies)	154	833	472	302	1760	100

Source: PV News, Vol. 25, No. 4, April 2006.

Solar photovoltaics have achieved enviable growth over the last few years. Worldwide grid-connected residential and commercial installations grew from 120 MW per year in 2000 to nearly 1,200 MW per year in 2005. The majority of these installations were in Japan and Germany, where strong subsidy programs have made the economics of PV very attractive. The US grid connected market was 70 MW in 2005, with most of these installations in California.

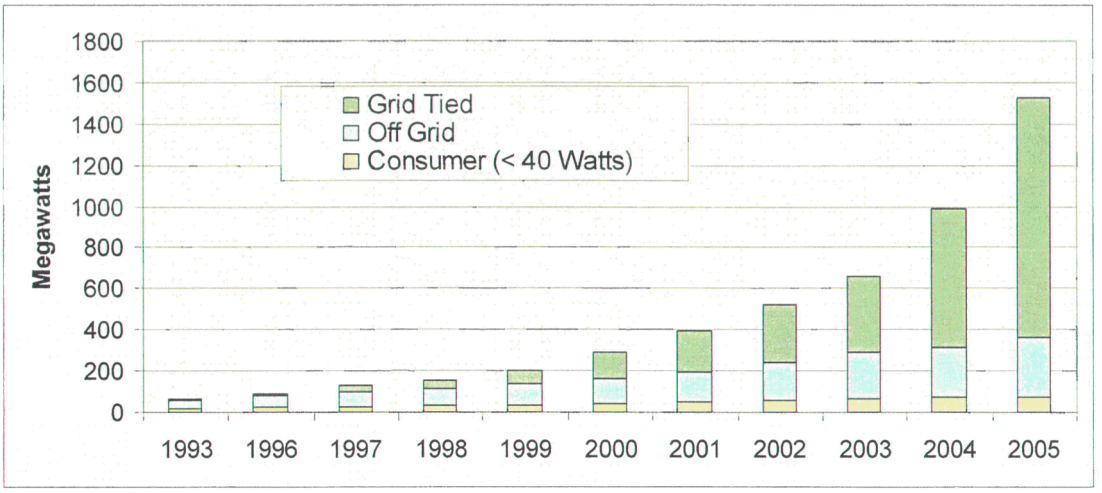


Figure 4-13. Worldwide PV Installations, MW (Source: Renewable Energy World).

Applications

Solar PV was originally developed as a power source for the space program. PV found its first terrestrial uses in remote industrial and residential applications. This "off

grid" use of solar has been cost effective for some time, as it is generally less expensive than extending the electricity grid to remote locations. While these off-grid installations were roughly half the worldwide PV market in 1999, the explosive growth of "grid tied" PV has dropped its share of the total PV market to 19 percent by 2005. Grid tied solar is the focus of this report – PV systems that are connected to the electricity grid and simply offset energy purchased from the grid. Figure 4-14 displays the PV application by market sector in the US.

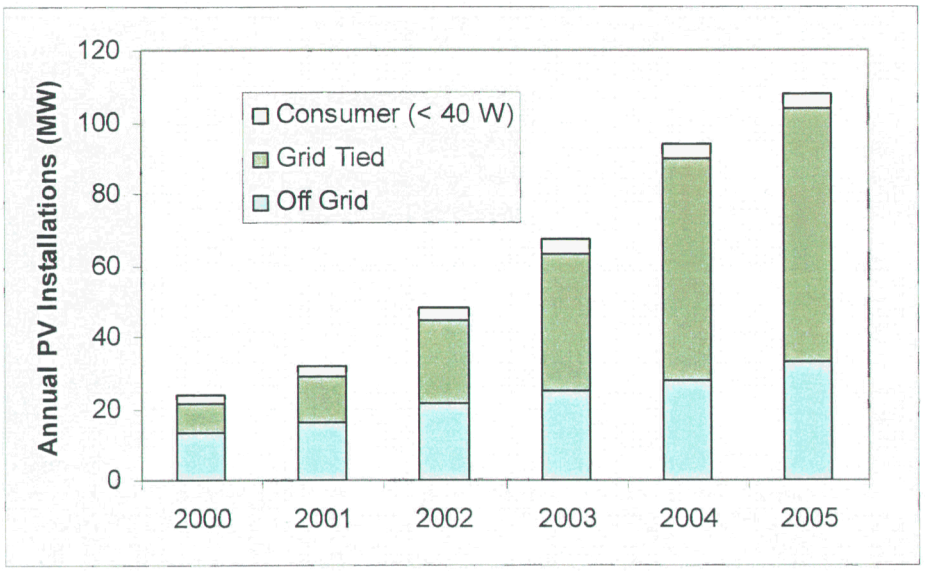


Figure 4-14. US Annual PV Installations (Renewable Energy World).

Concentrating Solar Photovoltaic Systems

Concentrating photovoltaic (CPV) plants provide power by focusing solar radiation onto a photovoltaic (PV) module, which converts the radiation directly to electricity. Either mirrors or lenses can be used to concentrate the solar energy for a CPV system. Most of the CPV systems use two axis tracking to achieve point focus images on PV cells. Single axis, line focus CPV systems have been built, but do not appear to have the long term commercial potential that the two axis tracking CPV systems have.

Concentrating photovoltaic (CPV) systems have potential for cost reduction compared with conventional, non-concentrating (also referred to as flat plate) PV systems in two key ways. First, a major portion of the conventional PV system cost is for the semiconductor material which makes up the PV modules. By concentrating sunlight onto a small cell, the amount of semiconductor material can be reduced, albeit at additional cost for mirrors or lenses and for tracking equipment. Recent rises in solar module prices

due to semiconductor-grade silicon have made CPV more attractive. Second, use of smaller cells allows for more advanced and efficient cell technology, making the overall system efficiency higher than for a conventional flat plate system.

CPV systems have been under development since the 1970's. This development has included single axis tracking, line focus CPV and two axis tracking, point focus CPV. Recent development has primarily been on the two-axis tracking systems. Developers of CPV technology include Amonix (Figure 4-15), Solar Systems (Figure 4-16), Energy Innovations, Sharp, EMCORE, and SolFocus.

Amonix systems have been deployed at Nevada Power (75 kW at Clark generating station) and Arizona Public Service (APS) facilities for a total capacity of over 600 kW. Planned deployments in the near future include 10 to 20 MW in Spain. Solar Systems Pty, Ltd, has a different approach to CPV, using a parabolic dish concentrator to focus DNI on a high concentration PV receiver. Ten dishes have been deployed since 2003, for a total capacity of 220 kW, with the construction of an additional 720 kW under way. Solar Systems recently announced a 154 MW solar power plant, but using distributed power towers with CPV receivers instead of dish systems.

It is unclear if any of these CPV technologies will achieve their desire cost targets of $70-$80/MWh. It does appear, however, that CPV may be more appropriate for utility-scale PV due to lower land requirements and reduced silicon use.

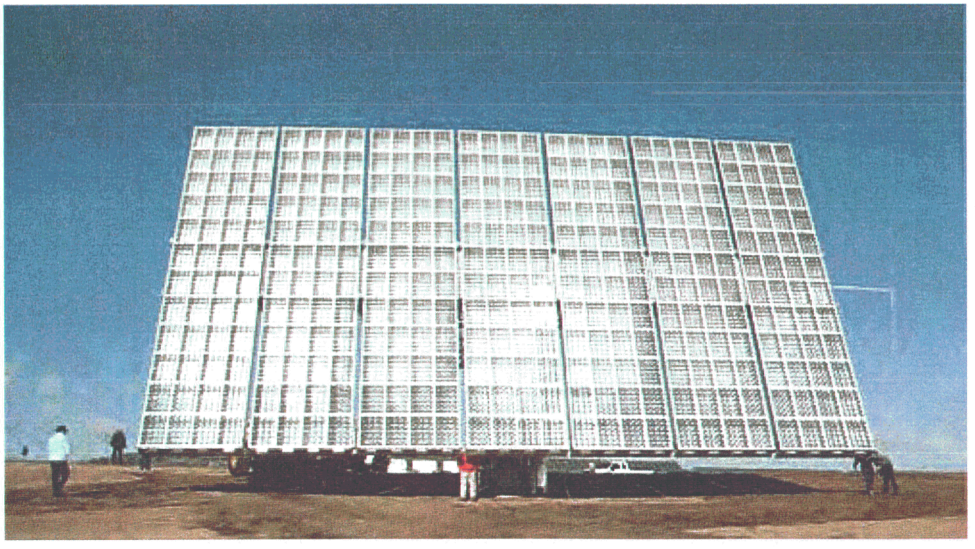


Figure 4-15. Amonix: Flat Acrylic Lens Concentrator with Silicon Cells (NREL).

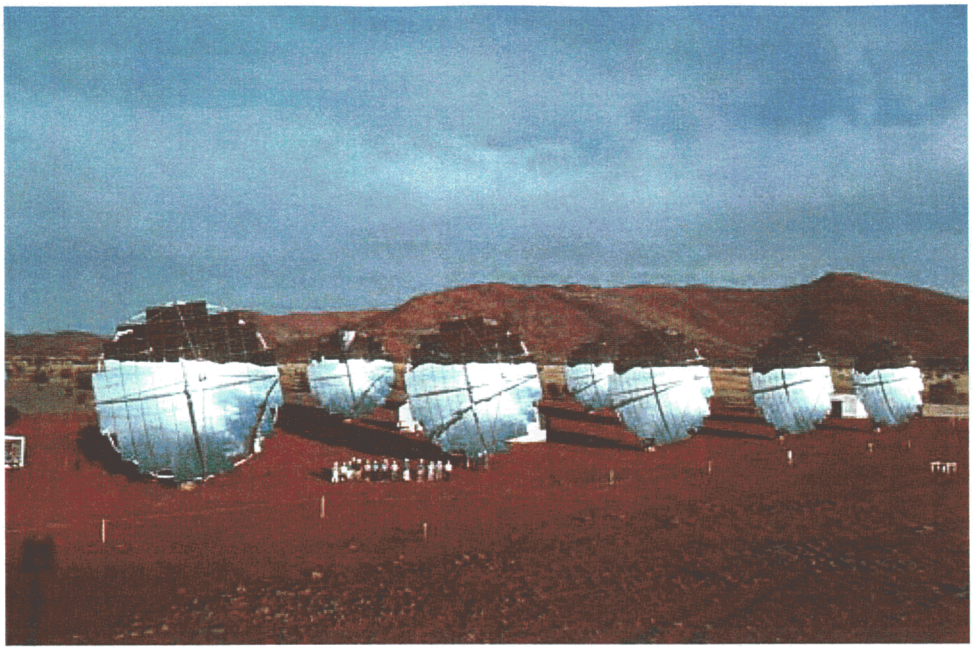


Figure 4-16. Solar Systems Pty, Ltd: Parabolic Dish PV Concentrator (NREL).

Resource Availability

Most PV systems installed today are flat plate systems that use global insolation. CPV systems require DNI, as discussed under the Solar Thermal section. Figure 4-17 shows the solar insolation resource for a flat plate collector in the US.

Cost and Performance Characteristics

Solar advocates have believed that solar costs would continue to decrease as better technology and manufacturing economies-of-scale reduced costs. Solar PV module costs were roughly $10 per watt in 1985, and were on a downward trajectory for almost two decades. In early 2004, however, increased worldwide demand (especially from Germany and Japan) started pushing module prices back up from their low of $5 per watt, due to a scarcity of silica. Module costs represent about half of the total cost of a system, so solar installations are especially sensitive to movement in module pricing. Figure 4-18 shows module prices for the past few years; note these represent published retail costs, not bulk purchase costs available to PV installers.

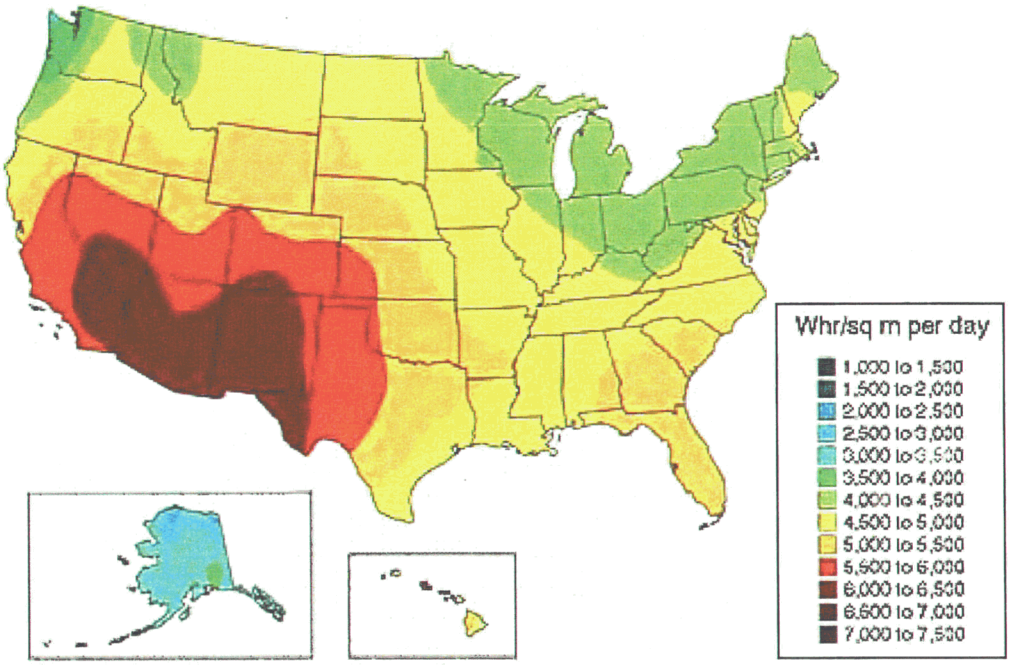


Figure 4-17. Solar Insolation Resource for a Flat-Plate Collector (Source NREL).

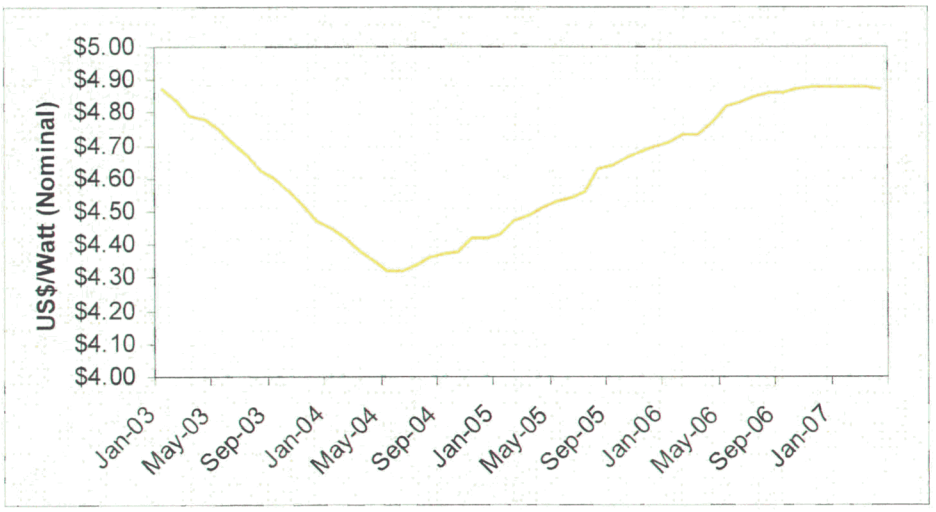


Figure 4-18. US Module Costs, $/Watt (Source: Solarbuzz).

Table 4-14 presents cost and performance characteristics of a 4 kW residential and a 250 kW commercial fixed-tilt, single crystalline PV system. The table also includes costs for a 3 MW utility scale tracking system.

Table 4-14. Solar PV Characteristics.

	Residential	Commercial	Utility Scale
Performance			
Typical Duty Cycle	As Available, Peaking	As Available, Peaking	As Available, Peaking
Net Plant Capacity (kWp)	4	250	3,000
Capacity Factor (percent, based on kWp)	18	20	23
Economics ($2007)			
Total Project Cost ($/kWp)	7,200 to 10,500	6,000 to 7,500	5,000 to 6,500
Fixed O&M ($/kWp-yr)	50	30	30
Levelized Cost ($/MWh)	358 to 509	321 to 407	278 to 365
Applicable Incentives	30% ITC*		
Technology Status			
Commercial Status	Commercial		
Installed US Capacity (MW)	~400		

Notes:
* Requires, taxable, non-utility ownership

4.4.3 Solar Technologies Development Prospects

The technical potential for both solar thermal and solar photovoltaic projects in Arizona is very large.

Concentrating solar projects rely on DNI resources. Figure 4-19 shows the DNI with Arizona with several exclusion factors. The map excludes areas of Arizona with less than 6.75 kWh/m²/day, areas with a slope greater than 1 percent, major urban areas and water, environmentally sensitive lands and remaining areas smaller than 5 km². This is done to focus on areas that have greatest potential for concentrating solar power. Concentrating solar power plants (thermal or CPV) generally require that the previous conditions be met.

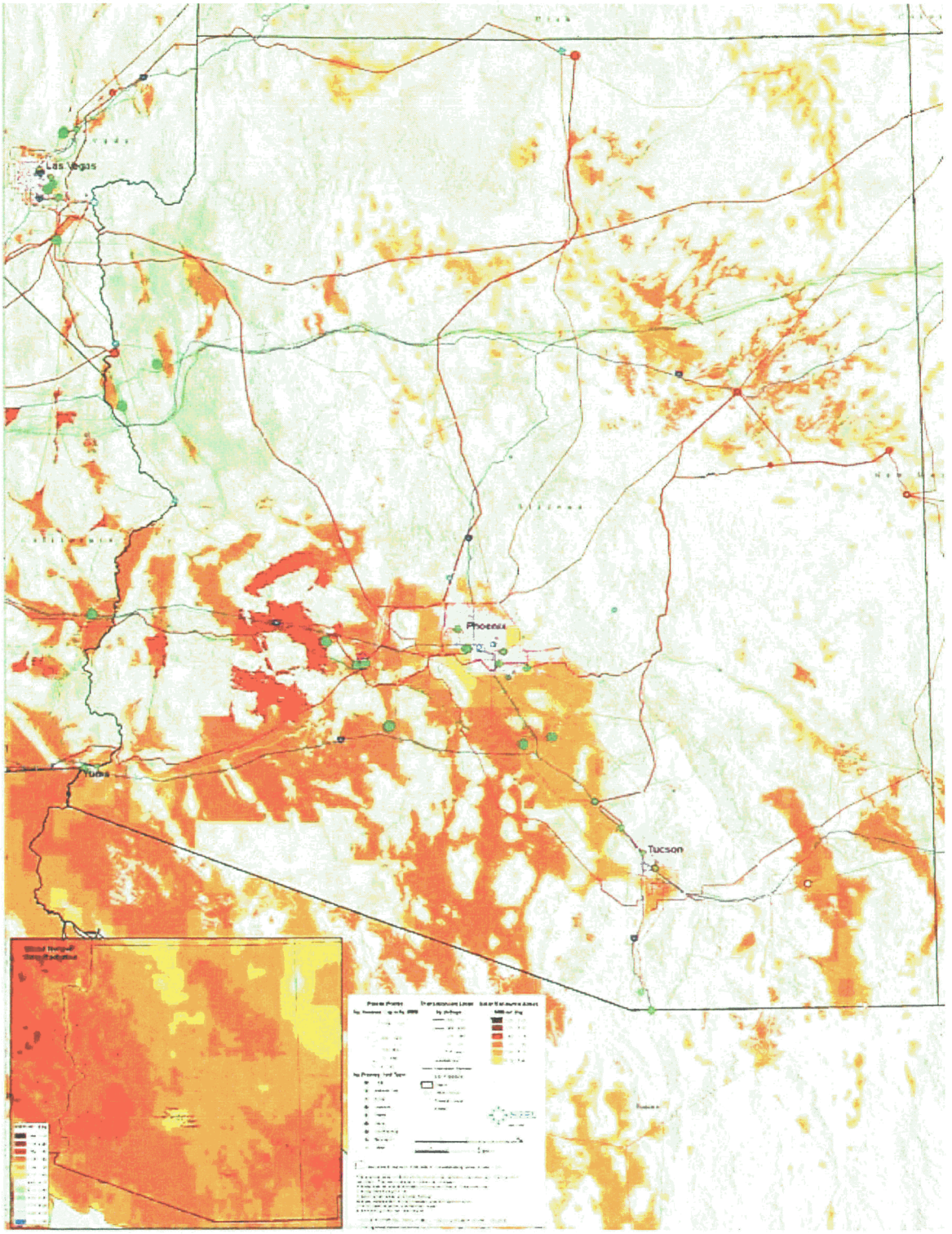


Figure 4-19. Arizona Concentrating Solar Power (DNI) Resources (NREL).

Flat panel photovoltaics installations have the ability to function in less sunny environments (at lower production levels) and can be installed on a wide range of sites including rooftops and urban areas. As an example of the theoretical potential for solar PV, see Table 4-15. Solar insolation data was gathered from NREL and the average annual solar insolation for a flat-plate collector was calculated for Arizona. The solar potential was calculated. The technical potential estimate assumes that there are no constraints on equipment availability, cost, or other site-specific criteria. Technical potential is not the same a developable potential which only includes projects that would be able to be financed and are subject to the constraints of product availability, cost and site-specific criteria. This estimate was based on installing photovoltaic panels on 0.25 percent of the land area in Arizona. This estimate yielded a photovoltaic potential capacity estimate in excess of the current demand for energy in Arizona.

Table 4-15. Theoretical Solar Power Production in Arizona.

AZ Total Square Miles	113,635
0.25% of Arizona Land Area in Square Miles	284 (17x17 mi)
Total Theoretical Solar Annual MWh PV Production in Arizona	123,500,000
Arizona Total Annual MWh Generation 2005	101,478,654
Notes: Assumes 4.6 kWh/m²/day insolation (an AZ minimum value), and 10% solar conversion efficiency.	

With energy storage, solar could theoretically supply the entire electricity needs of the state. It is interesting to note that the land requirements for solar are very reasonable compared to the suitable land available in the state for concentrating solar and the excellent resource even in urban areas for PV.

Given that the solar resource is so large, in the near term, developable solar potential is more limited by cost, manufacturing capacity of equipment suppliers, transmission adequacy and congestion issues,m and the development of suitable energy storage technologies to handle the intermittent output of the resource.

4.5 Hydroelectric

Hydroelectric power is generated by capturing the kinetic energy of water as it moves from a higher elevation to a lower elevation by passing it through a turbine. The amount of kinetic energy captured by a turbine is dependent on the head (vertical height the water is falling) and the flow rate of the water. Often, the water is raised to a higher potential energy by blocking its natural flow with a dam. If a dam is not feasible, it is

possible to divert water out of the natural waterway, through a penstock, and back to the waterway. Such "run-of-river" applications allow for hydroelectric generation without the impact of damming the waterway. The existing worldwide installed capacity for hydroelectric power is by far the largest source of renewable electricity at over 800,000 MW.

Applications

Hydroelectric projects are divided into a number of categories according to their size. Micro hydroelectric projects are below 100 kW. Systems between 100 kW and 1.5 MW are classified as mini hydroelectric projects. Small hydroelectric systems are between 1.5 and 30 MW. Medium hydroelectric projects range up to 100 MW, and large hydroelectric projects are greater than 100 MW. Medium and large hydroelectric projects are good resources for baseload power generation if they have the ability to store a large amount of potential energy behind a dam and release it consistently throughout the year. Small hydroelectric projects generally do not have large storage reservoirs and are not dependable as dispatchable resources (Figure 4-20).

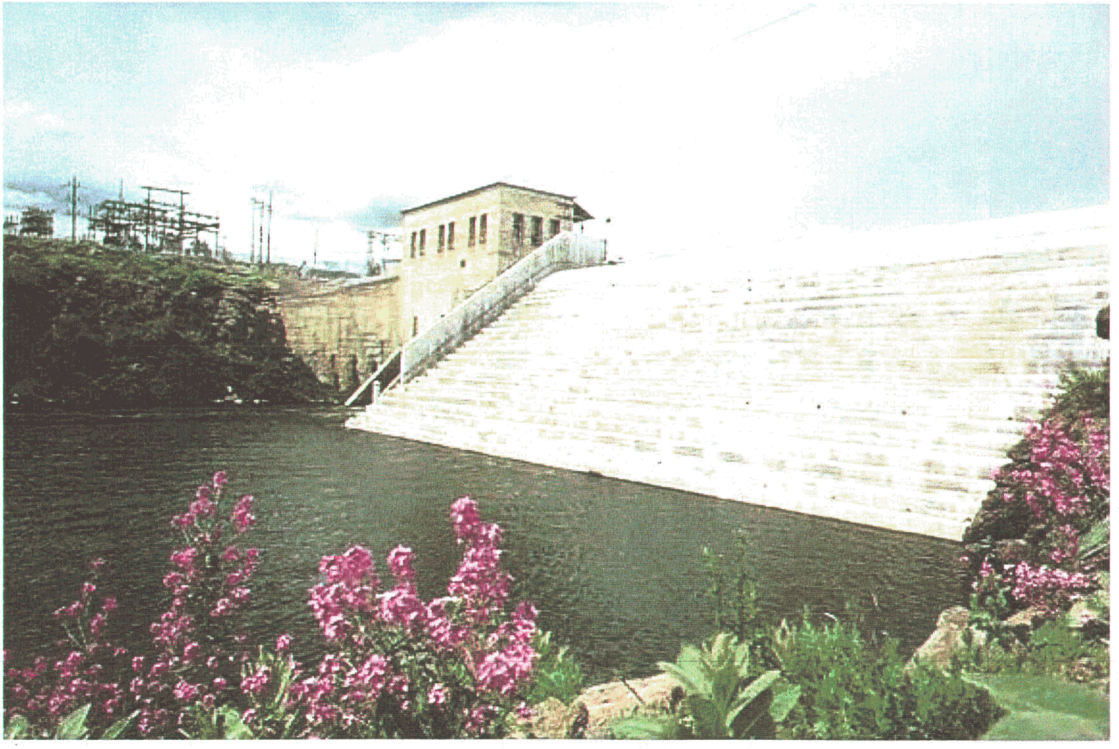


Figure 4-20. 3 MW Hydroelectric Plant.

Resource Availability

A hydroelectric resource can be defined as any flow of water that can be used to capture the kinetic energy. Projects that store large amounts of water behind a dam can regulate the release of water through turbines and generate electricity regardless of the season. These facilities can generally serve base loads. Run-of-river projects do not impound the water, but instead divert a part or all of the current through a turbine to generate electricity. At run-of-river projects, power generation varies with seasonal flows and can sometimes help serve summer peak loads.

All hydroelectric projects are susceptible to drought. In fact, the variability in hydroelectric output is rather large, even when compared to other renewable resources. The aggregate capacity factor for all hydroelectric plants in the United States has ranged from a high of 47 percent to a low of 31 percent.

Cost and Performance Characteristics

Hydroelectric generation is regarded as a mature technology that is unlikely to advance. Turbine efficiency and costs have remained somewhat stable, but construction techniques and costs continue to change. Capital costs are highly dependent onsite characteristics and vary widely. Table 4-16 provides ranges for performance and cost estimates for hydroelectric projects for two categories: new projects at undeveloped sites and additions or upgrades to hydroelectric projects at existing sites. These values are for representative comparison purposes only. Capacity factors are highly resource dependent and can range from 10 to more than 90 percent. Capital costs also vary widely with site conditions.

Environmental Impacts

The damming of rivers for small- and large-scale hydroelectric applications may have significant environmental impacts. One major issue involves the migration of fish and disruption of spawning habits. For dam projects, one of the common solutions to this problem is the construction of "fish ladders" to aid the fish in bypassing the dam when they swim upstream to spawn.

A second issue involves flooding existing valleys that often contain wilderness areas, residential areas, or archeologically significant remains. There are also concerns about the consequences of disrupting the natural flow of water downstream and disrupting the natural course of nature.

Table 4-16. Hydroelectric Technology Characteristics.

	New	Incremental
Performance		
Typical Duty Cycle	Varies with Resource	Varies with Resource
Net Plant Capacity (MW)	<50	1 to 160
Capacity Factor (percent)	40 to 60	40 to 60
Economics (2007$)		
Total Project Cost ($/kW)	2,500 to 4,000	600 to 3,000
Fixed O&M ($/kW-yr)	5 to 25	5 to 25
Variable O&M ($/MWh)	5 to 6	3.5 to 6
Levelized Cost ($/MWh)	44 to 121 (w/PTC)	5 to 92
Applicable Incentives	$10/MWh PTC – No dams or impoundments; 150 kW-5 MW	$10/MWh PTC
Technology Status		
Commercial Status	Commercial	
Installed US Capacity (MW)	99,000	

Arizona Hydroelectric Development Prospects

In general, the prospects for new hydroelectric development are limited. Arizona covers approximately 114,000 square miles with only 364 square miles covered by water. More than half of Arizona consists of mountains and dry plains. Arizona is arid. Some mountain regions can receive an annual rainfall of more than 30 inches but precipitation in most of the state is very low on average, 6 to 8 inches per year. Much of Arizona's history is that of having an inadequate water supply. Due to the geography and Arizona's mostly dry and arid climate hydroelectric potential is limited.

In spite of limited water resources, Arizona imports and transfers relatively large quantities of water over large distances. This results in a large portion of potential resources coming from numerous manmade conveyances.

It is important to consider the requirements of Arizona's Renewable Energy Standard when evaluating hydroelectric opportunities. In the previous Environmental Portfolio Standard hydroelectric was not eligible as a renewable electricity technology. However, in Arizona's new RES two kinds of hydroelectric are eligible to meet the RES requirements:

1) **"Eligible Hydropower Facilities"** under RES requirement are hydroelectric generators that were in existence prior to 1997 and that satisfy one of the following two criteria:

a) New Increased Capacity of Existing Hydroelectric Facilities: A hydroelectric facility that increases capacity due to improved technological or operational efficiencies or operational improvements resulting from improved or modified turbine design, improved or modified wicket gate assembly design, improved hydrological flow conditions, improved generator windings, improved electrical excitation systems, increases in transformation capacity, and improved system control and operating limit modifications. The electricity kWh that are eligible to meet the Annual Renewable Energy Requirements shall be limited to the new, incremental kWh output resulting from the capacity increase that is delivered to Arizona customers to meet the Annual Renewable Energy Requirement.

b) Generation from pre-1997 hydroelectric facilities that is used to firm or regulate the output of other eligible, intermittent renewable resources: The electricity kWh that are eligible to meet the Annual Renewable Energy Requirements shall be limited to the kWh actually generated to firm or regulate the output of eligible intermittent Renewable Energy Resources and that are delivered to Arizona customers to meet the Annual Renewable Energy Requirements.

2) **"New Hydropower Generator of 10 MW or Less"** under RES requirement is a generator, installed after January 1 2006 that produces 10 MW or less and is either:

a) A low-head, micro hydroelectric run-of-the-river system that does not require any new damming of the flow of the stream; or

b) An existing dam that adds power generation equipment without requiring a new dam, diversion structures, or a change in water flow that will adversely impact fish, wildlife, or water quality; or

c) Generation using canals or other irrigation systems.

Other hydroelectric resources not regulated by RES Rules, such as the Salt River Project, are generally considered a renewable resource by many states if less than 30 MW.

There are 21 existing dam sites in Arizona with additional hydroelectric potential identified by the federal government. The U.S. Department of Energy Idaho National Engineering and Environmental Laboratory (INL) provides this information as part of the National Energy Strategy. These sites consist of 13 undeveloped sites with no developed impoundment or diversion structure, 6 developed sites with some kind of impoundment or diversion structure, and 2 sites with developed hydroelectric generation but where the

potential has not been fully developed. Of these 21 sites, all are located within two major river basins, the Colorado Main Stream River Basin and the Gila River Basin. However, only 12 of the sites were identified by INL as hydroelectric prospects presumably because they were undeveloped or had the greatest potential for further development.

Table 4-17 and Table 4-18 list 12 sites which have been identified by INL. Table 4-17 lists undeveloped projects which due to environmental concerns based on INL opinion reduce the likelihood that the sites may be developed to their physical potential. All of these sites would also be ineligible for the RES because they are new sites larger than 10 MW. Table 4-18 lists projects that show the most promise. These projects are likely eligible for the RES and have little or no environmental concerns.

Table 4-17. Further Development Unlikely (environmental concerns).

Plant Name	Stream Name	Owner	Capacity (MW)
Livingstone	Pinal Creek	Salt River Project	11.5
Orme	Orme Canal	N/A	20.0
Walnut Canyon	Salt River	Salt River Project	25.2
Knob	Salt River	Salt River Project	28.5
Mule Hoof	Salt River	Salt River Project	43.5
Source: INL			

Table 4-18. Some Likelihood (little or no environmental concerns).

Plant Name	Stream Name	Owner	Capacity (MW)
Beardsley Canal Drop	Beardsley Canal	Maricopa County Municipal	1.0
Yuma Main Canal	Yuma Main Canal	Bureau of Reclamation	1.4
Waddell	Aqua Fria River	Maricopa County Municipal	1.5
CAP Canal Turnout	CAP Canal	Maricopa County Municipal	2.5
Roosevelt	Roosevelt Canal	Roosevelt Water Conservation District	3.2
Tucson	CAP Aqueduct	City of Tucson	0.4
Glen Canyon Upgrade	Colorado	Bureau of Reclamation	71.8
Total			**81.8**
Source: INL			

Of the seven sites in Table 4-18 the Aqua Fria and the Colorado River are the only natural waterways. The majority of the Aqua Fria River runs through Federal land. Permitting issues may cause problems or delays with any upgrades to the system as is common with any work or modifications to natural river bodies. Land use for the Aqua Fria watershed is irrigated pasture and hayland with rangeland being the vast majority of the usage. The Beardsley Canal, Yuma Main Canal, and Roosevelt Canal are primarily for irrigation purposes. The Central Arizona Project (CAP) Aqueduct's primary purpose is municipal water supply to the city of Tucson to supplement the City's dependence on groundwater. The CAP Canal is primarily municipal and irrigation. The 72 MW Glen Canyon project would be an upgrade of an existing project, with no new dams, impoundments, or diversion of water. As such, it appears eligible for the RES. Further study is recommended for all the sites in Table 4-18 with exception of Aqua Fria River, with a total of 80.3 MW.

The following map, Figure 4-21, shows the possible hydroelectric project locations from Table 4-17 and Table 4-18 (excluding Glen Canyon):

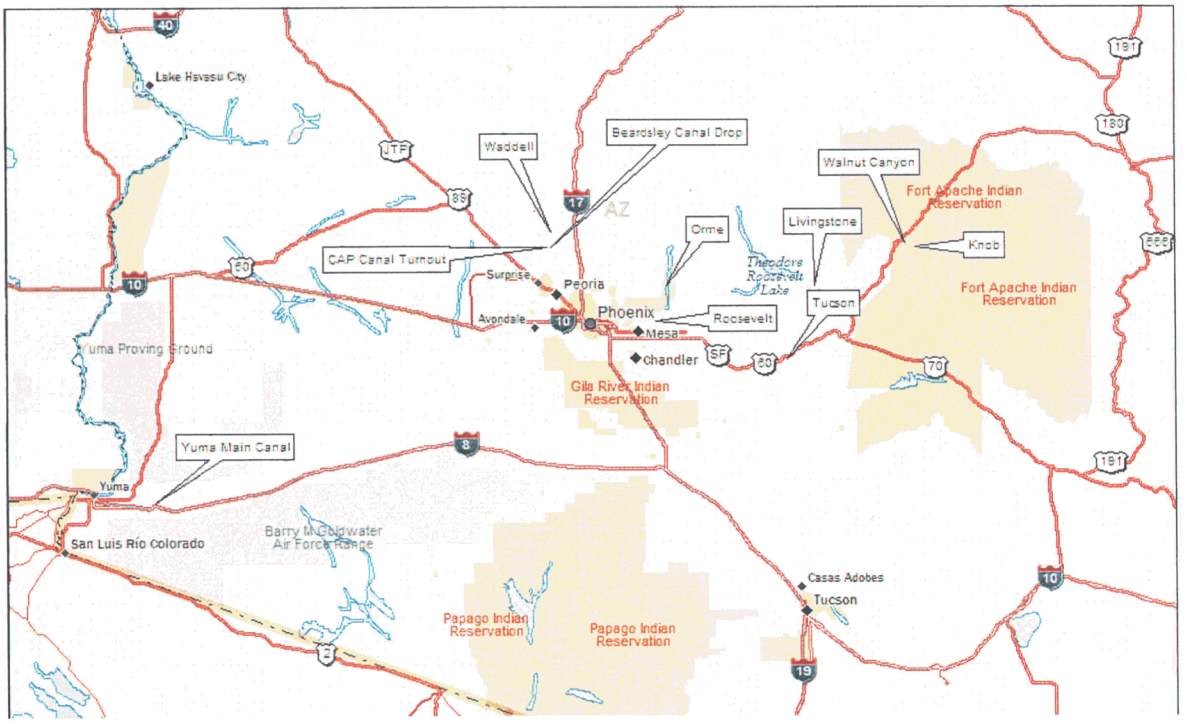


Figure 4-21. Potential Hydroelectric Locations in Arizona.

4.6 Wind Power

Wind power systems convert the movement of air to power by means of a rotating turbine and a generator. Wind power has been among the fastest growing energy sources over the last decade, with around 30 percent annual growth in worldwide capacity over the last five years. Cumulative worldwide wind capacity is now estimated to be more than 50,000 MW. In the United States, wind turbine capacity exceeded 10,000 MW in 2006. The US wind market has been driven by a combination of growing state mandates and the production tax credit (PTC), which provides an economic incentive for wind power. The PTC has expired and been renewed several times and is currently set to expire on December 31, 2008.

Applications

Typical utility-scale wind energy systems consist of multiple wind turbines that range in size from 1 to 2 MW. Wind energy system installations may total 5 to 300 MW, although the use of single, smaller turbines is also common in the United States for powering schools, factories, water treatment plants, and other distributed loads. Furthermore, offshore wind energy projects are now being built in Europe and are planned in the United States, encouraging the development of larger turbines (up to 5 MW) and larger wind farm sizes.

Wind is an intermittent resource, with average capacity factors generally ranging from 25 to 40 percent. The capacity factor of an installation depends on the wind regime in the area and energy capture characteristics of the wind turbine. Capacity factor directly affects economic performance; thus, reasonably strong wind sites are required for cost-effective installations. Since wind is intermittent, it cannot be relied upon as firm capacity for peak power demands. To provide a dependable resource, wind energy systems may be coupled with some type of energy storage to provide power when required, but this is not common and adds considerable expense to a system. Figure 4-22 shows a wind farm in California.

Resource Availability

Turbine power output is proportional to the cube of wind speed, which makes small differences in wind speed very significant. Wind strength is rated on a scale from Class 1 to Class 7, as shown in Table 4-19.

Figure 4-22. Wind Farm near Palm Springs, California.

Table 4-19. US DOE Classes of Wind Power.

Wind Power Class	Height Above Ground: 50 m (164 ft)*	
	Wind Power Density (W/m^2)	Speed** (m/s)
1	0 to 200	0 to 5.60
2	200 to 300	5.60 to 6.40
3	300 to 400	6.40 to 7.00
4	400 to 500	7.00 to 7.50
5	500 to 600	7.50 to 8.00
6	600 to 800	8.00 to 8.80
7	800 to 2000	≥ 8.80

Notes:

* Vertical extrapolation of wind speed based on the 1/7 power law, defined in Appendix A of the *Wind Energy Resource Atlas of the US, 1991.*

** Mean wind speed is based on Rayleigh speed distribution of equivalent mean wind power density. Wind speed is for standard sea level conditions. To maintain the same power density, wind speed must increase 3 percent per 1,000 m (5 percent per 5,000 ft) elevation.

Cost and Performance Characteristics

Table 4-20 provides typical characteristics for a 50 to 100 MW wind farm. Substantially higher costs are necessary for wind projects that require grid upgrades or

long transmission tie lines. Capital costs for new onshore wind projects had remained relatively stable for several years, but current demand has driven up the cost significantly over the past two years. Additionally, due to the increased demand and impending PTC expiration, the current earliest delivery date for new turbines is 2008. Significant gains have been made in recent years in identifying and developing sites with better wind resources and improving turbine reliability. As a result, the average capacity factor for all installed wind projects in the United States has increased from about 24 percent in 1999 to over 32 percent in 2005.

Table 4-20. Wind Technology Characteristics.

Performance	
Typical Duty Cycle	As Available
Net Plant Capacity (MW)	50 to 100
Capacity Factor (percent)	25 to 35[a]
Economics ($2007)	
Total Project Cost ($/kW)	1,600 to 1,900
Fixed O&M ($/kW-yr)	28
Variable O&M ($/MWh)	8
Levelized Cost ($/MWh)	51[b] to 93
Applicable Incentives	$20/MWh PTC, 5-yr MACRS
Technology Status	
Commercial Status	Commercial
Installed US Capacity (MW)	10,500[c]

Notes:
[a] Typical values for Class 3 to 4 winds, which make up the majority of the resource in Arizona.
[b] Ideal scenario, assumes highest capacity factor and lowest capital costs.
[c] Estimate as of September 2006.

Environmental Impacts

Wind is a clean generation technology from an emissions perspective. However, there are still environmental considerations associated with wind turbines. Opponents of wind energy frequently cite visual impacts and noise as drawbacks. Turbines are approaching and exceeding heights of 400 feet and, for maximum wind capture, tend to be located on ridgelines and other elevated topography. Turbines can cause avian fatalities and other wildlife impacts if sited in sensitive areas. To some degree, these

issues can be partially mitigated through proper siting, environmental review, and the involvement of the public during the planning process.

Arizona Wind Potential

Arizona has relatively large wind potential, although most of it is lower quality resources. Much of the wind resource in Arizona is considered to be Class 2 or less, which is generally considered to be non-economic. There are fairly large areas of Class 3 winds, which are considered marginal wind resources. These are in a long line that passes near Flagstaff and continues to the eastern part of the state. Higher wind resources are predicted to exist along ridgelines as well. The map in Figure 4-23 shows the Class 3 and above wind resources in Arizona.

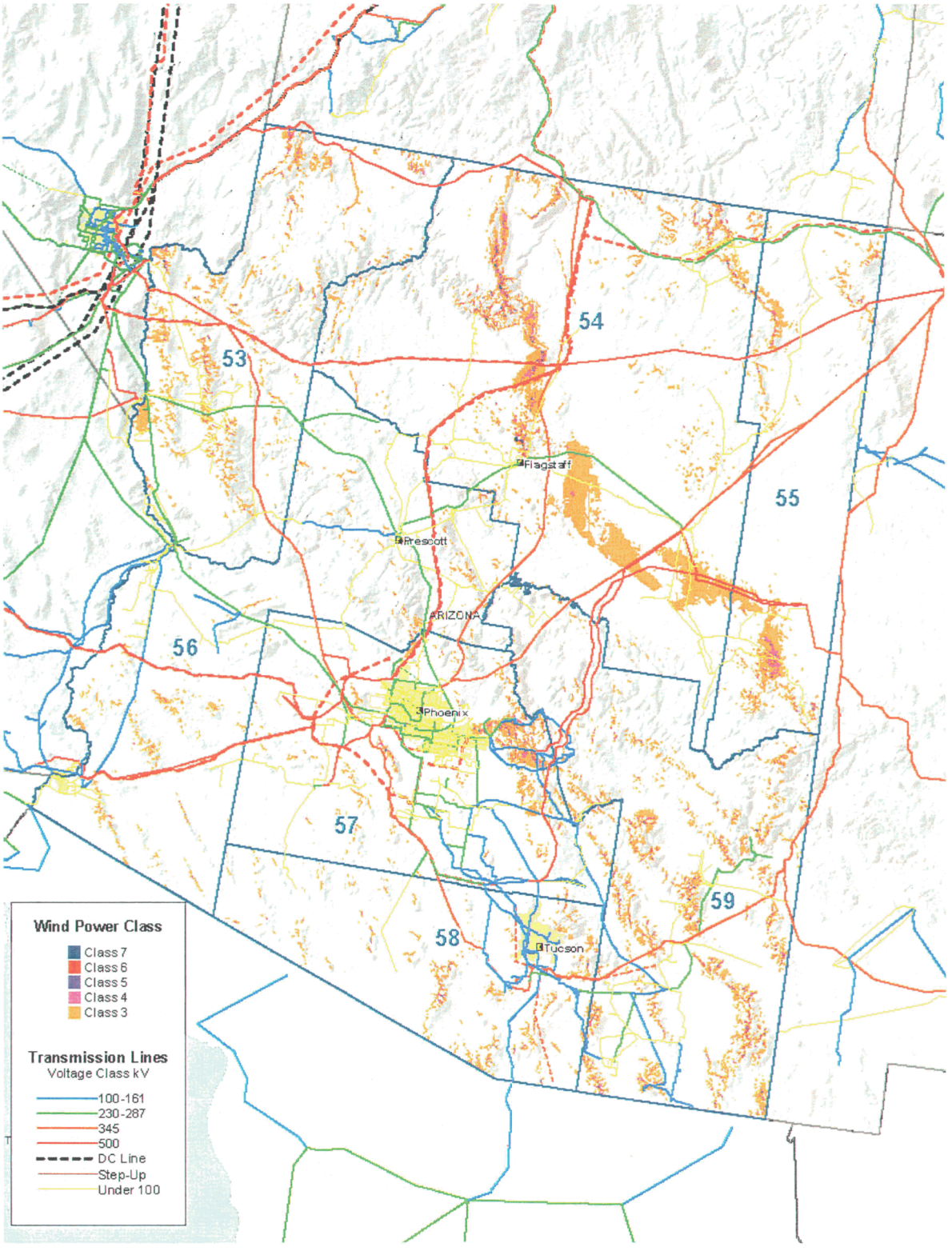


Figure 4-23. Wind Resources in Arizona, Class 3 and Above.

