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From: Jerry D. Smith
To: DGI Interested Parties
Date: 12/7/99 12:33pm
Subject: November 22 DGI Workgroup Meeting Minutes

(Reply by E-Mail if you desire to be removed from this distribution list)

As a party interested in the ACC's investigation of Distributed Generation and Interconnections you will find the following attached DGI Workgroup items:

1. November 22, 1999 Workgroup meeting minutes.
2. Chairman's presentation materials.
3. Final Committee Reports:
   A. Siting, Certification, and Permitting Committee Report (without Attachmentsminutes and white papers docketed separately)
   B. Access, Metering and Dispatch Committee Report (includes 11/24 update provided by Tariff Subcommittee Chair-Steve Schmollenger)
   C. Interconnection Committee Report- Revision 3 submitted 12/1

These items will be filed in ACC Docket Control per:
Docket No. E-00000A-99-0431
General investigation of Distributed Generation and Interconnections for potential retail electric competition rules consideration.

Please provide comments on the above documents by 12/22 to Jerry Smith at the Arizona Corporation Commission. This is a one week extension to the comment period reported in the above meeting minutes due to late distribution of the above documents.

CC: LLK

Special Open Meeting Minutes
Distributed Generation & Interconnections Workgroup

Date: November 22, 1999 **Time:** 10:00 A.M.

Place: Arizona Corporation Commission Hearing Rooms 1 & 2
1200 W. Washington St., Phoenix, AZ 85007

Purpose: The Arizona Corporation Commission (ACC) Utilities Division sponsored a special open meeting to report Distributed Generation & Interconnections (DGI) Workgroup progress.

Attendance:

- Arizona Corporation Commission (ACC): No quorum of Commissioners, Commission staff members
- City staff from Phoenix, Scottsdale, and Tucson
- Representatives of Distributed Energy Association of Arizona (DEAA), International Brotherhood of Electrical Workers (IBEW), Industrial Consultants Group, ME Consultants, and Residential Utility Consumers Office (RUCO)
- Representatives of ESPs / Utilities - APS, New Energy Inc., Phase Advanced Metering, TEP, SRP, SSVEC, and SW Gas
- Representatives of the following firms - Agra Simmons, Engine World, and Photovoltric Resources

Summary: The Workgroup Chairman, Jerry Smith, welcomed those in attendance and began the meeting with each Committee convening to approve their most recent meeting minutes. Mr. Smith then gave a short overview of the process that has been active since June 28, 1999. A copy of his presentation materials is attached to these minutes.

A major portion of the meeting was devoted to each committee's final report. The full membership of the Siting, Certification and Permitting Committee and the Access, Metering and Dispatch Committee had not previously reviewed their respective final reports. In addition the Interconnection Standards Committee requested the opportunity to continue to work on some unresolved issues and re-file their report by December 1. Nevertheless, those in attendance agreed the final report contents were a fair representation of their work effort. The most current version of each committee's report is provided as an attachment to these minutes.

Mr. Smith opened the afternoon session by citing a portion of a November 21, 1999 news article in The Arizona Republic entitled "Outlook for Arizona in new millennium." Jack Davis of APS projects the future of electric utility competition over the next 25 years in the article. He states that "... by 2010, technological advances make traditional electric utilities obsolete. Commercially viable, alternative energy sources such as small-scale solar, fuel cells and microgenerators have emerged and are widely used. But business opportunities for electric utilities will be abundant; many companies will supply/or maintain generators."

Assessment and Critique: The DGI Workgroup then proceeded to provide a process assessment and critique. Comments were received on each committee's final report and the workgroup process in general. Those comments are documented below.