Table 4-21 shows the theoretical potential capacity from wind power class in seven regions in Arizona as estimated by NREL. The regions correspond to the large regions shown in the wind resource map. The greatest potential is shown in Region 54 (north central Arizona), which contains most of the large areas of Class 3 winds. This theoretical or technical potential is not bound by the constraints of product availability (backordered turbines, for instance), site-specific constraints such as transmission capacity, environmental restrictions, or cost. The next section of this report identifies the near-term developable potential for wind. This is a much smaller set of resources that could potentially be built and financed in the near term.

Table 4-21. Arizona Wind Technical Potential

Region	Capacity by Wind Power Class					Total Capacity
	3	4	5	6	7	
53	2,042	255	47	9	1	**2,355**
54	12,764	586	240	104	12	**13,706**
55	3,376	407	62	18	1	**3,864**
56	129	22	2	0	0	**152**
57	713	115	33	16	2	**879**
58	194	60	12	2	0	**267**
59	1,321	370	123	53	4	**1,870**
Total	**20,538**	**1,814**	**519**	**202**	**20**	**23,093**

Source: Donna Heimiller, NREL, 2006
Note: Total technical potential, assuming 5 MW of capacity per square km.

Arizona currently has no operating wind facilities, but there are several proposed projects. Transmission lines exist near several of the larger Class 3 areas, and the terrain does not appear to be particularly challenging to development. However, the existence of transmission lines is not the same as transmission path availability, and a more detailed review of at transmission issues is needed (outside the scope of this study).

Wind energy appears to be a good source of renewable energy for Arizona, although further investigation is needed to define how much of the theoretical capacity is actually developable.

4.7 Geothermal

Geothermal resources can provide energy for power production and other applications by using heat from the earth to generate steam and drive turbine generators.

The global installed capacity for geothermal power plants is about 8,900 MWe (megawatt electrical). Additionally, about 16,000 MWth is used in direct heat applications. It is estimated that geothermal resources using today's technology could support between 35,500 and 72,000 MWe of electrical generating capacity worldwide. Using enhanced technology that is currently under development, global geothermal resources have the potential to support between 65,500 and 138,000 MWe.

It is estimated that US geothermal resources could support between 6,300 and 11,700 MWe of electric power with current technology and 15,000 to 25,000 MWe with advanced technology.

Applications

In addition to generation of electricity and direct space heating applications, hot water and saturated steam from a geothermal resource can be used for a wide variety of process heat applications.

Resource Availability

Geothermal power can be developed where subsurface temperature gradients are elevated, such as in areas of young volcanism. However, there are other geologic settings favorable to geothermal development, including (for example) the Basin and Range province of the United States, where the crust is relatively thin, which leads to greater heat flow from the earth's interior. Tectonically active (but not necessarily volcanic) areas are also favorable because of the presence of significant faulting and fracturing that can allow deep circulation and heating of ground waters. Subsurface temperature gradients measured in wells help to determine the potential for geothermal development and the type of geothermal power plant installed. High energy sites are suitable for electricity production, while low energy sites are suitable for direct heating. Most of the known and most easily accessible geothermal resources in the United States are concentrated in the west and southwest parts of the country. Figure 4-24 shows the 90 MW Coso Junction Navy II geothermal plant in California.

Figure 4-24. COSO Junction Navy II Geothermal Plant.

Cost and Performance Characteristics

Geothermal power is generated in two kinds of plants: flash steam and binary. In the former, the produced geothermal fluid is separated into steam and water phases; the steam is supplied directly to the turbine generator, and the separated water is injected back into the ground. In a binary power plant, a working fluid is passed through a heat exchanger, where it is heated by the geothermal fluid to its boiling point. The vapor passes through the turbine generator and condensed to be re-used again. Both the working fluid and the geothermal fluid are kept in separate, sealed loops. After its heat is transferred to the working fluid, the geothermal fluid is injected back into the ground.

For representative purposes, a binary cycle power plant is characterized in Table 4-22. Capital costs of geothermal facilities can vary widely for several reasons, but one of the most important variables is the drilling cost to develop the resource. First, exploration wells must be drilled to find and prove the resource; there are almost always one or two "dry holes" (those that do not provide commercially attractive temperatures and/or flow rates) drilled during this process. Once defined and proven, the development wells (production and injection) are drilled. Well costs increase non-linearly with depth, so the geologic controls on the geothermal system need to be well-understood (as a result of the exploration drilling program) to arrive at accurate cost estimates. However, because the "fuel supply" is developed up-front, fuel price risks are non-existent. This, combined with the high availability of geothermal projects (typically more than 95

percent) makes geothermal attractive for baseload generation and managing portfolio risk.

Table 4-22. Geothermal Technology Characteristics.

Performance	
Typical Duty Cycle	Baseload
Net Plant Capacity (MW)	30
Capacity Factor (percent)	70 to 90
Economics ($2006)	
Total Project Cost ($/kW)	3,000 to 4,000
Variable O&M ($/MWh)	25 to 30
Levelized Cost ($/MWh)	46 to 81
Applicable Incentives	$20/MWh PTC, 5-yr MACRS
Technology Status	
Commercial Status	Commercial
Installed US Capacity (MW)	2,534

Environmental Impacts

Binary geothermal development has relatively few environmental impacts. As with any power project, land area must be set aside for the power plant, substation and power lines. Some road access into remote areas may be required. Areas disturbed for exploration activities, drilling and pipelines are typically restored and re-vegetated. Although geothermal fluids contain small quantities of non-condensable gases, the power plants are designed to either remove them or keep them in solution to be reinjected underground. Owing to strict well design guidelines, there is no pollution of surface or groundwaters. Geothermal power plants with modern emission control technologies have minimal environmental impact. They emit less than 0.2 percent of the CO_2, less than 1 percent of the SO_2, and less than 0.1 percent of the particulates of the cleanest fossil fuel plant.

There is the potential for geothermal production to cause ground subsidence. However, proper resource management (most importantly including an effective injection strategy) mitigates this risk.

Arizona Geothermal Outlook

Geothermal potential for electric power production in Arizona is undemonstrated at present. Relative to developments in other western states, Arizona is at an early stage

of development. After a long period of relative inactivity, geothermal development in the US is booming. Table 4-23 lists current development prospects as identified by the Geothermal Energy Association. There is one project in Arizona identified with 2 to 20 MW of potential. This is the Clifton project that has been under development by Vulcan, although there is not project activity at this time.

Table 4-23. Current Geothermal Development Prospects.

	Projects	MW
Alaska	2	20.6
Arizona	1	2-20
California	15	821-870
Hawaii	2	38
Idaho	2	36
New Mexico	2	21
Nevada	19	547-661
Oregon	6	186-211
Utah	2	47.6
Total	51	1,720-1,925

Source: Geothermal Energy Association, Jan 2007, http://www.geo-energy.org/

4.8 Fuel Cells Using Renewable Fuels

Fuel cell technology has been developed by government agencies and private corporations. Fuel cells are an important part of space exploration and are receiving considerable attention as an alternative power source for automobiles. In addition to these two applications, fuel cells continue to be considered for power generation for permanent power and intermittent power demands. Figure 4-25 shows an example of a fuel cell in operation.

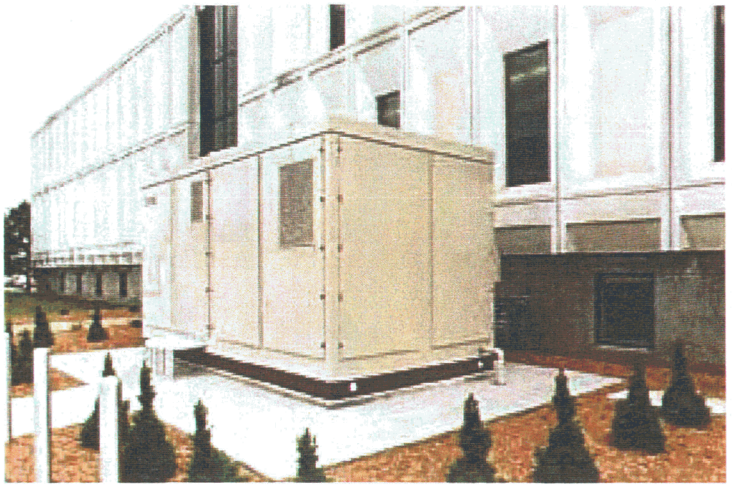


Figure 4-25. 200 kW Fuel Cell (Source: UTC Fuel Cells).

Operating Principles

Fuel cells convert hydrogen-rich fuel sources directly to electricity through an electrochemical reaction. Fuel cell power systems have the promise of high efficiencies because they are not limited by the Carnot efficiency that limits thermal power systems. Fuel cells can sustain high efficiency operation even under part load. The construction of fuel cells is inherently modular, making it easy to size plants according to power requirements.

There are four major fuel cell types under development: phosphoric acid, molten carbonate, solid oxide, and proton exchange membrane. The most developed fuel cell technology for stationary power is the phosphoric acid fuel cell (PAFC). PAFC plants range from around 200 kW to 11 MW in size and have efficiencies on the order of 40 percent. PAFC cogeneration facilities can attain efficiencies approaching 88 percent when the thermal energy from the fuel cell is utilized for low grade energy recovery. The potential development of solid oxide fuel cell/gas turbine combined cycles could reach electrical conversion efficiencies of 60 to 70 percent.

Applications

Most fuel cell installations are less than 1 MW. Commercial stationary fuel cell plants are typically fueled by natural gas, which is converted to hydrogen gas in a reformer. However, if available, hydrogen gas can be used directly. Other sources of fuel for the reformer under investigation include methanol, biogas, ethanol, and other hydrocarbons.

In addition to the potential for high efficiency, the environmental benefits of fuel cells remain one of the primary reasons for their development. High capital cost, fuel cell stack life, and reliability are the primary disadvantages of fuel cell systems and are the focus of intense research and development. The cost is expected to drop significantly in the future as development efforts continue, partially spurred by interest by the transportation sector.

Performance and Cost Characteristics

The performance and costs of a typical fuel cell plant are shown in Table 4-24. A significant cost is the need to replace the fuel cell stack every 3 to 5 years due to degradation. The stack alone can represent up to 40 percent of the initial capital cost. Most fuel cell technologies are still developmental and power produced by commercial models is not competitive with other resources. For reference, the price of fuel was assumed to range from $1 to $3/MBtu, which is representative of a landfill gas type resource.

Table 4-24. Fuel Cell Technology Characteristics.

Performance	
Net Capacity per Unit, kW	100-250
Net Plant Heat Rate, Btu/kWh	7,000-9,500
Capacity Factor, percent	70-90
Economics	
Capital Cost, $/kW	6,000-8,400
Fixed O&M, $/kW-yr*	650-910
Variable O&M, $/MWh	7-13
Fuel Cost ($/MBtu)	1.00 to 3.00
Levelized Cost, $/MWh	189 to 367
Applicable Incentives	30% ITC, capped at $1,000/kW
Technology Status	
Commercial Status	Early Commercial

Notes: Includes costs for cell stack replacement every four years.

Arizona Outlook

Fuel cells are a promising technology that shows potential for clean, renewable, distributed power generation in the future. Continued research and development is required to reduce the capital and O&M cost and increase the fuel cell stack life. In the near-term, fuel cells would be only be competitive with conventional power generation

technologies with considerable subsidies, and a low cost (or free) hydrogen fuel source. In the long-term (10-20 years), fuel cells could be a competitive power generation technology, pending advancements in R&D.

Methane sources (such as landfill, manure, MSW) are a good source of renewable hydrogen. Especially at a facility that already harvests the methane for power, reforming the gas instead to produce H2 is a good possibility. Because landfill, and digester gas is low heating value gas, the treatment to make H2 is more attractive. However, currently reciprocating engines are much more economical for these types of fuels.

Arizona State University has a significant fuel cell research effort. Most recently it has garnered some recognition for its work on fuel cells for laptop computer sized equipment. The Salt River Project has had two 5 kW fuel cells (Plug Power and GenSys 5CS) connected to its grid since 2005 for the purposes of testing them in the Arizona heat.

4.9 Compressed Air Energy Storage

Although it is not a renewable energy technology, compressed air energy storage can potentially help enable development of intermittent renewable energy sources, such as wind and solar. The technology is briefly introduced here.

Compressed air energy storage (CAES) is a technique used to supply electrical power to meet peak loads within an electric utility system. This method uses the power surplus from power plants during off-peak periods to compress and store air in an underground formation. The compressed air is later heated (with a fuel) and expanded through a gas turbine expander to produce electrical power during peak demand. A simple compressed air storage plant consists of an air compressor, turbine, generator unit, and a storage vessel. Exhaust gas heat recuperation can be added to increase efficiency.

The thermodynamic cycle for a compressed air storage facility is similar to that of a simple cycle gas turbine. Typically, gas turbines will consume 50 to 60 percent of their net power output to operate an air compressor. In a compressed air storage plant, the air compressor and the turbine are not connected, and the total power generated from the gas turbine is supplied to the electrical grid. By using off-peak energy to compress the air, the need for expensive natural gas or fuel oil is reduced by as much as two thirds, compared with conventional gas turbines.[9] This results in a very attractive heat rate for CAES plants, ranging from 4,000 to 5,000 Btu/kWh. Since fuel (typically natural gas) is supplied to the system during the energy generation mode, CAES plants actually provide

[9] Nakhamkin, M., Anderson, L., Swenson, E., "AEC 110 MW CAES Plant: Status of Project," *Journal of Engineering for Gas Turbines and Power*, October 1992, Vol. 114.

more electrical power to the grid than was used to compress the air. The capital costs for CAES facilities are approximately the same as a similar sized combined cycle facility.

The location of a CAES plant must be suitable for cavern construction or for the reuse of an existing cavern. However, suitable geology is widespread throughout the United States, with more than 75 percent of the land area containing appropriate geological formations.[10] There are three types of formations that can be used to store compressed gases: solution mined reservoirs in salt, conventionally mined reservoirs in salt or hard rock, and naturally occurring porous media reservoirs (aquifers).

CAES can potentially be a good match with renewable energy sources. CAES units are highly flexible; they have quick start-up times, high ramp rates, and good part-load efficiency. These attributes make them suitable to help balance intermittent wind and solar resources. In addition, it is possible that the fuel input needed during the expansion phase of the CAES cycle could be provided by biomass or biofuels.

The basic components of a CAES plant are proven technologies, and CAES units have a reputation for achieving good availability. The first commercial-scale CAES plant in the world was a 290 MW plant in Huntorf, Germany. This plant has been operating since 1978, providing 2 hours of generation with 8 hours of charging. In 1991, a 110 MW CAES facility was installed in McIntosh, Alabama. This plant remains the only US CAES installation, although several new plants have been announced. For example, the Iowa Association of Municipal Utilities is developing the Iowa Stored Energy Park. This project will combine up to about 200 MW of CAES with a wind farm.

Because it operates on the difference between off and on peak electricity prices, the economics of a CAES plant must be evaluated within the context of a specific market. Such an evaluation is outside the scope of this study. However, based on other studies Black & Veatch has performed, the following general conclusions can be drawn:

- CAES can be a very competitive option to serve intermediate loads.
- Because of its low heat rate, CAES can be more economical than combined cycle, especially at higher gas prices.
- To be cost effective, CAES requires access to low cost, off-peak energy from either coal, nuclear, hydroelectric, or wind facilities.
- Although CAES can help balance renewable energy resources, there is typically not enough value to justify a CAES project solely for this purpose. If new balancing or back-up capacity must be developed to "firm" wind and solar, simple cycle combustion turbines may offer a less expensive option.
- CAES can provide high value ancillary services (quick-start, spinning reserve, etc.) that need to be considered in an evaluation of CAES economics.

- The economics of CAES are not straightforward and are not easy to assess without detailed production cost modeling.

Although CAES seems to be gaining increased interest, it is not clear that there is a need for CAES in the near-term in Arizona to enable development of additional renewable resources. Based on the projections in this study, intermittent wind projects (which would benefit most from CAES) will likely comprise a relatively small fraction (< 5 percent) of the overall Arizona energy portfolio going forward. This level of wind penetration should be able to be accommodated without the need for a dedicated CAES facility. For this reason, CAES is not considered further in this study.

4.10 Renewable Energy Technology Summary

The technology cost and performance assumptions developed in the previous sections are summarized in Table 4-25. The values shown in the table were chosen as representative of the technology application in Arizona.

[10] Mehta, B., "Compressed Air Energy Storage: CAES Geology," *EPRI Journal*, October/November 1992.

Table 4-25. Renewable Technologies Performance and Cost Summary.[a]

	Net Plant Capacity, MW	Net Plant Heat Rate, Btu/kWh	Capacity Factor	Capital Cost, $/kW	Fixed O&M, $/kW-yr	Variable O&M, $/MWh	Fuel Cost, $/MBtu	Levelized Cost, $/MWh
Direct Biomass (UWW)	35	13500	70-90	2750-3500	83	11	1	66-94
Direct Biomass (FR)	35	13500	70-90	2750-3500	83	11	3	90-118
Biomass IGCC (UWW)	35	10000-11500	70-90	3000-4000	83	11	1	65-99
Biomass IGCC (FR)	35	10000-11500	70-90	3000-4000	83	11	3	82-120
Cofired Bio. (UWW)	30	10000	70-90	300-500	5-15	0	-0.5[c]	0-9
Cofired Bio. (FR)	30	10000	70-90	300-500	5-15	0	1	18-27
Anaerobic Digestion	0.15	11500	70-90	4000-6000	0	17	0	68-126
Landfill Gas	2-10	11500	70-90	1500-2000	0	17	1-3	40-80
Solar Thermal (trough)	100		37-43	5400-6300	0	20-25		132-176
Solar Thermal (dish)	14		20-25	5000-6000	0	10-20		184-281
Solar PV (residential)	0.004		18	8500-12500	50	0		358-509
Solar PV (commercial)	0.250		20	7000-9000	30	0		321-407
Solar PV (utility)	3		22	6000-8000	30	0		278-365
Hydro (new)	<50		40-60	2500-4000	5-25	5-6		44-121
Hydro (incremental)	1-160		40-60	600-3000	5-25	4-6		5-92
Wind	50-100		25-35	1600-1900	28	8		51-93
Geothermal	30		70-90	3000-4000	0	25-30		46-81
Fuel Cells	0.1-.25	7000-9500	70-90	5000-7400	650-910	7-13	1-3	189-367

Notes:
[a] Includes applicable incentives, subsidies, etc. All costs are in 2007 dollars.
[b] UWW = Urban Wood Waste ; FR = Forestry Residues
[c] Assumes payment for disposal of waste not taken to landfill.

4.10.1 Relative Costs

Of the renewable energy technologies evaluated, cofiring has the lowest capital cost per kW installed at $300-500/kW. The majority of the capital costs are associated with adding material handling equipment to an existing coal plant, as opposed to development of new plants for most other technologies. Wind has the next lowest capital cost at $1,600-1,900/kW. This has been a main driver in the 30 percent annual increase in wind installations worldwide over the last five years. Recently, however, system costs have begun to rise. In comparison, conventional biomass and geothermal technologies have capital costs in the range of $2,750-3,500/kW and $3,000-4,000/kW, respectively. The high cost of biomass plants is due to their relatively small size, extensive fuel and ash handling requirements, and the need for a robust plant design to handle the variability in the fuel quality. New hydroelectric power plants have a wide range of capital costs from $2,500-4,000/kW. Given that hydroelectric technology is quite mature and costs are low, the civil work that needs to be done to build dams and penstocks tends to be the driving factor behind the capital cost of these systems. Incremental hydroelectric improvements can be much lower in costs. Photovoltaic systems are by far the most expensive renewable energy technology, with capital costs from $6,000-12,500/kW and a capacity factor of only about 20 percent.

When comparing the levelized cost of energy produced by these systems, biomass, hydroelectric, anaerobic digestion, landfill gas, hydroelectric, wind and geothermal all have the potential to produce power at rates competitive with new coal and gas power generation. Although these resources have high capital costs, low operating costs combined with high operating capacity factors reduce the overall life-cycle costs.

Continued improvements will result in improvements in efficiency, capital cost, and operating and maintenance cost for several of the technologies. The technology areas where the levelized cost of power production should come down in the future are wind, biomass gasification, photovoltaics, solar thermal, and fuel cells. Large improvements are expected for solar technologies, with relatively modest improvements in other technologies.

4.10.2 Recommendations for Further Study

Based on the profiles described previously in this study, Table 4-26 presents our recommendations for further study. Due to their resource potential or low cost, these are the most promising technologies in Arizona.

Table 4-26. Promising Technologies for Arizona.

RECOMMENDED FOR FURTHER STUDY
Large Potential
• Wind • Solar Thermal (trough) • Solar Thermal (dish) • Solar PV (utility-scale, commercial)
Limited Potential, But Relatively Low Cost
• Direct Biomass • Cofired Biomass • Anaerobic Digestion • Landfill Gas • Hydroelectric (new) • Hydroelectric (incremental) • Geothermal
NOT RECOMMENDED FOR FURTHER STUDY
Emerging Technology / Technology Doesn't Yet Offer Compelling Cost Advantages over Other Alternatives
• Biomass IGCC • Fuel Cells • Plasma Arc • Compact Lens Fresnel Reflector
Distributed Applications (Outside Scope)
• Solar PV (residential)

5.0 Renewable Resource Assessment

The objective of this section is to assess the renewable energy resources of Arizona that are suitable for development in the near- to mid-term (next 20 years). Potential development prospects are identified, levelized generation costs are calculated, and a set of supply curves is developed. An end result of this process was the identification of a list of over 100 hypothetical renewable energy projects that might be developed to meet demands for renewable energy in Arizona.

The technologies reviewed in this section are:

- Direct Fired and Cofired Biomass
- Landfill Gas
- Anaerobic Digestion
- Solar Thermal Electric
- Solar Photovoltaic
- Hydroelectric
- Wind Power
- Geothermal

All costs presented in this section are in 2007$ unless otherwise stated. Additional economic assumptions impacting the projects are presented in Section 7.2.

5.1 Direct Fired and Cofired Biomass

Both direct-fired biomass and cofired biomass were identified as promising technologies in the first stage of the analysis. Cofiring is generally more economical, but it is limited to locations where biomass is available near an existing coal plant. If there are no coal plants in the vicinity, direct fired biomass is a more appropriate technology. This section characterizes the resources suitable for both technologies.

5.1.1 General Methodology

The feasibility of direct fired and cofired biomass projects is largely dependent upon obtaining an economical biomass fuel supply. A high-level review of biomass resources based primarily on data assembled by the National Renewable Energy Laboratory (NREL) was presented in Section 4 This estimate provided county-level estimates of biomass resources with the state. As discussed in Section 4, the national forests in Coconino, Navajo and Apache counties provide the largest sources of woody biomass resources. There are significant quantities of residues from forest thinning activities, and these residues are supplemented by mill residues from the Fort Apache

Timber Company (FATCO). Significant quantities of urban wood waste are found in the Phoenix and Tucson area. These metropolitan areas are surrounded by agricultural areas, which provide crop residues for smaller scale biomass energy facilities.

To obtain information regarding specific point sources of biomass resources that could be utilized to secure biomass fuel for actual biomass projects, Black & Veatch contacted potential suppliers of biomass resources via telephone. An initial round of phone calls were made to potential suppliers of biomass identified in a previous assessment of Arizona's biomass resources. This previous assessment, conducted by Black & Veatch in 2005 as part of a larger study for APS, identified over 60 potential suppliers, and the objective of the phone survey conducted for this present study was to verify that the resource previously identified were currently available and to determine if any additional resources were available. The focus of this effort was in the northern and eastern portions of the state as this is where much of the state's wood resources are located.

Following the initial round of calls, additional suppliers and agencies were contacted. Forestry and renewable energy experts at the University of Arizona and Northern Arizona University were consulted regarding biomass resources within the state, and national and state forestry officials were contacted to obtain information regarding potential forest thinning residues. Landfills were contacted to determine the availability of urban wood waste streams for use in biomass energy facilities.

Based on the conversations with biomass suppliers, forestry officials, and renewable energy experts, key findings of the updated assessment include:

- In general, the survey confirmed the presence of the biomass resources previously identified.
- One significant source of mill residues not previously identified was found. Southwest Forest Products has constructed a new sawmill in Ash Fork, which generates roughly 55 dry tons per day (dtpd) of mill residues.
- A significant competitor of biomass resources was also identified. An oriented strand board manufacturing facility is being developed in Winslow. This proposed facility would consume 1 million tons per year of biomass and may begin operation as soon as winter of 2008.
- The significant suppliers of primary mill residues are summarized in Table 5-1.
- The United States Forestry Service provided the current forest treatment plan for the national forests in Arizona. The estimated residues from forest thinning activities are summarized in Table 5-2.

- Information from landfills related to urban wood waste collection was inconsistent, and the specific quantity of potential resources could not be quantified. It is likely that smaller suppliers of urban wood waste, such as tree trimmers and landscapers, collect significant amounts of urban wood waste, but these suppliers were not contacted during this survey.

The general finding of the supplier survey is that the quantities of biomass resources identified in Section 4 of this report are currently available.

Table 5-1. Significant Primary Mill Residue Suppliers.

Supplier	Location	Quantity Available (dtpd)[1]
Fort Apache Timber Company (FATCO)	Whiteriver	210
Precision Pine and Timber	Heber	27
Southwest Forest Products	Ash Fork	55
Southwest Forest Products	Phoenix	36

Notes:
[1] Quantities listed are in units of dry tons per day (dtpd).

Table 5-2. Estimated Average Annual Forest Thinning Residues (2006-2015).

Forest	Quantity Available (dtpd)[1]	Quantity Available (dtpy)[1]
Apache-Sitgreaves	434	158,600
Coconino	176	64,400
Coronado	15	5,500
Kaibab	57	20,700
Prescott	18	6,500
Tonto	61	22,200

Source: United States Forestry Service, "Southwest Region 10-Year Treatment Plan." Obtained via e-mail from Marlin Johnson, USFS, on February 12, 2007.
Notes:
[1] Quantities listed are in units of dry tons per day (dtpd) and units of dry tons per year (dtpy).

In addition to the wood resources available, livestock population estimates listed in a spreadsheet of concentrated animal feeding operations (CAFOs) in Arizona were reviewed to determine the potential availability of animal manures and poultry litter (dryer material is suitable for combustion, wetter material is suitable for anaerobic digestion).

Following the rounds of resource assessment and review, the biomass resource estimates were aggregated. Considering the geographic distribution of the resources and the quantities available, two potential cofiring projects and one potential direct fired project were identified. The estimate of available resources is considered to be somewhat conservative, and it is likely that additional biomass projects could be developed if all of the resources identified were utilized by biomass facilities. However, biomass project developers generally attempt to identify at least 2 to 3 times the required tonnage needed for full-scale operation, and this assumption was used as a limit for the projects proposed in this study. Furthermore, the potential for biomass energy in Arizona is limited due to competition for the existing resources. In addition to typical competition for wood residues such as animal bedding and the new oriented strand board facility being developed in Winslow, there are also at least two significant biomass consumers in eastern Arizona:

- Forest Energy Corporation: Located in Show Low, Forest Energy produces almost 200 dry tons per day of pelletized wood, which is used as fuel for residential and commercial heating. Pellet fuel is generally thought to be too expensive for utility applications.
- Snowflake White Mountain Power (SWMP): Located near Snowflake, SWMP is a 24 MW biomass power facility scheduled to begin operation in 2008. In addition to burning recycled paper fibers from Abitibi, this facility will require roughly 250 additional dry tons per day of biomass.

The competition from these operations and other potential consumers of biomass resources will constrain the capacities of other biomass facilities.

5.1.2 Major Assumptions

The two potential cofiring projects identified in Arizona are assumed to be located at TEP's Springerville Generating Station and APS's Cholla Generating Station. Cofiring could also take place at SRP's Coronado station (with similar economics to that shown for Springerville). However, there may not be enough resources to support three cofiring projects in eastern Arizona.

The following assumptions were made in the evaluation of cofired biomass potential.

- The cofiring projects would employ a gasification system close coupled to the existing boiler.
- A Net Plant Heat Rate (NPHR) of 11,000 Btu/kWh was assumed for Cholla, based on boiler modeling conducted by Black & Veatch in a previous study. An NPHR of 10,000 was assumed for Springerville, based on information

available in Velocity Suite, a database of utility industry data maintained by Global Energy Decisions.

- The cofiring project at Springerville would utilize forest thinnings from Apache National Forests and mill residues from the Fort Apache Timber Company (FATCO). The thinning residues available from Apache National Forest are assumed to be one half of the total estimate for the combined Apache-Sitgreaves Forest provided by the US Forest Service.
- The cofiring project at Cholla would utilize forest thinnings from Coconino, Kaibab and Prescott National Forests and mill residues from Precision Pine and Timber (located in Heber, AZ) and Southwest Forest Products (located in Ash Fork, AZ).
- Only 50 percent of the forest thinnings estimated (according to the USFS plan) are assumed to be collected from the forests, as shown in Table 5-3.
- It was assumed that Springerville would only be able to obtain roughly 40 percent of the available resources from Apache National Forest and FATCO due to competition from existing biomass industries (e.g., Forest Energy) and planned biomass projects (e.g., Snowflake White Mountain Power), as shown in Table 5-4. The thinning residues available from Apache National Forest are assumed to be one half of the total estimate for the combined Apache-Sitgreaves Forest estimated by the US Forest Service.
- It was assumed that Cholla would be able to obtain 50 percent of the available mill residues from Precision Pine and Timber and Southwest Forest Products, as shown in Table 5-4.

Table 5-3. Potential Forest Thinnings.

National Forest	Total Estimate (dtpy)	Feasible Collection[1] (dtpy)
Apache	79,300	39,650
Coconino	64,400	32,200
Kaibab	20,700	10,350
Prescott	6,500	3,250

Source: US Forestry Service.
Notes:
[1] It was assumed that 50% of estimated forest thinnings would be collected.

Table 5-4. Biomass Resources Available for Cofiring.

	Total Resource Available (dtpy)	Percentage Available for Cofiring (%)	Resource Available for Cofiring (dtpy)
Springerville Cofiring			
Apache-Sitgreaves	39,650	40	15,900
FATCO	76,650	40	30,700
Total	**116,300**		**46,600**
Cholla Cofiring			
Coconino	32,200	100	32,200
Kaibab	10,350	100	10,350
Prescott	3,250	100	3,250
Precision Pine and Timber	9,850	50	4,900
SW Forest Prod.–Ash Fork	20,100	50	10,500
Total	**75,750**		**60,750**

The direct fired project identified is assumed to be located south of the Phoenix metropolitan area in Maricopa, Arizona.

The following assumptions were made in the evaluation of direct fired biomass potential.

- An NPHR of 14,500 Btu/kWh was assumed, which is typical of relatively small-scale (25 MW or less) combustion systems
- The proposed direct fired project would utilize a variety of biomass fuels, including mill residues, urban wood waste from Phoenix and Tucson, agricultural residues and beef manure.

If the cofiring projects face too many obstacles, an additional direct fired biomass facility could be developed in Northern Arizona in lieu of the cofiring projects. If all the biomass in the area were made available to the project, it is possible it could be sized as large as 20 MW. This project would be similar to the Maricopa project. There appears to be sufficient biomass in the vicinity to support either the cofiring projects or a direct fired, but not both. Because cofiring is likely less costly, it was decided to represent the renewable generation capacity as the two cofiring projects.

5.1.3 Future Cost and Performance Projections

Direct fired biomass is largely a mature technology. No changes in future cost or performance were assumed other than adjustments to account for normal inflation. The technology for gasifying biomass for use in cofiring PC units is still in the early

commercialization phase. While cost and performance improvements of such systems may change as expertise grows, improvements are expected to be relatively small. Therefore, no changes in future cost or performance were assumed other than adjustments to account for normal inflation.

5.1.4 Data Sources

Data sources used in this analysis included:

- Black & Veatch, "Cholla #1 Biomass Cofiring Conceptual Design Study." December, 2005.
- Spreadsheet of Concentrated Animal Feeding Operations (CAFO) in Arizona, provided by Thomas Ramey of APS on November 30, 2006.
- United States Forestry Service, "Southwest Region 10-Year Treatment Plan." Obtained via e-mail from Marlin Johnson, USFS, on February 12, 2007.
- Survey of Arizona biomass suppliers, forestry officials and landfills conducted by telephone. Survey conducted January-March, 2007.

5.1.5 Projects Identified

As mentioned above, two biomass cofiring projects have been identified. Based on the resources available and the assumptions listed above, a 10 MW cofiring project is feasible at Springerville Generating Station, and a 10 MW cofiring project is feasible at Cholla Generating Station. Assuming a capacity factor of 80 percent for both projects, annual biomass generation at Springerville and Cholla would be approximately 70 GWh/yr. These generation amounts do not represent additional generation, rather they represent displacement of coal with a renewable fuel. It is expected permitting and construction of the cofiring projects could be conducted in 18 to 24 months. Given a notice to proceed (NTP) of January 1, 2008, both cofiring projects could be operational by January 1, 2010.

A potential direct fired project has been identified south of the Phoenix metropolitan area. Based on the geographic distribution of the potential biomass resources, a likely potential site for this facility is Maricopa, Arizona. This location would allow the facility to utilize mill residues and urban wood wastes from Phoenix, urban wood wastes from Tucson and agricultural residues from Maricopa and Pinal counties.

A detailed permitting study was not completed for this task. However, both Maricopa County and Pinal County, in which the Maricopa facility would be located, are non-attainment areas for NOx and PM10. It is likely that a Selective Non-Catalytic Reduction (SNCR) would be required to control NOx, and a baghouse or electrostatic

precipitator (ESP) would be required to control particulate. A small scrubber may be necessary depending on the fuel mix. Although it is a relatively small plant, it is possible that the biomass facility would be considered a major source for these pollutants, in which case the purchase of offsets would also be required. A detailed review of these issues was beyond the scope of this study.

The proposed project has a nominal capacity of 20 MW, and assuming a capacity factor of 80 percent, the facility would produce roughly 140 GWh per year. It is expected permitting and construction of the direct fired project could be conducted in 42 to 48 months. Given a notice to proceed (NTP) of January 1, 2008, the Maricopa direct fired biomass project would likely be operational by January 1, 2012.

Table 5-5 shows the direct fired and cofired biomass projects identified for this study. All characteristics are year 2007 values, before any future cost and performance modifications have been made. Figure 5-1 shows the supply curve for cofired biomass and direct fired biomass projects. For the purposes of visualizing the projects on the supply curve, it has been assumed that all projects could be built in 2007. Appendix A shows a consolidated list of projects; Appendix B shows the same list with forecast levelized costs for each project from 2007 to 2025.

Considering the other renewable energy options evaluated in this study, the costs of the two cofiring projects are relatively low (about $60/MWh in 2010), and the costs of cofiring are certainly lower than the direct fired project (about $162/MWh in 2012). In general, the costs of biomass in Arizona are relatively high due to the lack of low cost biomass and the small scale of biomass projects.

Table 5-5. Direct Fired and Cofired Biomass Project Characteristics.

Project	Capacity, MW	CF, %	Genera-tion, GWh	First Year Available	Capital Cost, $/kW	Fixed O&M, $/kW-yr	Var. O&M, $/MWh	Fuel Cost,[1] $/MBtu	Nearest Utility	Transmission Line		
										Voltage, kV	Dist. to TL, miles	Owner
Cholla cofiring	10.0	80%	70	2010	900	61	0	2.50	APS	N/A	N/A	N/A
Springerville cofiring	10.0	80%	70	2010	900	61	0	2.30	TEP	N/A	N/A	N/A
Maricopa City Direct	20.0	80%	140	2012	4,000	160	11.50	1.89	APS	115	2	APS

Note:
[1] The fuel cost for cofiring projects is the incremental cost of biomass above the cost of coal.

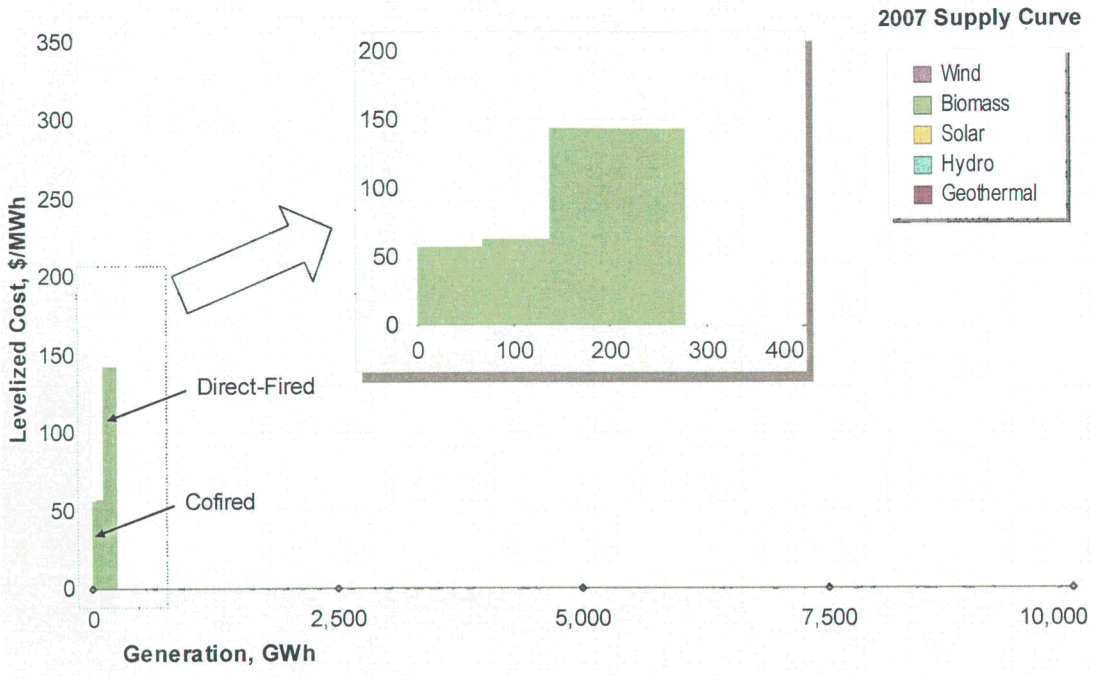


Figure 5-1. Levelized Cost Supply Curve for Solid Biomass Projects.

5.2 Landfill Gas

Landfill gas (LFG) is formed from the decomposition of waste buried in the landfill. The gas is primarily composed of methane and carbon dioxide, with sulfur oxides and other miscellaneous constituents making up the balance. Gas production varies significantly by site, depending on the composition of the waste, dimensions of the landfill, and climate. For example, Arizona's arid climate slows the rate of decomposition in landfills, thus reducing the volumetric rate of gas that can be recovered. However, a strong correlation exists between the tons of waste in place and quantity of gas production.

5.2.1 General Methodology

Black & Veatch utilized the Environmental Protection Agency (EPA) Landfill Methane Outreach Program (LMOP) database of landfills in Arizona to estimate the technical potential for landfill gas power generation at 27 sites. The database provides figures for the landfill size, waste in place, gas generation, and in some cases contact information. Of the 27 sites listed as candidate landfill gas projects, 2 are currently in development and are scheduled to come online in the future (27th Ave landfill and Skunk

Creek landfill). Black & Veatch considered the remaining 25 sites as the pool of potential renewable generation projects.

Black & Veatch attempted to contact candidate landfills to determine the amount of waste in place, yearly fill rate, gas collection system situation, plans to utilize landfill gas, ownership of landfill gas, and any other information to help gauge the potential for electric generation. Black & Veatch was able to make contact with representatives at 16 of the landfills Table 5-6.

Table 5-6. Candidate Landfill Contact Results.

Landfill	Made Contact?	On Potential Project List?
Butterfield Station Landfill	Yes	Yes
Salt River Landfill	Yes	Yes
27th Avenue Landfill	Yes	No – already in development
Apache Junction LF	No	Yes
Cinder Lake MSW LF	Yes	Yes
City of Glendale Municipal Landfill	Yes	Yes
Grey Wolf Landfill	Yes	Yes
Huachuca City Landfill	No	Yes
North Center Street Landfill	Yes	Yes
Northwest Regional MSW Landfill	No	Yes
Painted Desert Landfill	Yes	Yes
Queen Creek MSW Landfill	No	Yes
Rio Rico MSW Landfill	Yes	Yes
Skunk Creek Landfill	Yes	No – already in development
Cave Creek Landfill	No	No
Cocopah Landfill	No	Yes
Copper Mountain Landfill	Yes	No
Dudleyville Landfill	No	No
Harrison City Landfill	Yes	No
Ironwood Landfill	No	No
La Paz County Landfill	No	No
Lake Havasu Landfill	Yes	No
Mohave Valley Landfill	Yes	No
Sierra Estrella Landfill	No	No
Southwest Regional Landfill	Yes	Yes
Tangerine Road MSW Landfill	No	Yes
Vincent Mullins Landfill	Yes	No

Black & Veatch tried to contact all the LMOP landfills for which we could find contact information. The goal was to get data on waste in place, fill rate, typical waste

composition, gas production rate, gas collection system status, gas rights ownership, and known plans for using gas for generation. For some landfills it was difficult to reach a manager or engineer who was knowledgeable about the factors needed to assess the landfill's potential. For all landfills it was also difficult to get sufficient information on all pertinent factors needed to estimate generation potential with a high degree of accuracy. Additional information obtained from the phone survey helped better determine which projects have real potential, approximate how much generation could be expected, and estimate the earliest year each project could come online if project development were prioritized.

Some landfills were removed from the potential project list due to extremely small volumes and limited prospects for achieving a critical mass to make development worthwhile. For promising sites that we were not able to contact, we used the information included in the LMOP database to assess potential.

5.2.2 Major Assumptions

- The following assumptions were made in the evaluation of landfill gas potential.
- One million tons of waste in place can support 260 kW of generation capacity. This number was obtained by "normalizing" projections for Arizona landfill gas projects in development to data from previous landfill gas studies, based on waste in place. One million tons of waste in temperate conditions would generate gas sufficient to sustain 700+ kW of generation. While some arid landfills add water and microorganisms to the waste to increase the rate of gas production, all landfills were modeled to have the same waste to generation ratio. It should be noted that Black & Veatch did not prepare gas flow models for any of the potential projects.
- Although microturbines, larger combustion turbines, and other types of power conversion equipment are used to convert landfill gas to electricity, internal combustion engines account for a great majority of installations. Cost and performance data for internal combustion engines was used as a basis for this study.
- An annual capacity factor of 80 percent is assumed for all landfill gas projects.
- Responsibility for the gas collection system cost and maintenance was assumed to be on the landfill owner.
- Landfills that cannot support electric generation of at least than 250 kW were not included in the list of potential projects.

- Capital cost estimates were based on guidance from the EPA LMOP and range from $2330/kW for a 250 kW facility to $1980/kW for a 5 MW facility. These estimates do not include the cost of installing a gas collection system.
- Project construction period is one year.
- Operating and maintenance costs were estimated to be $17.5/MWh for all generation levels. This includes both fixed and variable cost components.
- Specific transmission lines were not identified. It was assumed that all landfills are currently being served with power, and the generation would back feed. Projects larger than 1 MW are assumed to have a small 34.5 kV substation.
- Interconnection costs are included in the capital costs for projects less than 1 MW.
- Landfill gas fuel cost was assumed to be $2/MBtu. This is the cost that a project developer would pay for the rights to the gas. This cost would support maintenance of the landfill gas collection system.

5.2.3 Future Cost and Performance Projections

Power generation from landfill gas is a largely a mature technology. No changes in future cost or performance were assumed other than adjustments to account for inflation.

5.2.4 Data Sources

Data sources used in this analysis included:

- EPA LMOP database. Available at http://epa.gov/lmop/proj/xls/lmopdata.xls
- EPA LOMP program. Available at http://epa.gov/lmop/
- Survey of Arizona landfills conducted by telephone. Survey conducted January-March, 2007.

5.2.5 Projects Identified

Fifteen potential projects were identified, totaling 9.8 MW of capacity and 68 GWh of annual generation, most of which could be available by 2010 if development were prioritized. As mentioned earlier, this capacity is much smaller than what would be expected for similar sized landfills in other states due to Arizona's dry climate. However, because the refuse in arid landfills decomposes at a slower rate, the gas production is expected to last longer than in temperate landfills.