Siting, Certification & Permitting Committee Report

1. Dan Goodrich asked for clarification regarding certification & pre-certification. Brian O'Donnell indicated both personnel and equipment were considered. The distinction between certification and pre-certification of equipment was stated as a matter of timing where a class or type of equipment or system was approved and on file for repetitive applications.
2. Sharon Madden stated that the application process documented in the report did not reflect the latest draft. It was noted that several alternatives were considered and documented by the committee. APS believes the 30 days response requirement is inappropriate and that the process needs to be interactive.
3. Bryan Gernet indicated 2 or 3 white papers were given out but not mentioned in the minutes or report.
4. Ron Franquero questioned the appropriateness and applicability of using the DASR process for DG customers. It was developed over the last couple of years to capture retail customer's meter data for billing purposes. It was not developed to capture generation production data. It was noted that a process standardization workgroup will consider standardization of electric competition business transactions beginning December 3. Jerry Smith stated that this DG customer service request, metering and billing issue must be resolved by one of these two workgroup processes or ACC Staff will incorporate its own views as it initiates an associated rulemaking requirement.
5. Steve Bischoff asked for clarification of what non-profit organization would perform the consumer DGI education per the recommendation on page 5? Brian O'Donnell indicated an organization such as DEAA could do it as they are not an ESP or UDC but have a vested interest in seeing DG deployed. Providing siting and application process requirements beyond those required by utilities would be the focus of the consumer education effort rather than marketing.
6. Carl Britton raised concerns about who would dictate, provide and enforce training of DG personnel? It was noted that local jurisdictions and industry standards and codes already specify when qualified personnel are required to construct, operate or maintain electrical equipment. The training obligation belongs with the employer.
7. Chuck DeCorse asked if the committee made a distinction between DC systems and AC systems when considering application requirements for DG units smaller than 10KW? The response was no.

Access, Metering, and Dispatch Committee Report

1. An inquiry was made regarding the schedule to develop tariffs/tariff structures. Chuck Miessner indicated the committee had reviewed current tariff practices and discussed

numerous ideas for new rates. The committee did not recommend any rate structures because they viewed that role would be assumed by the ACC during its rulemaking process. Steve Schmollenger reported that TEP's rates for DG are somewhat Neanderthal in approach. Rates are now developed on a case by case basis. They had to redesign rates for a new Food Mart DG project. It was noted that SRP has one set of rates for DG.

2. Bill Murphy asked who's going to dispatch DG units - ESP, UDC, or customer? Chuck Meissner reported that this will likely be handled as a contractual arrangement between the DG Customer, ESP and UDC. However, given the potential benefit of DG (including ancillary services), utilities may have an incentive to direct dispatch the DG owner's unit(s).
3. Jerry Smith asked if the committee discussed the concept of dispatching DG for resolving transmission constraints (ie. Must-run generation conditions) and if dispatch of these units in response to distribution constraints was considered. Steve Bischoff indicated the committee did not discuss dispatch and scheduling of DG from that context. Steve Schmollenger reported that many of the operational impacts were addressed when the committee visited with operations, engineering and planning personnel at SRP, APS and TEP.
4. Carl Britton raised concerns regarding communication practices for dispatching field personnel.

Interconnection Standards Committee Report

1. David Townley asked how a dispute between the DG customer and the utility regarding interconnection requirements would be resolved - is a rapid dispute process needed? Linda Buczyinski also indicated the matter of who should bear cost responsibility for specific interconnection features where there are mutual benefits also may be an area of dispute. Prem Bahl , Doug Nelson and Sharon Madden offered views of how such disputes are resolved today by internal utility dispute processes and ultimately through the complaint process with the ACC. Concern was expressed by David Townley that exiting processes may not be swift enough to enable a DG project to take advantage of a small window of economic opportunity.
2. Steve Bischoff asked what was recommended regarding interconnecting with networks? This is a topic that the IS Committee had not reached consensus on. Bryan Gernet indicated that APS' network is not set up for DG and a white paper has been submitted regarding this topic. Following extended discussion regarding complications of interconnections with different types of distribution system networks Jerry Smith remarked that this must be an example of the volatile issues dealt with by this committee.
3. David Townley suggested DG transmission connections and DG distribution network connections might be topics worthy of a specific ACC workshop.

General Comments

1. Steve Schmollenger raised concerns about each committee having proceeded with its investigation without sufficient awareness of what the other two committees were

considering. Jerry Smith indicated that was the purpose of having the monthly workgroup meetings to allow interim progress reports from each of the committees. He also indicated the Workgroup's action plan to be discussed as the next agenda item should also attend to this concern.