The potential Arizona projects modeled in the supply curves do not include two projects that are currently under development—27th Ave. landfill (3 MW of capacity, online in 2008) and Skunk Creek landfill (3 MW of capacity, online in 2009). All of the candidate projects are less than 3 MW in capacity and most are less than 1 MW. Most of the projects are located near transmission lines owned by SRP or APS.

Many of the identified projects are not far-removed from development and commercial operation. Most of the sites already have a gas collection system in place and could have online generation by 2010. As these projects are smaller in scale than other projects such as wind farms or solar trough fields, they are better suited for coming online in the near future to increase Arizona's developed renewable energy. However, there are not enough landfill gas resources in Arizona to make landfill gas facilities a large portion of the state's overall renewable energy portfolio. Additionally, the economics for small landfill projects can be challenging. Development costs are prohibitively high for any one project to absorb all of the costs; individually projects are not attractive, but collectively they are acceptable. Black & Veatch would recommend a small-scale modular technology with lower capital and maintenance costs, such as provided by INGENCO. INGENCO provides small-scale engines designed to be modularly installed in landfills that are not viable for other types of equipment. INGENCO projects have potentially lower construction and maintenance costs than the "typical" landfill gas project characteristics assumed for this study.

Table 5-7 shows the landfill gas projects identified for this study. All characteristics are year 2007 values, before any future cost and performance modifications have been made. Figure 5-2 shows the supply curve for landfill gas generation potential (anaerobic digestion projects are also shown). For the purposes of visualizing the projects on the supply curve, it has been assumed that all projects could be built in 2007.

The overall prospects for landfill gas generation are small. Landfill gas projects can take less time to develop than large solar or wind projects, so landfill gas may play a more significant role in the near term.

Table 5-7. Landfill Gas Project Characteristics.

Project	Capacity, MW	CF, %	Genera-tion, GWh	First Year Available	Capital Cost, $/kW	Fixed O&M, $/kW-yr	Var. O&M, $/MWh	Fuel Cost, $/MBtu	Nearest Utility	Transmission Line		
										Voltage, kV	Dist. to TL, miles	Owner
Butterfield Station Landfill	2.4	80%	17	2009	2062	0	18	2	APS	34.5	N/A	APS
Salt River Landfill	0.8	80%	5	2009	2193	0	18	2	SRP	N/A	N/A	SRP
Apache Junction LF	0.3	80%	2	2010	2328	0	18	2	APS	N/A	N/A	SRP
Cinder Lake MSW LF	0.6	80%	4	2011	2233	0	18	2	APS	N/A	N/A	APS
City of Glendale Municipal Landfill	1.3	80%	9	2009	2132	0	18	2	SRP	34.5	N/A	APS
Grey Wolf Landfill	0.8	80%	5	2012	2193	0	18	2	APS	N/A	N/A	APS
Huachuca City Landfill	0.3	80%	2	2012	2305	0	18	2	TEP	N/A	N/A	TEP
North Center Street Landfill	0.5	80%	4	2008	2242	0	18	2	SRP	N/A	N/A	SRP
Northwest Regional MSW Landfill	0.3	80%	2	2010	2328	0	18	2	SRP	N/A	N/A	APS
Painted Desert Landfill	0.4	80%	3	2010	2277	0	18	2	APS	N/A	N/A	APS
Queen Creek MSW Landfill	0.4	80%	3	2011	2277	0	18	2	SRP	N/A	N/A	SRP
Rio Rico MSW Landfill	0.3	80%	2	2008	2328	0	18	2	TEP	N/A	N/A	TEP
Cocopah Landfill	0.6	80%	4	2011	2230	0	18	2	APS	N/A	N/A	APS
Southwest Regional Landfill	0.3	80%	2	2010	2302	0	18	2	APS	N/A	N/A	APS
Tangerine Road MSW Landfill	0.5	80%	4	2008	2236	0	18	2	TEP	N/A	N/A	TEP

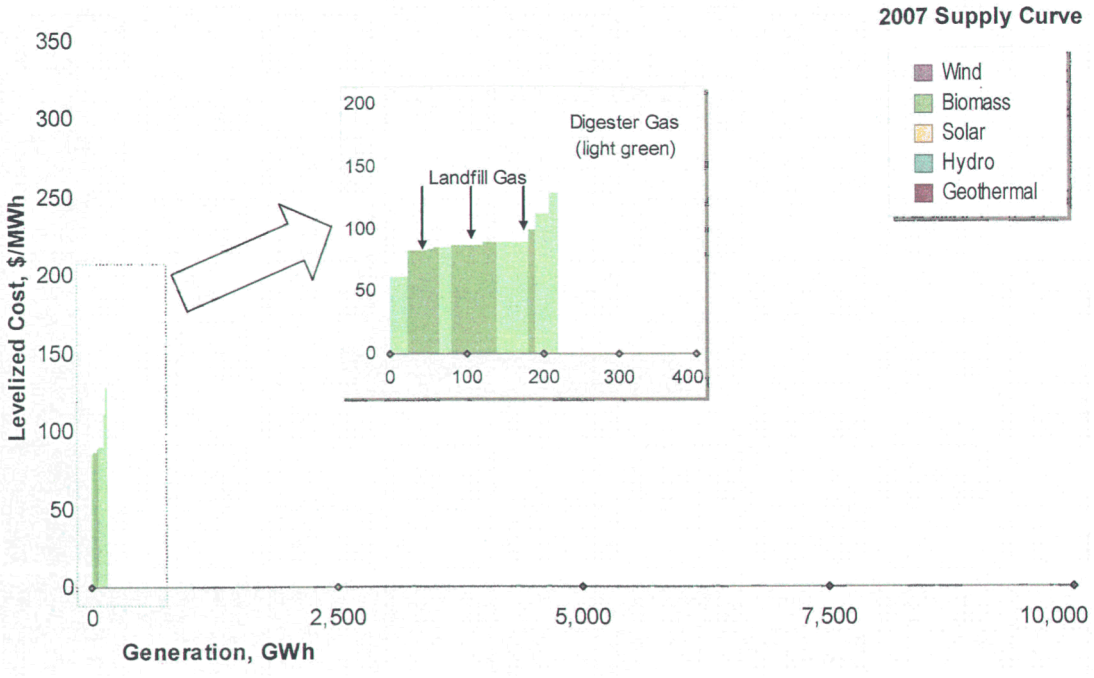


Figure 5-2. Levelized Cost Supply Curve for Biogas Projects.

5.3 Anaerobic Digestion

The utilization of biogas generated from anaerobic digestion was identified as a technically feasible option in the first stage of the analysis. While this resource has a relatively limited generation potential, anaerobic digestion projects could be executed relatively quickly and with low levels of risk. Electrical generation systems could be installed around anaerobic digestion systems co-located with either concentrated animal feeding operations (CAFOs) or waste water treatment plants (WWTPs). As mentioned in the first stage of the analysis, power demands at WWTPs often exceed the quantities of electricity generated from biogas, and little electricity is exported to the grid. Therefore, anaerobic digestion projects identified in this stage of the analysis are based upon the utilization of anaerobic digestion systems operated in association with CAFOs. These projects are discussed in this section.

5.3.1 General Methodology

Potential anaerobic digestion projects were selected based on the concentration of livestock operations within an area. The focus was on identification of larger projects (>1 MW), that could export significant quantities of power. A spreadsheet of CAFOs in Arizona provided by APS was used to identify single CAFOs with sufficient animal

populations to sustain a project and geographic areas with multiple CAFOs from which significant animal wastes could be aggregated and utilized to sustain a project. The populations of dairy cattle, swine and egg-laying chickens were reviewed to identify potential projects. The populations of beef cattle and chicken broilers were not considered for anaerobic digestion projects because these wastes are more suited for combustion projects due to their drier composition. Based on the livestock estimates provided in the CAFO spreadsheet, a total of four anaerobic digestion projects were identified in the counties of Maricopa, Navajo and Pinal.

5.3.2 Major Assumptions

The following assumptions were made in the evaluation of anaerobic digestion potential.

- It was assumed that each head of livestock could sustainably support electrical generation capacity ranging from 1.0 to 100.0 kW. This value depended upon the type of livestock, as shown in Table 5-8. These values are considered conservative.
- To simplify system design and operation, projects were identified and defined such that each project would process only one type of animal waste.
- Permitting is assumed to require 12 months and construction is assumed to require an additional 12 months.

Table 5-8. Per Head System Capacity for Anaerobic Digestion Processes.

Livestock Type	System Capacity (Watts per Head)
Dairy cattle	100.0
Swine	28.0
Chicken (layers)	1.0
Sheep	7.0

5.3.3 Future Cost and Performance Projections

Anaerobic digestion systems are relatively mature technologies. No changes in future cost or performance were assumed other an adjustments to account for inflation.

5.3.4 Data Sources

Data sources used in this analysis included:

- Spreadsheet of Concentrated Animal Feeding Operations (CAFO) in Arizona, provided by Thomas Ramey of APS on November 30, 2006

5.3.5 Projects Identified

Four anaerobic digestion projects were identified:

- A 3.5 MW swine manure digestion project located in Snowflake
- A 2.5 MW dairy cattle manure digestion project located in Buckeye
- A 1.5 MW dairy cattle manure digestion project located in Chandler
- A 2.4 MW poultry waste digestion project located in Maricopa

The swine manure project is proposed at Pigs for Farmer John (PFFJ) in Snowflake. The swine population of PFFJ is estimated to be 120,000 head, which could support approximately 3.5 MW of electrical generation. Assuming a capacity factor of 80 percent, this project could generate 25 GWh per year of electricity. It is assumed that this project would be located on the site of the hog operation, which will eliminate the cost of transporting manure to another location. It should be noted that Arizona voters in 2006 passed a proposition that will force this plant to change its animal management practices in the next few years. Local plant management has noted that plant closure is an option being considered. For this reason, there is some uncertainty regarding the viability of a renewable energy project at this site.

Two dairy manure projects are proposed in Maricopa County. The first project would be located in Buckeye and would produce 2.5 MW of electricity. Assuming a capacity factor of 80 percent, this facility would generate approximately 18 GWh per year of electricity. There are 29 dairy operations in Buckeye according to the CAFO spreadsheet, and the total size of the dairy population from these 29 operations is roughly 26,000 head. This population could support the entire 2.5 MW of generation proposed. However, there are also 14 dairy operations in Tolleson with over 15,000 head of cattle and additional operations in the vicinity to supplement the dairy manure resource.

The second dairy manure project would be located in Chandler and would produce 1.5 MW of electricity. Assuming a capacity factor of 80 percent, this facility would generate approximately 11 GWh per year of electricity. There are 17 dairy operations in Chandler, with another 10 operations in nearby Gilbert and Higley. The combined cattle population of these 27 operations is over 30,000 head, which is more than sufficient to provide the manure resources to provide 1.5 MW of capacity.

The chicken manure project would be located at Hickman's Egg Ranch in Maricopa. The size of the Hickman operation is estimated at 2,400,000 chickens, and this population could support 2.4 MW of electrical generation. Assuming a capacity factor of 80 percent, this project could generate roughly 17 GWh per year of electricity. Because this project is supplied by manure from one location (similar to the swine

manure project), the transportation cost of the manure will be significantly reduced, if not eliminated.

Given a notice to proceed of January 1, 2008, all of the proposed anaerobic digestion projects would likely be operational by January 1, 2010. The costs for the anaerobic digestion projects range from $70/MWh to $140/MWh (in 2010), largely dependent on project scale.

Table 5-9 shows the anaerobic digestion projects identified for this study. All characteristics are year 2007 values, before any future cost and performance modifications have been made. Figure 5-2 in the previous section shows the supply curve for anaerobic digestion gas generation potential (landfill gas projects are also shown). For the purposes of visualizing the projects on the supply curve, it has been assumed that all projects could be built in 2007. Appendix A shows a consolidated list of projects; Appendix B shows the same list with forecast levelized costs for each project from 2007 to 2025.

Table 5-9. Anaerobic Digestion Project Characteristics.

Project	Capacity, MW	CF, %	Genera-tion, GWh	First Year Available	Capital Cost, $/kW	Fixed O&M, $/kW-yr	Var. O&M, $/MWh	Fuel Cost, $/MBtu	Nearest Utility	Transmission Line		
										Voltage, kV	Dist. to TL, miles	Owner
Snowflake Digester (Swine)	3.50	80%	25	2010	2,000	0.00	20.00	$0.00	APS	34.5	0	N/A
Buckeye Digester (Dairy)	2.50	80%	18	2010	3,000	0.00	20.00	$1.50	SRP	34.5	0	N/A
Chandler Digester (Dairy)	1.50	80%	11	2010	3,500	0.00	20.00	$1.50	SRP	34.5	0	N/A
Maricopa Digester (Poultry)	2.40	80%	17	2010	3,000	0.00	20.00	$0.00	SRP	34.5	0	N/A

5.4 Solar Thermal Electric

The various solar thermal electric technologies were discussed in detail in Section 4. One solar thermal electric technology, parabolic trough, is currently proven commercially, with over 350 MW operating in the Mohave Desert since about 1990, and with multiple plants of 50 MW or larger being constructed in the US and in Spain. This section will primarily focus on trough plants. Parabolic dish engine systems, for which there are power purchase agreements in California for hundreds of MWs, are unproven, but are treated as a special sensitivity case. Power tower and compact linear Fresnel reflector (CLFR) technologies hold potential, but are not included in this section because of uncertainty in cost and performance.

5.4.1 General Methodology

The potential for solar thermal was characterized in a different manner than other technologies. Whereas technologies such as biomass and geothermal are largely limited by resource availability, solar resources in Arizona are much larger than the potential near-term demand. Rather than being limited by resource, the technology is practically limited by equipment availability, development timelines, and ultimately economics. These factors were taken into account when forecasting potential solar thermal development.

The first parabolic trough plant was assumed to be a 100 MW facility with no thermal storage, but with hybrid fossil capability, which would go on line in 2011. Hybrid fossil capability means that the plant would have the ability to burn natural gas to generate electricity when the solar resource is unavailable.[11] This design is identical to the operating solar trough plants in California. The size is consistent with first trough plants in planning. Subsequent plants would be 200 MW with levels of thermal storage as discussed later in this section.

Broad siting regions were identified rather than specific sites. A map of Arizona direct normal insolation overlaid with terrain constraints was obtained from the National Renewable Energy Laboratory (see Figure 4-19 in the previous chapter). This map was used to identify broad areas of interest. It should be noted that Arizona has vast areas which could be suitable for solar thermal electric plants. Generally, solar resource is quite high throughout the state, with terrain, transmission, and water availability being key constraints. For this study, terrain was considered via the NREL maps. It has been

[11] In California, natural gas may be used for up to 25 percent of the facility output, without impacting the eligibility of the facility for renewable energy designation. For the purposes of this study, although the

assumed that projects would be sited such that water for wet cooling would be available. Should water not be available, dry cooling would substantially lower water requirements, but would result in performance decreases and capital cost increases that would generally raise the cost of energy by about 10 percent.

Performance estimates have been based on Black & Veatch's use of the NREL Excelergy model for Phoenix. Output was adjusted for direct normal insolation (DNI) estimates and latitude of the subject site. Excelergy estimates trough output on an hourly basis, estimating through collector field and power block thermal flows through the system, leading to net electrical output. Excelergy, which was developed by NREL, has been checked versus SEGS plant operation by NREL.

Phoenix output was modeled using Typical Meteorological Year (TMY2) data for Phoenix, along with the Phoenix latitude and longitude. Annual output for other sites was based on a comparison of satellite DNI for 0.1 degree latitude, 0.1 degree longitude pixels (about 5.7 miles east-west and 6.9 miles north-south in Arizona), and adjustment for latitude (trough output decreases with increase in latitude).

5.4.2 Major Assumptions

Solar thermal development will be constrained in the near term due to the practical limitations of the industry's supply chain. Demand for solar thermal equipment and supporting engineering and construction services is at an unprecedented level worldwide. Due to these constraints, it has been assumed that the first 100 MW trough plant in Arizona could not be completed until 2011. Beginning in 2013, plants will be 200 MW to take advantage of economy of scale of larger plants. It is assumed that the near term supply chain constraints in the industry will be alleviated by 2013, and two to four 200 MW plants could be constructed per year thereafter.

Solar thermal plants need large amounts of contiguous land for a project. A 200 MW plant can require up to 1,400 acres. Securing such parcels of land with ideal terrain and transmission characteristics is sometimes difficult. As an example of the total amount of land that might be necessary for a large-scale solar expansion, Black & Veatch's base case forecast estimates 2100 MW of solar trough development. Assuming a density of 7 acres/MW, this results in a need for 14,700 acres (23 square miles) of total land. By comparison, Phoenix proper covers an area of about 500 square miles.

The land used for solar thermal plants would likely be a mix of Arizona state land and BLM land. There is a bill currently proposed in congress designating "solar park" land for several GW of solar plants in the Southwest, with a lease fee of $200/acre/year.

facility is assumed capable of burning natural gas to provide a firm resource, no generation from gas was assumed.

This may ease permitting requirements on federal lands. The Arizona land office is currently contemplating streamlined permitting requirements for solar parks. Private land is also an option, but it may be more expensive and more difficult to aggregate large contiguous parcels.

Unlike most other technologies evaluated for this study, it is expected that significant technical and cost advances will be realized for solar thermal trough plants. The initial plant available to be built in 2011 would be based on existing technology. This plant will have no thermal storage, but will have hybrid fossil capabilities. Plants built through 2016 will use current heat transfer fluid (HTF) technology: synthetic oil such as Therminol VP-1 or Dowtherm A. Beginning in 2017, plants are expected to use molten salt as the HTF to take advantage of higher temperatures, higher efficiencies, and cost savings. Moving to molten salt as the HTF will require technology and engineering advances. Such advances are consistent with industry projections.

Energy storage capability would be incorporated into plants beginning in 2013. Plants built in 2013 are assumed to have 3 hours of thermal storage. These plants would also have an increased solar multiple (larger solar field thermal output to turbine thermal input ratio), and thus larger mirror field, to accommodate longer operating hours using thermal storage. These plants would use synthetic oil as the HTF, with molten salt as the storage medium. This will require an oil-to-molten salt heat exchanger. Plants starting in 2014 are assumed to have 6 hours of thermal storage, increasing the operating hours and allowing increased dispatchability.

The following additional assumptions have been made in characterizing projects:

- Projects would be sited in areas with access to sufficient cooling water for wet cooling.
- Projects would be sited near existing transmission (a 230 kV substation with a 1 mile interconnect is assumed for all projects).
- Transmission constraints or the need for new transmission development have not been considered (similar to the remainder of the study).

5.4.3 Future Cost and Performance Projections

Future cost and performance projections are shown in Table 5-10 for four prospective sites. (Note that costs are in constant 2007$). The sites are discussed further in Section 5.4.5. Cost projections show the following trends, which can be somewhat off-setting.

- Cost per kW increases with the addition of storage and increase of solar multiple.
- Cost per kW decreases with capacity increase from 100 MW to 200 MW.

- Costs decrease with time for the following reason.
- Increased deployment results in lower costs associated with perceived risk, with more efficient construction means.
- Increased competition by suppliers.
- More locally based manufacturing, and in particular, mirrors and receiver tubes decreasing shipping costs, import fees, and exchange rate issues.
- Improved technology, increasing efficiency and decreasing required mirror area.

Cost decreases have been estimated from data in Excelergy, the Western Governors Association report, the Sargent & Lundy report, and the Black & Veatch NREL report referenced in the next section.

Future performance projections include modest improvements with technology. These estimates were based on Excelergy model projections.

Table 5-10. Solar Thermal Electric Project Characteristics (Constant 2007$).

COD Year	MW	HTF*	Hrs Storage	$/kW	O&M $/kW-year	Land Area Acres	Water Usage Acre-ft/year**	Capacity Factors (%)			
								Stoval	Yuma	Phoenix	Tucson
2011	100	VP-1	0	4,200	55	570	610	29.8	29.3	27.3	28.7
2012	200	VP-1	3	4,000	50	1,300	1,450	35.1	34.5	32.2	33.8
2013	200	VP-1	3	4,000	50	1,300	1,450	35.1	34.5	32.2	33.8
2014	200	VP-1	6	4,500	48	1,500	1,740	42.3	41.6	38.8	40.7
2015	200	VP-1	6	4,500	48	1,500	1,740	42.3	41.6	38.8	40.7
2016	200	VP-1	6	4,500	48	1,500	1,740	42.3	41.6	38.8	40.7
2017	200	MS	6	4,500	45	1,450	1,740	42.3	41.6	38.8	40.7
2018	200	MS	6	4,200	45	1,450	1,780	43.3	42.6	39.7	41.7
2019	200	MS	6	4,200	45	1,450	1,780	43.3	42.6	39.7	41.7
2020	200	MS	6	4,200	45	1,450	1,780	43.3	42.6	39.7	41.7
2021	200	MS	6	3,700	45	1,450	1,820	44.3	43.6	40.6	42.7
2022	200	MS	6	3,700	45	1,450	1,820	44.3	43.6	40.6	42.7
2023	200	MS	6	3,700	45	1,450	1,820	44.3	43.6	40.6	42.7
2024	200	MS	6	3,700	45	1,450	1,820	44.3	43.6	40.6	42.7
2025	200	MS	6	3,700	45	1,450	1,820	44.3	43.6	40.6	42.7

* VP-1 is a silicone oil. MS is molten salt.

**Water usage based on Stoval site. All plants assumed to use wet cooling.

5.4.4 Data Sources

Cost data for the trough evaluation are based on several sources:

- Black & Veatch Engineer, Procure, Construct bid price developed for confidential client, 2006.
- *Preferred Plant Size,* Bruce Kelly, Nexant, draft prepared for National Renewable Energy Laboratory, 2005-2006
- *Economic, Energy, and Environmental Benefits of Concentrating Solar Power in California*, NREL/SR-550-39291, Black & Veatch, Prepared for National Renewable Energy Laboratory, April 2006.
- *Assessment of Parabolic Trough and Power Tower Solar Technology Cost and Performance Forecasts,* Sargent & Lundy Consulting Group, Prepared for Department of Energy and National Renewable Energy Laboratory (NREL), May 2003.
- *Excelergy,* Parabolic Trough Spreadsheet Model, developed by NREL.
- *"Solar Task Force Report,"* Western Governor's Association, January 2006.
- Southwestern US DNI Satellite Data, spreadsheet obtained from NREL.
- Arizona DNI Map Overlaid with 1 Percent Slope, NREL website.

It should be noted that parabolic trough system costs are considerably higher than shown in many of the referenced documents. Costs of commodities, such as steel and copper, have risen significantly in the last two years. Furthermore, many of the trough components are manufactured in Europe, resulting in cost increases as the dollar has weakened compared to the euro.

5.4.5 Projects Identified

Specific site locations were not identified at this stage of analysis. Generic projects have been identified for four areas in Arizona:

- Stoval
- Yuma
- Phoenix
- Tucson

Characteristics for these plants are shown in Table 5-11.

The Stoval area, about 80 miles southwest of Phoenix along Interstate 8, has the highest DNI of the potential sites (7.4 kwh/m^2/day – per satellite data), with potential areas of low land slope. Because of the improved performance, it has been assumed that

initial project deployment would occur at Stoval. A key issue with this area is that a large portion of the land in the region is within the Barry M. Goldwater Air Force Range.

The Yuma site would be southeast of Yuma in the Yuma Desert. The Yuma area has a high satellite DNI of 7.3 kwh/m^2/day. Like the Stoval area, the Yuma area could be subject to constraints because of the Barry M. Goldwater Air Force Range.

The Phoenix area would generally be west of Phoenix because of terrain constraints. The area has a satellite DNI of 6.8 kwh/m^2/day. The Phoenix TMY2 DNI is 6.9 kWh/m^2/day.

The Tucson area could include areas such as the Avra Valley to the west of Tucson and the Sulphur Springs Valley to the east. The area has a satellite DNI of 7.2 kwh/m^2/day.

Figure 5-3 shows the supply curve for solar thermal trough projects. The supply curve is relatively flat with the lowest cost projects generating power for about $160/MWh (hypothetical 2007 project, includes 30 percent investment tax credit). This cost is substantially higher than non-solar resources profiled in this study. The potential supply of solar thermal potential is vast, and exceeds what is shown on the chart. For the purposes of visualizing the projects on the supply curve, it has been assumed that all projects could be built in 2007.

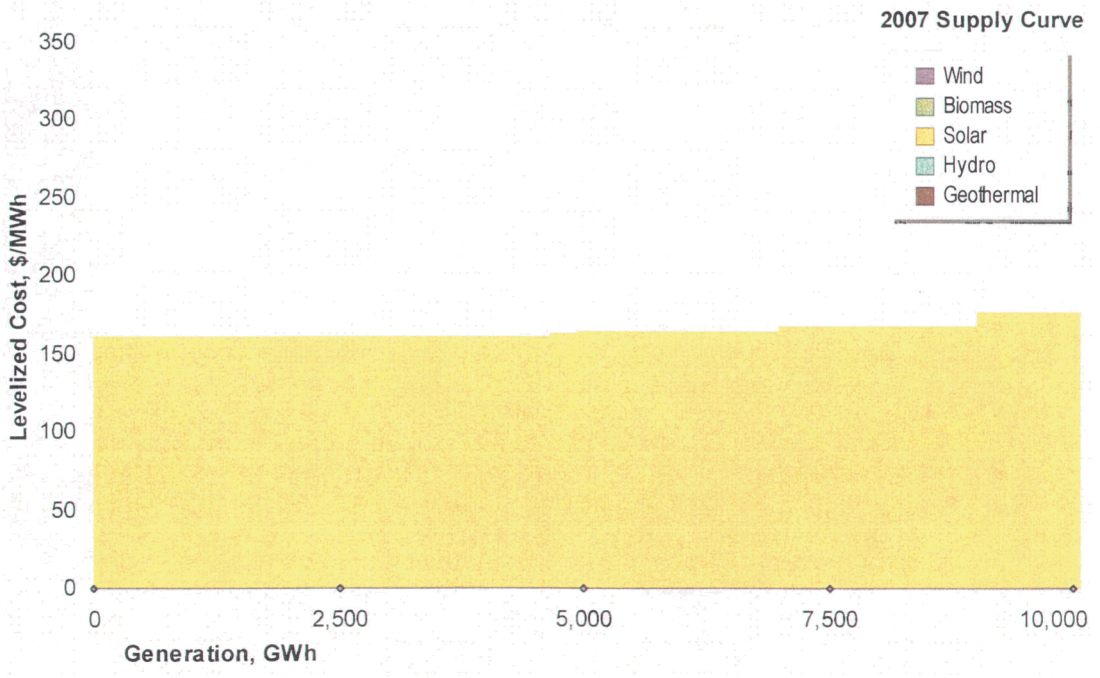


Figure 5-3. Levelized Cost Supply Curve for Solar Thermal Electric (Trough) Projects.

5.4.6 Parabolic Dish Engine Assumptions

At the present time, there are no operating commercial dish engine power plants. There are, however, hundreds of megawatts of proposed projects which, if implemented successfully, would substantially advance the technology. For this reason, dish engine technology was not included in the base renewable energy development model (Section 7), but was included as a special sensitivity run. Stirling Engine Systems (SES), the principal dish engine developer in the United States, projects that the cost of dishes will decrease dramatically with hundreds of MWs of central station, grid connected deployment.

Cost and performance data (Table 5-11) for the dish engine systems were provided by SES, and represent a projection by SES of costs for 100 MW block system. Black & Veatch is unaware of any current independent cost estimates for parabolic dish Stirling systems. The estimate assumes significant deployment of dish systems, resulting in substantially lower capital costs than exist at present. The estimate also assumes that with the large deployment there are appropriate gains in system reliability.

The 100 MW system would comprise 4,000 x 25 kW dishes. The system would provide electricity in a sun-following mode, i.e., it would generate electricity when DNI is available and would not generate electricity at night or during cloud cover. The assumed capacity factor for dish systems at higher DNI sites in Arizona is 27.4 percent. Capacity factor will vary slightly depending on the site; however, this has not been included in the model.

Engineering, permitting, and other indirect costs are lower for dish engine plants than for parabolic trough plants. Trough plants require significant site-specific engineering compared to the far more modular dish systems.

Table 5-11. Solar Thermal Electric Project Characteristics.

Project	Capacity, MW	CF, %	Genera-tion, GWh	First Year Available	Capital Cost, $/kW	Fixed O&M, $/kW-yr	Var. O&M, $/MWh	Fuel Cost, $/MBtu	Nearest Utility	Transmission Line		
										Voltage, kV	Dist. to TL, miles	Owner
Stoval Trough 1	100	30%	261	2011	4,200	55	–	–	APS	230	1	APS
Stoval Trough 2	200	30%	522	2013	4,200	55	–	–	APS	230	1	APS
Stoval Trough 3	200	30%	522	2013	4,200	55	–	–	APS	230	1	APS
Stoval Trough 4	200	30%	522	2014	4,200	55	–	–	APS	230	1	APS
Stoval Trough 5	200	30%	522	2014	4,200	55	–	–	APS	230	1	APS
Stoval Trough 6	200	30%	522	2015	4,200	55	–	–	APS	230	1	APS
Stoval Trough 7	200	30%	522	2015	4,200	55	–	–	APS	230	1	APS
Stoval Trough 8	200	30%	522	2016	4,200	55	–	–	APS	230	1	APS
Stoval Trough 9	200	30%	522	2016	4,200	55	–	–	APS	230	1	APS
Stoval Trough 10	200	30%	522	2016	4,200	55	–	–	APS	230	1	APS
Phoenix Trough 1	200	27%	478	2019	4,200	55	–	–	APS	230	1	APS
Phoenix Trough 2	200	27%	478	2019	4,200	55	–	–	APS	230	1	APS
Phoenix Trough 3	200	27%	478	2019	4,200	55	–	–	APS	230	1	APS
Phoenix Trough 4	200	27%	478	2019	4,200	55	–	–	APS	230	1	APS
Tucson Trough 1	200	29%	503	2018	4,200	55	–	–	TEP	230	1	Local
Tucson Trough 2	200	29%	503	2018	4,200	55	–	–	TEP	230	1	Local
Tucson Trough 3	200	29%	503	2018	4,200	55	–	–	TEP	230	1	Local
Tucson Trough 4	200	29%	503	2018	4,200	55	–	–	TEP	230	1	Local
Yuma Trough 1	200	29%	513	2017	4,200	55	–	–	APS	230	1	APS
Yuma Trough 2	200	29%	513	2017	4,200	55	–	–	APS	230	1	APS
Yuma Trough 3	200	29%	513	2017	4,200	55	–	–	APS	230	1	APS
Yuma Trough 4	200	29%	513	2017	4,200	55	–	–	APS	230	1	APS
Solar Dish 1	100	27.4%	240	2011	3,300	23	25	–	N/A	230	1	N/A
Solar Dish 2	100	27.4%	240	2012	3,300	23	25	–	N/A	230	1	N/A
Solar Dish 3	100	27.4%	240	2013	3,300	23	25	–	N/A	230	1	N/A
Solar Dish 4	200	27.4%	480	2014	3,300	23	25	–	N/A	230	1	N/A
Solar Dish 5	200	27.4%	480	2015	3,300	23	25	–	N/A	230	1	N/A
Solar Dish 6	200	27.4%	480	2016	3,300	23	25	–	N/A	230	1	N/A
Solar Dish 7	400	27.4%	960	2017	3,300	23	25	–	N/A	230	1	N/A
Solar Dish 8	400	27.4%	960	2018	3,300	23	25	–	N/A	230	1	N/A
Solar Dish 9	400	27.4%	960	2019	3,300	23	25	–	N/A	230	1	N/A
Solar Dish 10	400	27.4%	960	2020	3,300	23	25	–	N/A	230	1	N/A
Solar Dish 11	400	27.4%	960	2020	3,300	23	25	–	N/A	230	1	N/A

Table 5-11. Solar Thermal Electric Project Characteristics.

Project	Capacity, MW	CF, %	Genera-tion, GWh	First Year Available	Capital Cost, $/kW	Fixed O&M, $/kW-yr	Var. O&M, $/MWh	Fuel Cost, $/MBtu	Nearest Utility	Transmission Line		
										Voltage, kV	Dist. to TL, miles	Owner
Solar Dish 12	400	27.4%	960	2021	3,300	23	25	–	N/A	230	1	N/A
Solar Dish 13	400	27.4%	960	2021	3,300	23	25	–	N/A	230	1	N/A

Future capital cost projections for solar dish plants assume significant cost reductions obtained due to large and sustained manufacturing economies of scale. For the purposes of this study, Black & Veatch has assumed that 50 percent of SES's forecasted improvement will actually be realized. Figure 5-4 compares the relative capital cost forecasts for different solar technologies examined in this study. Photovoltaic (PV) and concentrating photovoltaic (CPV) are included for comparison (PV assumptions are detailed in the next section). It can be seen that both dish and CPV technologies assumed dramatic improvements in project capital cost. A comparison of all-in levelized costs for different solar technologies over time is given in Section 7.

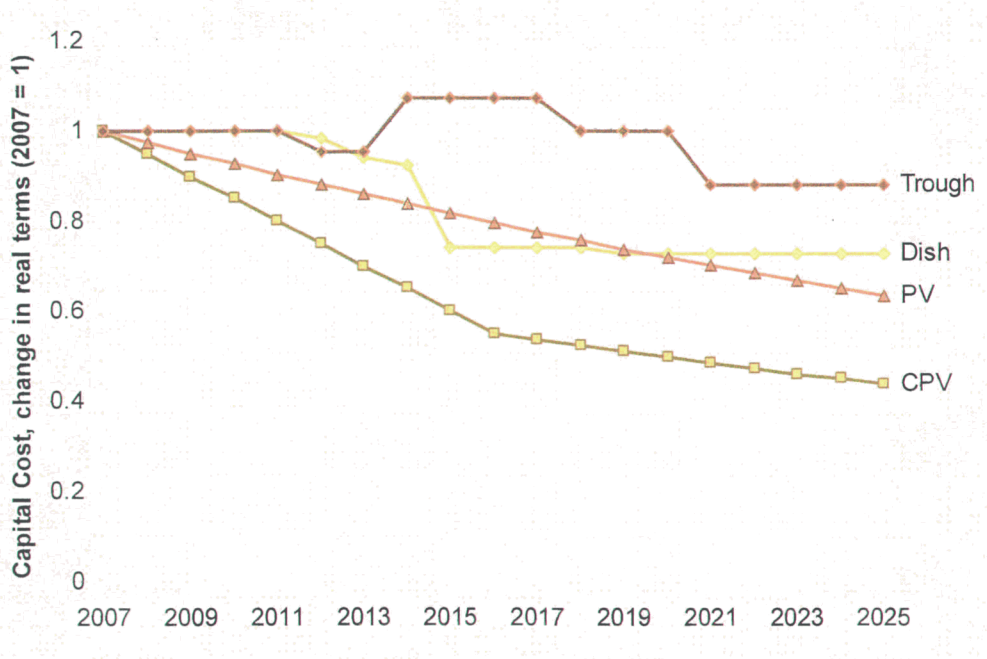


Figure 5-4. Relative Capital Cost for Forecasts for Different Solar Technologies.

5.5 Solar Photovoltaic

Solar photovoltaics (PV) and concentrating photovoltaics (CPV) were identified as promising technologies in the first stage of the analysis. The solar resource in Arizona is very large, but both of these technologies have high capital costs and intermittent generation. The focus for both of these technologies was on utility scale projects, not on distributed residential or commercial PV.

5.5.1 General Methodology

As discussed in the previous section, solar is a special case because the resource is generally available anywhere in the state; the constraints in solar are mainly capital costs and equipment availability. PV and CPV use little water, and projects were assumed to be in the 5-10 MW range, requiring 50-100 acres of land and minimal transmission capacity. Resource, transmission and land were assumed to be available for PV and CPV development. The approach was to make assumptions about future capital costs and the equipment available for utility scale projects.

5.5.2 Major Assumptions

The following assumptions were made in the evaluation of solar photovoltaic potential.

- Siting for PV or CPV projects is not a major constraint, due to modest land requirements and low environmental impact.
- PV projects will be up to 10 MW in any given location through 2015, allowing interconnection to distribution networks or low voltage transmission. We would expect larger plants after that time if economics are viable.

5.5.3 Future Cost and Performance Projections

Black & Veatch feels traditional flat plate for utility scale will see modest cost reduction in the near term. Utility scale PV has limited economies of scale, and module costs make up a large portion of total capital costs. Current capital costs for utility scale PV in the US are around $6,000/kWp, and there is little room for future improvement in non-module costs such as inverters and wiring. While there are promising developments in thin-film PV and non-silicon materials, these modules may be better suited for the distributed PV market. Most current utility scale PV projects are using traditional silicon materials due to concerns about degradation and the life of thin-film modules. Black & Veatch assumed that PV costs would remain flat in nominal dollars for the indefinite future. This translates to a 2.5 percent annual decrease in real dollars.

Concentrating PV was seen as more promising for cost reductions in utility applications. Concentrating PV uses far less silicon than traditional PV, and high efficiency chips are more cost-effective in CPV applications. Spectrolab, a Boeing subsidiary and a leader in high performance triple-junction solar cells, recently crossed the 40 percent efficiency barrier. Concentrating PV is still an immature industry, which makes cost reductions more likely. Mass production of lenses and tracking components could bring costs down over the next decade. There are a number of companies addressing concentrating PV, including Amonix, Sharp, Sol Focus, Green Volts, and

others. Many of these companies have been recently funded by venture capital and are currently developing products.

Black & Veatch assumed capital costs for CPV would decrease in real dollars by approximately 5 percent annually, maturing in 2016 at 55 percent of current costs (a 5 MW CPV plant would drop from $7,200/kWp to $3,960/kWp in 2016). Capacity factors would remain unchanged.

Figure 5-4 in the previous section compares the relative capital cost forecasts for different solar technologies examined in this study. A comparison of all-in levelized costs for different solar technologies over time is given in Section 7.

5.5.4 Data Sources

Data sources used in this analysis included:

- Black & Veatch Independent Engineering report for utility scale PV and CPV plant, confidential client, March 2007.
- Western Governor's Association, Clean and Diversified Energy Initiative, "Solar Task Force Report" January 2006. Available at http://www.westgov.org/wga/initiatives/cdeac/solar.htm
- Maycock, Paul. "PV Market Update" Renewable Energy World, July-August 2005
- Navigant Consulting, "Arizona Solar Electric Roadmap Study" prepared for the Arizona Department of Commerce, January 2007. Available at http://www.azcommerce.com/doclib/energy/az_solar_electric_roadmap_study_full_report.pdf
- Wiser, Ryan et al "Letting the Sun Shine on Solar Costs: An Empirical Investigation of Photovoltaic Cost Trends in California" LBNL January 2006. Available at http://eetd.lbl.gov/EA/EMP
- "The US Photovoltaic Industry Roadmap," Available at http://www.sandia.gov/pv/docs/PVRMPV_Road_Map.htm Western Governor's Association, Clean and Diversified Energy Initiative, "Solar Task Force Report" January 2006. Available at http://www.westgov.org/wga/initiatives/cdeac/solar.htm

5.5.5 Projects Identified

Most flat plate PV is sensitive to temperature and insolation, which varies capacity factors across the state. PV, especially crystalline silicon used in most utility scale PV projects, performs best in areas of low temperatures and high insolation, such as TEP's Springerville plant or APS's Prescott plant. For flat plate PV, Black & Veatch

assumed a typical 5 MWp plant, either a fixed installation (such as Springerville) or with single axis tracking (Prescott). Capital costs shown are $/kWp and do not include the federal 30 percent ITC. Capital costs are from current utility scale PV projects. Black & Veatch used PV simulation software to estimate the capacity factors for four locations in the state: Prescott, Tucson, Phoenix and Flagstaff. The software takes insolation and temperature into account to generate capacity factors.

While the main limits to PV are cost, there are also limitations in the global supply chain for PV modules. Black & Veatch assumed that 15 MW were available for utility scale projects in Arizona for 2008 and 2009, ramping up to 500 MW in 2010 and later. However, because of the high cost of solar photovoltaics, larger projects are not forecast to be built.

Concentrating PV is less sensitive to ambient temperature, as the solar modules are designed to withstand higher temperatures, and CPV systems typically include heat rejection. Concentrating PV has a higher capacity factor than flat plate PV due to increased cell efficiency and the use of dual-axis tracking. Concentrating PV, like solar thermal technologies, use direct normal insolation (DNI). The best locations for CPV are therefore similar to the locations for solar thermal. Black & Veatch did not specify individual sites for CPV, due to the small size of projects and the lack of resource and transmission constraints.

Because of the immaturity of the industry, there are limitations to the amount of concentrating PV systems that can be installed in any given year. CPV is also capital intensive – 100 MW of CPV represents a $500 million investment. In addition, PV industry is a global industry and other markets (Germany, Japan, California) will place demands on the global supply. Black & Veatch assumed the following ramp up of the industry

- 1 MW of CPV could be installed in 2008
- A single 5 MW CPV plant could be installed in 2009
- Two 5 MW CPV plants (10 MW total) could be installed in 2010
- Two 10 MW CPV plants (20 MW total) could be installed in 2011
- Four 10 MW CPV plants (20 MW total) could be installed in 2012
- Ten 10 MW CPV plants (100 MW total) could be installed in 2013-2015

Figure 5-5 shows the supply curve for PV projects. The curve does not include CPV projects, but they are considered in Section 8.

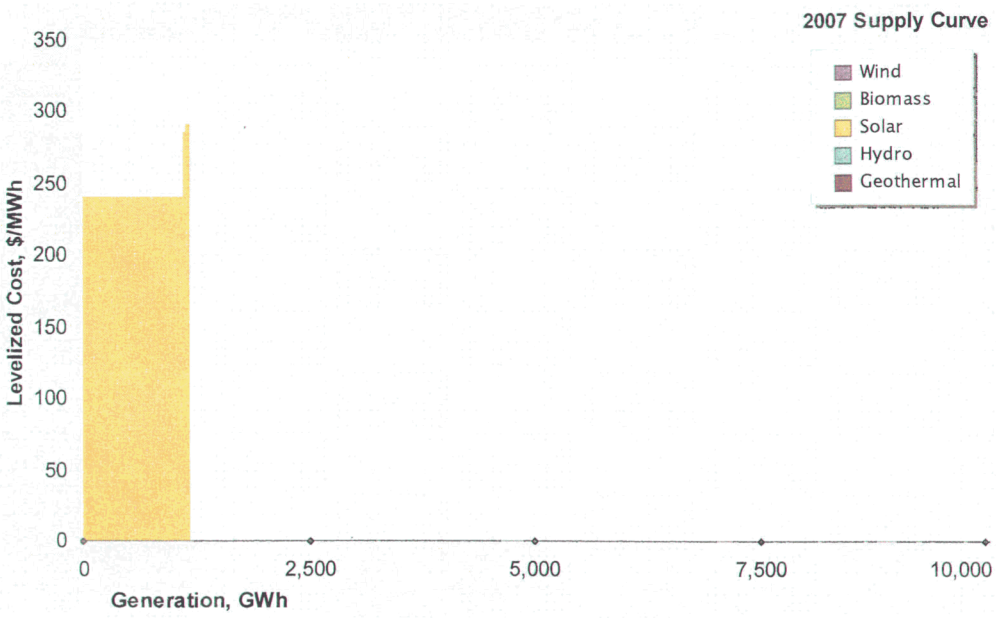


Figure 5-5. Levelized Cost Supply Curve for PV Projects.

Table 5-12 shows the solar photovoltaic projects identified for this study. These projects are largely generic without specific sites identified. All characteristics are year 2007 values, before any future cost and performance modifications have been made. Appendix A shows a consolidated list of projects; Appendix B shows the same list with forecast levelized costs for each project from 2007 to 2025.

Table 5-12. Solar Photovoltaic Project Characteristics.

Project	Capacity, MW	CF, %	Genera-tion, GWh	First Year Available	Capital Cost, $/kW	Fixed O&M, $/kW-yr	Var. O&M, $/MWh	Fuel Cost, $/MBtu	Nearest Utility	Transmission Line		
										Voltage, kV	Dist. to TL, miles	Owner
CPV 1	1.00	29.0%	3	2008	7,600	100	–	0	N/A	35	0	N/A
CPV 2	5.00	29.0%	13	2009	7,200	60	–	0	N/A	35	0	N/A
CPV 3	5.00	29.0%	13	2010	7,200	60	–	0	N/A	35	0	N/A
CPV 4	5.00	29.0%	13	2010	7,200	60	–	0	N/A	35	0	N/A
CPV 5	10.00	29.0%	25	2011	6,800	50	–	0	N/A	35	0	N/A
CPV 6	10.00	29.0%	25	2011	6,800	50	–	0	N/A	35	0	N/A
CPV 7	10.00	29.0%	25	2012	6,800	50	–	0	N/A	35	0	N/A
CPV 8	10.00	29.0%	25	2012	6,800	50	–	0	N/A	35	0	N/A
CPV 9	10.00	29.0%	25	2012	6,800	50	–	0	N/A	35	0	N/A
CPV 10	10.00	29.0%	25	2012	6,800	50	–	0	N/A	35	0	N/A
CPV 11	10.00	29.0%	25	2013	6,800	50	–	0	N/A	35	0	N/A
CPV 12	10.00	29.0%	25	2013	6,800	50	–	0	N/A	35	0	N/A
CPV 13	10.00	29.0%	25	2013	6,800	50	–	0	N/A	35	0	N/A
CPV 14	10.00	29.0%	25	2013	6,800	50	–	0	N/A	35	0	N/A
CPV 15	10.00	29.0%	25	2013	6,800	50	–	0	N/A	35	0	N/A
CPV 16	10.00	29.0%	25	2013	6,800	50	–	0	N/A	35	0	N/A
CPV 17	10.00	29.0%	25	2013	6,800	50	–	0	N/A	35	0	N/A
CPV 18	10.00	29.0%	25	2013	6,800	50	–	0	N/A	35	0	N/A
CPV 19	10.00	29.0%	25	2013	6,800	50	–	0	N/A	35	0	N/A
CPV 20	10.00	29.0%	25	2013	6,800	50	–	0	N/A	35	0	N/A
CPV 21	10.00	29.0%	25	2014	6,800	50	–	0	N/A	35	0	N/A
CPV 22	10.00	29.0%	25	2014	6,800	50	–	0	N/A	35	0	N/A
CPV 23	10.00	29.0%	25	2014	6,800	50	–	0	N/A	35	0	N/A
CPV 24	10.00	29.0%	25	2014	6,800	50	–	0	N/A	35	0	N/A
CPV 25	10.00	29.0%	25	2014	6,800	50	–	0	N/A	35	0	N/A
CPV 26	10.00	29.0%	25	2014	6,800	50	–	0	N/A	35	0	N/A
CPV 27	10.00	29.0%	25	2014	6,800	50	–	0	N/A	35	0	N/A
CPV 28	10.00	29.0%	25	2014	6,800	50	–	0	N/A	35	0	N/A
CPV 29	10.00	29.0%	25	2014	6,800	50	–	0	N/A	35	0	N/A
CPV 30	10.00	29.0%	25	2014	6,800	50	–	0	N/A	35	0	N/A
Tucson Fixed PV 1	5.00	21.2%	9	2008	5,200	30	–	0	TEP	35	0	TEP
Phoenix Fixed PV 1	10.00	20.1%	18	2008	5,200	30	–	0	APS	35	0	APS
Tucson Fixed PV 2	5.00	21.2%	9	2009	5,200	30	–	0	TEP	35	0	TEP

Table 5-12. Solar Photovoltaic Project Characteristics.

Project	Capacity, MW	CF, %	Genera-tion, GWh	First Year Available	Capital Cost, $/kW	Fixed O&M, $/kW-yr	Var. O&M, $/MWh	Fuel Cost, $/MBtu	Nearest Utility	Transmission Line		
										Voltage, kV	Dist. to TL, miles	Owner
Phoenix Fixed PV 2	10.00	20.1%	18	2009	5,200	30	–	0	APS	35	0	APS
Tucson Fixed PV tracked (overall AZ)	500.00	26.9%	1,178	2010	6,000	30	–	0	TEP	35	0	TEP

5.6 Hydroelectric

Black & Veatch reviewed hydroelectric options that included power production options from man-made water flows, improvements at existing facilities, new sites and pumped storage for load management. This assessment is based on projects previously identified as promising in the Interim Report (Section 4). Seven projects were identified for further investigation

5.6.1 General Methodology

Black & Veatch identified seven hydroelectric projects for characterization and an additional seven pumped storage projects. The overall number of projects were limited to these based on water resource availability and environmental concerns.

5.6.2 Major Assumptions

There are a variety of methods to estimate performance of proposed hydroelectric projects. One useful method of estimating plant performance is to review generation records. Except for the Glen Canyon project, power generation records for the existing hydroelectric facilities were not available for review for this study. Flow duration curves can also be used to estimate performance; however, these were not available either. For this study 40 percent capacity factor was assumed for the smaller hydroelectric projects. This percentage was based on Black & Veatch experience with projects of these characteristics. Forty-five percent was assumed for Glen Canyon dam which is classified as medium hydroelectric project. Without specific site layouts it is impossible to determine a site specific capacity factor. Therefore the capacity factors in the model are estimates only.

A nationwide database of hydroelectric construction cost information per kW of capacity is available from the Department of Energy. In 2003, the nationwide average to develop a hydroelectric project ranged from about $500-6,000/kW, with a median about $2,700/kW for an undeveloped site, and $700/kW for upgrade projects at sites with existing generation. As would be expected, specific costs decrease with plant size and previous development of the site. Most of the selected projects fit within this range.

Like wind and solar, capital costs for hydroelectric projects make up most of the overall costs since the "fuel" is "free" once the required infrastructure is in place. For hydroelectric projects, much of the cost is often off-site from the power plant in the diversion structures, penstock, and their associated access roads. The variability in project site requirements leads to broad ranges of potential costs. For this reason, it is

difficult to develop generic estimates of project costs without detailed site studies, and past detailed estimates, despite their age, are preferred.

Project O&M costs are estimated based on percent of construction cost and staff allocation. O&M costs are expected to be higher for upgrade plants because, though some of the equipment would be new, the diversion and conveyance structures may still require a greater level of maintenance than a new project.

Hydroelectric projects are expected to take longer to develop than other renewable energy projects. Except for Glen Canyon, all the projects identified in this report assume installation by 2013. The Glen Canyon addition is assumed to not be complete until 2015.

5.6.3 Future Cost and Performance Projections

Hydroelectric power generation and hydroelectric pumped storage are largely mature technologies. No changes in future cost or performance were assumed other than adjustments to account for inflation.

5.6.4 Data Sources

Data sources used in this analysis included:

- U.S. Hydropower Resource Assessment for Arizona, Rinehart, Ben, Conner, Alison and Francfort, James, October 1997, Idaho National Engineering and Environmental Laboratory, and Renewable Energy Products Department, Lockheed Martin Idaho Technologies Company, http://hydropower.inel.gov/resourceassessment/pdfs/states/az.pdf.
- Telephone conversations with Doug Hall, Program Manager for INL Hydropower Program.
- Contacts with individual site owners, as possible.

5.6.5 Projects Identified

This section provides descriptions of seven hydroelectric projects identified previously in Section 4. These projects have been previously identified and studied by the Idaho National Laboratory (INL), previously INEEL, the Idaho National Engineering and Environmental Laboratory. Six of the seven project sites are located in the southern portion of the state and have a relatively small capacity in comparison to the total capacity of hydroelectric in the state.

Using the INL database as a starting point, this study included a further detailed search of public records on the internet, contacting the reported owners of each of the projects, and contacting Doug Hall who is the current program manager for the INL

hydroelectric program. After several discussions via telephone and email correspondence with Mr. Hall it was discovered that INL had limited or no information available for the exact project locations and site layouts of the identified projects for the study. This was confirmed by Mr. Hall after his staff performed a brief search for the Arizona hydroelectric information INL had on the initial study performed. Because of this, some assumptions were made to identify approximate project locations using aerial maps provided by Google Earth.

After contacting the project site owners it appeared the owners were very interested and willing to assist in providing data for this study. However, because the INL report lacked detailed location information, data was not readily available to take this study beyond a desktop level study and therefore site visits are recommended to pinpoint and identify specifics on these projects.

Table 5-13 below, gives a summary of the identified projects. The projects are described further in this section.

Table 5-13. Potential Hydroelectric Projects for Arizona.

No.	Project Name	Location	Head Available (ft)	Flow (cfs)	Assumed Type of Project
1	Beardsley	Not Known	77	47	New site with single generator
2	Yuma	Not Known	32	476	New or Existing site with single generator
3	Waddell	New Waddell Dam	264	600	Existing site with single generator
4	CAP Canal	Not Known	150	57	New site with single generator
5	Roosevelt	Not Known	Not Known	Not Known	New site with single generator
6	Tucson	Southern Tucson	92	Not Known	New site with single generator
7	Glen Canyon	Glen Canyon Dam	583	15,000 max	Existing site with new generator(s)

Beardsley Canal Drop

Information provided by INL and public records do not give the precise location or details of the Beardsley canal drop project. The estimated Beardsley Canal project site is located approximately 26 miles from Phoenix, Arizona with overhead power owned by Arizona Public Service available along the presumed project location. The average flowrate in the canal is estimated at 47 cubic feet per second (cfs) with a hydraulic head of 77 feet (ft). Since the information provided on the location of this project can not reasonably pinpoint the project site location it is unclear how to take advantage of the 77 ft of hydraulic head. A local drop in the canal might make it attractive as an open flume, however the hydraulics of this situation with the energy extraction at the powerhouse, would create a sizeable tailwater pool. Further study would be necessary to locate a local drop.

Yuma Main Canal

The locations from the INL database do not clearly identify the location or details of the Yuma Main Canal project. Coordinates listed by INL show the location near the canal. The estimated Yuma Main Canal project site is located approximately 140 miles from Phoenix, with overhead power owned by the Department of Energy available along the presumed project location. Hydraulic head for this site is 32 ft and the flow rate for this site is estimated at 476 cfs. The flow rate is quite large for a canal indicating that a location at the end of a canal run is questionable. Further research uncovered an existing siphon-drop power plant located along the Yuma Main Canal located near Yuma, Arizona. The new power plant began operation in 1987, replacing an earlier power plant located 500 ft downstream that ended operation in 1972. Further study would be necessary to identify this project as a new site or simply an upgrade to the existing power plant.

Waddell

The locations from the INL database do not clearly identify the location or details of the Waddell project. Coordinates listed by INL show the location near the New Waddell Dam. New Waddell Dam is located approximately 30 miles from Phoenix and is located at the New Lake Pleasant Reservoir. The U.S. States Department of the Interior website listed New Waddell Dam as not currently having power generation at the site. However further research uncovered an existing hydroelectric facility in operation. The outlet works capacity is listed at 600 cfs and has a hydraulic head of approximately 264 ft. It is assumed that this project would consist of adding a generator at the existing power plant at New Waddell Dam.

CAP Canal Turnout

Information provided by INL does not give the precise location or details of the CAP Canal Turnout project. The estimated site of the CAP Canal Turnout project is located approximately 26 miles from Phoenix, with overhead power owned by the Arizona Public Service available near the presumed project location. The average flow rate in the canal is estimated at 57 cfs with a hydraulic head of 150 ft. The information provided on the location of this project can not reasonably pin point the project site location. In order to take advantage of the 150 ft of head available a drop in the canal might make it attractive as an open flume, however the hydraulics of this situation, with the energy extraction at the powerhouse, would create a sizeable tailwater pool. Further study would be necessary to locate a local drop this project.

Roosevelt

Information provided by INL does not give specifics on the precise location or details of the Roosevelt project. The estimated site for the Roosevelt project is located approximately 20 miles from Phoenix with overhead power owned by the Salt River Project available near the presumed project location. No hydraulic head or flow information was available for this site. The information provided on the location of this project can not reasonably pin point the project site. The canal appears to traverse down relatively steep terrain which makes a site located at the end of this canal foreseeable. Further study would be necessary to verify this project location.

Tucson

The Tucson hydroelectric site is located at a CAP pressure breakdown station at Technical Way and Palo Verde in southern Tucson. It is operated by Tucson Water. The site was analyzed by TEP in 2000 to produce power at a levelized cost of $0.105 per kWh. The site has available overhead power, owned by TEP. Head was calculated at about 92 feet, varying with upstream reservoir elevation. Flow was estimated to sustain 400 kW of generation at a 99 percent capacity factor due to the reliable flow of water.

Glen Canyon

Glen Canyon Dam is located approximately 250 miles from Phoenix. The dam forms Lake Powell Reservoir and is part of the Colorado River Storage Project. The United States Department of the Interior website listed Glen Canyon Dam's discharge as not exceeding 15,000 cfs with a hydraulic head of 583 ft.

Glen Canyon Dam provides more storage capacity than all other storage features of the Colorado River Storage Project combined. The power plant at the toe of the dam

consists of four 118,750 kW and four 136,562 kW generators driven by eight turbines. Total generating capacity for the power plant is 1,021,248 kW. Eight penstocks through the dam convey water to the turbines. The project would consist of adding an additional 71.8 MW generator at the power plant, however drought conditions have lowered Lake Powel considerably the past few years and there is now question as to the long term sustainable rate of electrical production possible at this site. This project is by far the largest of all projects profiled.

Based on past studies and upgrades, the 1995 environmental flow restrictions placed on Glen Canyon Dam, and environmental concerns, Black & Veatch and Jane Blaire of the Bureau of Reclamation believe that the 71.8 MW identified by INL is an upgrade to existing machines. However, no mention of a 71.8 MW upgrade was found by the Bureau or INL to verify this assumption.

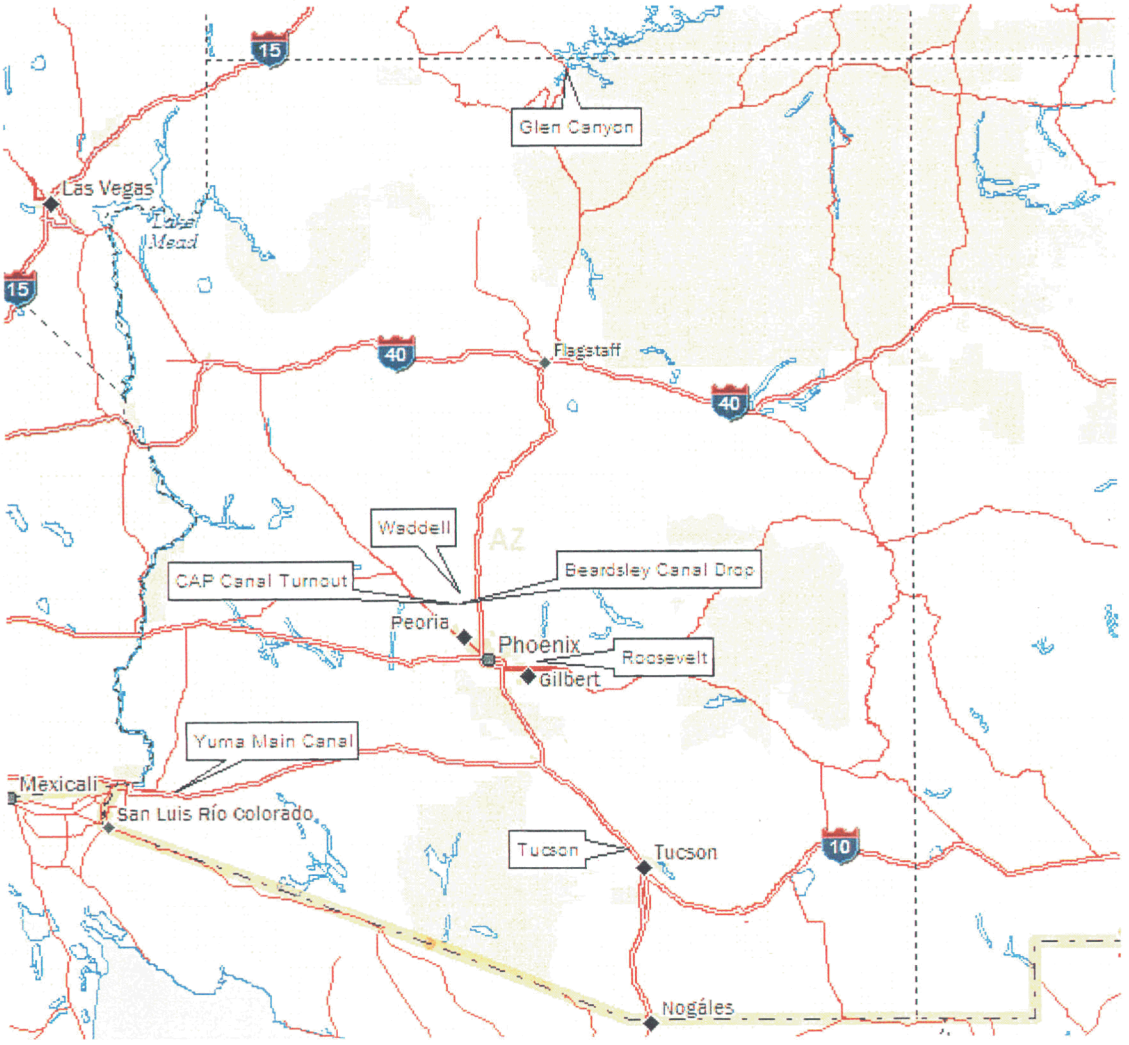


Figure 5-6. Potential Hydroelectric Locations in Arizona.

Table 5-14 shows the hydroelectric projects identified for this study. All characteristics are year 2007 values, before any future cost and performance modifications have been made. Figure 5-7 shows the supply curve for potential hydroelectric projects in Arizona. For the purposes of visualizing the projects on the supply curve, it has been assumed that all projects could be built in 2007. Appendix A shows a consolidated list of projects; Appendix B shows the same list with forecast levelized costs for each project from 2007 to 2025.

The total combined capacity of the seven projects identified is 85.7 MW, with an energy generation potential of 330 GWh/yr. The Glen Canyon project makes up about 85 percent of this total. Of the seven projects, Glen Canyon and Waddell are the only projects that could be reasonably identified. These sites have the most head and flow available compared to other sites. They also have existing hydroelectric installed and therefore show the most potential for further study. The Glen Canyon project is the lowest cost project of all the renewable energy projects surveyed for this study. It is forecast to cost about $50/MWh in 2015. The other hydroelectric projects are all projected to be much more expensive, at costs over $150/MWh in 2013, the first year they are projected to be available.

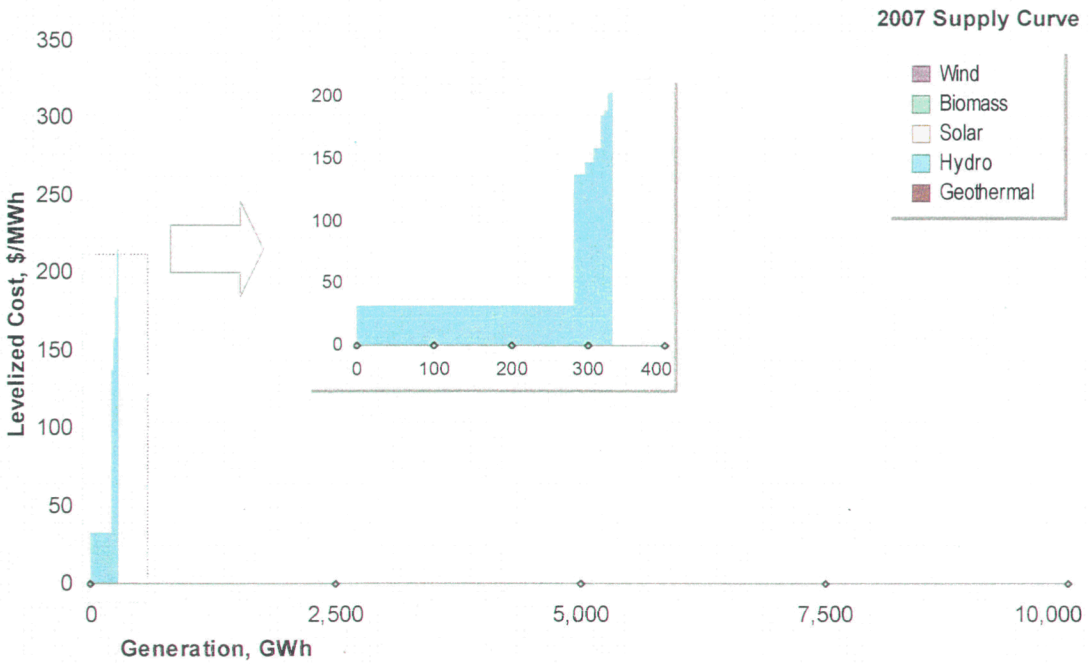


Figure 5-7. Levelized Cost Supply Curve for Hydroelectric Projects.

Table 5-14. Hydroelectric Project Characteristics.

Project	Capacity, MW	CF, %	Genera-tion, GWh	First Year Available	Capital Cost, $/kW	Fixed O&M, $/kW-yr	Var. O&M, $/MWh	Fuel Cost, $/MBtu	Nearest Utility	Transmission Line*		
										Voltage, kV	Dist. to TL, miles	Owner
Beardsley Canal Drop	1.0	40%	3.5	2013	4,324	24	5.6	0	APS	N/A	N/A	N/A
Yuma Main Canal	1.4	40%	4.9	2013	4,079	22	5.2	0	APS	N/A	N/A	N/A
Waddell	1.5	40%	5.3	2013	4,037	21	5.2	0	APS	N/A	N/A	N/A
CAP Canal Turnout	2.5	40%	8.8	2013	3,718	19	4.7	0	APS	N/A	N/A	N/A
Roosevelt (RWCD)	3.2	40%	11.2	2013	3,579	18	4.4	0	SRP	N/A	N/A	N/A
Tucson	0.4	99%	3.5	2013	3,429	17	4.2	0	TEP	N/A	N/A	N/A
Glen Canyon	71.8	45%	283.1	2015	997	8	2.4	0	APS	500	1	

Pumped Storage

The following provides and a brief introductory study and summary of two existing and five proposed pumped storage hydroelectric projects. As part of the preliminary study, pumped storage was not included. For this report existing pumped storage projects were researched using public records available on the internet. Some of the projects looked at had no identifiable locations and limited or no data readily available.

Pumped storage methods are typically used to provide power during peak demand periods. In a pumped storage facility, water is pumped during off-peak demand periods from a reservoir at a lower elevation for storage in a reservoir at a higher elevation. Electricity is then generated during peak demand periods by releasing the pumped water from the higher reservoir and allowing it to flow downhill through the hydraulic turbine(s) connected to generators. During the off-peak pumping cycle, the pumped storage facility is a consumer of electricity which can account for the lower capacity factor. Pumped storage facilities, however, can be economical because they consume low-cost off-peak electricity, but generate high-value on-peak electricity. As with hydroelectric plants, drought conditions can reduce the quantity of on-peak electricity pumped storage facilities can generate.

To date, only a few pumped storage facilities have been built and all are associated with existing dams. Pumped storage can easily be complimented by other renewable resources if available to increase off-peak efficiency. For this study pumped storage was included and was assumed to have a capacity factor of 33 percent.

Table 5-15 lists a summary and descriptions of existing and proposed pumped storage projects in Arizona:

Table 5-15. Potential Pumped Storage Development in Arizona.

Plant Name	Owner	Location	Capacity (MW)
Montezuma	Not Known	25 miles South of Phoenix	500
Starhills	Arizona Independent Power, Inc.	20 miles West of Phoenix	Not Known
Ford Canyon	Arizona Independent Power, Inc.	30 miles North-West of Phoenix	1,250
Azipco	Arizona Independent Power, Inc.	30 miles North-West of Phoenix	1,250
Spring Canyon	Not Known	225 miles North-West of Phoenix	2,000
Horse Mesa	Bureau of Reclamation	45 miles North-East of Phoenix	Not Known
Mormon Flat	Bureau of Reclamation	40 miles North-East of Phoenix	Not Known
Total (Known)			**5,000**

Source: ASCE Compendium of Pumped Storage Plants in the United States, & Web Search

Montezuma Pumped Storage Project

The Montezuma project is to be located approximately twenty-five miles south of the city of Phoenix. It appears that this project may be located at an existing water plant. No other information on permit status was available for this study.

Starhills Pumped Storage Project

Arizona Independent Power, Inc. has filed an application with the commission for this proposed project that would be located on lands administered by the Bureau of Indian Affairs on the Gila River Indian Reservation, in Pinal County, Arizona. The permit was issued in November 2002 and Arizona Independent Power, Inc. has since requested that its preliminary permit be terminated.

Ford Canyon Pumped Storage Project

Arizona Independent Power, Inc. filed an application in February 1997 for this project which would be located in White Tank Mountain Regional Park, in Maricopa County, Arizona. The project will utilize water from the Colorado River System and have an annual generation of 1,250 MW.

Azipco Pumped Storage Project

This project was to be located on the Beardsley Canal, in Maricopa County. The proposed project would consist of a 350 foot high by 1700 foot long earth and rockfill upper dam. This proposed reservoir would have a surface area of 180 acres and a storage capacity of 13,000 acre-feet and have a normal water surface elevation of 3,000 feet with a proposed 200 foot high by 2600 foot long earth and rockfill lower dam. A proposed reservoir having a surface area of 150 acres and a storage capacity of 14,000 acre-feet with a normal water surface elevation of 1,800 feet would complete the lower portion of this project. The proposed powerhouse would consist of five generating units having a total capacity of 1,250 MW. The original permit was issued in February 2001. Arizona Independent Power, Inc. has requested that its preliminary permit be terminated.

Spring Canyon Pumped Storage

Spring Canyon Pumped Storage Project was to have been a 2,000 MW pumped storage project. This project never went beyond the planning phases. No other information was readily available for this study. This project may have been stopped due to its impacts on the environment. Further study would be necessary to confirm this assumption. No information on permit application could be found, however the application was most likely applied for in the mid to late 1980's.

Horse Mesa Dam and Reservoir

The Horse Mesa Dam and reservoir is located on the Salt River approximately 65 miles northeast of Phoenix. Horse Mesa Dam forms Apache reservoir.

One pumped storage hydroelectric unit was added in 1972 and rated at 97,000 kW. The pumped storage unit permits recycling of water for hydroelectric production and keep lake levels relatively constant. The turbine generating units at this dam produce power during periods of peak demands. The turbines are reversed to pump water during off peak periods from the lower reservoir back to the upper reservoir for repeated usage.

Mormon Flat Dam and Reservoir

Mormon Flat Dam is a 224-foot high concrete thin-arch structure and is located on the Salt River 51 miles northeast of Phoenix. Constructed by the Salt River Valley Water Users' Association from 1923-1926, it creates Canyon Lake reservoir.

The pumped storage unit was built in 1971 and is rated at 50,000 kW. The pumped storage unit permits recycling of water for hydroelectric production and keep lake levels relatively constant. The turbine generating units at this dam produce power

during periods of peak demands. The turbines are reversed to pump water during off peak periods from the lower reservoir back to the upper reservoir for repeated usage.

Pumped Storage Summary & Location Map

Of the potential capacity identified in Arizona to date, only two pumped storage facilities have been built and all are associated with existing dams. Pumped storage projects do not appear to be a viable alternative due to it low capacity factor, evaporation, environmental impacts. New pumped storage sites were not identified in this study however, and it is not recommended to consider new pumped storage sites. Due to environmental impacts and permitting issues, it is unlikely that a new pumped storage project would make it past the application process.

Figure 5-8, below identifies the pumped storage projects discussed in this report.

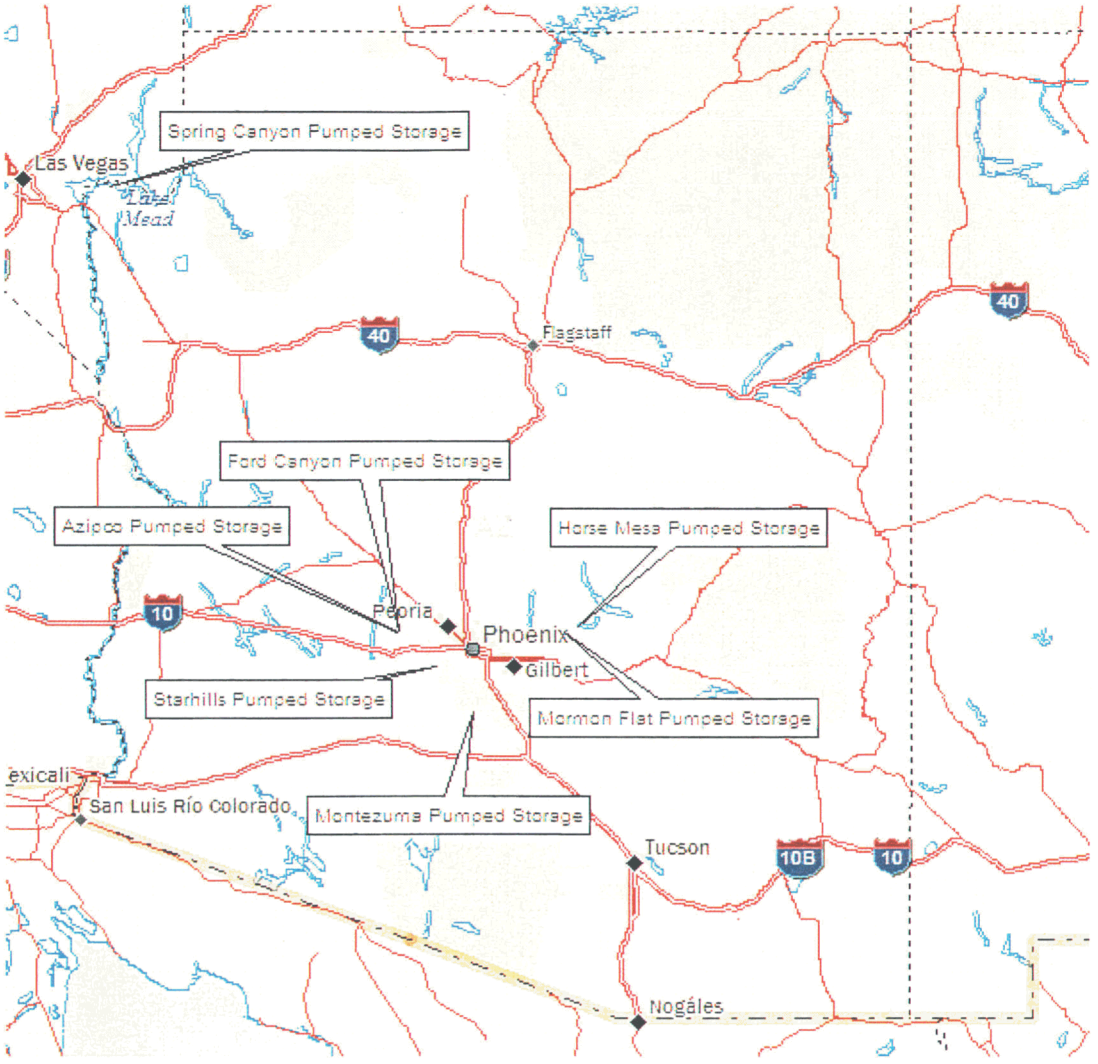


Figure 5-8. Potential Pumped Storage Locations in Arizona.

5.7 Wind Power

Wind power was identified as a promising technology in the first stage of the analysis. Most of Arizona wind resources are marginal, especially when compared to higher speed wind resources in adjacent states. The economics of wind energy in Arizona vary based on the resource, and the specific attributes of each site will dictate suitable turbine models. This section characterizes the resources suitable for wind technology and those turbines thought to be appropriate for use at the prospective sites.

5.7.1 General Methodology

Information was gathered on Arizona's estimated wind resource, geological characteristics, transmission infrastructure, environmental and federal land areas in order to identify specific areas conducive to the development of a utility scale wind energy project. Information was collected on current wind development activity in the state. Black & Veatch also spoke with several wind developers, Northern Arizona University, and a member of the Arizona Wind Working group.

An initial list of sites was created based upon the presence of significant land area of at least a class 3 wind resource (greater than 6.3 m/s annual wind speed), which is considered marginal, and specific terrain features that allow a project to be oriented perpendicular with the prevailing wind direction. Each of the sites on this list was then reviewed in light of the following characteristics:

- Close proximity to adequate transmission (greater than 69 kV)
- Not located within or close to federal or environmentally sensitive areas
- Constructability

Sites that were not located within 8 to 10 miles of transmission lines with voltages above 69 kV were eliminated from the list. In addition, sites were eliminated in areas with "fatal flaws" due to environmental or other reasons. Of the remaining sites, the next review criteria were based on the overall constructability and suitability of the site.

Each site's constructability was measured by the ability to both access the wind resource area and construct turbines on it. Sites that had numerous areas of high slope grades and access routes that presented insurmountable equipment delivery issues were eliminated from the list. For those sites deemed to be constructable, site boundaries where created around areas that could likely support the installation of numerous utility scale wind turbines, and had existing access roads or areas where access road construction would likely not be cost prohibitive.

An analysis was then performed for those sites remaining on the list to determine key cost and performance metrics. The following site specific parameters were calculated

for use in the supply curve model; other values pertaining to project costs were also input into the analysis and will be discussed separately in the sections below.

- Nameplate capacity (MW)
- Net Capacity Factor (%)
- Net Generation (GWh/yr)

The Gamesa G87 2 MW turbine was used in the supply curve analysis to provide an equal platform on which to compare each of the perspective projects. This turbine has an 87 meter rotor and is assumed to be installed on an 80 meter tower. Nameplate capacity, net generation and capacity factor inputs for the supply curve model are all based upon the specifications of this particular turbine. Other turbines were considered for the supply curve analysis; basis for the turbine selection and the results of the analysis will be discussed in the sections below.

Nameplate capacity was determined for each site by estimating how many G87's could be placed within the prospective wind class areas within each site. While the final spacing of turbines is dependent on many site specific characteristics, research has shown that energy deficits tend to decrease with increasing wind speed. Also, the amount of land available to install turbines will vary based on terrain features (i.e. flat pasture vs. mountain tops). As such, Black & Veatch implemented a general wind class specific "rule of thumb" where each subsequently higher wind class area is assigned a tighter spatial distribution for turbine placement and each area is assigned specific terrain multiplier to compensate for land availability issues at each site. These values for terrain and spacing are based upon approved industry standards and Black & Veatch's project experience.

Most of the wind sites in Arizona are at altitude, where lower air density reduces the energy density of the wind. Energy production estimates were made using manufacturer published annual production values as a function of annual wind speed, Weibull parameter and air density. In order to use these production tables, the annual average wind speed at each site was estimated using the AWS Truewind 70 meter wind speed map and then adjusted for elevation. Annual production was then identified and a 15 percent loss was applied to obtain net annual generation and capacity factor values for each site. The results of this analysis are presented in the following sections.

5.7.2 Major Assumptions

The following assumptions were made in the evaluation of wind power potential. Table 5-17 shows the wind class comparison assumptions used for the desktop analysis.

- Transmission constraints were not considered.
- All projects developed with the Gamesa G87 2 MW wind turbines, or similar
- Terrain multipliers are based on an overall desktop observation of slope grade
- Project distance is an approximate straight line distance from project site to location specified
- Capital costs are based on the following criteria presented in Table 5-16

Table 5-16. Cost Assumptions.

Capital Costs	$1,600 per kW, excluding substation and transmission costs[12]
Flat Terrain Multiplier	1.00; Less than 4% grade
Hills Terrain Multiplier	1.05; 4%-8% grade
Mtn Terrain Multiplier	1.15;10% grade or higher
Fixed O&M	$25/kW-yr
Variable O&M	$7-9/MWh

Table 5-17. Wind Class Comparison Assumptions by Wind Class

Parameter	Class 3		Class 4		Class 5		Class 6	
WTG Spacing; row: column *(rotor Dia.)*	3.4	11	3	10	2.6	9	2.2	7
Average Net Capacity Factor	23%		26%		32%		35%	

5.7.3 Turbine Selection

While the energy production estimates for the G87 were used as inputs for the supply curve model, energy production values for another Gamesa turbine, the G80, and two versions of the Vestas turbine, the V80, also were also calculated. The purpose of this comparison was to show the variance of energy production that can exist between similar turbine types.

Different wind turbines are designed to operate in a variety of wind resource areas and are classified as such. The wind turbine classes are essentially defined by the nature of the wind speeds and the characteristic turbulence intensity at 15 meters per second. Developers often specify one or more particular set of turbines for energy production

[12] Although the wind industry appears to be on solid footing, wind capital costs have increased substantially over the past five years due to a number of factors including the weakness of the dollar, rising materials costs, a concerted movement towards increased manufacturer profitability, and a shortage of components and turbines. This trend may continue for the next couple of years, but is expected to wane over the long term. It is expected that costs will moderate by 2010 when the first Arizona projects are expected. Section 8 analyzes the impact of higher costs.

estimates, but ultimately it is the manufacturer who will dictate what turbine can be used for a project. Due to the low anticipated wind speeds at these sites, an IEC Class II[13] machine would be preferential; however, the expected high turbulence intensities associated with these sites would likely warrant a special case Class II turbine to be used. It is Black & Veatch's experience from other projects that turbine vendors will require a Class I turbine (to reduce the stresses on the rotor, tower, gearbox, etc.) instead of a modifying a Class II.

The differences in the machines used in this analysis are related to how the manufacturer will modify the one design to satisfy the requirements for different wind turbine classes. The Gamesa G80 and G87 are essentially the same machines in that they use the same type of tower, same generator, etc. The only major difference between the two turbines is the size of rotor diameter; the G80 has an 80 meter rotor diameter and the G87 has an 87m rotor diameter. The Vestas approach is similar, in that the V80 class I turbine uses a different gear box than the V80 class II, which results in the different nominal rotor speed for each class.

Black & Veatch has provided estimates of the net capacity factors in the table below for each of the perspective project sites using the turbines mentioned above.

Table 5-18. Net Capacity Factors Per Wind Turbine Type.

Project Site Name	Wind Turbine Net Capacity Factor Data			
	G80; IEC I	G87; IEC II	V80; IEC I	V80; IEC II
Rattlesnake Crater 1	22.5%	25.6%	24.4%	23.6%
Rattlesnake Crater 2	26.3%	29.5%	28.5%	27.6%
Buckhorn	26.3%	29.5%	28.5%	27.6%
Buffalo Range	26.3%	29.5%	28.5%	27.6%
Chevelon 1	29.2%	32.5%	31.5%	30.6%
Chevelon 2	26.3%	29.5%	28.5%	27.6%
Chevelon 2	26.3%	29.5%	28.5%	27.6%
Chevelon 3	26.3%	29.5%	28.5%	27.6%
Greens Peak	26.3%	29.5%	28.5%	27.6%
Kingstone	24.0%	27.1%	26.0%	25.2%

The net capacity factors for turbines used in this analysis can change with a different project loss assumptions and site specific annual wind speed data and climate information. Overall, these turbines represent technology that has been well studied.

[13] IEC 61400-1 2005, classifies turbines by reference wind speed average over 10 minutes and expected mean characteristic turbulence intensity at 15 meters per second.

5.7.4 Future Cost and Performance Projections

Wind technology has improved measurable over the last few years. As part of work performed for the American Wind Energy Association, Black & Veatch analyzed monthly capacity factor data from over 5,000 MW of wind plants installed in the US Midwest for the years 2000 through 2005. The Midwest was chosen to ensure all the plants were in a similar wind regime. Capacity factors have shown enormous improvement, *averaging 15 percent improvement every two years*. This improvement is due to improved availability, increased hub heights and rotor diameters, as well as better siting. Average hub heights went from roughly 60 meters in 2000-2001 to 85 meters in 2005. Rotor diameters increased from 47 meters to 80 or 90 meters, doubling swept area.

Black & Veatch believes this improvement will continue, although at a slower pace. Capacity factors are forecast to increase another 20 percent from 2005 to 2030, based on higher hub heights, larger rotors, and advanced power electronics.

5.7.5 Data Sources

Data sources used in this analysis included:

- AWS TrueWind, Arizona Wind Maps
- Elliott, D.L, 1991, "Status of Wake and Array Loss Research", Pacific Northwest Laboratory, Richland, Washington
- "The Arizona Meteorological Network", available at: http://ag.arizona.edu/AZMET/.html, accessed: March, 2007
- "Geospatial Data and Metadata Statewide Coverages for Arizona BLM", available at: http://www.blm.gov/az/gis/files.htm, accessed: March, 2007
- Northern Arizona University, available at: http://wind.nau.edu/, accessed: March, 2007
- IEC 61400-1 2005, Wind Turbines – Part 1: Design requirement

5.7.6 Projects Identified

At the conclusion of the review, ten projects at six sites totaling 991 MW of wind energy remained from the original list. Black & Veatch estimates that the total production of these projects will annually yield 2,551 GWh, with an average project net capacity factor of 28.9 percent. The characteristics of these individual projects are provided in Table 5-19. Figure 5-9 shows the general locations of each of the identified project areas overlain on a wind speed map for Arizona. The following sections contain descriptions of each project. Each section contains a map which has the local wind speed map overlain on the site topography. Transmission lines are also indicated. Military training zones may impact the total developable amounts of wind generation and should be

reviewed in detail before project development. Additionally, the Arizona Fish and Game Department has recommended that a three year bird and bat study be performed prior to commencing a wind project in Arizona. Finally, while it is possible that other wind sites could be developed in Arizona, these sites are either further from transmission, have environmental restrictions, are in difficult to construct areas, or have weaker wind resources.

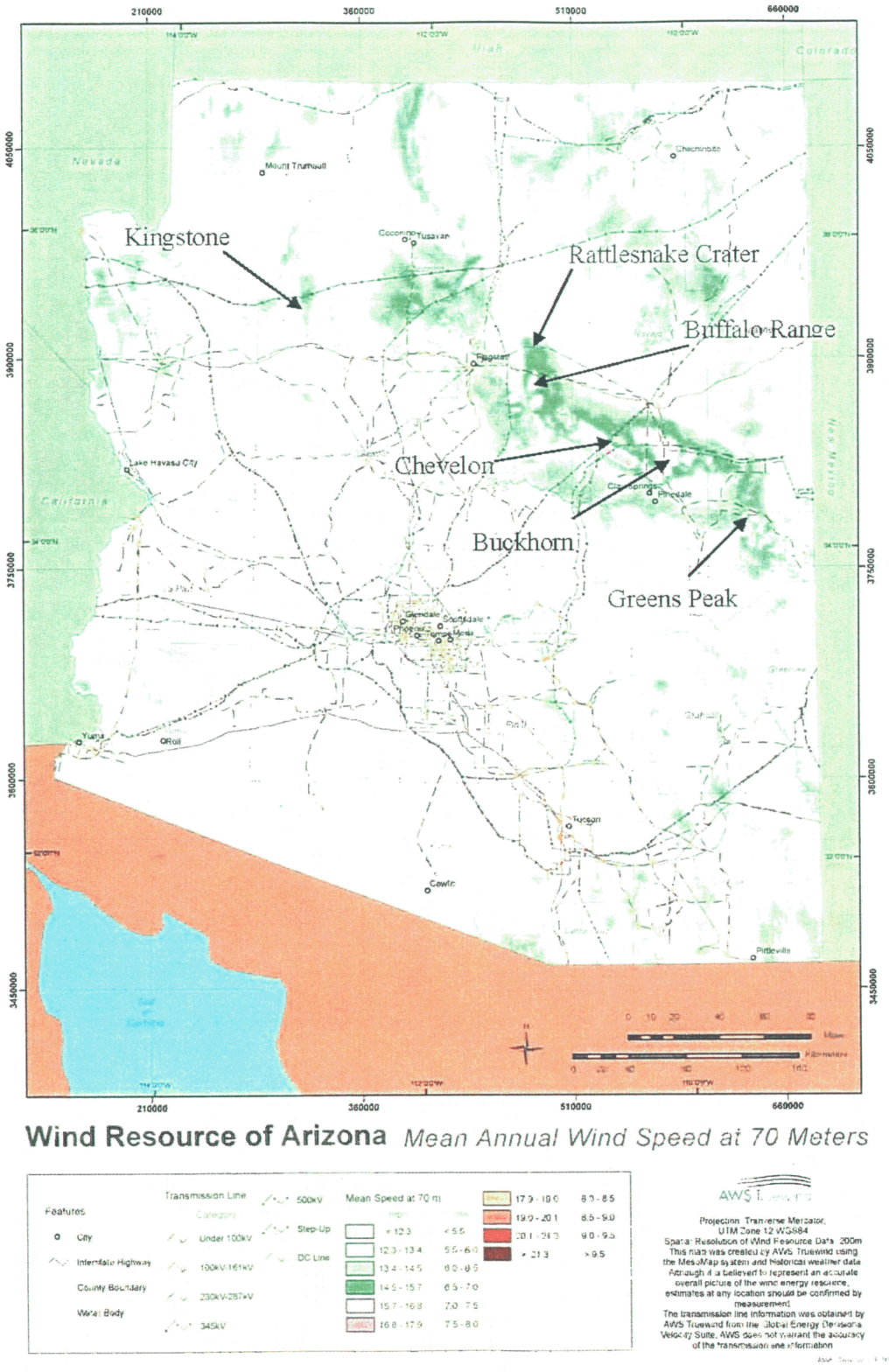


Figure 5-9. Arizona Wind Energy Project Site Areas (Wind Map: AWS Truewind).

Buckhorn Project Site

The Buckhorn project area is located on the north side of Route 277, approximately 8 miles west of Snowflake, AZ. This site area is primarily desert with rolling hills and a moderate decrease in elevation the northeast. This site maintains good exposure to the prevailing winds and sits within a class 4 and 5 wind resource. Several of the existing roads that appear to run through project site that would likely provide an easy means of access to many of the class 4 and 5 wind resource areas shown in light and dark pink in Figure 5-10. Two 69 kV transmission lines were identified to exist near the project site; however, the owners of these lines are not known. A 46 MW project sited at this location is estimated to have and annual average 70m wind speed of 7.3 meters per second, producing 139 GWh annually with a capacity factor of approximately 25.6 percent. Buckhorn is near the proposed PPM Energy Dry Lake project.