2. It was suggested that designing tariffs to reflect the benefits of DG will be difficult and require everyone to keep an open mind. Jerry Smith indicated UDCs may find it advantageous to encourage DG applications in specific geographic locations or to defer distribution plant investment on local basis. Accompanying tariffs would look quite different than those currently in use.
3. The question of who has jurisdiction over wholesale transactions for DG connected at either distribution or transmission system voltages was raised. Are we moving to foster wholesale transactions for the distribution system? It was suggested that the final report needs some treatment of this topic.
4. It was noted that this investigation has focused on interconnecting at the distribution level and attention is still needed regarding DG interconnecting at the transmission level. Prem Bahl indicated that the size of unit would determine whether connection at the transmission level was necessary. ACC jurisdictional authority was also questioned regarding this issue. Jerry Smith of APS indicated that WSCC reliability standards govern the nature of interconnecting at the transmission level.
5. The Workgroup Chairman was asked to comment on what ACC Staff assumes its jurisdictional authority is regarding the two previous issues. Jerry responded that the jurisdictional framework is under going change at both the federal and local state level due to restructuring of the electric utility industry and re-functionalization of the transmission and distribution systems for retail electric competition. The ACC has taken the position with FERC that it does not intend to defer the state's right to regulate retail transactions. With the formation of RTOs, FERC is beginning to defer some of its regulatory authority to the independent regional entities and local states. Distributed generation is an application of technology primarily at the distribution system level and for retail consumers. On this basis, the ACC Staff assumes jurisdictional authority for the two issues stated above. It is recognized that challenging jurisdictional authority through the courts and established hearing processes is common place in today's society. Therefore it is not presumed the ACC's authority in the upcoming rulemaking process will go unchallenged.

Action Plan:

The following action plan was established for completing the workgroup effort and transitioning to an ACC rulemaking process-

1. Complete Workgroup documentation through November 22, 1999 meeting.

   a. Each Committee will electronically submit to Jerry Smith by December 1, 1999 approved minutes of its final committee meeting, its final committee report and any white papers considered. If white papers and meeting materials are only available in hard copy they should be mailed to Jerry for filing under docket control. It was noted that some committee reports failed to identify who had participated in the process.

b. Jerry Smith will prepare minutes of the November 22, 1999 meeting.

c. Jerry Smith will file all items supplied per the above requirement in ACC Docket Control under Docket No. E-00000A-99-0431 and distribute electronically to the list of DGI Interested Parties.

2. Complete comment period for committee final reports by **December 15, 1999**. Comments are to be submitted (electronic preferred) to Jerry Smith at the Utilities Division of the Arizona Corporation Commission for filing in ACC Docket Control and for use in completing DGI Workgroup tasks.

3. An advisory committee will be formed to complete DGI Workgroup tasks. Jerry Smith will chair the advisory committee. Advisory Committee membership will consist of the six DGI committee chairmen, co-chairmen, and subcommittee chairmen and an equal number of at-large members. The at-large members will be selected by the Workgroup Chairman to ensure balanced stakeholder representation. At-large members will be selected from those that formally submit comments regarding the committee final reports and declare an interest in participating. The chairmen reserves the right to invite participation by someone not meeting the stated prerequisite if a stakeholder group would otherwise not be adequately represented on the committee.

4. The Advisory Committee is to review the three committee final reports and associated docketed comments, evaluate and critique the DGI Workgroup process and publish a DGI Workgroup Final Report documenting the aforementioned tasks. This effort is to include seeking comments from affected parties that may not have participated in the DGI Workgroup process. The Advisory Committee is to complete its efforts during the month of January 2000.

5. ACC Staff will use all of the DGI Workgroup work products as a foundation for drafting DGI rules during the month February. A review and comment period will be utilized prior to finalizing ACC Staff proposed DGI rules.

6. Staff will file proposed DGI rules for ACC rulemaking consideration beginning in March 2000. The process will span a period of three to four months.