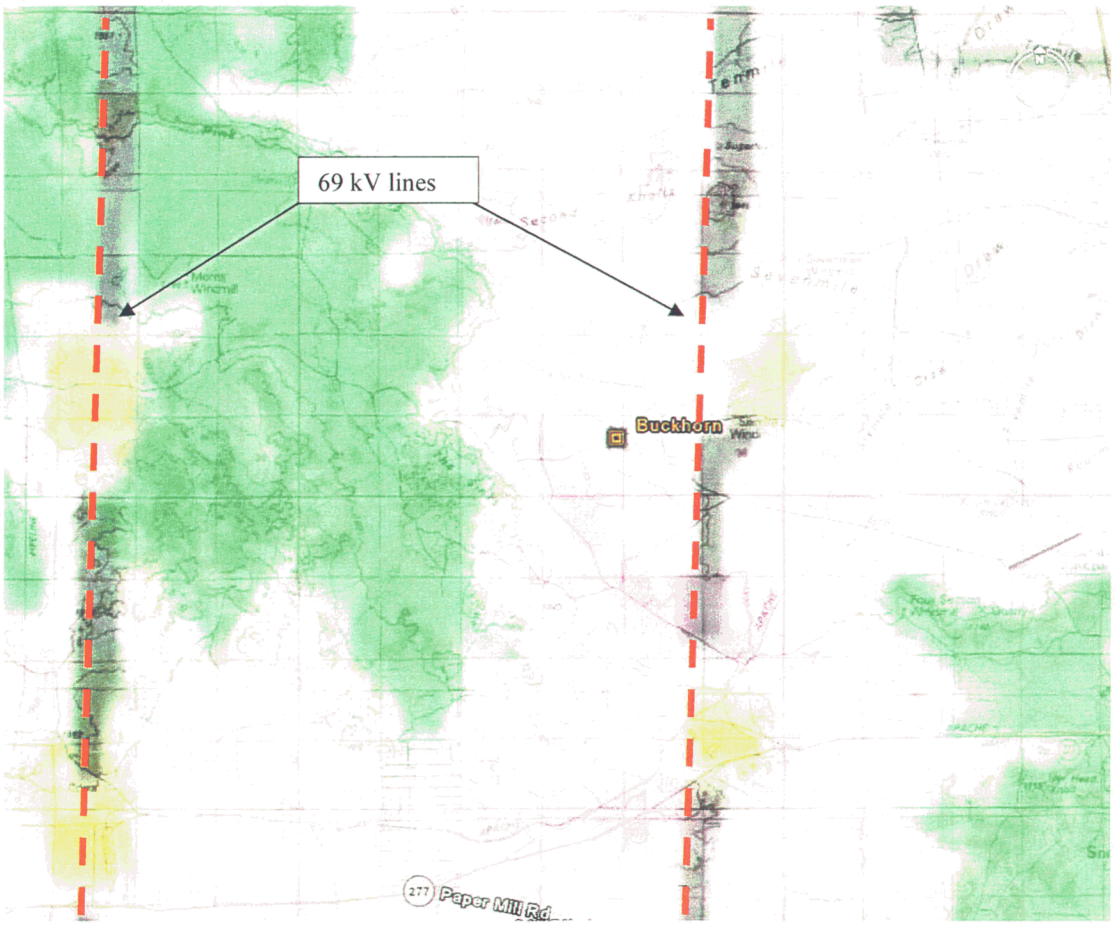


Figure 5-10. Buckhorn Project Area.

Buffalo Range Project Site

The Buffalo Range site area is located along the southern side of Interstate 40, twenty miles east of Flagstaff, AZ. The site is primarily made up of flat desert land providing many options for project size and layout. Existing roads that appear to run through project site would provide an easy means of access to many areas within the class 4 resources of this site shown as light pink areas in Figure 5-11. The site is located in close proximity to an APS 230 kV and a 69 kV transmission line. A 158 MW project sited at this location is estimated to have and annual average 70m wind speed of 7.3 meters per second, producing 409 GWh annually with a capacity factor of approximately 29.5 percent. Buffalo Range is on the other side of I-40 from the planned Foresight Energy Sunshine wind park.

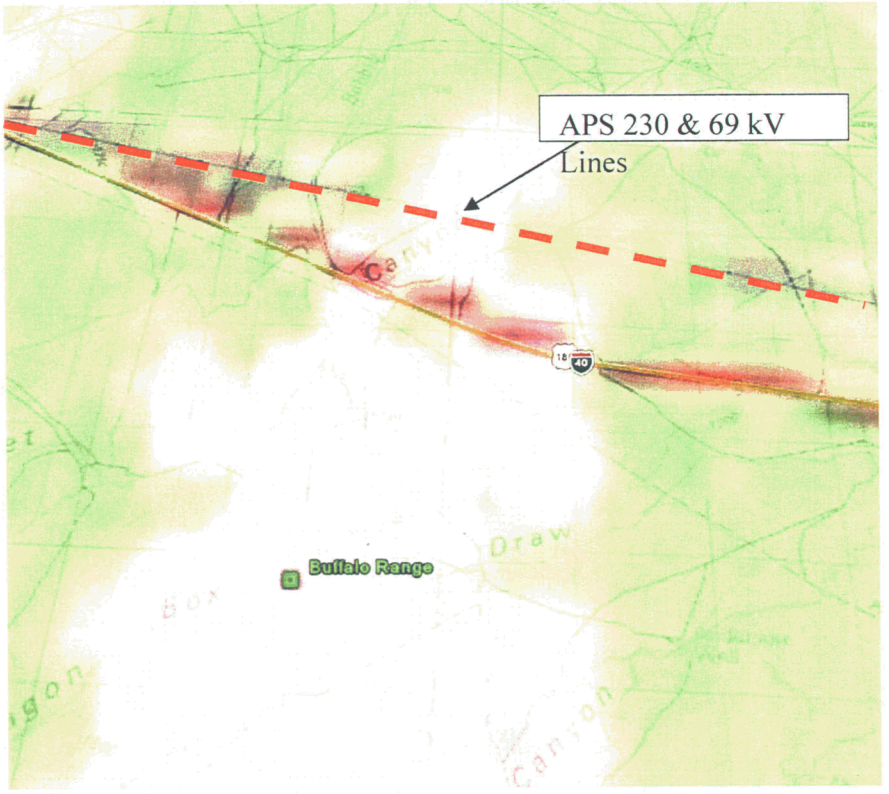


Figure 5-11. Buffalo Range Project Site.

Chevelon Project Sites

The Chevelon project area is located on the west side of highway 99, approximately 30 miles from Clay Springs, AZ. This vast site area consists primarily of wide open flat desert land with a moderate decrease in elevation the northeast. This site has little vegetation, maintains good exposure to the prevailing winds and sits within a class 4 and 5 wind resource. Several of the existing roads that appear to run through project site that would likely provide an easy means of access to many of the class 4 and 5 wind resource areas that are shown in light and dark pink in Figure 5-12. Two APS owned 500 kV transmission lines and one APS owned 345 kV line were identified that run directly through the project site. Due to the vast area of wind resource, this project area could support the build out of several large phases. Three 171 MW projects were sited at this location and estimated to have and annual average 70m wind speed of 7.3 meters per second, producing 442 GWh annually with a capacity factor of approximately 29.5 percent. One 84 MW project was also sited at this location and estimated to have and annual average 70m wind speed of 7.8 meters per second, producing 239 GWh annually with a capacity factor of approximately 32.5 percent.

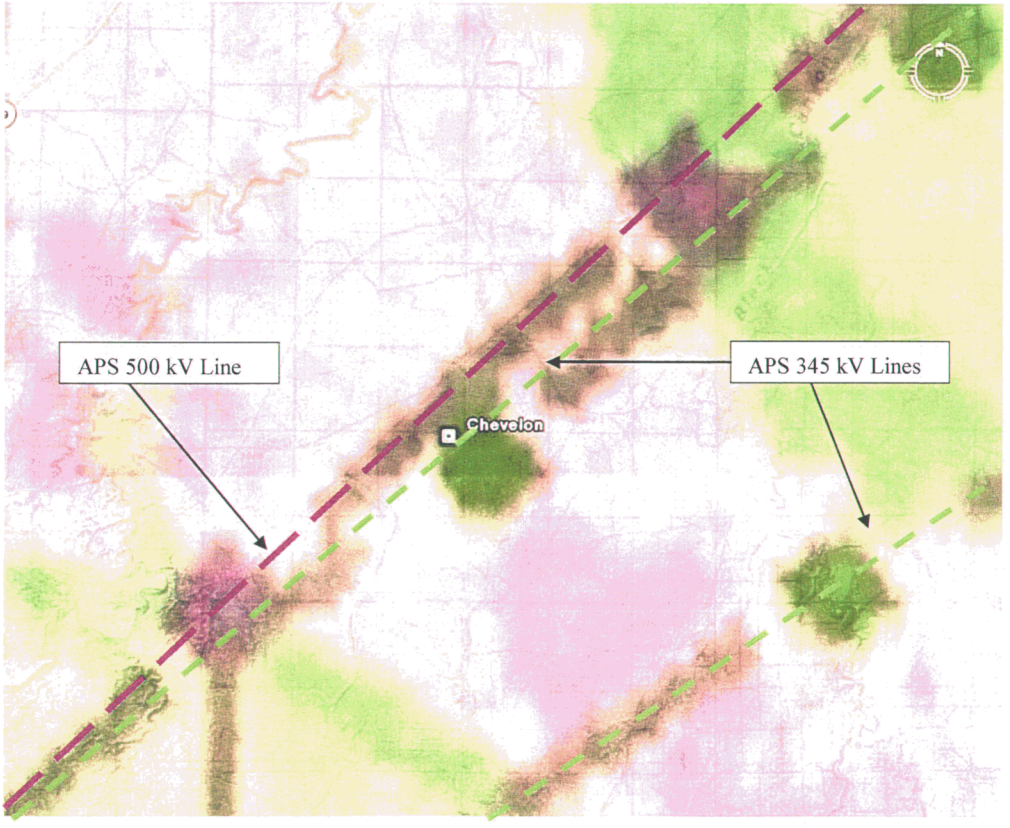


Figure 5-12. Chevelon Project Area.

Greens Peak Project Site

The Greens Peak project area is located on the north side of Highway 260, approximately 14 miles west of Springerville, AZ. While this site area is primarily desert with rolling hills, the landscape is covered with thick vegetation and a few areas of complex terrain features. Exposure of this site to prevailing winds appears to be somewhat restricted to specific areas; however, wind resource maps indicate that strong class 4 and 5 wind resources present in this area. Several of the existing roads that appear to run through project site that would likely provide an easy means of access to many of the wind resource areas shown in light and dark pink in Figure 5-13. Several Navopache Electric Cooperative owned 69 kV transmission lines were identified to exist near the project site. A 31 MW project sited at this location is estimated to have and annual average 70m wind speed of 7.6 meters per second, producing 79 GWh annually with a capacity factor of approximately 29.5 percent.

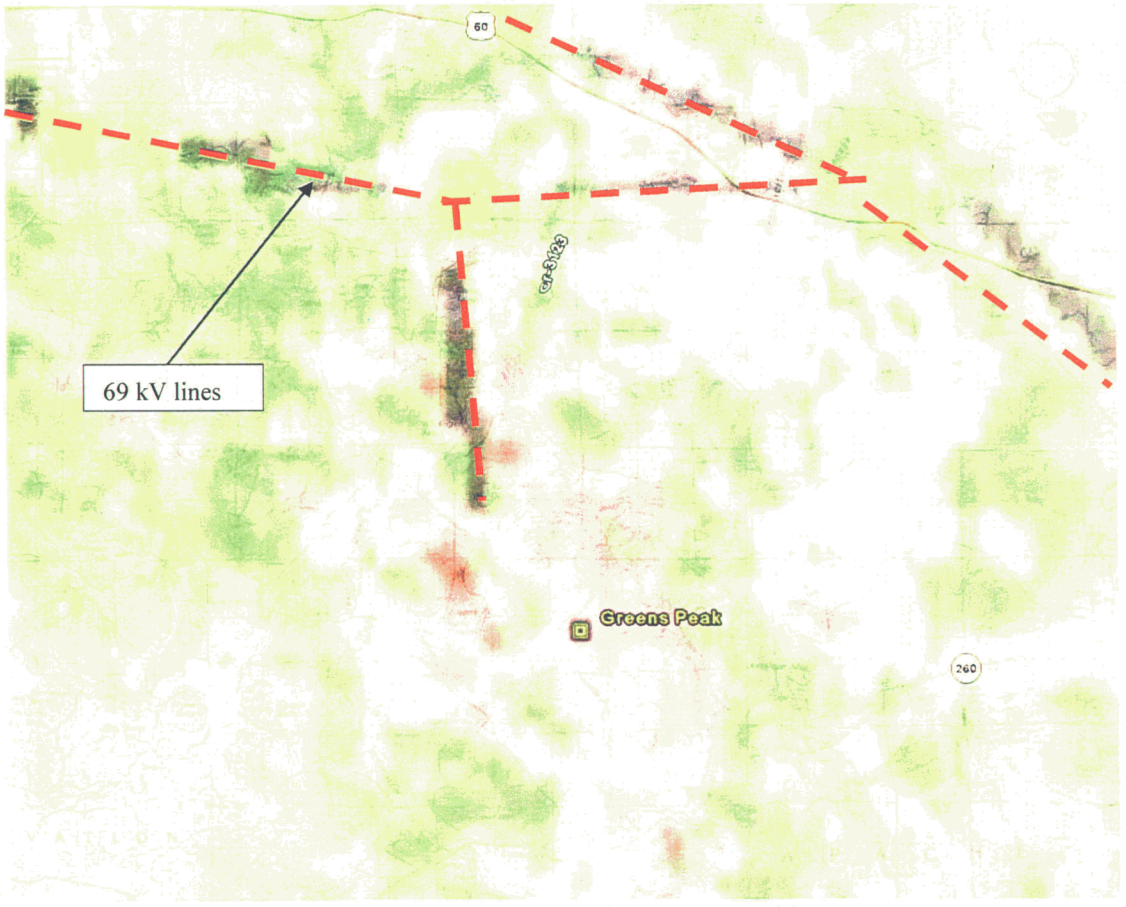


Figure 5-13. Greens Peak Project Area.

Kingstone Project Site

The Kingstone project area is located on the north side of interstate 40, approximately 10 miles north of Seligman, AZ. This project is located along the Aubrey Cliff that provides excellent exposure to the prevailing winds that make up the class 3 and 4 and wind resources in this area. Several of the existing roads appear to run along the project site that would likely provide an easy means of access to many of the resource areas as shown in light and dark green in Figure 5-14. An APS owned 230 kV transmission lines was identified to exist near the project site. An 18 MW project sited at this location is estimated to have and annual average 70m wind speed of 7.0 meters per second, producing 44 GWh annually with a capacity factor of approximately 27.1 percent.

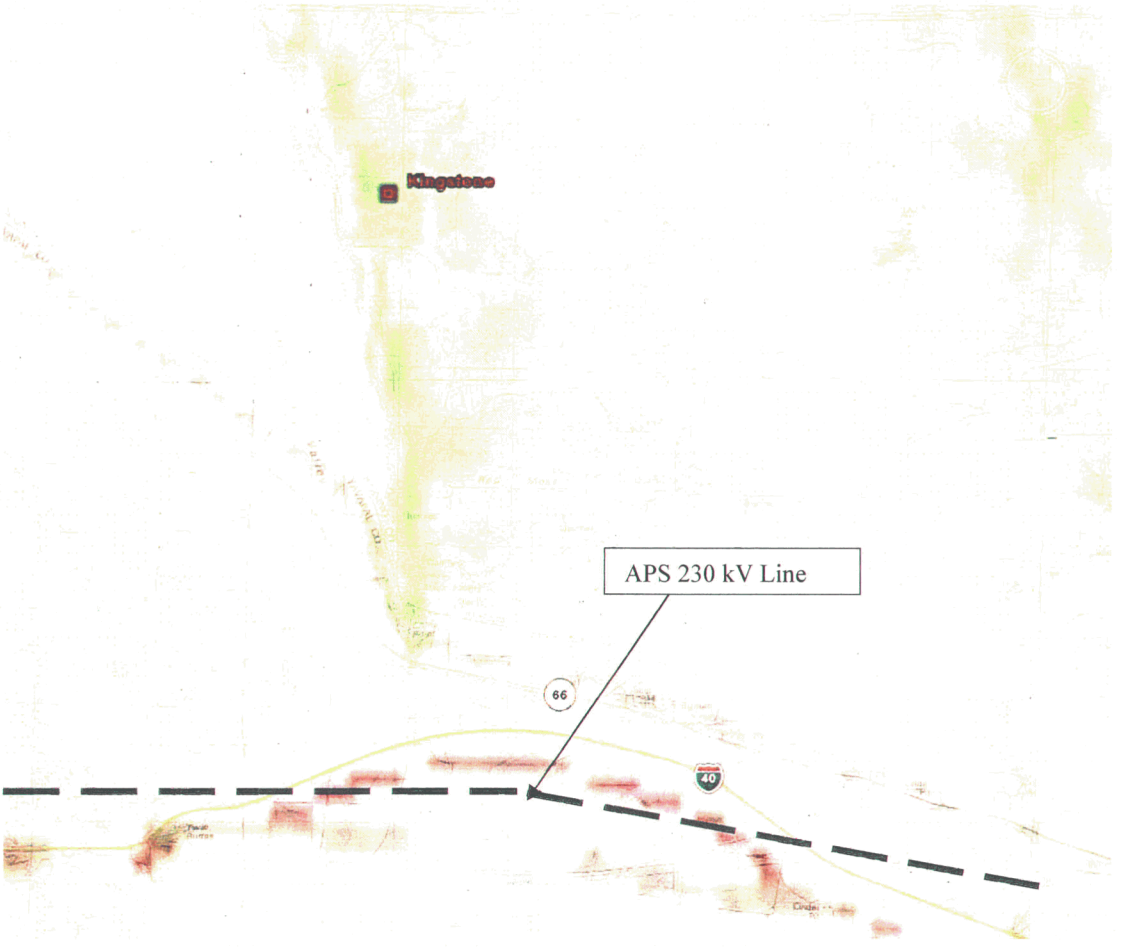


Figure 5-14. Kingstone Project Area.

Table 5-19 shows the wind power projects identified for this study. All characteristics are year 2007 values, before any future cost and performance modifications have been made. Figure 5-15 shows the supply curve for wind power. For the purposes of visualizing the projects on the supply curve, it has been assumed that all projects could be built in 2007. Appendix A shows a consolidated list of projects; Appendix B shows the same list with forecast levelized costs for each project from 2007 to 2025.

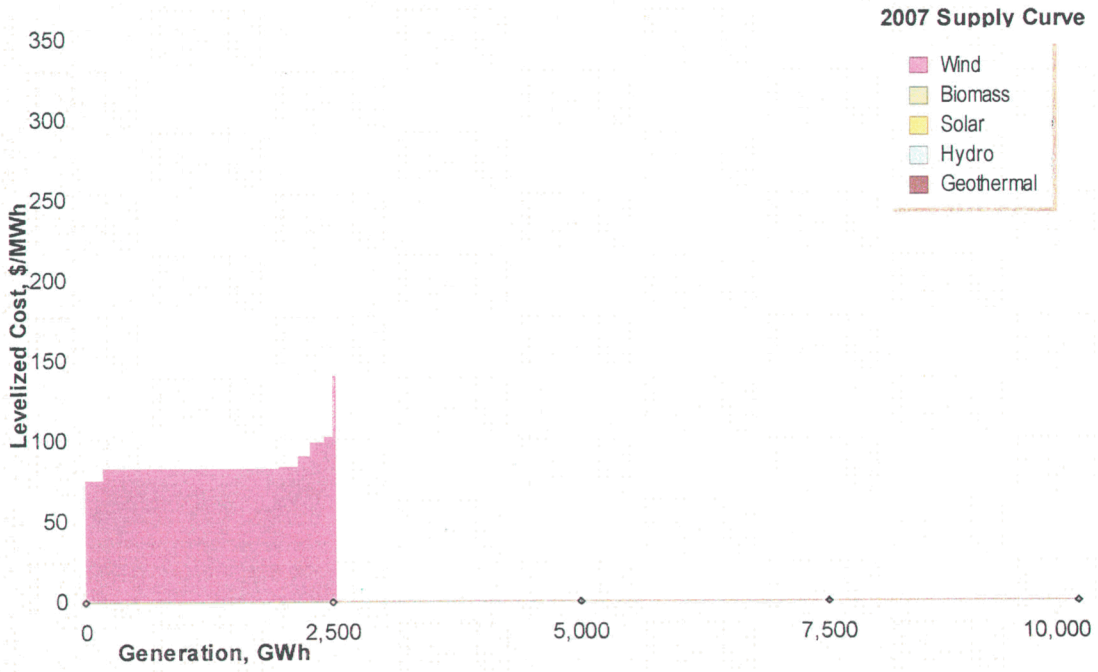


Figure 5-15. Levelized Cost Supply Curve for Wind Power Projects.

Table 5-19. Wind Power Project Characteristics.

Project	Capacity, MW	CF, %	Genera-tion, GWh	First Year Available	Capital Cost, $/kW	Fixed O&M, $/kW-yr	Var. O&M, $/MWh	Fuel Cost, $/MBtu	Nearest Utility	Transmission Line		
										Voltage, kV	Dist. to TL, miles	Owner
Rattlesnake Crater 1	62	26%	139	2010	1,600	25	9		APS	230	0	APS
Rattlesnake Crater 2	78	30%	203	2011	1,600	25	8		APS	230	0	APS
Buckhorn	46	30%	119	2010	1,680	25	8		APS	69	7	APS
Buffalo Range	158	30%	409	2010	1,600	25	8		APS	230	1	APS
Chevelon 1	171	30%	442	2010	1,600	25	8		APS	345	0	APS
Chevelon 2	171	30%	442	2011	1,600	25	8		APS	345	0	APS
Chevelon 3	171	30%	442	2012	1,600	25	8		APS	345	0	APS
Chevelon 4	84	33%	239	2013	1,600	25	7		APS	345	0	APS
Greens Peak	31	30%	79	2010	1,680	25	8		APS	69	6	APS
Kingstone	18	27%	44	2012	1,840	25	8		APS	230	5	APS

5.8 Geothermal

Geothermal was identified as a relatively unquantified, but potentially promising resource in the first phase of this study. This section explores two potential projects in more detail.

5.8.1 General Methodology

In Arizona, the geothermal resource is not as well explored and characterized as in some areas of the Southwestern United States. Electric power production from geothermal is undemonstrated in Arizona. Because of the limited work done to this point to identify specific developable geothermal resources in the state, projects are based on the two areas where there has been some focus on understanding the resource potential.

Without a known location that would support a flash steam geothermal facility, binary cycle type plants have been characterized.

5.8.2 Major Assumptions

Because projects are still in their early exploratory state, there is not enough data available to accurately characterize the geothermal projects with a high degree of precision. Even identifying the potential project size is still speculative. For this reason, generic project assumptions (similar to those presented in Section 4) were adjusted for economies of scale and then applied to the two projects identified.

The following assumptions were made in the evaluation of geothermal potential.

- Two sites, Gillard Hot Springs and Clifton
- 15 and 20 MW power plants
- Binary cycle plant type
- Construction time of 3.5 years
- Available for operation in 2013 and 2014
- Capacity factor of 70 percent, which is typical for dry-cooled binary resources (the most likely type to be developed in Arizona)

At best, these assumptions identify "place-holder" projects that must be further defined as more information about the true potential of each site is discovered.

5.8.3 Future Cost and Performance Projections

The geothermal technologies of flash steam and binary cycle are largely mature technologies. No changes in their future cost or performance were assumed. "Enhanced Geothermal Systems" described below, are new techniques that may bring more

geothermal development to Arizona, not because of lower costs or higher efficiencies, but because they may make new geothermal resource areas available for production.

Although the focus for most geothermal projects to date has been conventional hydrothermal resources, there is considerable potential in Arizona for the so-called "Enhanced Geothermal Systems" or "Hot Dry Rock" type of projects. Such projects are developed in areas with high underground temperatures but insufficient permeability to support commercial flow rates. In such projects, the reservoir rock is stimulated by hydraulic and/or chemical methods, creating a large network of fine fractures, thus forming an underground heat exchanger. Fluid is injected at one location and produced at another, having passed through the fracture network, gaining heat on the way. These non-conventional resources are experimental and strategic at this point, but many projects are underway in the US, Europe and Australia to determine the most effective methods of stimulation and heat recovery. The project at Soultz-sous-Forêts in France is likely to be the first to produce power from EGS/HDR resources, with one of the Australian projects likely to be the next. This type of development is probably 10 years or more from being commercial; more experience in the development and operational aspects of EGS/HDR resources is needed, and cost reductions need to enable this technology to be considered commercial. EGS/HDR resources were not explicitly modeled in this study. However, there appears to be sufficient promise that development of the technology should be closely monitored.

5.8.4 Data Sources

Data sources used in this analysis included:

- NOAA (National Oceanic and Atmospheric Administration, 1982. Geothermal Resources of Arizona. Oversized map with text and tables.
- INL (Idaho National Engineering and Environmental Laboratory), 2003. Arizona Geothermal Resources. One-page map. Publication No. INL/MIS-2002-1616 Rev.1.
- Witcher, James C., 1995. Geothermal Resource Data Base: Arizona." Southwest Technology Development Institute, New Mexico State University.
- David Brown and Associates, 2006. GRED III Final Report, Clifton Hot Springs Geothermal Project, Greenlee County, Arizona. Report on worked funded by US Department of Energy, DE-FC36-04GO14346.
- Morgan, P., W. Duffield., J. Sass and T. Felger, 2003. Searthing for an electrical-grade geothermal resource in northern Arizona to help Geopower the West. Transactions, Geothermal Resources Council, Vol. 27.

5.8.5 Projects Identified

The two known geothermal resources with the highest temperatures are located in the eastern part of the state: the Clifton Hot Springs project, and the Gillard Hot Springs. Interpretation of temperature and geochemical data suggest that resource temperatures may be as high as 140°C (just under 300°F) at both areas, which would enable binary power generation.

One of the springs at Gillard Hot Springs has a temperature of 183.2°F (84°C), but no wells have been drilled to intercept a potential resource. Exploration is somewhat further advanced at Clifton, including drilling funded under the GRED III program of US Department of Energy. Two core holes were drilled to 635 feet and 1,000 feet respectively. The deeper well had a temperature of 129°F at bottomhole, and a linear temperature gradient of 100°C/km, which is attractive. Deeper drilling is required to determine if this gradient results from a relatively shallow (but deeper than 1,000 feet), low-temperature resource or a deeper, higher temperature resource. Geochemistry suggests resource temperatures may be on the order of 140°C (just under 300°F); as mentioned above, this would be appropriate for a binary power development. The resistivity survey that was carried out as part of the same DOE-funded work may help to understand the subsurface better, but the resource can only be proven by drilling. APS is a collaborator on this project.

Another USDOE program (GRED II) provided funding in 2004 to Northern Arizona University to evaluate the geothermal potential of the San Francisco Peaks area, north of Flagstaff. The results of this work show that the San Francisco Peaks have silicic eruptions as young as 50,000 years in age, which is promising for the presence of high-temperature geothermal resources. However, there are no hot springs associated with these young volcanoes, and Morgan et al. (2003) believe that thermal waters are rising and mixing into a large, deep regional aquifer, which is obscuring the geothermal "signature." Funding is being sought for deep core hole drilling in the area to evaluate this hypothesis and hopefully identify a geothermal resource.

Table 5-20 shows the geothermal projects identified for this study. All characteristics are year 2007 values, before any future cost and performance modifications have been made. Figure 5-16 shows the supply curve for geothermal. For the purposes of visualizing the projects on the supply curve, it has been assumed that all projects could be built in 2007. Appendix A shows a consolidated list of projects; Appendix B shows the same list with forecast levelized costs for each project from 2007 to 2025.

Table 5-20. Geothermal Project Characteristics.

Project	Capacity, MW	CF, %	Genera-tion, GWh	First Year Available	Capital Cost, $/kW	Fixed O&M, $/kW-yr	Var. O&M, $/MWh	Fuel Cost, $/MBtu	Nearest Utility	Transmission Line		
										Voltage, kV	Dist. to TL, miles	Owner
Clifton	20.0	70%	123	2013	4,000		30	0	APS	35	10	
Gillard	15.0	70%	92	2014	4,500		30	0	APS	35	10	

Note: Transmission Line voltage and Distance to transmission line is unknown. Fixed O&M costs are included in the capital cost and variable O&M cost numbers.

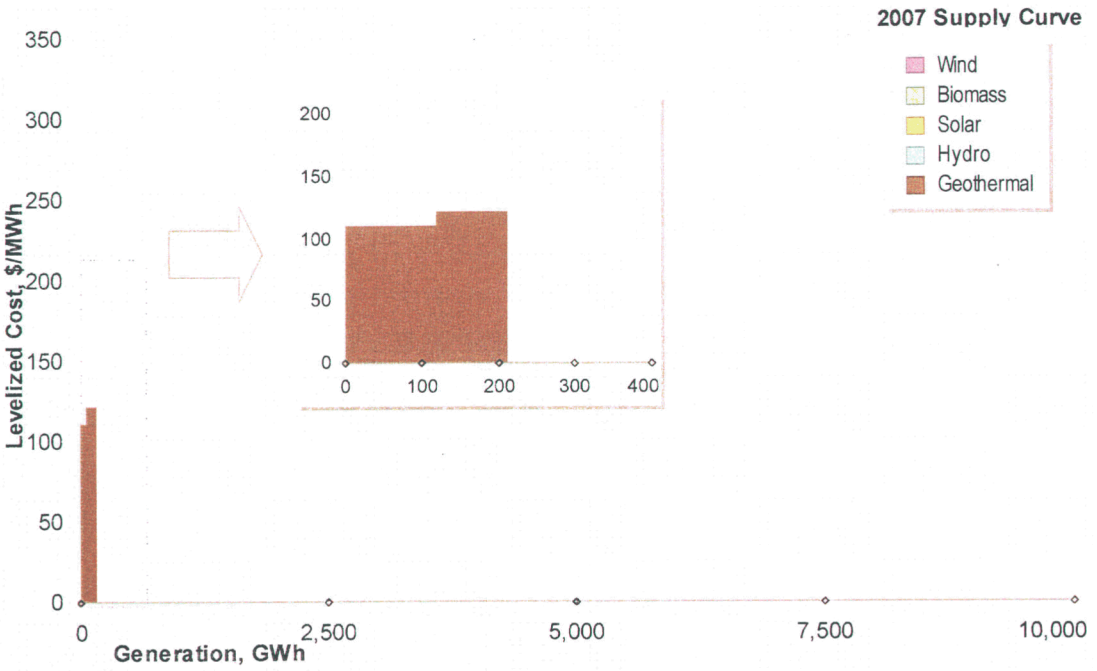


Figure 5-16. Levelized Cost Supply Curve for Geothermal Projects.

6.0 Renewable Energy Financial Incentives

A number of financial incentives are available for the installation and operation of renewable energy technologies. These incentives can substantially influence profitability and can make the difference between a non-viable and a viable project. The following discussion provides a brief list of existing and proposed incentives that are available to new renewable energy facilities. Although many of these incentives are designed as tax credits, it may still be possible for non-taxable entities (or others with limited tax appetite) to benefit from the incentives by establishing facility ownership through a third-party taxable entity or other project structures. It should be noted that the intent of this section is to provide general information on available incentives; Black & Veatch cannot provide tax advice concerning the implications of the specific incentive programs.

6.1 Tax Related Incentives

The predominant incentive offered by the federal government for renewable energy has been through the US tax code in the form of tax deductions, tax credits, or accelerated depreciation. An advantage of this form of incentive is that it is defined in the tax code and is not subject to annual congressional appropriations or other limited budget pools (such as grants and loans). Tax related incentives include:

- Section 45 Production Tax Credit (PTC)
- Section 48 Investment Tax Credit (ITC)
- Accelerated depreciation

The ability to utilize tax credits is limited not only by specific legal considerations, but also by practical considerations. It can be difficult to line up the risks and benefits of a specific transaction with the appropriate participants and their tax status.

Government-owned utilities and other tax-exempt entities are not able to directly take advantage of these tax incentives. Tax-exempt entities, however, do enjoy a number of other benefits when financing and operating capital investments. The most obvious benefit is freedom from federal and state income tax liability. Depending on project location and local laws, payment of property taxes may also be reduced or eliminated. These entities are also able to issue tax-exempt debt, which carries considerably lower interest rates than comparable corporate debt.

The Section 45 PTC is available to private entities subject to taxation for the production of electricity from various renewable energy technologies. The *Energy Policy Act of 2005* expanded and extended the PTC through 2007. The PTC was further extended in late 2006 until the end of 2008. For most technologies, the facility must be in service by December 31, 2008. The income tax credit amounts to 1.5 cents/kWh

(subject to annual inflation adjustment and equal to 2.0 cents/kWh in 2007) of electricity generated by wind, solar, geothermal, and closed-loop biomass. The credit is equal to 0.75 cents/kWh (inflation adjusted, equal to 1.0 cents/kWh in 2007) for all other renewable energy technologies. A problem with the credit is the ever present threat of expiration, which promotes boom and bust building patterns.

Table 6-1 shows the provisions of the production tax credit for renewable energy, as revised by the Energy Policy Act of 2005.

Table 6-1. Major Production Tax Credit Provisions.

Resource	Eligible In-service Dates	Credit Size*	Special Considerations
Wind	12/31/93 - 12/31/08	**Full**	None
Biomass			
Closed-Loop	12/31/92 - 12/31/08	**Full**	Crops grown specifically for energy
Closed-Loop Cofiring	Before 12/31/08	**Full**	Only specific coal power plants; based on % of biomass heat input
Open-Loop	Before 12/31/08	Half	Does not include cofiring
Livestock Waste	10/22/04 - 12/31/08	Half	>150 kW; Does not include cofiring
Poultry Waste	12/31/99 - 12/31/03	**Full**	Incorporated with "livestock waste" with the American Jobs Creation Act of 2004
Geothermal	10/22/04 - 12/31/08	**Full**	Can't also take investment tax credit
Solar	10/22/04 - 12/31/05	**Full**	Can't also take investment tax credit; eligibility expired Dec. 31, 2005
Small Irrigation Hydro	10/22/04 - 12/31/08	Half	No dams or impoundments; 150 kW-5 MW
Incremental Hydro	8/8/05 - 12/31/08	Half	Increased generation from existing sites
Landfill Gas	10/22/04 - 12/31/08	Half	Can't also take Sec. 29 tax credit
Municipal Solid Waste	10/22/04 - 12/31/08	Half	Includes new units added at existing plants.

Notes:
* All PTCs are inflation-adjusted and equaled $20/MWh ("Full") or $10/MWh ("Half") in 2007.

The Section 48 ITC effectively offsets a portion of the initial capital investment in a project. The *Energy Policy Act of 2005* modified the ITC to include additional resources and to increase the credit amount. The current ITC provisions:

- **Solar** – Eligible solar equipment includes solar electric and solar thermal systems. The credit amount for solar is 30 percent for projects that come online prior to December 31, 2008; otherwise, it is 10 percent.
- **Fuel cells** – Fuel cells installed prior to December 31, 2008 are eligible for the ITC. The credit amount is 30 percent with the maximum credit capped at $1,000/kW.

- **Microturbines** – Microturbines installed prior to December 31, 2008 are eligible for the ITC. The credit amount is 10 percent with the maximum credit capped at $200/kW.
- **Geothermal** – Geothermal includes equipment used to produce, distribute, or use energy derived from a geothermal deposit. It does not include geothermal heat pumps. The credit amount is 10 percent, but it cannot be taken in conjunction with the PTC.

The language of the PTC extension does not allow claiming of both the PTC and the ITC. Project developers must choose one or the other. For capital intensive solar projects, the ITC is typically more attractive. For geothermal projects, the PTC is more attractive. The ITC also interacts with accelerated depreciation, as discussed further below.

Section 168 of the Internal Revenue Code contains a Modified Accelerated Cost Recovery System (MACRS) through which certain investments can be recovered through accelerated depreciation deductions. There is no expiration date for the program. Under this program, certain power plant equipment may qualify for 5-year, 200 percent (i.e., double) declining-balance depreciation, while other equipment may also receive less favorable depreciation treatment. Renewable energy property that will receive the 5-year MACRS includes:

- **Solar** – Solar property that meets the same standards for eligibility required by the federal 10 percent investment tax credit.
- **Wind** – Wind property subject to the same 25 percent limit on dual-fueled equipment required for solar property.
- **Geothermal** – Geothermal property up to the electrical transmission stage.
- **Biomass** – Qualifying Facilities 80 MW or less that directly burn at least 50 percent biomass to generate electricity. The power plant must burn the biomass directly to qualify.

The accelerated depreciation law also specifies that the depreciable basis is reduced by the value of any cash incentives received by the project, and by half of any federal investment tax credits (e.g., the ITC). This provision has the effect of lowering the depreciable basis to 95 percent for projects that receive the 10 percent ITC (and 85 percent for projects that take the 30 percent ITC) but no other cash incentives.

6.2 Non Tax-Related Incentives

The Renewable Energy Production Incentive (REPI) program was developed as a public sector counterpart to the PTC (Section 45) discussed previously. The REPI has been recently renewed through September 30, 2016 as part of the Energy Policy Act of

2005. Qualifying facilities must use solar, wind, ocean, geothermal, or biomass (except for municipal solid waste) generation technologies. Under the REPI program, qualifying facilities are eligible for an annual incentive payment of 1.5 cents/kWh (subject to annual inflation adjustment and equal to 1.9 cents/kWh in 2005). The payment is given for a period of ten years after the facility begins operation. The payment is subject to the availability of annual congressional appropriations.

There are two major shortcomings of the REPI program as it currently exists. First, the REPI program's reliance on annual Congressional appropriations limits its effectiveness as a financial incentive. Second, program appropriations for recent years (2003 and 2004) have not been sufficient to make full incentive payments for electricity. As a result, planners of renewable energy generation facilities have often not relied on REPI payments when evaluating the feasibility of projects. The DOE recognizes the problems of the REPI program and has sought and reviewed comments on options to make REPI a more effective incentive. These options would require either regulatory or statutory change and would need significantly higher levels of appropriations, which may be unrealistic.

Clean Renewable Energy Bonds (CREBs) were introduced as part of the Energy Policy Act of 2005 as a response to the perceived problems with the REPI program. CREBs provide interest-free loans to public utilities (including rural electric co-ops), while providing tax credits to purchasers (the investors who buy the bonds). Qualifying projects are renewable energy projects which meet the same technical definitions as the Section 45 PTC (with the exception of the placed-in-service date). Congress originally authorized $800 million in bonds over two years with repayment terms of 12 to 15 years.

Of the $800 million allocated, a maximum of $500 million is for governmental entities, with the remainder reserved for co-ops. The deadline for applying for the first round of CREBs was April 26, 2006. The IRS allocated funding beginning with the smallest request and continuing with the next smallest until the funds are exhausted. This makes the CREB funds much more likely to be available for small projects. Although the initial pool of $800 million of CREBs has been allocated, in December 2006 the government authorized an additional $400 million to continue the CREB program.

7.0 Renewable Energy Development Model Results

Black & Veatch has developed a model to help utilities, states, and other entities identify and compare renewable resources to develop renewable energy plans. This tool has been used for resource assessment, RPS compliance cost projections, renewable energy credit market price forecasts, and strategic planning. For the utilities represented in this study, Black & Veatch evaluated the renewable energy potential for the state of Arizona in light of increased demand for renewable energy stimulated \y an increased Renewable Energy Standard and other factors. The model was then used to forecast potential renewable energy development in the state through 2025.

This section describes the model methodology, assumptions, and results.

7.1 Methodology

Black & Veatch developed an objective methodology to model renewable energy potential and development based on sound utility generation planning fundamentals and the specific challenges inherent to analyzing renewable energy generation technologies. This methodology evaluates the total lifecycle cost of renewable energy projects, including capital and operating costs, performance, and transmission system impacts. Projections are made for future changes in technology cost and performance based on Black & Veatch's experience in the field. This methodology can be used to identify the single most economic project, or to analyze a portfolio of projects to meet a specified renewable energy demand or other regulatory requirement. By allowing the model to consider all possible renewable energy resources in Arizona, the study assesses the full potential of all renewable energy resources while accounting for the economic variables of developing those resources.

The approach includes the following major steps:

- Technology characterization and selection
- Project characterization
- Future Cost and Performance Projections
- Transmission System Cost Analysis
- Levelized Cost Calculation
- Supply Curve Generation

Figure 7-1 shows a basic flow-chart of the renewable energy planning process and illustrates how the various steps integrate to produce an overall assessment plan.

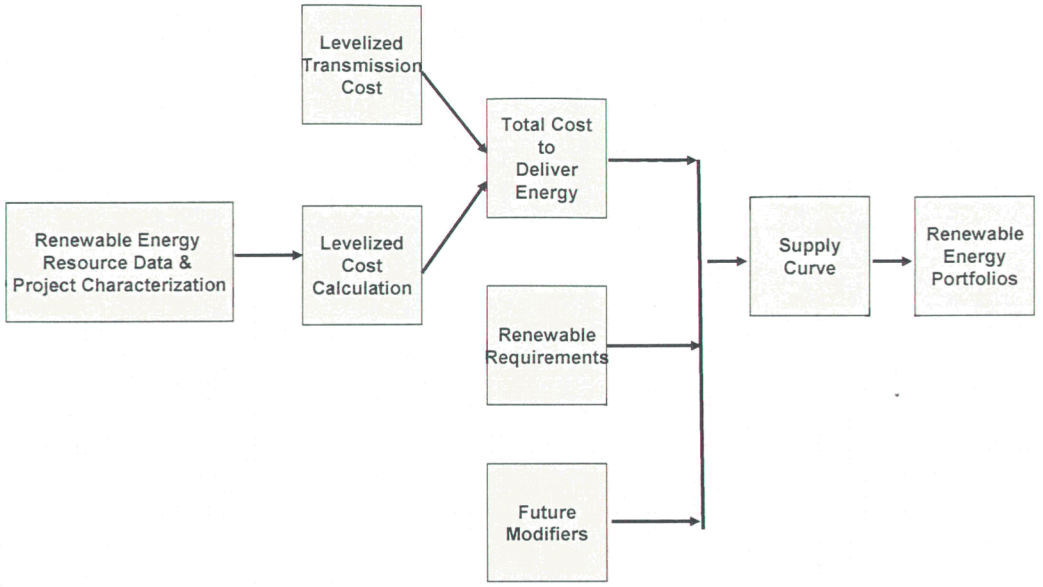


Figure 7-1. Renewable Resource Assessment Methodology.

7.1.1 Technology Characterization and Selection

Technology characterization and selection consists of identifying those renewable energy technologies that could be reasonably applied to harness the available resources in a particular area. Black & Veatch assessed the level of commercialization for each technology in comparison to Arizona's overall resource supply. As a result, the analysis focused on the more promising technologies for Arizona, namely:

- Direct Fired and Cofired Biomass
- Landfill Gas
- Anaerobic Digestion
- Solar Thermal Electric
- Solar Photovoltaic
- Hydroelectric
- Wind Power
- Geothermal

7.1.2 Project Characterization

For each promising renewable energy resource, Black & Veatch determined the potential capacity and locations where development is possible. Using several data sources, including maps, GIS data, and databases, renewable energy technology specialists identified high potential locations across Arizona for their respective technologies. For each location, these specialists quantified the generation potential of

each renewable energy resource (e.g. biomass quantity, direct solar insolation, etc.) This information led to estimating capacity and annual production realizable from developing projects in these locations. The results of the project characterization are presented in Section 5.

Black & Veatch then determined how much of the theoretical resource potential can practically be developed. This "developable potential" is the available resource that can be realistically developed with the appropriate technology and siting constraints. The developable resource is determined by considering constraints on land use, proximity to transmission, resource quality, and theoretical efficiency. Land constraints are critical in Arizona, where much of the available land is national park, national forest, Native American lands, or rugged and remote.

Black & Veatch assigned performance and cost assumptions for each project or resource class that reflect current industry operating experience and actual costs observed to develop projects based on previous experience. Black & Veatch worked with representatives from the utilities to agree on realistic assumptions for the current Arizona renewable energy climate.

7.1.3 Future Cost and Performance Projections

Since renewable energy technologies are still developing, cost and performance are expected to change in the future. The model reflects these changes to estimate penetrations of each resource in the future, as current assumptions for these technologies will likely not be valid within 10 to 20 years. For example, solar photovoltaic modules are expected to decline considerably in cost over the next 10 to 20 years. Black & Veatch evaluated changes to all technology characteristics, including:

- Capacity factor
- Typical capacity
- Applicable incentives
- Capital cost
- O&M costs
- Fuel costs (if applicable)
- Tax credits and other incentives

7.1.4 Transmission System Cost Analysis

The transmission cost analysis for this project was necessarily simplified. Transmission costs were considered up to the point of grid connection (that is, costs for substation and project tie-line were included), but no costs for system upgrades or wheeling were identified. In addition, the availability of capacity on specific

transmission lines was not assessed. Lines were assumed to have available capacity to accommodate the projects.

Based on input from the utilities, Black & Veatch estimated interconnection substation and transmission line spur costs for each potential project. Black & Veatch also identified the utility that corresponded to the service area and transmission line.

7.1.5 Levelized Cost of Electricity Calculations

Black & Veatch calculated the levelized cost of electricity by using the performance and cost assumptions for each project combined with the appropriate financing and economic assumptions for the type of development (see Table 7-3). The levelized cost is a measure of the life-cycle cost to generate electricity with a particular project. This cost allows various technologies, both conventional and renewable, to be compared on an equal economic basis ($/MWh). The methodology for levelized cost calculation is described in Section 4.1.

7.1.6 Supply Curve Development

Black & Veatch developed supply curves for the aggregate mix of renewable energy projects available to Arizona. Supply curves are used in economic analysis to determine the quantity of a product that is available for a particular price (e.g., the amount of renewable energy that can be generated within a utility system for under $50/MWh). The supply curve is constructed by plotting the amount of generation or capacity added by each technology or project against its corresponding levelized cost. For this study, the renewable generation added by each project class is plotted against its levelized cost of electricity in ascending order. As an example, see Figure 7-2. In this case, generation (GWh/yr) is on the x-axis and levelized cost ($/MWh) is shown on the y-axis. The supply curve shows that there are only a few projects that would be able to supply power for under $100/MWh by 2020. However, there is a large pool of solar resources at a cost of about $200/MWh.

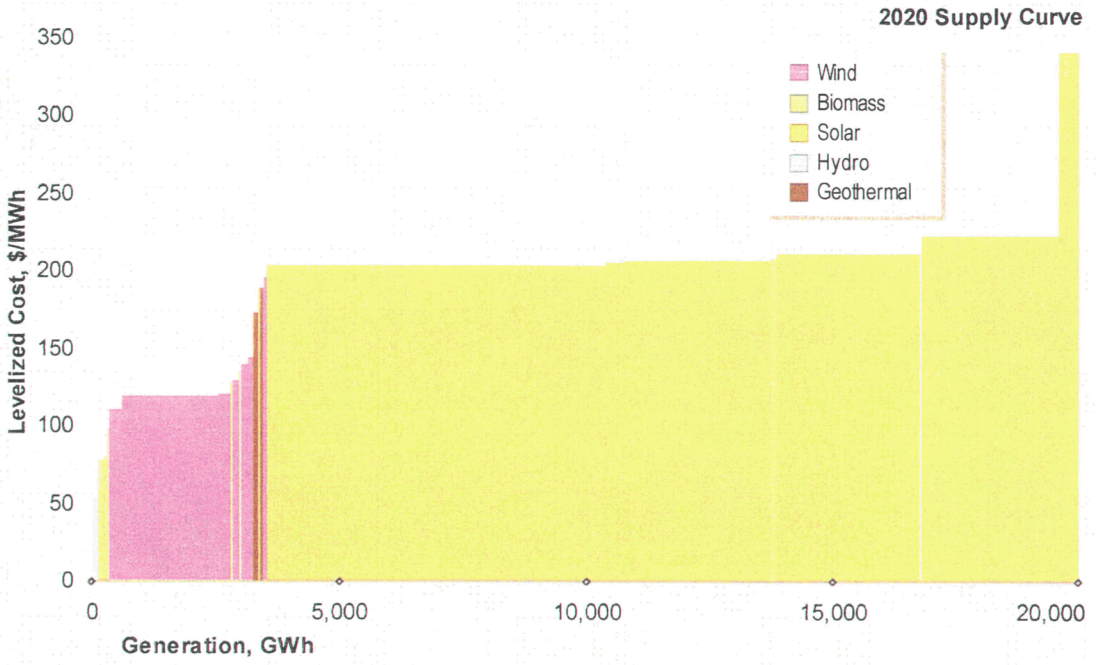


Figure 7-2. Arizona Resource Supply Curve.

Every "step" on the graph represents an individual project color-coded by its technology type. The curve compares the quantities and costs for the renewable resources and shows which products can be brought to market at the lowest cost (resources towards the left side). Supply curves were generated for each of the technologies under study (Section 5) and then combined.

Because a supply curve models potential projects, every year has a different supply curve. Due to time required for resource procurement, engineering, ACC approval, and construction, many projects are not feasibly available for energy production for several years. Of the many potential projects in Arizona, only a select few could be available over the next two years. However, by 2015, the majority of potential projects could feasibly be available. The further out the time horizon, the "longer" the supply curves become, representing a large pool of available generation.

As time proceeds, the lower cost renewable energy resources are most likely to be developed first, while higher price resources would likely be developed in future years. However, it is important to note that supply curves will change each year for variety of factors, including:

- The least-cost projects are assumed to be developed first and can no longer be considered as part of the supply curves for new generation

- Minimum project development timelines constrain project development (e.g., not all wind resource could be developed in 2009)
- Improvements in technology over time affect costs
- Commercial availability of new renewable technologies (e.g., dish engine solar in 2015)
- Timing of development of proposed transmission projects enabling development of new resources
- Expiration of tax credits and other incentives

The supply curves help the utilities determine the optimal mix of renewable energy to balance cost and generation. Importantly, however, there are numerous other factors to consider in addition to the generation cost shown in the supply curves. These are described below.

7.1.7 Model Limitations

The model used for this report was a relatively simple linear model. The renewable energy supply curves were developed based largely on best available public information and they represent a snapshot of what could be developed in the near term without consideration of significant future technology advancements. The projects identified, although based on analysis of best-available data, should be considered hypothetical but representative of actual projects that could be developed to meet renewable energy demand. In addition, the model has the following limitations, many of which were established by the agreed-upon scope of work for this project:

- No resources were considered outside of Arizona (including existing power purchase agreements)
- No distributed generation resources were considered
- No banking of excess renewable generation was included to meet future demands. In addition there was no carry-forward of under-procurement.
- The transmission assessment has been simplified, as described previously.
- No consideration has been made for the differential value of different resources (avoided cost).
- Except for already announced projects (assumed to fail at a 50 percent rate), project failure was not explicitly modeled.
- No intra-annual variability of resources was considered.
- Costs to integrate intermittent resources (e.g., firming of wind) were not included. (Note, however, that wind comprises a relatively small portion of the portfolio. Solar projects largely include integrated thermal storage.)

- The model is not a production cost model and does not simulate system dispatch.

In selecting projects to develop or procure, utilities may further consider these limitations, which may result in a different order of resource/project development than shown in the supply curves in this report. The most important additional factors that should be considered are competitiveness of out-of-state resources, transmission costs needed to access some resources (particularly wind), and the differential avoided cost (or value) of resources.

Consideration of avoided costs is particularly important. Avoided cost is typically determined by assessing a resource's capacity value (based on degree of "firmness" at the time of a utility's system peak demand) and its energy value (based on time of delivery). This is important when comparing resources such as wind and solar. For example, wind energy projects only provide fractional capacity value (often estimated at 20 percent or less of the nameplate capacity) and are more likely to offset low cost energy resources during the winter and spring. Solar resources can readily provide firm capacity with gas hybridization or thermal storage. Further, solar is generally coincident with times of higher energy needs, when less efficient (and more expensive) peaking resources are more likely to be offset.

There are numerous methods to calculate avoided cost, and costs are specific to individual utility systems. Figure 7-3 shows an example calculation for wind and solar. For wind, the following assumptions have been made:

- Energy – offsets electricity from a natural gas combined cycle. The wind would offset the variable component of a combined cycle plant, which is the sum of the variable operations and maintenance cost and the fuel cost (heat rate times gas cost).
- Capacity – offsets 20 percent of the capacity of a natural gas simple cycle. The fixed carrying cost of a simple cycle has been assumed to be $100/kW-yr.
- Integration cost – the intermittent nature of wind results in higher system operations costs for utilities to integrate its varying output. This cost is generally relatively small at low levels of penetration. A value of $3.50/MWh has been assumed as an additional cost for wind.

For solar thermal (with natural gas back-up or integrated storage), the following assumptions have been made:

- Energy – offsets electricity from a natural gas simple cycle.
- Capacity – offsets 100 percent of the capacity of a natural gas simple cycle.

- Integration cost – No additional cost. (Note that solar photovoltaic projects, which are typically built without any storage, would likely incur integration costs due to the intermittency effect caused by cloudiness.)

Energy Component		
Characteristics of marginal unit offset		
Heat rate, MBtu/MWh		7.50
Gas Price, $/MWh		$7.50
Variable O&M, $/MWh		$2.50
Marginal Energy Value, $/MWh		**$58.75**
Capacity Component		
Wind Capacity Factor		35%
Wind Capacity Credit		20%
Simple Cycle NG Capacity value, $/kW-yr		$100
Wind Capacity Value, $/kW-yr		$20
Capacity value, $/MWh	$	**6.52**
Additional Integration Cost	$	**3.50**
Total Avoided Cost		**$61.77**

WIND

Energy Component		
Characteristics of marginal unit offset		
Heat rate, MBtu/MWh		10.00
Gas Price, $/MWh		$7.50
Variable O&M, $/MWh		$2.00
Marginal Energy Value, $/MWh		**$77.00**
Capacity Component		
Solar Capacity Factor		45%
Solar Capacity Credit		100%
Simple Cycle NG Capacity value, $/kW-yr		$100
Solar Capacity Value, $/kW-yr		$100
Capacity value, $/MWh	$	**25.65**
Additional Integration Cost	$	-
Total Avoided Cost		**$102.65**

SOLAR

Figure 7-3. Hypothetical Avoided Cost Calculation for Wind and Solar Resources.

This example shows the avoided cost of wind at about $60/MWh and the avoided cost of solar (with natural gas back-up or integrated storage) at over $100/MWh. While solar costs more than wind, it has substantially higher value. For this reason, it is important for utilities to consider not only the costs of various resources, but their value (avoided cost) as well.

7.2 Assumptions

Conservative assumptions for the performance and financing of renewable technologies were made to construct realistic estimates of the development potential and costs. This section describes the general assumptions, economic assumptions, and Arizona renewable energy demand assumptions used for the resource assessment.

7.2.1 General Assumptions

Interconnection substation costs and transmission spur line costs were included in total levelized cost of electricity calculations (see Table 7-1). Transmission wheeling costs were not included. Transmission assumptions were based on current market conditions in Arizona. Voltage was identified by determining the voltage of the nearest transmission line to which a project would most likely connect.

Table 7-1. Transmission Assumptions.

Transmission Line Voltage (kV)	Substation Cost ($)*	Spur Line Cost ($/mile)*
34.5	1,200,000	200,000
69	2,400,000	400,000
115	3,000,000	800,000
138	3,500,000	1,200,000
230	4,100,000	1,600,000
287	4,900,000	1,650,000
345	5,700,000	1,700,000
500	10,500,000	2,600,000

Source: APS OASIS site.

Note: Does not include siting and ROW.

* All projects less than 1 MW of capacity are assumed to have their interconnection costs already included with the project capital costs.

It was assumed that technology learning for less mature technologies would result in improving capacity factors and declining costs (in real terms). This was implemented in the model through a set of future modifiers shown in Table 7-2. The other technologies' costs are assumed to stay constant in real terms. The future modifiers have the effect of making wind, solar trough, concentrating PV (CPV), and solar dish less expensive in later years relative to earlier years in the study. These assumptions are based on Black & Veatch forecasts of technology improvement and published data from independent sources (see Section 5 for further discussion)

Table 7-2. Future Modifiers (Costs decrease in real terms).

	2007	2010	2015	2020	2025
Capacity Factor					
Solar Trough	1.00	1.00	1.42	1.45	1.45
Wind	1.00	1.06	1.09	1.13	1.16
Capital Cost					
Solar Trough	1.00	1.00	1.07	1.00	0.88
Solar Dish	1.00	1.00	0.74	0.72	0.72
PV	1.00	0.93	0.82	0.72	0.63
CPV	1.00	0.85	0.60	0.55	0.55
Variable O&M					
Wind	1.00	0.86	0.78	0.72	0.70
Solar Dish	1.00	1.00	0.60	0.56	0.56
Fixed O&M					
CPV	1.00	0.97	0.92	0.90	0.90
Solar Trough	1.00	1.00	0.87	0.82	0.82
Solar Dish	1.00	1.00	0.74	0.57	0.57

7.2.2 Economic Assumptions

A levelized generation cost for each of the technology classifications identified in the resource assessment was calculated. This cost allows the various technologies to be compared to identify the least cost renewable energy resources likely to be developed earlier. To develop an estimate of the cost to generate power over the life of the project, the following assumptions are required:

- Project performance
- Project life
- Financing structure (debt/equity)
- Debt cost
- Loan term
- Equity cost
- Depreciation cycle
- Levelized fixed charge rate

Table 7-3 shows the economic assumptions made for the resource assessment.

Table 7-3. Economic Assumptions.

Technology	Economic Life	Financing Structure (Debt/Equity)	Debt Term	Interest Rate	Equity Cost	Tax Life	Fixed Charge Rate
Biomass Digester	15	70/30	10	8%	15%	12	16.4%
Landfill Gas	15	70/30	10	8%	15%	12	16.4%
Biomass Cofiring	20	70/30	20	7.5%	11%	20	14.0%
Biomass Direct	20	70/30	15	8%	15%	5	13.0%
Geothermal	20	70/30	15	8%	15%	5	13.0%
Hydro	30	70/30	15	8%	15%	20	13.6%
PV	20	70/30	20	7.5%	11%	5	11.7%
Solar Dish	20	70/30	15	8%	15%	5	13.0%
Solar Trough	20	70/30	15	8%	15%	5	13.0%
CPV	20	70/30	15	8%	15%	5	13.0%
Wind	20	70/30	15	8%	15%	5	13.0%

The economic life of each technology was selected to reflect current industry expectations for the life of each project. The financing structure of 70 percent debt and 30 percent equity was chosen for all technologies to reflect a common structure for project developers. The interest rate for debt is indicative of current market rates, and those received by recent projects. Debt terms were chosen to reflect current industry practice for each technology. The cost of equity is an approximation of the return on investment a renewable energy project investor would require taking into account the rate of return that an investor could receive on a comparable market. It was assumed that the utilities would be the most likely developers of biomass cofiring and PV projects, thereby achieving reduced financing costs. These technologies were given a lower interest rate and cost of equity for a lower overall weighted cost of capital. The levelized fixed charge rate is used to calculate a constant annual charge to offset a project's fixed costs. This rate is applied to the total capital cost of a project and accounts for financing costs, taxes, and other fixed costs related to the plant.

Alternative project and cost structures for solar PV projects are currently being refined that have the potential to substantially lower the all-in cost of energy from solar PV. Given the high capital costs for PV, any improvement in capital structure or financing costs has a relatively strong impact on the final levelized cost. These structures have not been modeled in this report.

Expanded federal tax incentive programs were included in the analysis of the cost to generate electricity. The Federal Production Tax Credit (PTC) was modeled at

$20/MWh (2007$) for wind and geothermal resources and at $10/MWh (2007$) for biomass digester, landfill gas, biomass direct, and hydroelectric resources. The production incentive was modeled to be available for 10 years of a project's life and escalated at 2.5 percent per year. Although the PTC is set to expire at the end of 2008, there is a strong belief that it will be extended as it has previously. For the study the PTC was modeled to be extended through 2012. A federal investment tax credit for all solar technologies was also applied. This credit was modeled as 30 percent of capital cost, available for projects built by the end of 2012. A sensitivity analysis in Section 8 explores the impacts of different tax credit assumptions.

7.2.3 Arizona Renewable Energy Demand Assumptions

Table 7-4 outlines the forecasted renewable energy demand in Arizona. This forecast was based partially on the objectives to meet the RES standard through 2025. The renewable energy demand was developed based on a simple load forecast estimate. Total capacity demand for Arizona utilities from 2007 to 2015 was provided by the utilities. Using the average growth rate for those years (approximately 3.5 percent), Black & Veatch estimated the total capacity (MW) demand from 2016 to 2025. A load factor of 50 percent was used to calculate total energy (GWh) required for every year.

While APS and TEP are mandated to meet the ACC's RES requirements, SRP and some other utilities are not required to do so. However, SRP and other utilities have established their own goals, which will increase demand for renewables. SRP's goal is 15 percent by 2025, but it includes existing large hydroelectric and energy efficiency. It was assumed that 75 percent of the total state load would "meet the spirit" of goals set out in the RES. The impacted load was multiplied by the corresponding non-DG RES requirement (see Table 3-3) to calculate the total amount of renewable energy required for each year. Black & Veatch subtracted the amount of energy produced from existing renewable generation projects and other planned projects (Table 3-2) to ensure that the renewable energy demand in the model represented incremental amounts beyond current and expected production. Only 50 percent of potential energy from announced projects was included, as some will likely not come on-line as planned. This "failure rate" is consistent with experience in other states, but a conservative estimate as this number may decline due to RFP risk management protocol, more experienced developers, increased financial resources, and industry experience.

Table 7-4. Arizona Renewable Energy Demand Forecast (Cumulative GWh).			
Year	**Total Renewable Demand**	**Existing and Planned Projects**	**Net New Development Required**
2007	884	312	572
2008	1,010	683	328
2009	1,128	825	303
2010	1,373	825	548
2011	1,597	825	773
2012	1,799	825	974
2013	2,126	825	1,302
2014	2,474	825	1,650
2015	2,844	825	2,019
2016	3,532	825	2,707
2017	4,265	825	3,440
2018	5,045	825	4,220
2019	5,874	825	5,049
2020	6,755	825	5,930
2021	7,691	825	6,866
2022	8,683	825	7,859
2023	9,736	825	8,912
2024	10,852	825	10,028
2025	12,034	825	11,210

7.3 Results

The model was used to simulate the renewable resources that could be developed to meet the 2025 demand of 11,210 GWh shown in Table 7-4. Although the model includes a variety of renewable energy resources that could be developed, other than solar, these resources appear relatively limited. In the mid to near-term, developable potential for new biomass, geothermal, and hydroelectric projects combined could contribute about 1,080 GWh/yr, or 1 percent of the electricity that was generated in Arizona in 2005. Wind could contribute about 2.5 percent. Despite the relatively limited potential of wind, biomass, geothermal and hydroelectric resources, they serve an important role in forestalling the need to install expensive solar. As such, their development may be important to keep renewable energy costs lower in the near term.

However, the relatively limited potential of these resources compared to surrounding states may serve as a deterrent for large, out-of-state renewable energy project developers.

Based on the resource assessments and future modifiers developed for each resource, supply curves were generated at annual increments from 2007 through 2025. Each supply curve was then compared against the total renewable energy demand required for each period. Supply curves for each year are provided in Appendix C. Figure 7-4 provides an example supply curve for 2015. This curve shows the Glen Canyon upgrade project the first year it is available as the lowest cost project (about $50/MWh). The potential demand line for 2015 crosses the supply line at the Glen Canyon project, indicating that Glen Canyon would likely be developed in 2015. The supply curve analysis was conducted under the assumption that each project would be developed and sold at its cost (including a reasonable developer profit), and not at the highest cost ("market clearing" price) in the respective period. This assumption is reasonable if it assumed that developers are pricing projects based on their costs and not unreasonably raising prices to take advantage of supply constraints in the market. This assumption is further examined in Section 8.

The projects selected for a particular year are removed from the next year's supply curve. Thus, the supply curve in the last year does not represent a comprehensive supply curve of all resources available, but only those resources available for development at that time. It can be seen that the cost paid for renewable and advanced energy gradually increases as the lower cost resources are developed earlier in the RES term.

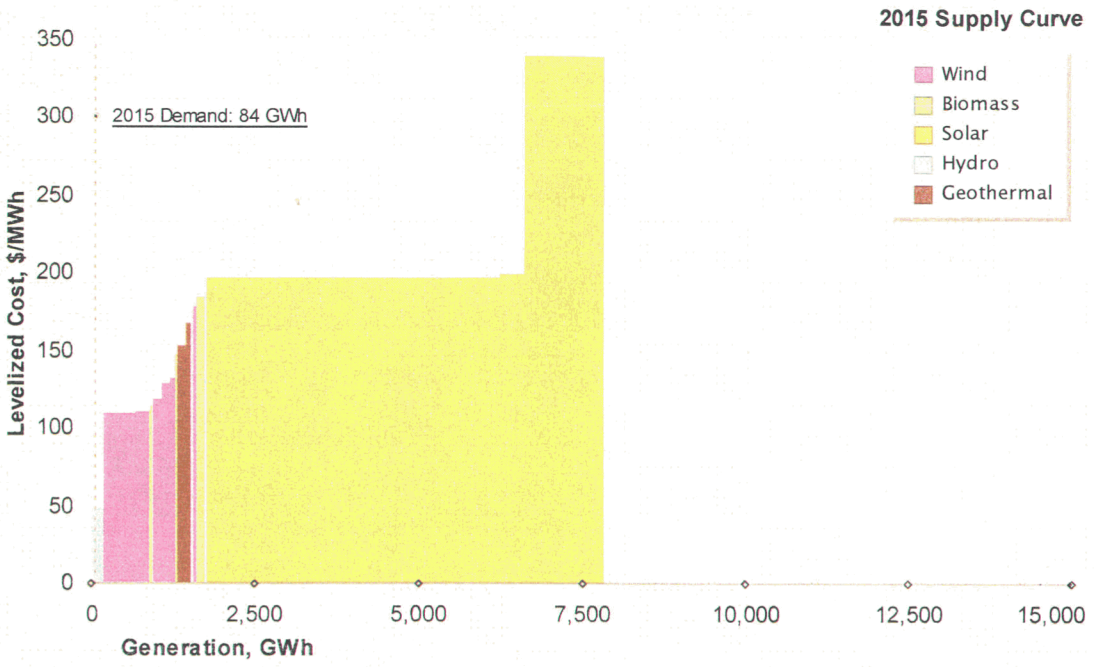


Figure 7-4. 2015 Supply Curve.

Figure 7-5 illustrates how the supply curves are different for each year, as new projects are added as they become available and other projects are removed as they are developed.

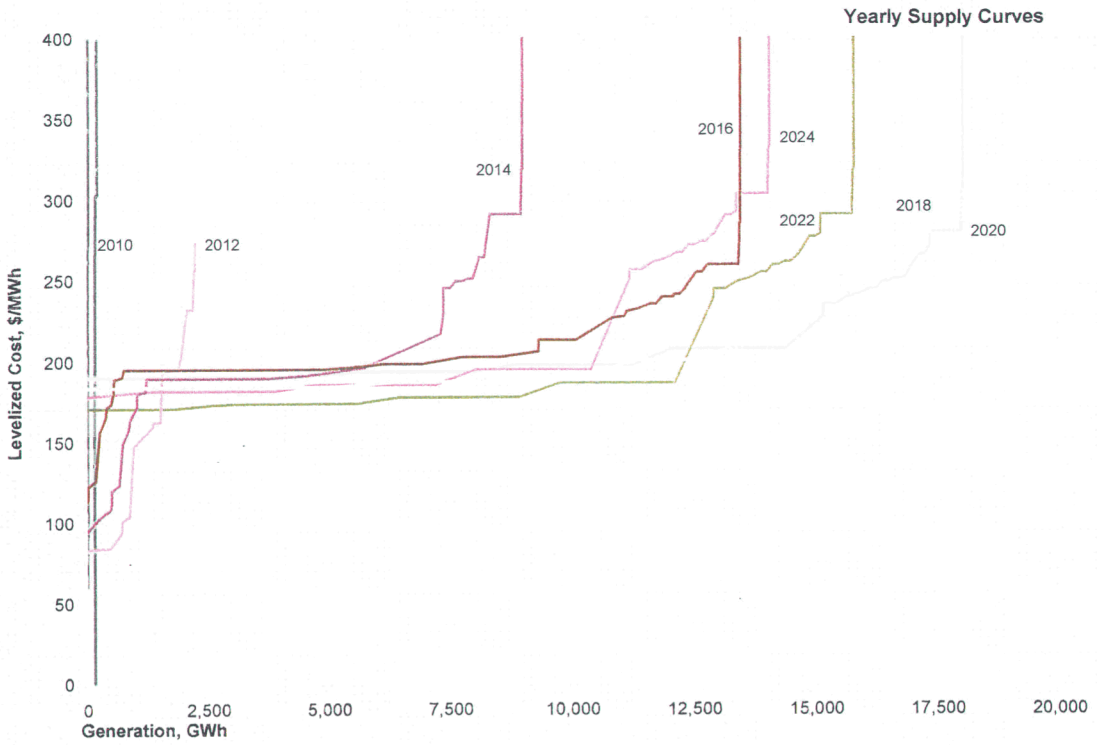


Figure 7-5. Supply Curves.

Figure 7-6 shows the total supply curve for Arizona in the year 2025. This supply curve is different from the others in that it has been assumed that no projects would be developed prior to 2025. The other supply curves do not show projects that have already been built. The 2025 curve shown has all the potential projects that were identified in this study and their cost in 2025. The curve also shows a demand line indicating the projected 2025 renewable energy demand of 11,210 GWh. If development of renewables in Arizona were economically optimum, then all of the projects to the left side of the demand line would be built by 2025.

It should be noted that there are additional higher cost resources that would extend the potential supply of renewables further to the right than indicated on this chart. However, once sufficient projects were identified to meet demand, Black & Veatch did not continue to identify higher cost projects.

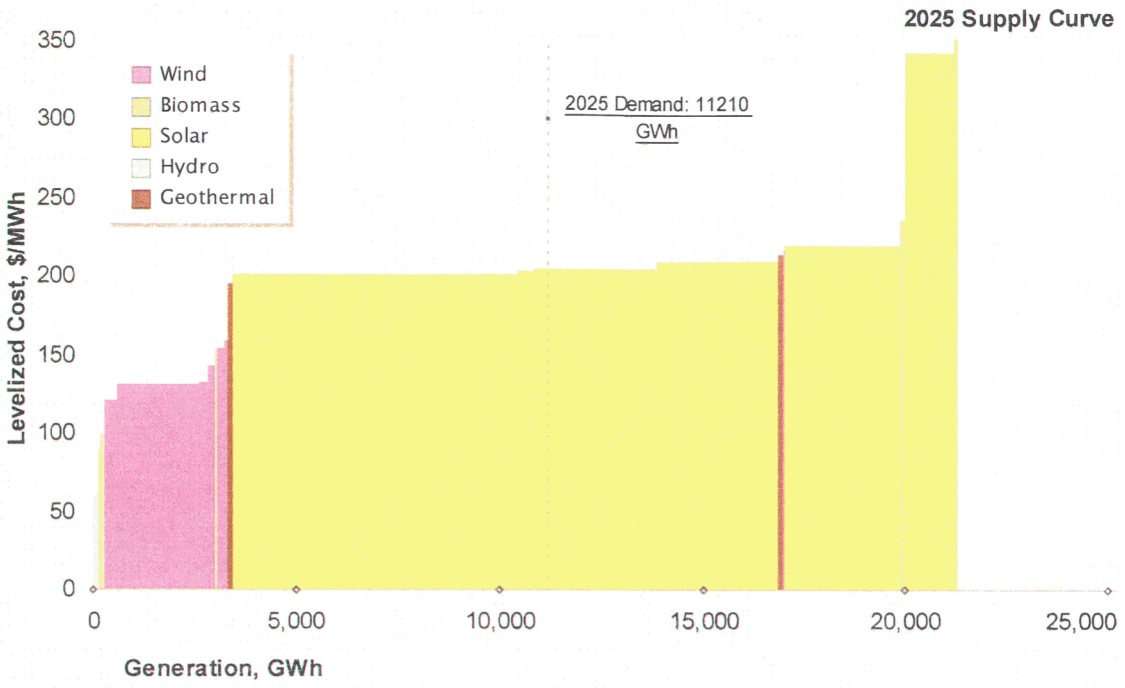


Figure 7-6. Total Arizona Renewable Supply Potential in 2025.

Figure 7-7 shows the breakdown of the total portfolio by energy for 2009, 2017, and 2025. This analysis shows three different phases of renewable energy development. Until 2009, there are only a few renewable energy projects available to come online (solar PV and landfill gas). During this stage, the model assumes that any potential project needs to be developed to meet demand, regardless of cost. From 2009 to 2017, several large wind projects are constructed as the least expensive renewable technologies. A handful of other projects are also built during this time. After 2017, most of the non-solar projects have already been developed, so solar trough projects provide the rest of the renewable energy as the lowest cost technology.

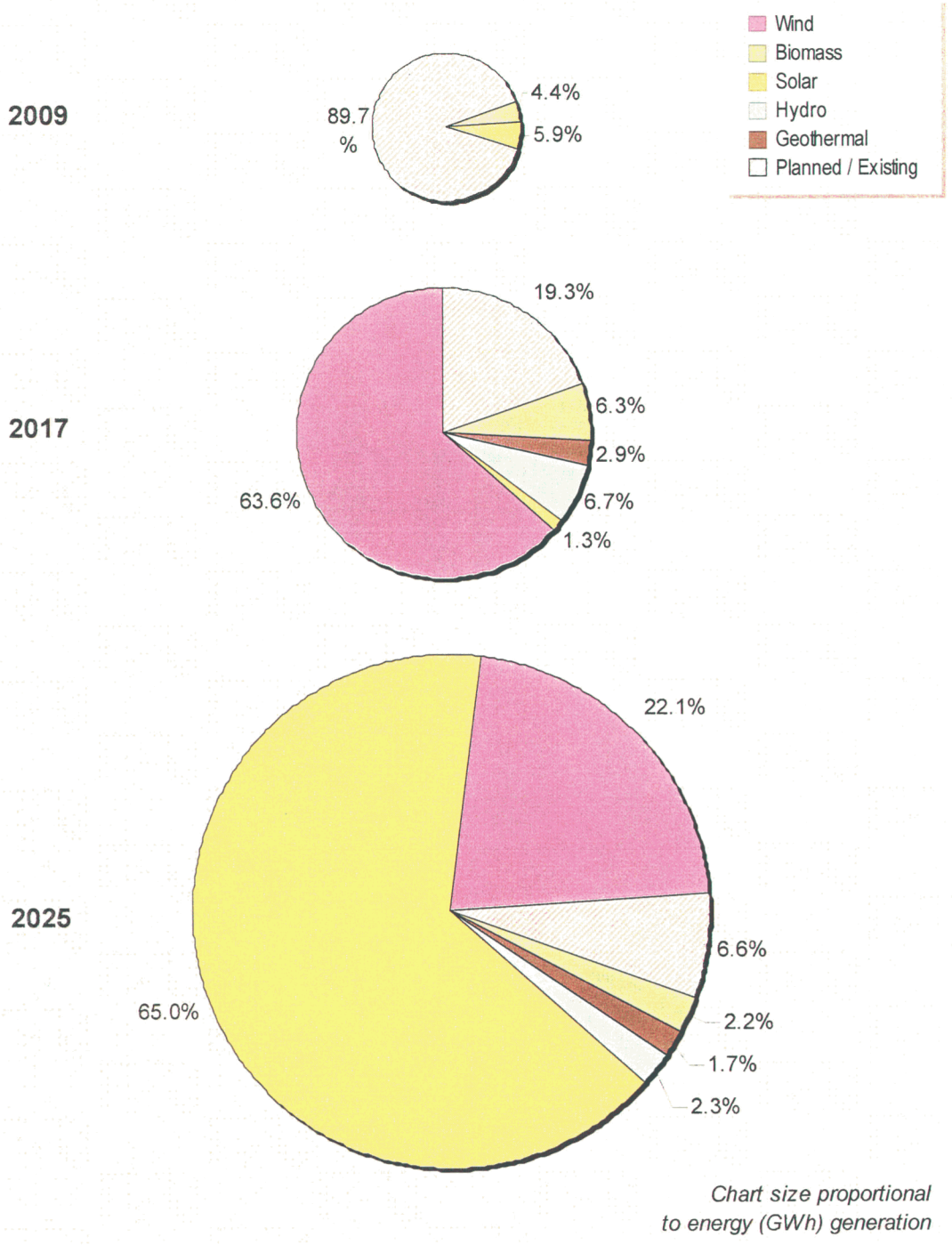


Figure 7-7. Renewable Energy Mix.

Because there are few renewable energy projects available to come online in the near future, there is a renewable energy deficit compared to the demand (see Figure 7-8).

In the near term, in-state resources are insufficient to meet demand. Arizona utilities may have to obtain renewable energy from out-of-state resources. After 2010, there will be sufficient developable projects to "catch up" with demand. In the long run, Arizona will have sufficient renewable resources.

This study did not include an assessment of regional renewable energy supply and demand. Neighboring states, namely California, New Mexico, and Nevada, have aggressive renewable energy standards. These states may have more economical renewable energy sources than Arizona (for example, Salton Sea geothermal resources and New Mexico wind); however, given their own aggressive in-state demands and transmission limitations, they are not a dependable source for Arizona to meet its long-term renewable energy needs. While the importation of renewable energy may help to meet a portion of Arizona's needs, it is not likely to fully satisfy them.

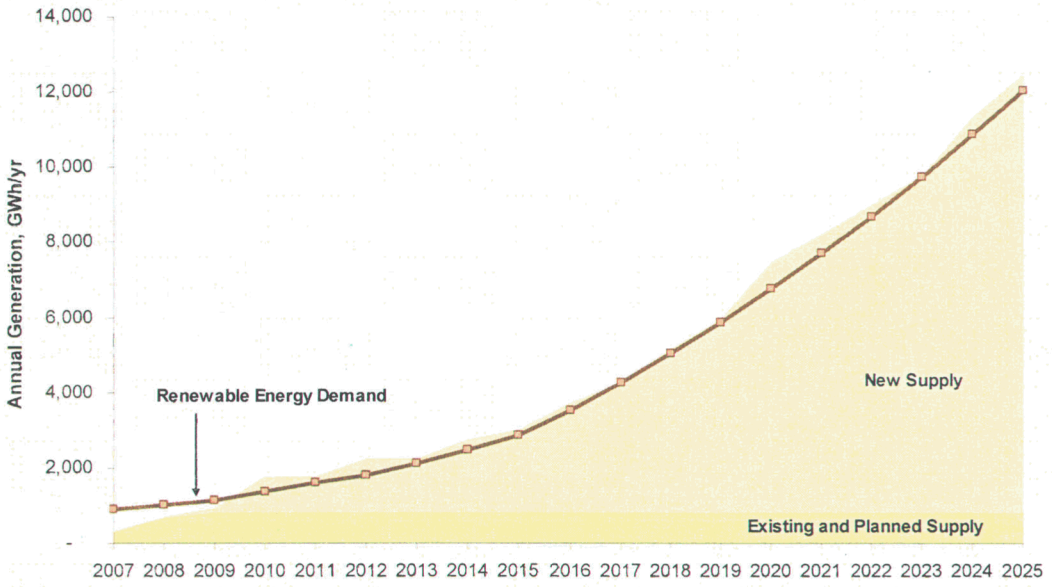


Figure 7-8. Development Compared to Demand.

8.0 Assessment of Key Risk Factors

Black & Veatch analyzed some of the risk factors of interest to utilities in Arizona to determine how sensitive the supply curve results would be to changing situations. These factors include tax credit changes, implementation of advanced solar technologies, delayed technical advances, escalating construction costs, manufacturing/supply chain constraints, near term performance learning curve, and competition for limited resources.

8.1 Sensitivity to Tax Credit Changes

The base model assumes that the PTC and ITC will remain in place for another five years, until 2012. Because these tax credits have a significant impact on the cost of power from renewable sources, two sensitivity runs were performed around this assumption:

- Tax credits expire at the end of 2008 (current law)
- Tax credits never expire

Tax credits do not affect the availability of renewable resources, but they do impact the economics. In the long term, whether tax credits expire in 2008 or 2012 has surprisingly little impact on the cumulative average cost of meeting renewable energy demand in Arizona (less than 1 percent). This is because many of the most expensive, large solar projects would likely be built after 2012; they have the same cost under both scenarios. In the near term (through 2014), impacts are more significant. Costs are about 20 percent higher in the period 2009-2012. If tax credits never expire, the impact is significant. By 2025, the total renewable energy cost is about 25 percent lower than the base case assumption.

8.2 Advanced Solar Technologies

Solar is the most expensive of the renewable resources profiled in this study. The lower cost solar resources (about $180-205/MWh in 2007) are about twice as expensive as the bulk of the non-solar resources (about $70-110/MWh in 2007). The base case model included only proven, fully commercial solar technologies such as solar photovoltaics and solar thermal trough. Concentrating PV (CPV) and dish engine technologies have the potential to lower the cost of electricity from solar.

Figure 8-1 shows the forecasted levelized costs for representative solar projects included in the model (the large jump after 2012 is due to tax credit expiration). It can be seen that the solar photovoltaic technologies do not compete with the solar thermal technologies for large, centralized generation using the financing assumptions in the base case model (Section 7 describes the possibility of innovative financing approaches for

solar PV reducing costs substantially). However, if Black & Veatch's assumptions for advancement of dish engine systems prove correct, costs for this technology will become competitive with conventional parabolic trough systems.

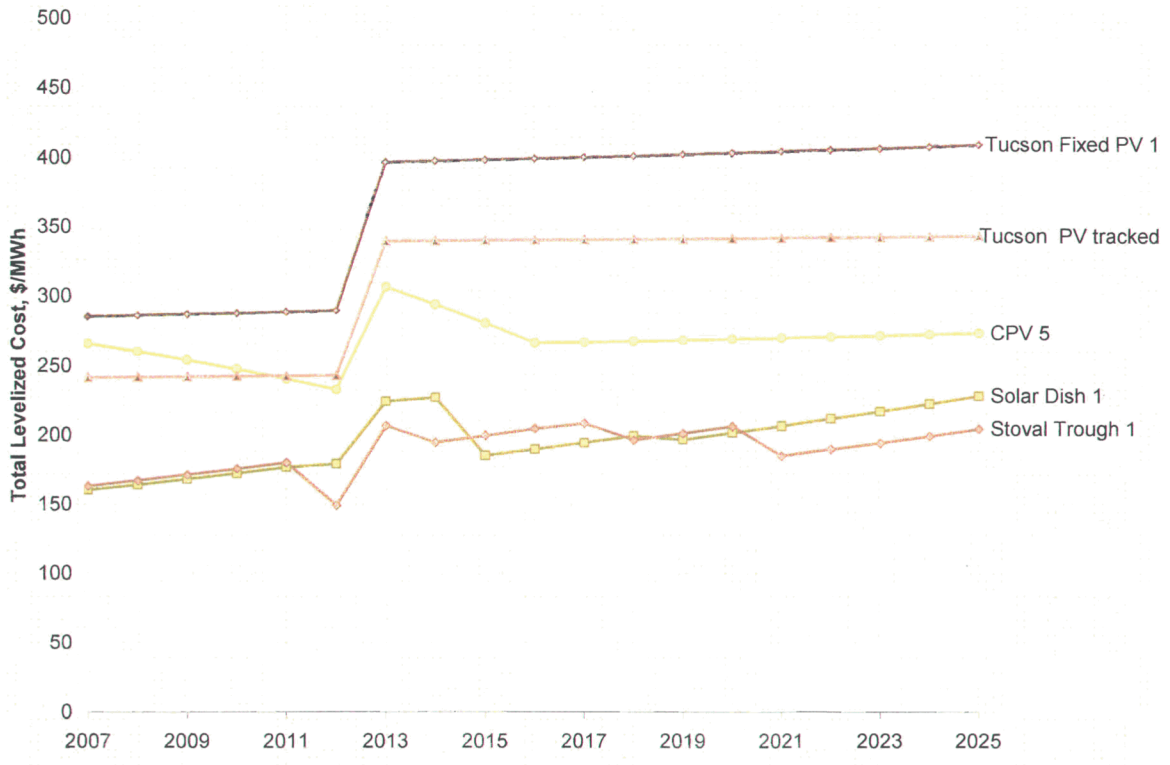


Figure 8-1. Representative Solar Costs.

Arizona appears unique in the U.S. in its dependence on in-state solar energy to meet its mandated renewable energy demands. In the base case, it is estimated that 65 percent of the Arizona renewable demand in 2025 will be met by solar. Generally speaking, other states in the Southwest U.S. will likely be less reliant on solar to meet their renewable energy requirements. This is because other states generally have a larger base of non-solar renewables that they can rely on for near-term needs. By comparison, Arizona's non-solar resources are relatively limited. Solar technologies will play a key part of renewables future in Arizona.

8.3 Delayed Technical Advances

The model base case accounts for expected incremental advances in wind and solar technologies. These are characterized by increasing capacity factors, decreasing

O&M costs, and falling capital costs for solar technologies. However, there is a risk that such advancement may be delayed or not realized. To assess the risk that wind and solar projects would experience delayed technical improvements, Black & Veatch reduced projected technology improvements in the model. To model no improvements in wind turbine design for wind projects, it was assumed that project capacity factors would not increase and O&M costs would not improve on a real basis. For solar thermal projects, it was assumed that capacity factor improvements due to storage would not be available until 2017 instead of 2012 and O&M costs would not improve on a real basis. For solar PV projects, it was assumed that capital costs would not improve on a real basis.

In this sensitivity analysis, wind and solar thermal projects were not as productive compared to the base case. Solar projects, particularly in the out years, are higher cost than the base case. The reduced technical advances will keep levelized costs for wind and solar higher, which will make other technologies (biomass and geothermal) comparatively more attractive in early years. The cumulative effect on the total renewable energy cost will likely be an increase of 15 to 20 percent by 2025. Overall, the delayed technical advances should not be expected to significantly alter the aggregate project mix. The general trend of exhausting nearly all potential biomass, wind, and hydroelectric, and geothermal projects before building solar trough projects holds true.

8.4 Escalating Construction Costs

The model base case has a capital cost escalation of 2.5 percent, which is meant to track close to general inflation. There is a risk that construction costs escalate at a higher rate, depending on future markets for materials and labor. For the sensitivity analysis of construction costs escalating faster than inflation, the capital cost escalator was changed to 5.0 percent.

Increasing the escalator increased levelized busbar costs for all projects. The increase is particularly pronounced for projects further into the future. At year 2025, levelized costs are about 37 percent higher than the base case.

8.5 Manufacturing and Supply Chain Constraints

Manufacturing and supply chain constraints are already built into the model. The projects most likely to be impacted by such constraints are solar and wind. For wind projects, there is currently a delay of up to two years between turbine order and turbine delivery because demand is greater than manufacturing capability. Wind projects were assigned "first year available" dates with this constraint in mind. The earliest any wind project is modeled to be available is 2010, with some not available until 2012 or 2013. If there are additional constraints in the wind supply chain, then it is likely that renewable

energy demand would likely not be met in some years with in-state resources. It should be noted that turbine delivery time is dependent upon the developer. Large developers have framework agreements that may bring turbines to projects more quickly than for smaller developers. Several of the developers of announced wind projects in Arizona should have access to turbines for their pipeline projects.

Solar projects were also modeled with manufacturing constraints in mind. For example, there is a supply constraint for reflective mirrors that are used in solar trough projects. Because of a supply lag, the first solar trough project is not modeled to be available until 2011. After that point, the number of solar trough facilities that can be developed each year is limited by the anticipated future manufacturing capability. Similarly, CPV projects are modeled to be available on a small scale in the near future. However, the amount of CPV potential capacity slowly grows to reflect an expanding manufacturing base.

8.6 Near-Term Performance Learning Curve

In the near-term, projects may under-deliver renewable energy as they gain experience during the initial operational and development learning period. For example, many planned wind projects in Arizona have experienced significant delays or have been completely stalled. Projects may also fail outright, and not supply any renewable energy. Both factors would impact overall renewable energy portfolio development.

Most entities obligated by an RPS have chosen to purchase renewable generation from an independent power producer (IPP), as opposed to owning a renewable generation facility. IPP ownership of renewable generation is due to historical factors, especially the Public Utility Regulatory Policies Act (PURPA) of 1978. There is less experience contracting for renewable energy compared to more mature energy technologies. Utilities are forced to stay aware of the risk of contract failure that comes as a result of learning curve effects.

Even if a renewable project has made it far enough in the development cycle to secure a power purchase agreement (PPA) with a utility, there are still many things that can go wrong to end or significantly delay a project. In 2006 Black & Veatch co-authored a report on contract failure for the California Energy Commission.[14] Black & Veatch surveyed roughly 30 utilities regarding their renewable purchases, and collected data on nearly 3,000 MW of renewable energy contracts.

[14] "Building a "Margin of Safety" into Renewable Energy Procurements: A Review of Experience with Contract Failure" January 2006. California Energy Commission contractor's report. Available at www.energy.ca.gov

The results from the study, summarized in Figure 8-2 show that close to half of renewable energy contracts fail after contract execution. While "failure" here is defined as projects that were canceled, significantly delayed, or were in default, even if failure is defined as canceled, a quarter of all projects fail. The report attempts to capture some of the reasons for contract failure, such as site or permit problems, inability to obtain financing, or other reasons. The issues mentioned by utility personnel as reasons for contract failure are shown in Figure 8-3.

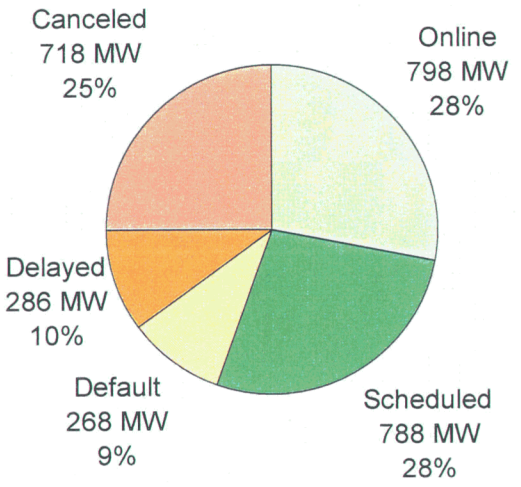


Figure 8-2. Contract Failure Data for North American Renewables

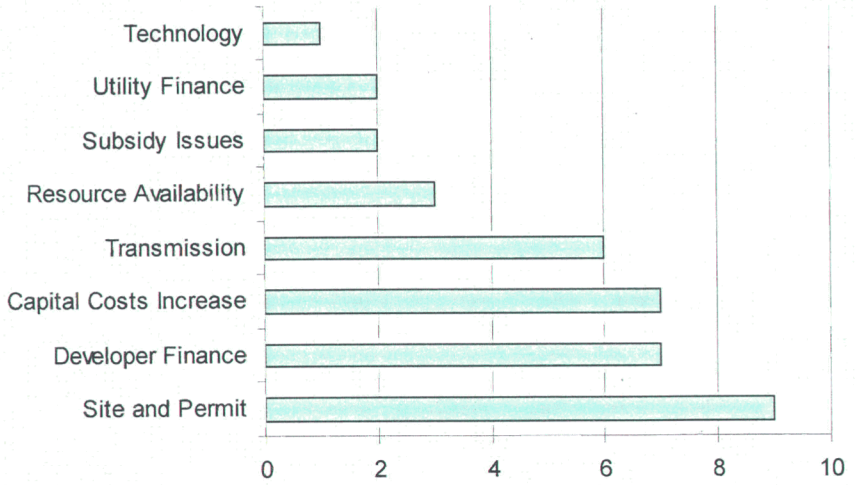


Figure 8-3. Causes of Contract Failure, Frequency of Mentions.

Most, if not all, of the reasons renewable energy contracts fail are beyond the control of the utility, and some are beyond the control of the developer. No matter the cause, contract failure is a real problem for utilities trying to meet renewable energy demands.

To apply learning curve effects, it is important to understand that one of the reasons renewable energy contracts fail is a lack of experience with contracting for renewables. To mitigate this risk, utilities may "over-procure" renewable energy. For example, if a utility wanted renewable projects to produce 600 GWh for a certain year, the utility might enter into contract with projects for 800 GWh or more with the assumption that some projects would either be significantly delayed or never come online.

From a supply curve standpoint, contract failure and the utility counter measure of over-procurement serve to shift the supply curve to the left. When a project fails, its generation is removed from the supply curve, while all projects to the right (more expensive projects) shift left to fill in the space. As lower-priced projects fail, utilities will be forced to contract with more expensive renewable projects to secure renewable energy.

8.7 Competition for Limited Renewable Resources

As more and more renewable energy projects are developed, there will be fewer renewable resources to utilize in the future. There is a risk that utility competition for limited renewable resources will increase prices.

For renewable energy procurement, utilities typically contract with the least expensive energy available (projects on the left side of the supply curve). As renewable projects are developed, the supply curve shifts to the left. Utilities see an increasing marginal levelized cost as more expensive projects become the new lowest cost options. That is, costs increase as more renewable energy is developed. This is an expected phenomenon. However, there is a risk that IPPs will charge Arizona utilities the highest price possible that stays below the marginal cost of energy. Consider an example of a utility wanting to procure energy from three renewable energy projects for a certain year. The utility would have likely have several projects at different energy costs from which to choose. Other factors being equal, the three lowest priced projects would be chosen, with the most expensive project setting the marginal cost of energy (the most the utility is willing to pay at the time). If developers of the other two projects knew the utility's marginal cost for renewables, they might be incented to raise their prices to the marginal cost to maximize profit. The utility would be forced to pay more for the energy, with no

other less expensive projects to pursue. This phenomenon occurs in supply constrained markets.

For Arizona utilities, it is possible that renewable energy developers may set energy prices as high as possible while still beating the marginal cost of energy. This would increase the price of power purchase agreements.

Appendix A. Consolidated Project Assumptions

Project Name	Technology	Net Capacity, MW	Capacity Factor	Net Generation, GWhr/yr	First Year Available	Capital Cost, $/kW	Fixed O&M, $/kWyr	Variable O&M, $/MWhr	Fuel Cost, $/Mbtu	NPHR, Btu/kWhr	Interconnection Voltage, kV	Distance to line, miles	Transmission Owner	Project Life, years	Interest during Construction, $/kW
Rattlesnake Crater 1	Wind Onshore	62	26%	138.8	2010	1600	25	9	0.0	0	230	0	APS	20	45
Rattlesnake Crater 2	Wind Onshore	78	30%	202.5	2011	1600	25	8	0.0	0	230	0	APS	20	45
Buckhorn	Wind Onshore	46	30%	119.3	2010	1680	25	8	0.0	0	69	7	APS	20	47
Buffalo Range	Wind Onshore	158	30%	409.0	2010	1600	25	8	0.0	0	230	1	APS	20	45
Chevelon 1	Wind Onshore	171	30%	442.2	2013	1600	25	8	0.0	0	345	0	APS	20	45
Chevelon 2	Wind Onshore	171	30%	442.2	2011	1600	25	8	0.0	0	345	0	APS	20	45
Chevelon 3	Wind Onshore	171	30%	442.2	2012	1600	25	8	0.0	0	345	0	APS	20	45
Chevelon 4	Wind Onshore	84	33%	238.6	2010	1600	25	7	0.0	0	345	0	APS	20	45
Greens Peak	Wind Onshore	31	27%	72.8	2010	1680	25	8	0.0	0	69	6	unknown	20	47
Kingstone	Wind Onshore	18	27%	43.8	2012	1840	25	8	0.0	0	230	5	APS	20	52
Beardsley Canal Drop	Hydro	1.0	40%	3.5	2013	4324	24	6	0.0	0	35	1	unknown	30	363
Yuma Main Canal	Hydro	1.4	40%	4.9	2013	4079	22	5	0.0	0	35	1	unknown	30	343
Waddell	Hydro	1.5	40%	5.3	2013	4037	21	5	0.0	0	35	1	unknown	30	339
CAP Canal Turnout	Hydro	2.5	40%	8.8	2013	3718	19	5	0.0	0	35	1	unknown	30	312
Roosevelt (RWCD)	Hydro	3.2	40%	11.2	2013	3579	18	4	0.0	0	35	1	unknown	30	301
Tucson	Hydro	0.4	99%	3.5	2013	3429	17	4	0.0	0	35	1	unknown	30	288
Glen Canyon	Hydro	71.8	45%	283.1	2015	997	8	2	0.0	0	230	1	APS	30	84
Clifton	Geothermal	20.0	70%	122.6	2013	4000	0	30	0.0	0	35	10	APS	20	392
Gillard	Geothermal	15.0	70%	92.0	2014	4500	0	30	0.0	0	35	10	APS	20	441
Butterfield Station Landfill	Biomass Landfill Gas	2	80%	16.9	2009	2062	0	18	2.0	11500	35	0	APS	15	58
Salt River Landfill	Biomass Landfill Gas	1	80%	5.5	2009	2193	0	18	2.0	11500	0	0	SRP	15	61
27th Avenue Landfill	Biomass Landfill Gas	3	80%	21.0	2050	2037	0	18	2.0	11500	35	0	0	15	57
Apache Junction LF	Biomass Landfill Gas	0	80%	1.8	2010	2328	0	18	2.0	11500	0	0	SRP	15	65
Cinder Lake MSW LF	Biomass Landfill Gas	1	80%	3.9	2011	2233	0	18	2.0	11500	0	0	APS	15	63
City of Glendale Municipal Landfi	Biomass Landfill Gas	1	80%	9.1	2009	2132	0	18	2.0	11500	35	0	APS	15	60
Grey Wolf Landfill	Biomass Landfill Gas	1	80%	5.5	2012	2193	0	18	2.0	11500	0	0	APS	15	61
Huachuca City Landfill	Biomass Landfill Gas	0	80%	2.2	2012	2305	0	18	2.0	11500	0	0	TEP	15	65
North Center Street Landfill	Biomass Landfill Gas	1	80%	3.6	2008	2242	0	18	2.0	11500	0	0	SRP	15	63
Northwest Regional MSW Landfi	Biomass Landfill Gas	0	80%	1.8	2010	2328	0	18	2.0	11500	0	0	APS	15	65
Painted Desert Landfill	Biomass Landfill Gas	0	80%	2.7	2010	2277	0	18	2.0	11500	0	0	APS	15	64
Queen Creek MSW Landfill	Biomass Landfill Gas	0	80%	2.7	2011	2277	0	18	2.0	11500	0	0	SRP	15	64
Rio Rico MSW Landfill	Biomass Landfill Gas	0	80%	1.8	2008	2328	0	18	2.0	11500	0	0	TEP	15	65
Skunk Creek Landfill	Biomass Landfill Gas	3	80%	21.0	2050	2037	0	18	2.0	11500	35	0	0	15	57
Cocopah Landfill	Biomass Landfill Gas	1	80%	4.0	2011	2230	0	18	2.0	11500	0	0	APS	15	62
Southwest Regional Landfill	Biomass Landfill Gas	0	80%	2.2	2010	2302	0	18	2.0	11500	0	0	APS	15	64
Tangerine Road MSW Landfill	Biomass Landfill Gas	1	80%	3.8	2008	2236	0	18	2.0	11500	0	0	TEP	15	63
Cholla cofiring	Biomass Cofiring	10	80%	70.1	2010	900	61	0	2.5	11000	0	0	APS	20	24
Springerville cofiring	Biomass Cofiring	10	80%	70.1	2010	900	61	0	2.3	10000	0	0	TEP	20	24
Maricopa City Direct	Biomass Direct	20	80%	140.2	2012	4000	160	12	1.9	14500	115	2	0	20	224
Snowflake Digester (Swine)	Biomass Digester	4	80%	24.5	2010	2000	0	20	0.0	15000	35	0	0	15	112
Buckeye Digester (Dairy)	Biomass Digester	3	80%	17.5	2010	3000	0	20	1.5	15000	35	0	0	15	168
Chandler Digester (Dairy)	Biomass Digester	2	80%	10.5	2010	3500	0	20	1.5	15000	35	0	0	15	196
Maricopa Digester (Beef)	Biomass Digester	6	80%	42.0	2050	3500	0	20	0.0	15000	35	0	0	15	196
Maricopa Digester (Poultry)	Biomass Digester	2	80%	16.8	2010	3000	0	20	0.0	15000	35	0	0	15	168
Solar Dish 1	Solar Dish	100	27%	240.0	2011	3300	23	25	0.0	0	230	1	N/A	20	0
Solar Dish 2	Solar Dish	100	27%	240.0	2012	3300	23	25	0.0	0	230	1	N/A	20	0
Solar Dish 3	Solar Dish	100	27%	240.0	2013	3300	23	25	0.0	0	230	1	N/A	20	0
Solar Dish 4	Solar Dish	200	27%	480.0	2014	3300	23	25	0.0	0	230	1	N/A	20	0
Solar Dish 5	Solar Dish	200	27%	480.0	2015	3300	23	25	0.0	0	230	1	N/A	20	0
Solar Dish 6	Solar Dish	200	27%	480.0	2016	3300	23	25	0.0	0	230	1	N/A	20	0
Solar Dish 7	Solar Dish	400	27%	960.1	2017	3300	23	25	0.0	0	230	1	N/A	20	0
Solar Dish 8	Solar Dish	400	27%	960.1	2018	3300	23	25	0.0	0	230	1	N/A	20	0
Solar Dish 9	Solar Dish	400	27%	960.1	2019	3300	23	25	0.0	0	230	1	N/A	20	0
Solar Dish 10	Solar Dish	400	27%	960.1	2020	3300	23	25	0.0	0	230	1	N/A	20	0
Solar Dish 11	Solar Dish	400	27%	960.1	2020	3300	23	25	0.0	0	230	1	N/A	20	0
Solar Dish 12	Solar Dish	400	27%	960.1	2021	3300	23	25	0.0	0	230	1	N/A	20	0

Solar Dish 13	Solar Dish	400	27%	960.1	2021	3300	23	25	0.0	0	230	1	N/A	20	0
Stoval Trough 1	Solar Trough	100	30%	261.0	2011	4200	55	0	0.0	0	230	1	0	20	0
Stoval Trough 2	Solar Trough	200	30%	522.1	2013	4200	55	0	0.0	0	230	1	0	20	0
Stoval Trough 3	Solar Trough	200	30%	522.1	2013	4200	55	0	0.0	0	230	1	0	20	0
Stoval Trough 4	Solar Trough	200	30%	522.1	2014	4200	55	0	0.0	0	230	1	0	20	0
Stoval Trough 5	Solar Trough	200	30%	522.1	2014	4200	55	0	0.0	0	230	1	0	20	0
Stoval Trough 6	Solar Trough	200	30%	522.1	2015	4200	55	0	0.0	0	230	1	0	20	0
Stoval Trough 7	Solar Trough	200	30%	522.1	2015	4200	55	0	0.0	0	230	1	0	20	0
Stoval Trough 8	Solar Trough	200	30%	522.1	2016	4200	55	0	0.0	0	230	1	0	20	0
Stoval Trough 9	Solar Trough	200	30%	522.1	2016	4200	55	0	0.0	0	230	1	0	20	0
Stoval Trough 10	Solar Trough	200	30%	522.1	2016	4200	55	0	0.0	0	230	1	0	20	0
Phoenix Trough 1	Solar Trough	200	27%	478.3	2019	4200	55	0	0.0	0	230	1	0	20	0
Phoenix Trough 2	Solar Trough	200	27%	478.3	2019	4200	55	0	0.0	0	230	1	0	20	0
Phoenix Trough 3	Solar Trough	200	27%	478.3	2019	4200	55	0	0.0	0	230	1	0	20	0
Phoenix Trough 4	Solar Trough	200	27%	478.3	2019	4200	55	0	0.0	0	230	1	0	20	0
Tucson Trough 1	Solar Trough	200	29%	502.8	2018	4200	55	0	0.0	0	230	1	0	20	0
Tucson Trough 2	Solar Trough	200	29%	502.8	2018	4200	55	0	0.0	0	230	1	0	20	0
Tucson Trough 3	Solar Trough	200	29%	502.8	2018	4200	55	0	0.0	0	230	1	0	20	0
Tucson Trough 4	Solar Trough	200	29%	502.8	2018	4200	55	0	0.0	0	230	1	0	20	0
Yuma Trough 1	Solar Trough	200	29%	513.3	2017	4200	55	0	0.0	0	230	1	0	20	0
Yuma Trough 2	Solar Trough	200	29%	513.3	2017	4200	55	0	0.0	0	230	1	0	20	0
Yuma Trough 3	Solar Trough	200	29%	513.3	2017	4200	55	0	0.0	0	230	1	0	20	0
Yuma Trough 4	Solar Trough	200	29%	513.3	2017	4200	55	0	0.0	0	230	1	0	20	0
CPV 1	Concentrating Solar P	1	29%	2.5	2008	7600	100	0	0.0	0	35	0	N/A	30	399
CPV 2	Concentrating Solar P	5	29%	12.7	2009	7200	60	0	0.0	0	35	0	N/A	30	378
CPV 3	Concentrating Solar P	5	29%	12.7	2010	7200	60	0	0.0	0	35	0	N/A	30	378
CPV 4	Concentrating Solar P	5	29%	12.7	2010	7200	60	0	0.0	0	35	0	N/A	30	378
CPV 5	Concentrating Solar P	10	29%	25.4	2011	6800	50	0	0.0	0	35	0	N/A	30	357
CPV 6	Concentrating Solar P	10	29%	25.4	2011	6800	50	0	0.0	0	35	0	N/A	30	357
CPV 7	Concentrating Solar P	10	29%	25.4	2012	6800	50	0	0.0	0	35	0	N/A	30	357
CPV 8	Concentrating Solar P	10	29%	25.4	2012	6800	50	0	0.0	0	35	0	N/A	30	357
CPV 9	Concentrating Solar P	10	29%	25.4	2012	6800	50	0	0.0	0	35	0	N/A	30	357
CPV 10	Concentrating Solar P	10	29%	25.4	2012	6800	50	0	0.0	0	35	0	N/A	30	357
CPV 11	Concentrating Solar P	10	29%	25.4	2013	6800	50	0	0.0	0	35	0	N/A	30	357
CPV 12	Concentrating Solar P	10	29%	25.4	2013	6800	50	0	0.0	0	35	0	N/A	30	357
CPV 13	Concentrating Solar P	10	29%	25.4	2013	6800	50	0	0.0	0	35	0	N/A	30	357
CPV 14	Concentrating Solar P	10	29%	25.4	2013	6800	50	0	0.0	0	35	0	N/A	30	357
CPV 15	Concentrating Solar P	10	29%	25.4	2013	6800	50	0	0.0	0	35	0	N/A	30	357
CPV 16	Concentrating Solar P	10	29%	25.4	2013	6800	50	0	0.0	0	35	0	N/A	30	357
CPV 17	Concentrating Solar P	10	29%	25.4	2013	6800	50	0	0.0	0	35	0	N/A	30	357
CPV 18	Concentrating Solar P	10	29%	25.4	2013	6800	50	0	0.0	0	35	0	N/A	30	357
CPV 19	Concentrating Solar P	10	29%	25.4	2013	6800	50	0	0.0	0	35	0	N/A	30	357
CPV 20	Concentrating Solar P	10	29%	25.4	2013	6800	50	0	0.0	0	35	0	N/A	30	357
CPV 21	Concentrating Solar P	25	29%	63.5	2014	6800	50	0	0.0	0	35	0	N/A	30	357
CPV 22	Concentrating Solar P	25	29%	63.5	2014	6800	50	0	0.0	0	35	0	N/A	30	357
CPV 23	Concentrating Solar P	25	29%	63.5	2014	6800	50	0	0.0	0	35	0	N/A	30	357
CPV 24	Concentrating Solar P	25	29%	63.5	2014	6800	50	0	0.0	0	35	0	N/A	30	357
CPV 25	Concentrating Solar P	50	29%	127.0	2015	6800	50	0	0.0	0	35	0	N/A	30	357
CPV 26	Concentrating Solar P	50	29%	127.0	2015	6800	50	0	0.0	0	35	0	N/A	30	357
CPV 27	Concentrating Solar P	100	29%	254.0	2016	6800	50	0	0.0	0	35	0	N/A	20	357
CPV 28	Concentrating Solar P	100	29%	254.0	2016	6800	50	0	0.0	0	35	0	N/A	20	357
CPV 29	Concentrating Solar P	200	29%	508.1	2017	6800	50	0	0.0	0	35	0	N/A	20	357
CPV 30	Concentrating Solar P	300	29%	762.1	2018	6800	50	0	0.0	0	35	0	N/A	20	357
Tucson Fixed PV 1	Solar Photovoltaic	5	21%	9.3	2008	5200	30	0	0.0	0	35	0	TEP	20	273
Phoenix Fixed PV 1	Solar Photovoltaic	10	20%	17.6	2008	5200	30	0	0.0	0	35	0	APS	20	273
Tucson Fixed PV 2	Solar Photovoltaic	5	21%	9.3	2009	5200	30	0	0.0	0	35	0	TEP	20	273
Phoenix Fixed PV 2	Solar Photovoltaic	10	20%	17.6	2009	5200	30	0	0.0	0	35	0	APS	20	273
Tucson PV tracked	Solar Photovoltaic	500	27%	1178.2	2010	6000	30	0	0.0	0	35	0	TEP	20	315

Appendix B. Forecast Cost of Energy for Each Project

Levelized Cost Calculator

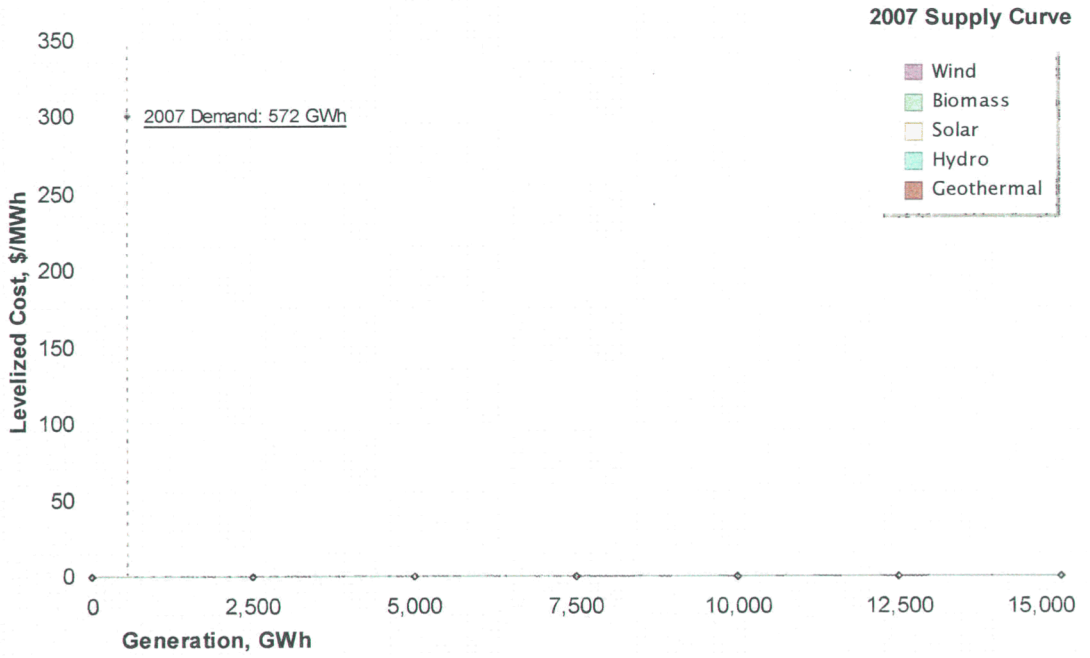
Incremental Levelized Cost

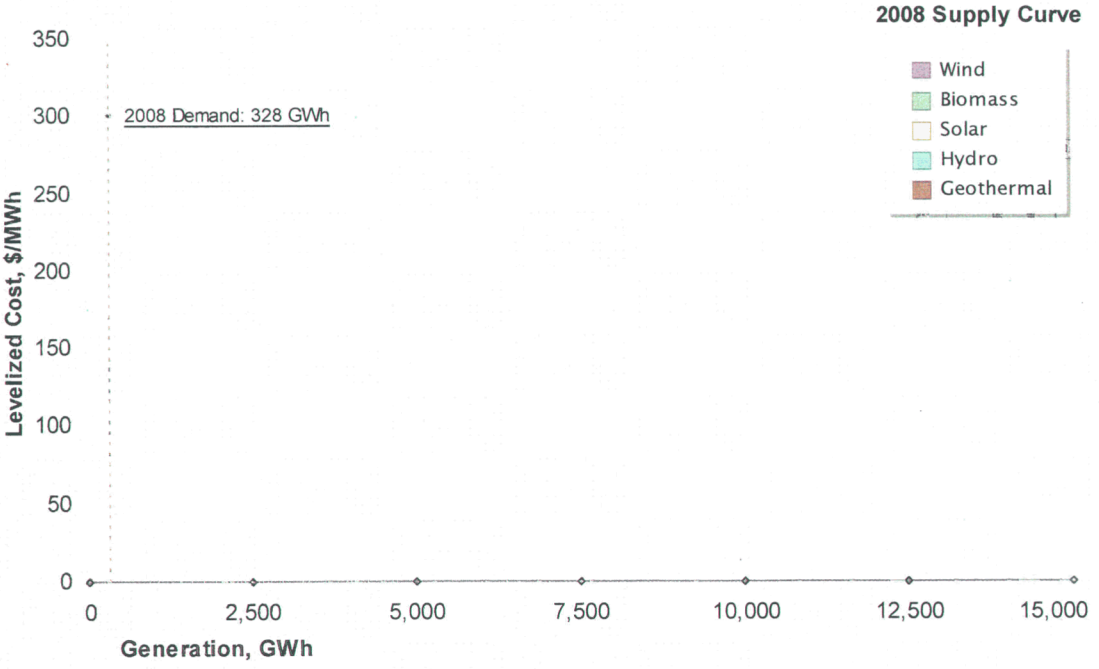
Project Name	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Rattlesnake Crater 1	99	100	101	101	103	104	124	126	128	130	133	135	137	140	143	145	148	151	154
Rattlesnake Crater 2	84	84	84	85	86	88	106	108	110	112	114	116	118	120	123	125	127	130	132
Buckhorn	90	91	92	92	94	95	114	116	118	120	123	125	127	129	132	134	137	140	142
Buffalo Range	83	83	83	84	85	87	105	107	109	111	113	115	117	119	121	124	126	129	131
Chevelon 1	83	83	83	84	85	86	105	107	109	111	113	115	117	119	121	124	126	128	131
Chevelon 2	83	83	83	84	85	86	105	107	109	111	113	115	117	119	121	124	126	128	131
Chevelon 3	83	83	83	84	85	86	105	107	109	111	113	115	117	119	121	124	126	128	131
Chevelon 4	75	76	76	76	77	79	97	99	101	103	105	106	108	110	112	115	117	119	121
Greens Peak	102	103	103	104	106	108	127	129	131	134	136	139	141	144	147	150	152	155	158
Kingstone	141	142	144	145	148	151	171	174	178	181	185	188	192	196	200	204	208	213	217
Beardsley Canal Drop	215	220	226	231	237	243	257	264	270	277	284	291	299	306	314	321	330	338	346
Yuma Main Canal	189	194	199	204	209	214	228	233	239	245	251	257	264	270	277	284	291	299	306
Waddell	185	190	194	199	204	209	223	228	234	240	246	252	258	265	272	278	285	292	300
CAP Canal Turnout	158	162	166	170	174	178	191	196	201	206	211	216	222	227	233	239	245	251	257
Roosevelt (RWCD)	147	151	155	159	162	167	179	184	188	193	198	203	208	213	218	224	229	235	241
Tucson	105	107	110	113	116	118	130	133	136	140	143	147	150	154	158	162	166	170	174
Glen Canyon	32	33	34	35	36	36	46	47	48	49	50	52	53	54	56	57	59	60	62
Clifton	110	113	116	119	122	125	145	149	153	157	161	165	169	173	177	182	186	191	196
Gillard	122	125	128	132	135	138	159	163	167	171	176	180	185	189	194	199	204	209	214
Butterfield Station Landfill	89	91	94	96	98	101	114	117	120	123	126	129	132	136	139	142	146	150	153
Salt River Landfill	82	84	86	88	91	93	106	108	111	114	117	120	123	126	129	132	135	139	142
27th Avenue Landfill	87	89	91	94	96	98	111	114	117	120	123	126	129	132	136	139	142	146	150
Apache Junction LF	85	87	89	91	94	96	109	112	114	117	120	123	126	129	133	136	139	143	146
Cinder Lake MSW LF	83	85	87	89	91	94	107	109	112	115	118	121	124	127	130	133	137	140	143
City of Glendale Municipal Landfill	99	102	104	107	109	112	125	129	132	135	138	142	145	149	153	157	161	165	169
Grey Wolf Landfill	82	84	86	88	91	93	106	108	111	114	117	120	123	126	129	132	135	139	142
Huachuca City Landfill	84	86	89	91	93	95	108	111	114	117	120	123	126	129	132	135	139	142	146
North Center Street Landfill	83	85	87	89	92	94	107	110	112	115	118	121	124	127	130	133	137	140	144
Northwest Regional MSW Landfill	85	87	89	91	94	96	109	112	114	117	120	123	126	129	133	136	139	143	146
Painted Desert Landfill	84	86	88	90	92	95	108	110	113	116	119	122	125	128	131	134	138	141	145
Queen Creek MSW Landfill	84	86	88	90	92	95	108	110	113	116	119	122	125	128	131	134	138	141	145
Rio Rico MSW Landfill	85	87	89	91	94	96	109	112	114	117	120	123	126	129	133	136	139	143	146
Skunk Creek Landfill	87	89	91	94	96	98	111	114	117	120	123	126	129	132	136	139	142	146	150
Cocopah Landfill	83	85	87	89	91	94	107	109	112	115	118	121	124	127	130	133	136	140	143
Southwest Regional Landfill	84	86	89	91	93	95	108	111	114	117	120	122	126	129	132	135	139	142	146
Tangerine Road MSW Landfill	83	85	87	89	92	94	107	109	112	115	118	121	124	127	130	133	137	140	144
Cholla cofiring	63	65	66	68	70	71	73	75	77	79	81	83	85	87	89	91	94	96	99
Springerville cofiring	58	59	61	62	64	65	67	69	70	72	74	76	78	79	81	84	86	88	90
Maricopa City Direct	143	147	151	154	158	162	176	180	184	189	194	199	204	209	214	219	225	230	236
Snowflake Digester (Swine)	62	64	65	67	69	70	82	85	87	89	91	93	96	98	100	103	106	108	111
Buckeye Digester (Dairy)	112	115	117	120	123	126	140	143	147	151	154	158	162	166	170	175	179	184	188
Chandler Digester (Dairy)	128	132	135	138	142	145	159	163	167	171	176	180	185	189	194	199	204	209	214
Maricopa Digester (Beef)	90	92	95	97	99	102	115	118	121	124	127	130	133	136	140	143	147	151	154
Maricopa Digester (Poultry)	86	88	90	92	95	97	110	113	115	118	121	124	127	130	134	137	141	144	148
Solar Dish 1	160	164	168	172	177	179	224	227	185	190	194	199	196	201	206	212	217	222	228
Solar Dish 2	160	164	168	172	177	179	224	227	185	190	194	199	196	201	206	212	217	222	228

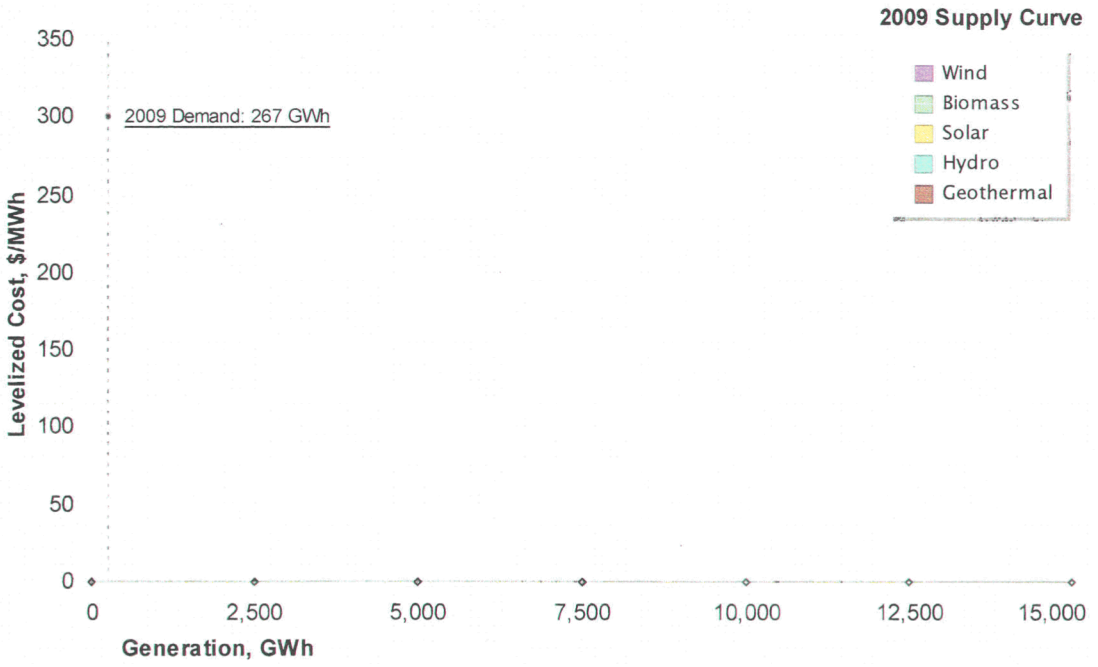
Solar Dish 3	160	164	168	172	177	179	224	227	185	190	194	199	196	201	206	212	217	222	228
Solar Dish 4	158	162	166	171	175	177	222	225	183	188	192	197	194	199	204	209	214	220	225
Solar Dish 5	158	162	166	171	175	177	222	225	183	188	192	197	194	199	204	209	214	220	225
Solar Dish 6	158	162	166	171	175	177	222	225	183	188	192	197	194	199	204	209	214	220	225
Solar Dish 7	158	162	166	170	174	176	221	224	182	187	191	196	193	198	203	208	213	219	224
Solar Dish 8	158	162	166	170	174	176	221	224	182	187	191	196	193	198	203	208	213	219	224
Solar Dish 9	158	162	166	170	174	176	221	224	182	187	191	196	193	198	203	208	213	219	224
Solar Dish 10	158	162	166	170	174	176	221	224	182	187	191	196	193	198	203	208	213	219	224
Solar Dish 11	158	162	166	170	174	176	221	224	182	187	191	196	193	198	203	208	213	219	224
Solar Dish 12	158	162	166	170	174	176	221	224	182	187	191	196	193	198	203	208	213	219	224
Solar Dish 13	158	162	166	170	174	176	221	224	182	187	191	196	193	198	203	208	213	219	224
Stoval Trough 1	163	167	171	175	180	149	206	194	199	204	208	196	201	206	185	189	194	199	204
Stoval Trough 2	161	165	170	174	178	147	205	193	197	202	206	194	199	204	183	187	192	197	202
Stoval Trough 3	161	165	170	174	178	147	205	193	197	202	206	194	199	204	183	187	192	197	202
Stoval Trough 4	161	165	170	174	178	147	205	193	197	202	206	194	199	204	183	187	192	197	202
Stoval Trough 5	161	165	170	174	178	147	205	193	197	202	206	194	199	204	183	187	192	197	202
Stoval Trough 6	161	165	170	174	178	147	205	193	197	202	206	194	199	204	183	187	192	197	202
Stoval Trough 7	161	165	170	174	178	147	205	193	197	202	206	194	199	204	183	187	192	197	202
Stoval Trough 8	161	165	170	174	178	147	205	193	197	202	206	194	199	204	183	187	192	197	202
Stoval Trough 9	161	165	170	174	178	147	205	193	197	202	206	194	199	204	183	187	192	197	202
Stoval Trough 10	161	165	170	174	178	147	205	193	197	202	206	194	199	204	183	187	192	197	202
Phoenix Trough 1	176	181	185	190	194	160	223	210	216	221	225	212	217	223	199	204	210	215	220
Phoenix Trough 2	176	181	185	190	194	160	223	210	216	221	225	212	217	223	199	204	210	215	220
Phoenix Trough 3	176	181	185	190	194	160	223	210	216	221	225	212	217	223	199	204	210	215	220
Phoenix Trough 4	176	181	185	190	194	160	223	210	216	221	225	212	217	223	199	204	210	215	220
Tucson Trough 1	168	172	176	180	185	153	212	200	205	210	214	202	207	212	190	194	199	204	209
Tucson Trough 2	168	172	176	180	185	153	212	200	205	210	214	202	207	212	190	194	199	204	209
Tucson Trough 3	168	172	176	180	185	153	212	200	205	210	214	202	207	212	190	194	199	204	209
Tucson Trough 4	168	172	176	180	185	153	212	200	205	210	214	202	207	212	190	194	199	204	209
Yuma Trough 1	164	168	172	177	181	149	208	196	201	206	210	197	202	207	186	190	195	200	205
Yuma Trough 2	164	168	172	177	181	149	208	196	201	206	210	197	202	207	186	190	195	200	205
Yuma Trough 3	164	168	172	177	181	149	208	196	201	206	210	197	202	207	186	190	195	200	205
Yuma Trough 4	164	168	172	177	181	149	208	196	201	206	210	197	202	207	186	190	195	200	205
CPV 1	376	371	366	361	355	348	432	420	407	394	396	400	403	406	410	414	417	421	425
CPV 2	291	285	279	272	265	257	335	322	308	293	294	295	296	297	298	300	301	302	304
CPV 3	291	285	279	272	265	257	335	322	308	293	294	295	296	297	298	300	301	302	304
CPV 4	291	285	279	272	265	257	335	322	308	293	294	295	296	297	298	300	301	302	304
CPV 5	266	260	254	247	240	233	306	294	280	266	267	267	268	269	270	271	271	272	273
CPV 6	266	260	254	247	240	233	306	294	280	266	267	267	268	269	270	271	271	272	273
CPV 7	266	260	254	247	240	233	306	294	280	266	267	267	268	269	270	271	271	272	273
CPV 8	266	260	254	247	240	233	306	294	280	266	267	267	268	269	270	271	271	272	273
CPV 9	266	260	254	247	240	233	306	294	280	266	267	267	268	269	270	271	271	272	273
CPV 10	266	260	254	247	240	233	306	294	280	266	267	267	268	269	270	271	271	272	273
CPV 11	266	260	254	247	240	233	306	294	280	266	267	267	268	269	270	271	271	272	273
CPV 12	266	260	254	247	240	233	306	294	280	266	267	267	268	269	270	271	271	272	273
CPV 13	266	260	254	247	240	233	306	294	280	266	267	267	268	269	270	271	271	272	273
CPV 14	266	260	254	247	240	233	306	294	280	266	267	267	268	269	270	271	271	272	273
CPV 15	266	260	254	247	240	233	306	294	280	266	267	267	268	269	270	271	271	272	273
CPV 16	266	260	254	247	240	233	306	294	280	266	267	267	268	269	270	271	271	272	273
CPV 17	266	260	254	247	240	233	306	294	280	266	267	267	268	269	270	271	271	272	273
CPV 18	266	260	254	247	240	233	306	294	280	266	267	267	268	269	270	271	271	272	273

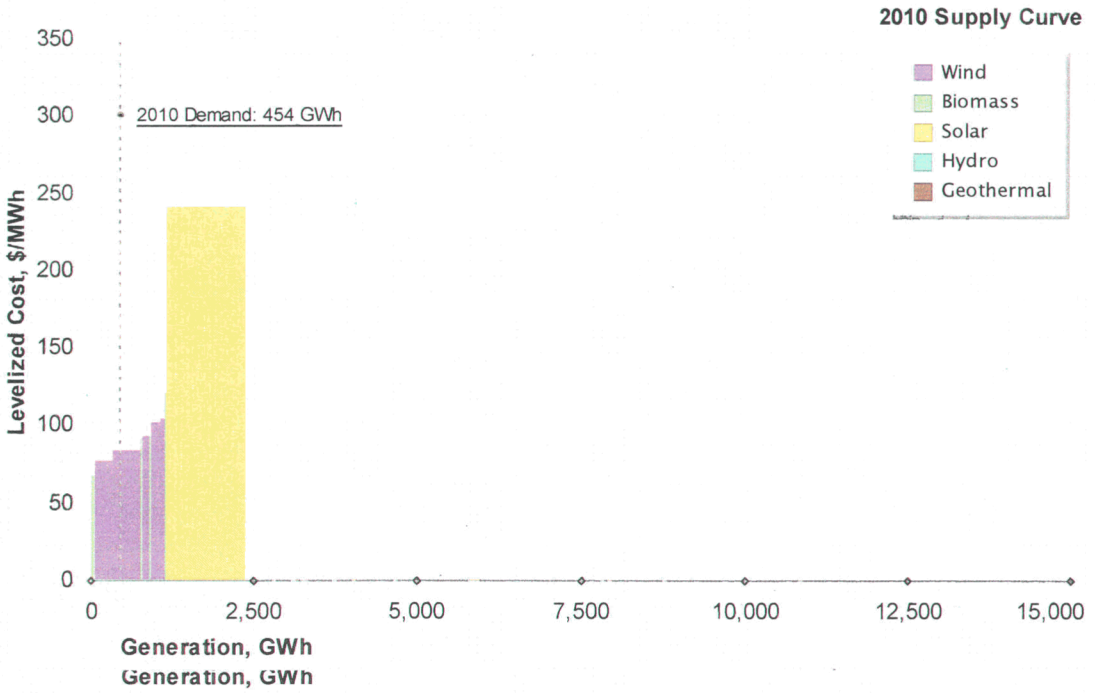
CPV 19	266	260	254	247	240	233	306	294	280	266	267	267	268	269	270	271	271	272	273
CPV 20	266	260	254	247	240	233	306	294	280	266	267	267	268	269	270	271	271	272	273
CPV 21	262	256	250	243	236	228	302	289	276	261	262	262	263	263	264	265	266	266	267
CPV 22	262	256	250	243	236	228	302	289	276	261	262	262	263	263	264	265	266	266	267
CPV 23	262	256	250	243	236	228	302	289	276	261	262	262	263	263	264	265	266	266	267
CPV 24	262	256	250	243	236	228	302	289	276	261	262	262	263	263	264	265	266	266	267
CPV 25	260	255	248	242	234	227	300	288	274	260	260	260	261	262	262	263	264	264	265
CPV 26	260	255	248	242	234	227	300	288	274	260	260	260	261	262	262	263	264	264	265
CPV 27	260	254	248	241	234	226	300	287	273	259	259	260	260	261	261	262	263	263	264
CPV 28	260	254	248	241	234	226	300	287	273	259	259	260	260	261	261	262	263	263	264
CPV 29	259	254	247	241	233	226	299	286	273	258	259	259	260	260	261	262	262	263	264
CPV 30	259	254	247	240	233	226	299	286	273	258	258	259	260	260	261	261	262	263	263
Tucson Fixed PV 1	285	286	287	288	289	290	396	397	398	399	400	401	402	403	404	405	406	408	409
Phoenix Fixed PV 1	292	292	293	294	294	295	407	408	408	409	410	411	411	412	413	414	415	416	416
Tucson Fixed PV 2	285	286	287	288	289	290	396	397	398	399	400	401	402	403	404	405	406	408	409
Phoenix Fixed PV 2	292	292	293	294	294	295	407	408	408	409	410	411	411	412	413	414	415	416	416
Tucson PV tracked	241	241	242	242	242	242	339	339	340	340	340	340	341	341	341	342	342	343	343

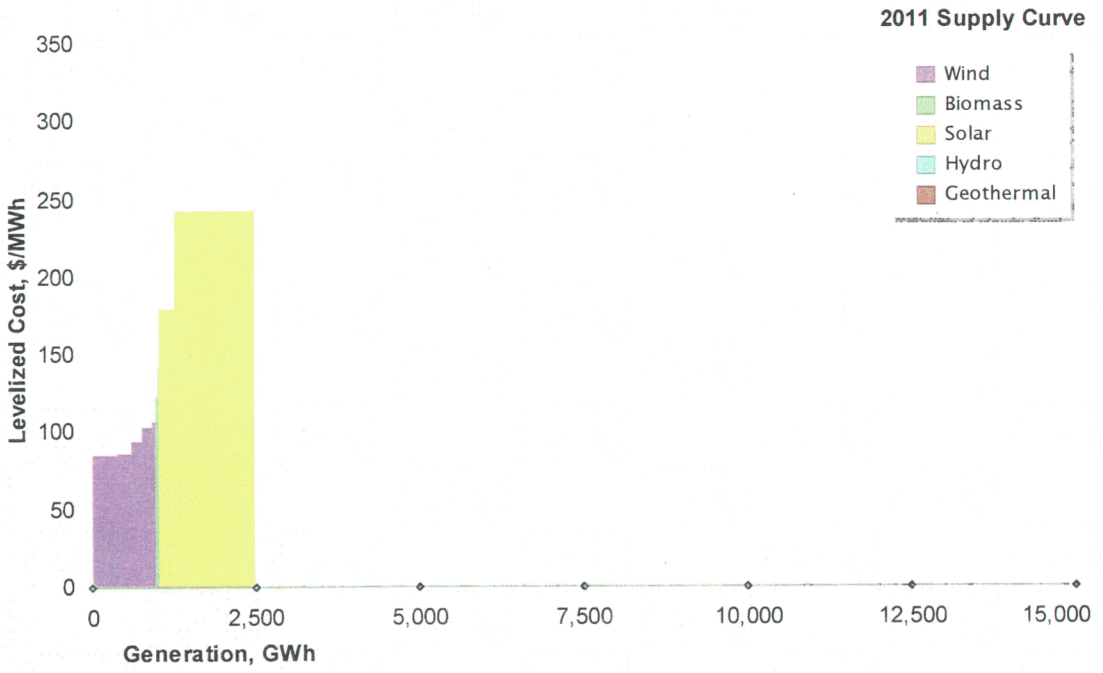
Appendix C. Supply Curves

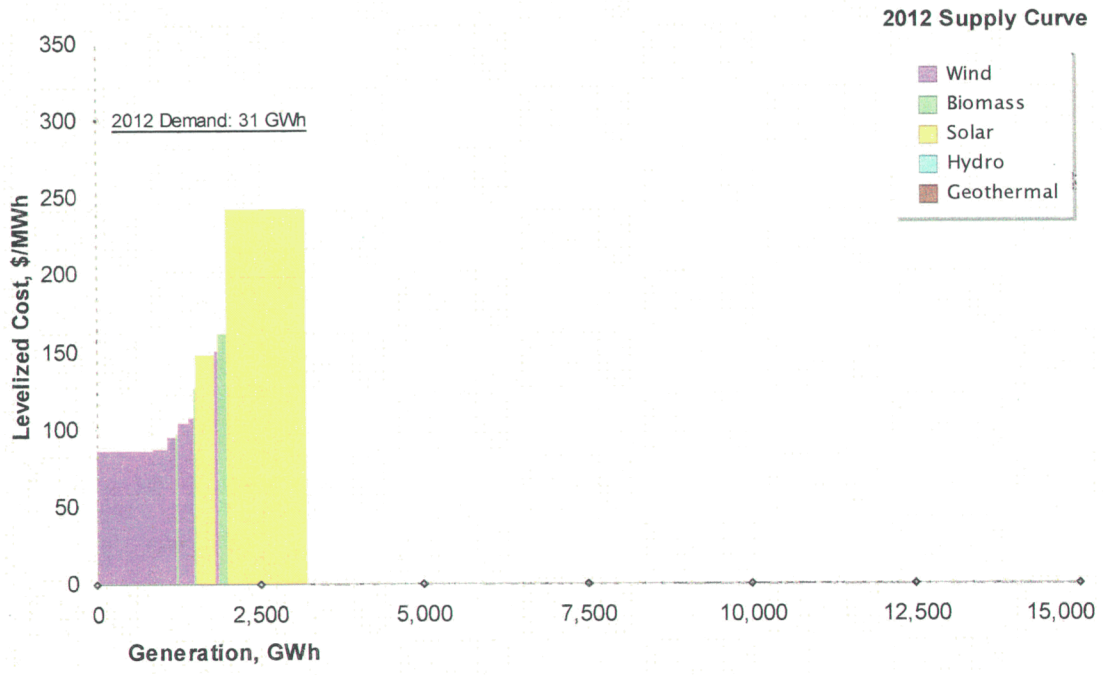


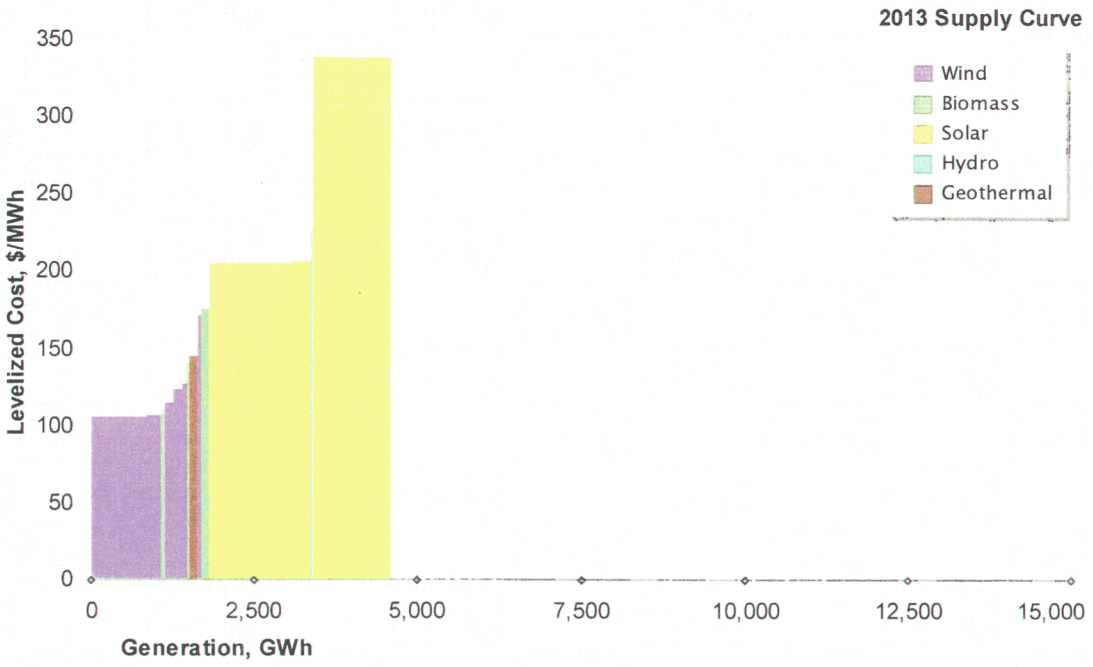


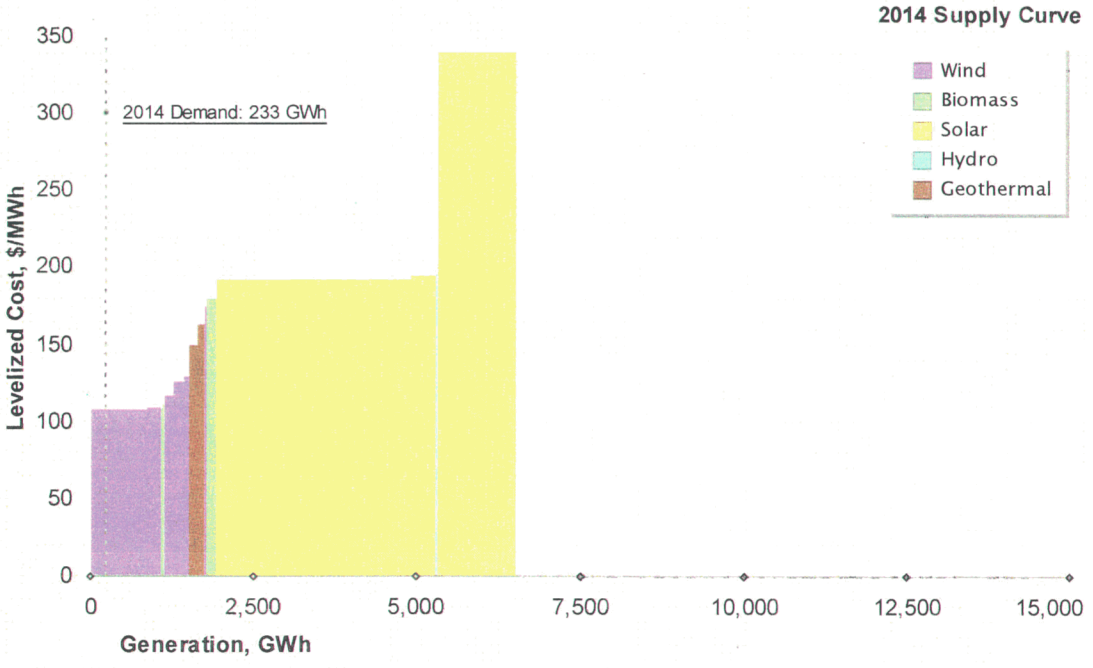

2009 Supply Curve
Wind
Biomass
Solar
Hydro
Geothermal
2009 Demand: 267 GWh
Levelized Cost, $/MWh
350
300
250
200
150
100
50
0
0
2,500
5,000
7,500
10,000
12,500
15,000
Generation, GWh

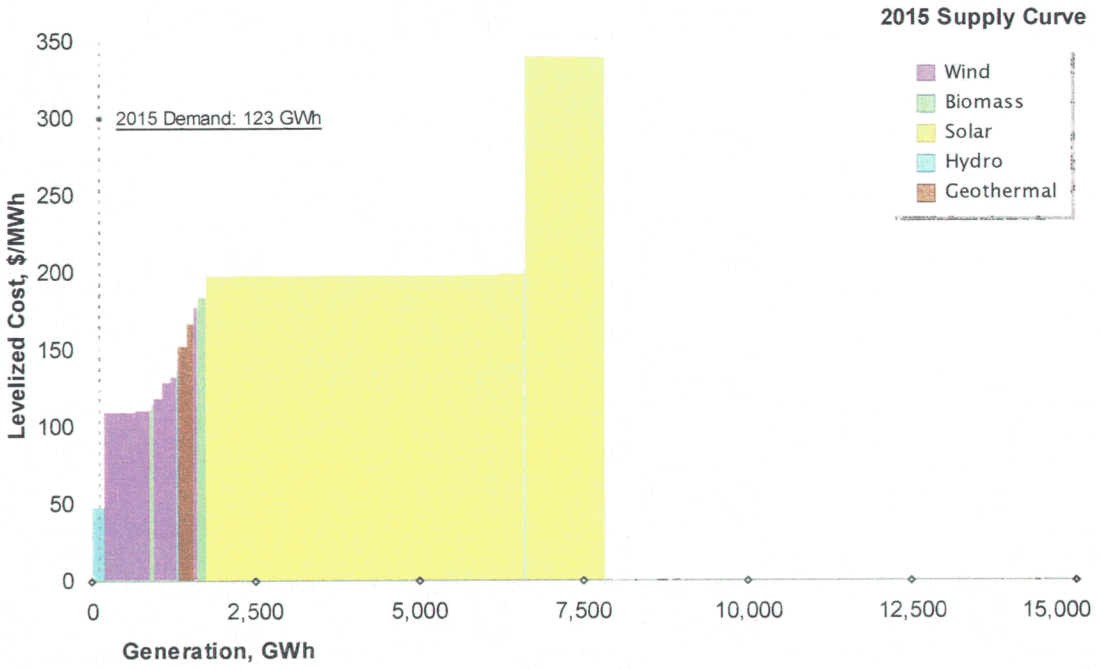

2010 Supply Curve
Wind
Biomass
Solar
Hydro
Geothermal
2010 Demand: 454 GWh
Levelized Cost, $/MWh
350
300
250
200
150
100
50
0
0
2,500
5,000
7,500
10,000
12,500
15,000
Generation, GWh
Generation, GWh

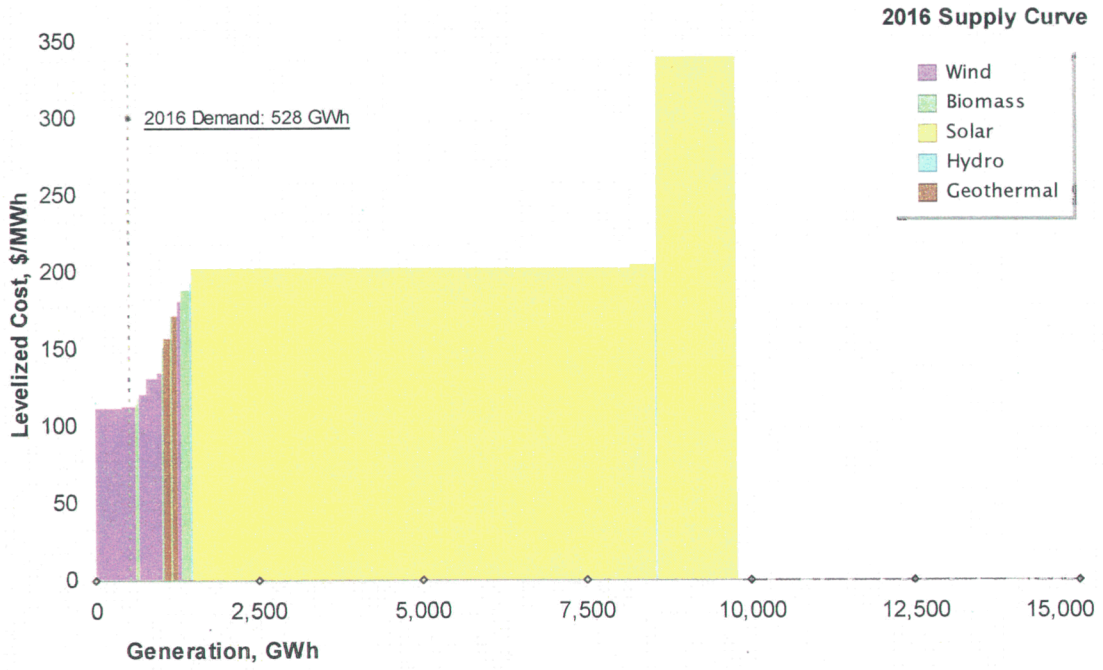

2011 Supply Curve
Wind
Biomass
Solar
Hydro
Geothermal
Levelized Cost, $/MWh
350
300
250
200
150
100
50
0
0
2,500
5,000
7,500
10,000
12,500
15,000
Generation, GWh

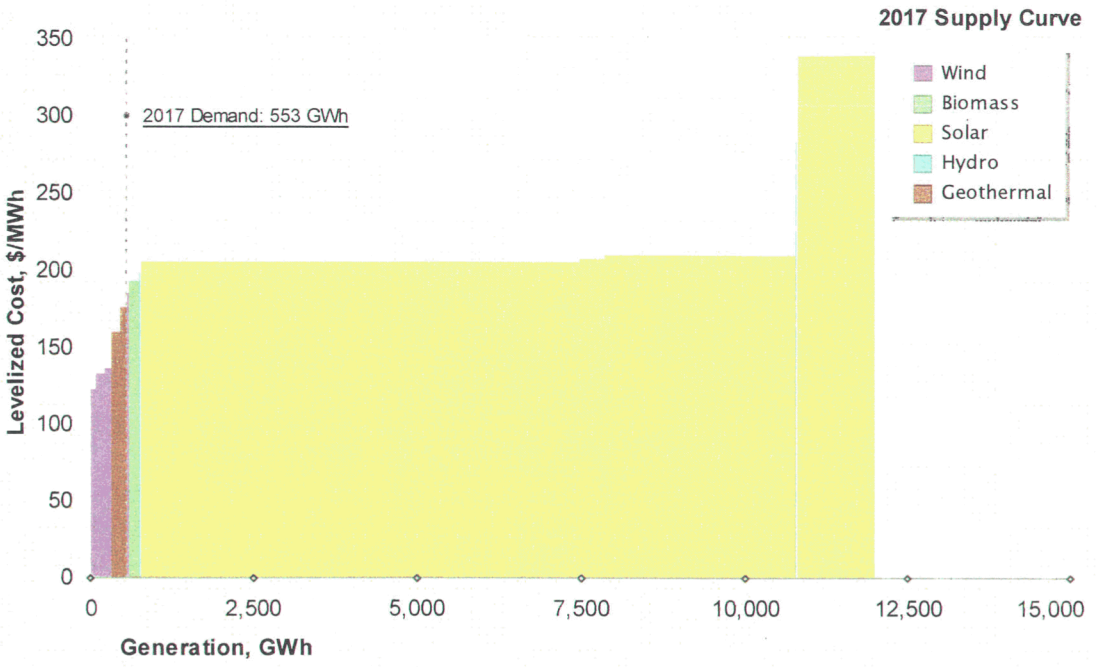

2012 Supply Curve
Wind
Biomass
Solar
Hydro
Geothermal
2012 Demand: 31 GWh
Levelized Cost, $/MWh
350
300
250
200
150
100
50
0
0
2,500
5,000
7,500
10,000
12,500
15,000
Generation, GWh

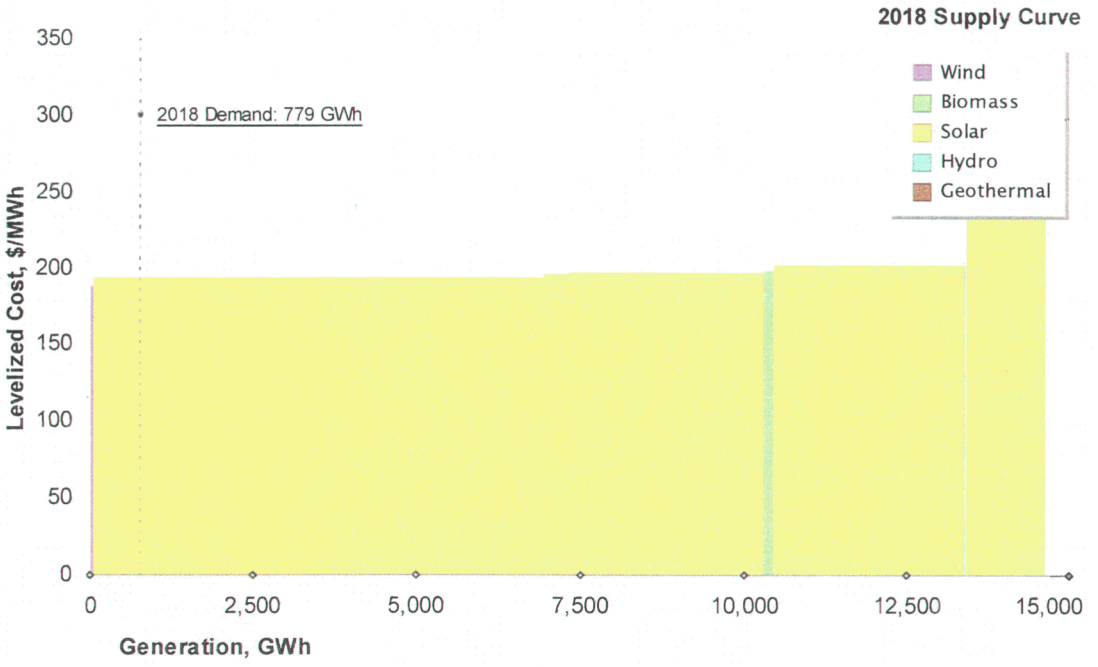

2013 Supply Curve
Wind
Biomass
Solar
Hydro
Geothermal
Levelized Cost, $/MWh
350
300
250
200
150
100
50
0
0
2,500
5,000
7,500
10,000
12,500
15,000
Generation, GWh

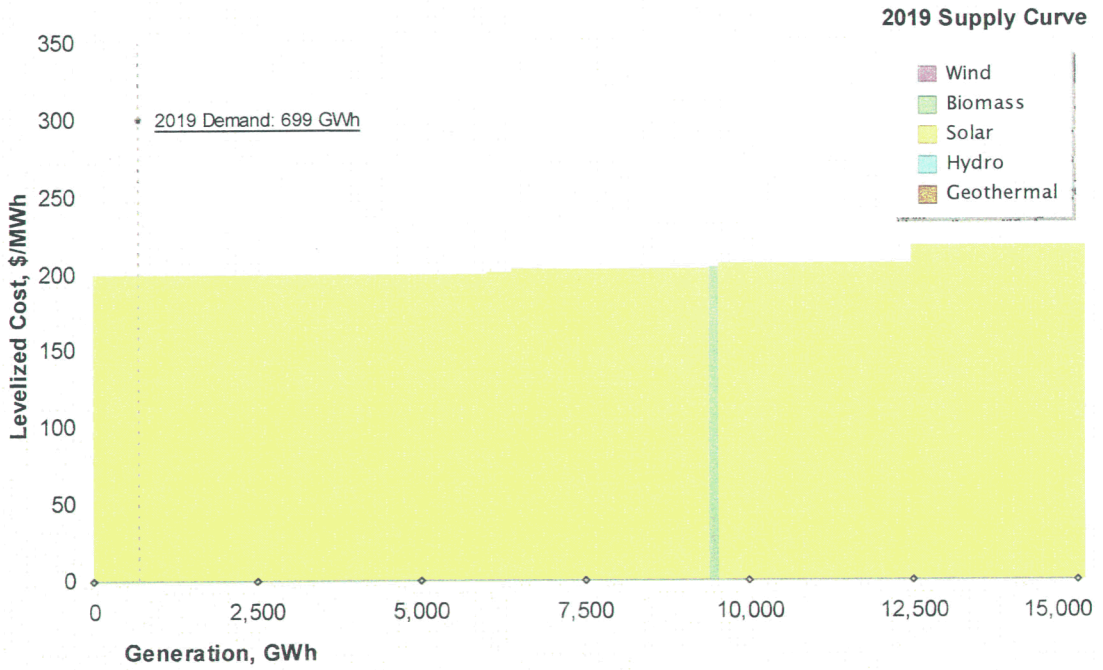

2014 Supply Curve
Wind
Biomass
Solar
Hydro
Geothermal
2014 Demand: 233 GWh
Levelized Cost, $/MWh
350
300
250
200
150
100
50
0
0
2,500
5,000
7,500
10,000
12,500
15,000
Generation, GWh

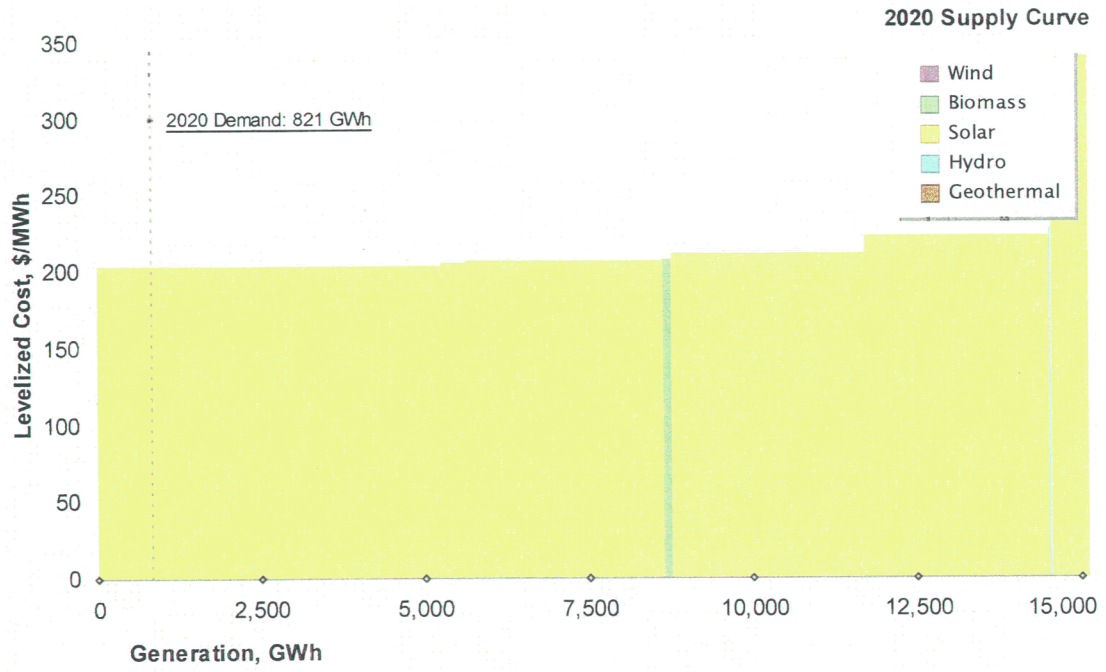

2015 Supply Curve
Wind
Biomass
Solar
Hydro
Geothermal
2015 Demand: 123 GWh
Levelized Cost, $/MWh
350
300
250
200
150
100
50
0
0
2,500
5,000
7,500
10,000
12,500
15,000
Generation, GWh

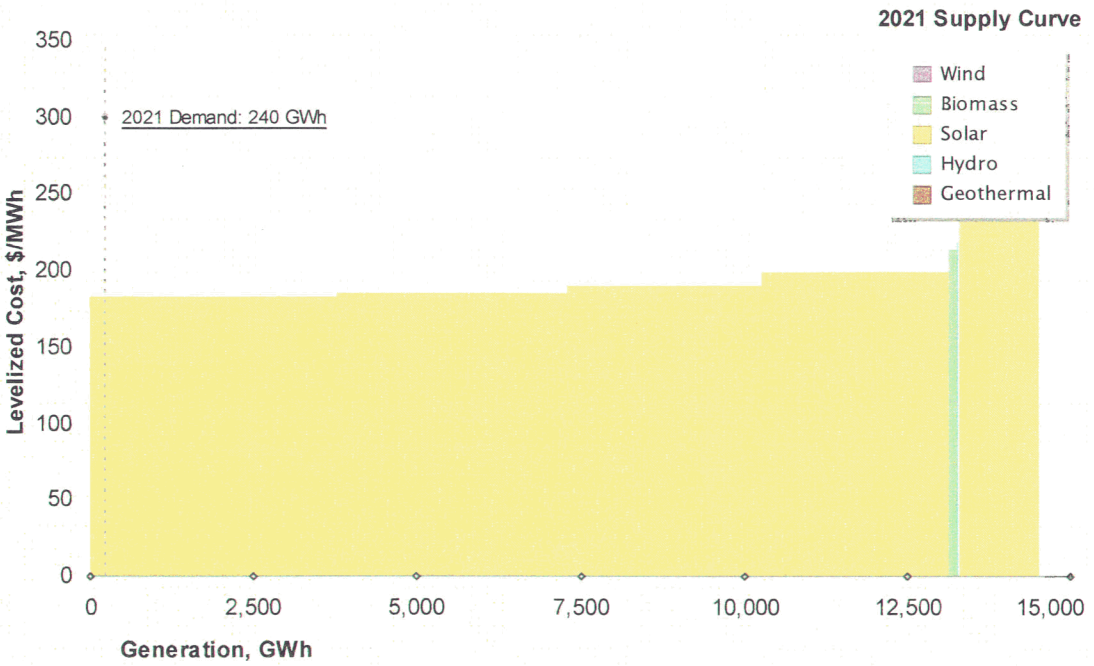

2016 Supply Curve
Wind
Biomass
Solar
Hydro
Geothermal
2016 Demand: 528 GWh
Levelized Cost, $/MWh
350
300
250
200
150
100
50
0
0
2,500
5,000
7,500
10,000
12,500
15,000
Generation, GWh

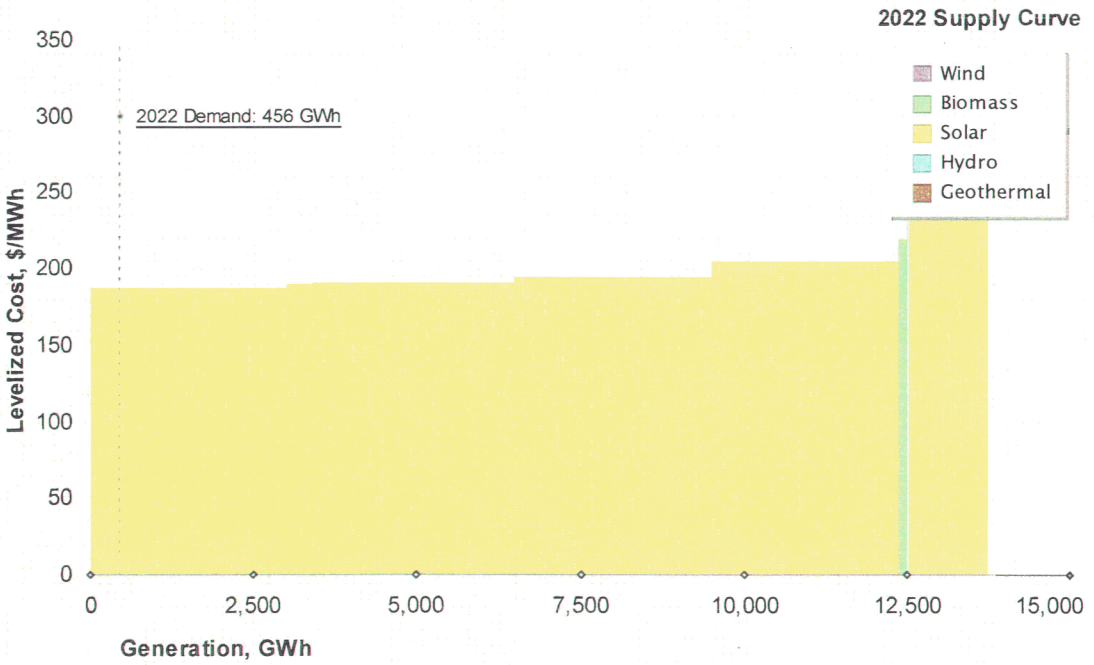

2017 Supply Curve
Wind
Biomass
Solar
Hydro
Geothermal
2017 Demand: 553 GWh
Levelized Cost, $/MWh
350
300
250
200
150
100
50
0
0
2,500
5,000
7,500
10,000
12,500
15,000
Generation, GWh

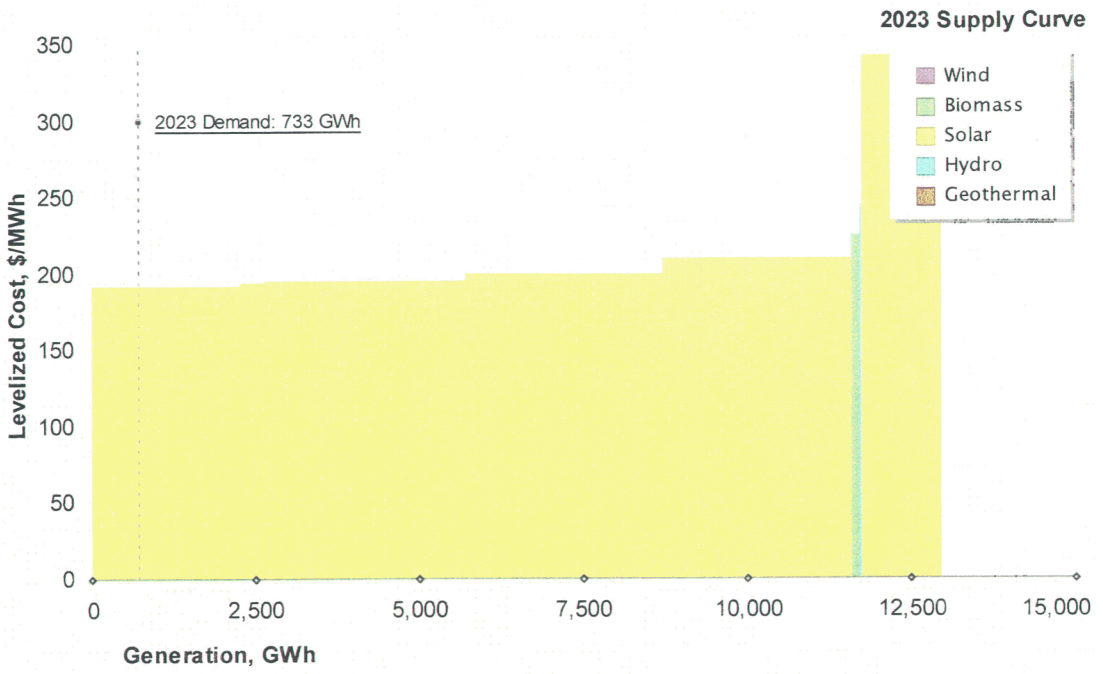

2018 Supply Curve
Wind
Biomass
Solar
Hydro
Geothermal
2018 Demand: 779 GWh
Levelized Cost, $/MWh
350
300
250
200
150
100
50
0
0
2,500
5,000
7,500
10,000
12,500
15,000
Generation, GWh

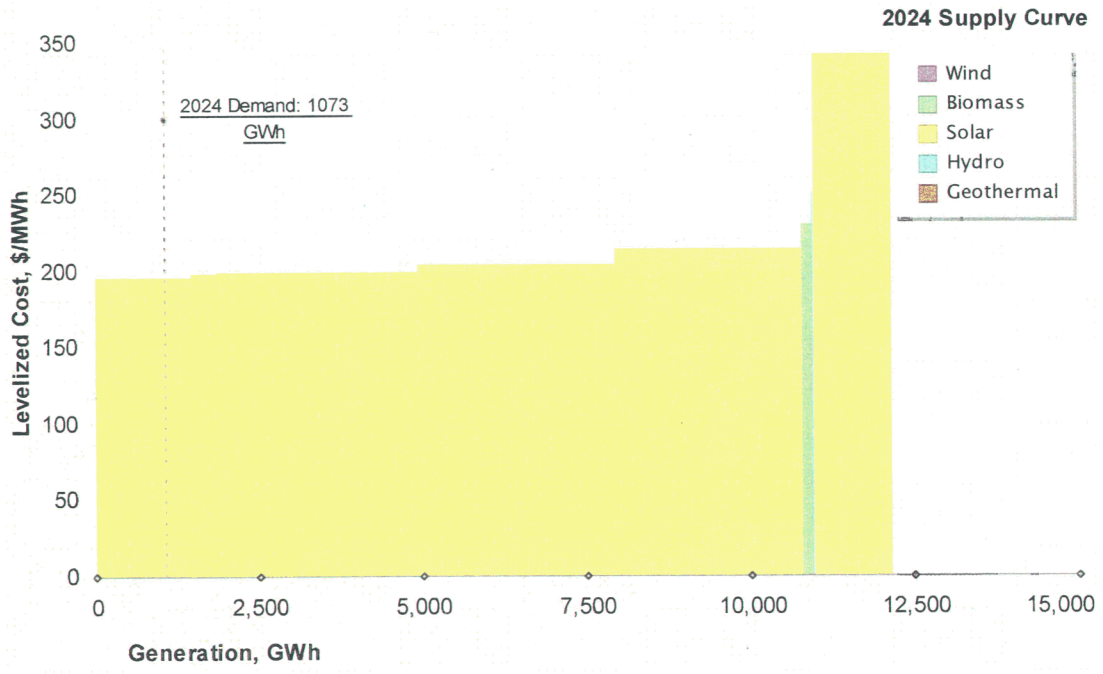

2019 Supply Curve
Wind
Biomass
Solar
Hydro
Geothermal
2019 Demand: 699 GWh
Levelized Cost, $/MWh
350
300
250
200
150
100
50
0
0
2,500
5,000
7,500
10,000
12,500
15,000
Generation, GWh

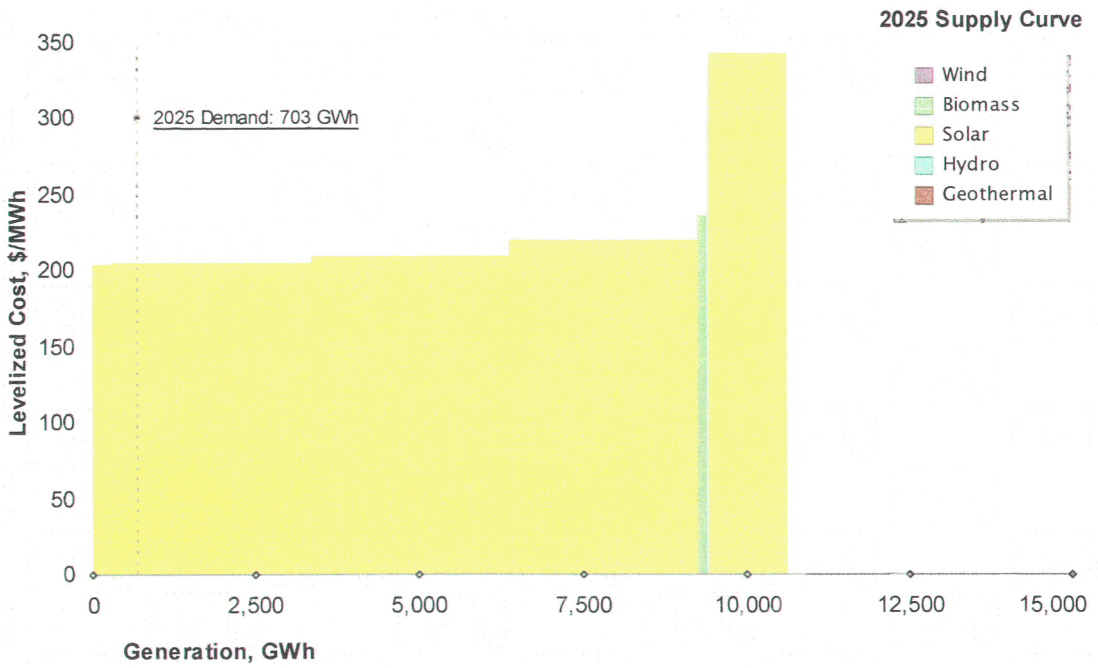

2020 Supply Curve
Wind
Biomass
Solar
Hydro
Geothermal
2020 Demand: 821 GWh
Levelized Cost, $/MWh
350
300
250
200
150
100
50
0
0
2,500
5,000
7,500
10,000
12,500
15,000
Generation, GWh


2021 Supply Curve
Wind
Biomass
Solar
Hydro
Geothermal
2021 Demand: 240 GWh
Levelized Cost, $/MWh
350
300
250
200
150
100
50
0
0
2,500
5,000
7,500
10,000
12,500
15,000
Generation, GWh


2022 Supply Curve
Wind
Biomass
Solar
Hydro
Geothermal
2022 Demand: 456 GWh
Levelized Cost, $/MWh
350
300
250
200
150
100
50
0
0
2,500
5,000
7,500
10,000
12,500
15,000
Generation, GWh


2023 Supply Curve
Wind
Biomass
Solar
Hydro
Geothermal
2023 Demand: 733 GWh
Levelized Cost, $/MWh
350
300
250
200
150
100
50
0
0
2,500
5,000
7,500
10,000
12,500
15,000
Generation, GWh


2024 Supply Curve
Wind
Biomass
Solar
Hydro
Geothermal
2024 Demand: 1073 GWh
Levelized Cost, $/MWh
350
300
250
200
150
100
50
0
0
2,500
5,000
7,500
10,000
12,500
15,000
Generation, GWh


2025 Supply Curve
Wind
Biomass
Solar
Hydro
Geothermal
2025 Demand: 703 GWh
Levelized Cost, $/MWh
350
300
250
200
150
100
50
0
0
2,500
5,000
7,500
10,000
12,500
15,000
Generation, GWh

Appendix E. BLM Land Lease Applications

BLM Land Lease Applications

Field Office	Serial Number CACA	Project #	Applicant	Date Application Received	Acres	DWMA, Critical Habitat, ACEC, MUC Class	Megawatts (Mw)	Planned Technology	Geographic Area	Status of Application
Hassayampa	34184AZA		Boulevard Associates LLC	6/26/2007	7,375	Wildlife (Big Horn sheep) corridore issues	250	Parabolic-Trough	Maricopa Co. btwn Harquahala Mtns. And Vulture Mtns.; south of Aguila AZ	Received $25K Cost Recovery deposit.
Hassayampa	34186AZA		Boulevard Associates LLC	6/26/2007	6,232	Wildlife (Big Horn sheep) corridore issues	250	Parabolic-Trough	Maricopa Co. and south of Big Horn Mtns and north of I-10 (exit 81) Burnt Mtn.	Received $25K Cost Recovery deposit.
Lower Sonoran	34187AZA		Boulevard Associates LLC	6/26/2007	13,440		250	Parabolic-Trough	Maricopa Co. West of SR85 and the Jojoba Substation	Received $25K Cost Recovery deposit.
Kingman	34200AZA		Boulevard Associates LLC	6/22/2007	4,787		250	Parabolic-Trough	Mohave County T26N, R20W secs. 7,17,18,20,21,28,29,32,33	Incomplete
Kingman	34201AZA		Boulevard Associates LLC	6/22/2007	15,654	Unknown	250	Parabolic-Trough	Mohave County T27N, R20W secs. 4-6 T28N/R20W, Secs.5-8, 17-20,28-33; T27N/R21W. Sec. 1 T28N/R21W, Secs. 1,2,11,12,13,24,25, 36	Incomplete
Hassayampa	34321AZA		Ausra AZ II LLC	10/1/2007	9,950	Wildlife (Big Horn sheep) corridore issues	180	Parabolic-Trough	Maricopa Co. and southeast of Big Horn Mtns. And north of I-10	Received $25K Cost Recovery deposit. No POD

	Lake Hvasu	34335AZA		Boulevard Associates LLC	6/8/2007	24,221		250	Parabolic-Trough	La Paz County T6N, R18 W secs. 3-10 T7N, R18W secs. 2-11,14,15,17-19,21-23,26-35 T7N, R19W secs., 1, 12	Send cost reimbursement agreement
	Lower Sonoran	34357AZA		Opti-Solar Inc.	11/6/2007	6,100		300	Photovoltaic	Maricopa Co. South of Gila Bend	Received $25K Cost Recovery deposit.
	Lower Sonoran	34358AZA		Opti-Solar Inc.	11/6/2007	6,400		300	Photovoltaic	Maricopa Co. Saddle Mtn. south of I-10	Received $25K Cost Recovery deposit.
	Yuma	34416AZA		Pacific Solar Investments	12/2/2004	19,000	Water Supply, VRM concerns, area near and partially within area proposed as an Area with Wilderness Characteristics by public during RMP Revision scoping.	1,500	Parabolic-Trough	Lands East of Hovatter Road and South of I-10	Received $25K Cost Recovery deposit.
	Hassayampa	34424AZA		Pacific Solar	12/4/2007	13,400	Wildlife (Big Horn sheep) corridore issues	500	Parabolic-Trough	Maricopa Co. and southwest of Big Horn Mtns. And north of I-10	Received $25K Cost Recovery deposit.
	Lower Sonoran	34425AZA		Pacific Solar	12/7/2007	5,800		500	Parabolic-Trough	Maricopa Co. in Hyder Valley	Received $25K Cost Recovery deposit.
	Yuma	34426AZA		Pacific Solar Investments	12/2/2007	26,000	Water Supply, VRM concerns, area near and partially within area proposed as an Area with Wilderness Characteristics by public during RMP Revision scoping.	2,000	Parabolic-Trough	Lands West of Hovatter Road and South of I-10	YFO is preparing cost recovery letter, have only had a pre-application meeting, start of NEPA is pending establishment of cost recovery account and receipt of completed POD

	Yuma	34568AZA		NextLight Renewable Power, LLC	3/26/2008	23,500	Water Supply, possible VRM, cultural and biological concerns, no surveys have been conducted	500	Parabolic-Trough	T.4S.,R11W., secs. 30,31 T5S., R.12W., secs. 2-10, 15,17-20, 22,23,25,26,28,29,33	YFO is preparing cost recomvery lette,r have not had a pre-application meeting, start of NEPA is pending establishment of cost recovery account and receipt of completed POD
	Yuma	34560AZA		NextLight Renewable Power, LLC	3/26/2008	15,000	Water Supply, possible, cultural and biological concerns, no surveys have been completed	500	Parabolic-Trough	T3N, R15W secs. 8-17, 20-29, 32-35	YFO is preparing cost recovery letter, have only had a pre-application meeting, start of NEPA is pending establishment of cost recovery account and receipt of completed POD
	Yuma	34561AZA		NextLight Renewable Power, LLC	3/26/2008	15,000	Water Supply, possible VRM, cultural and biological concerns, no surveys have been conducted	500	Parabolic-Trough	T1S, R19W secs. 1-11, 14-23, 26-30	YFO is preparing cost recovery letter, have only had a pre-application meeting, start of NEPA is pending establishment of cost recovery account and receipt of completed POD
	Yuma	34566AZA		NextLight Renewable Power, LLC	3/26/2008	14,000	Water Supply, possible VRM, cultural and biological concerns, no surveys have been conducted	500	Parabolic-Trough	T2N., R11W Secs. 1, 3-17, 22-24, 26-30 T2N, R12W Secs. 1, 12 T3N, R12W sec. 36	YFO is preparing cost recovery letter, have only had a pre-application meeting, start of NEPA is pending establishment of cost recovery account and receipt of completed POD

	Yuma	34554AZA		NextLight Renewable Power, LLC	3/26/2008	20,699	Water Supply, VRM conceerns within view oshed of KOFA Wildlife Refuge and Wilderness, survey not started while proponent working on developing information concerning water supply and a portion is in the Long Term Visitor Area (LTVA)	500	Parabolic-Trough	T.3N. R19W. Secs.1-4 T3N.R19W., secs 9-16 T3N. R19W. Secs. 19-36 T3N. R20W. Secs. 24,25,36	YFO is preparing cost recovery letter, have only had a pre-application meeting, start of NEPA is pending establishment of cost recovery account and receipt of completed POD
	Yuma	34427AZA		Pacific Solar Investments	6/6/2007	32,000	Water Supply, VRM concerns, area near and partially within area proposed as an Area with Wilderness Characteristics by public during RMP Revision scoping.	2,000	Parabolic-Trough	Lands South of Quartzite in the Stone Cabin area on both the East and West sides of U.S. 95	Received $25K Cost Recovery deposit.
	Lake Havasu	3AZA		Horizon Wind Energy LLC	3/4/2008	28,760			Parabolic-Trough	La Paz County T6N, R12 W secs. 1-14,18 T6N, R11W secs. 3-7,11 T6N, R13W secs1,2,10-15,22,23,27 T7N, R11W secs. 15,17,20-22,27-34 T7N, R12W secs.22,25,26,32-35	Draft letter to applicant requesting more information.
					Total	**299,943**		**11,030**			
						96,440	**Total**		**Parabolic-Trough**		

						12,500	Total		Photovoltaic		
				Boulevard Associates LLC	Total	24,459		750			
				Opti-Solar Inc.	Total	12,500					
				Pacific Solar	Total	47,760		1,500			
				Ausra AZ II LLC		24,221		250			