Concerns were raised about why the DGI Workgroup process was rushed to completion by December 1, 1999 while some states have spent in excess of one year. The chairmen responded that by the end of the rulemaking process, Arizona will have taken approximately one year to complete its consideration of DGI. Arizona's efforts are driven by a desire to extend DG as a retail competition choice and alternative solution to anticipated system constraints by the year 2001.

Meetings Adjourned at 3:10 PM

Recorded By: Lori L. Knudson, Utilities Division, Arizona Corporation Commission

Arizona Corporation Commission
DGI Workgroup Meeting

Docket No. E-00000A-99-0431

November 22, 1999

Agenda

- Process Overview
- Approval of Committee Minutes
- Committee Final Reports to Workgroup
- Process Assessment / Critique
- Action Plan for ACC Rulemaking

DGI PROCESS OVERVIEW

Docket No. E-00000A-99-0431

DATE	EVENT	OUTCOME
June 28	Workshop	Spkr - S. McKinley Panel A - Local Exp. Panel B - Retail Comp. Issues Defined
August 30	Workgroup Mtg 1	Committees Formed Workscope Assgn Issues Assgn
October 4	Workgroup Mtg 2	Committee Reports
October 25	Workgroup Mtg 3	Spkr - S. Castelaz Committee Reports
November 22	Workgroup Mtg 4	Committee Reports Eval. / Critique Action Plan

Workgroup Purpose

- Consider 6/28/99 DGI Workshop issues and related topics arising during investigation of Distributed Generation & Interconnections.
- Propose a framework for accommodating DGI applications in Arizona.

Process Assessment / Critique

- Have committees adequately addressed assigned work scope and issues?
- Does a committee consensus exist for concepts & processes recommended?
- Are committees' recommendations complimentary or divergent?
- What has not received sufficient consideration?

Action Plan: ACC Rulemaking

- Dec. - Assemble comments regarding DGI Workgroup process and committee report.
- Jan. - Advisory Committee addresses DGI process inadequacies or inconsistencies.
- Feb. - ACC Staff drafts & files DGI Rules.
- Mar. - Begin ACC Rulemaking.

Committees

The DGI Workgroup will utilize the following committee structure to facilitate its investigation of the DGI topic:

- Siting, Certification and Permitting (SCP)
- Market Access, Metering and Dispatch (AMD)
- Interconnection Standards (IS)

Time Frame for Tasks

- Each committee will complete its assigned tasks and provide a consensus committee report to the DGI Workgroup by December 1, 1999.
- Then the DGI Workgroup will draft regulatory language deemed necessary and appropriate for ACC consideration in the year 2000.

Siting, Certification & Permitting Committee Work Scope

- Identify thresholds for which siting is a public issue regarding:
  Air Quality, Fuel Supply, Noise, Safety
- Establish how thresholds are affected by: Type of Unit, Unit Size, Location of Project, Intended Operational Uses, Residential vs. Commercial Applications
- Recommend circumstances warranting training, certification or licensing of personnel or pre-certification of distributed generation system packages.
- Recommend a standardized application process and required information.
- Recommend jurisdiction appropriate for each siting, certification and permitting issue.

Market Access, Metering & Dispatch Committee Work Scope

- Develop framework for DG customers accessing the energy market to:
  - Supplement self-provided energy with purchases from ESPs
  - Sell excess energy to others
  - Contribute to ancillary services requirements
- ID scheduling and accounting means for the above transactions so system constraints are not exceeded.
- ID conditions where CAO needs dispatch control over customer's DG unit.
- Consider system disturbance management in the presence of DG units.
- ID technical requirements associated with the above functions.
- ID when system benefits or stranded cost may warrant pricing consideration
- Develop tariff concepts that facilitate the above transactions.

Interconnection Standards Committee Work Scope

- Research national, industry and regulatory interconnection standards.
- Recommend standards for Arizona to reference and adopt for interconnection of small, medium and large DG units considering:
  - Type of proposed generating unit
  - System voltage class of interconnection
  - Parallel vs. islanded generator operation
  - Inverter vs. Synchronous connection of units
- ID when site specific interconnection requirements should be considered.
- Recommended interconnection standards should address the following:
  - Safe construction, maintenance, and operational practices
  - Power quality impacts
  - System reliability impacts
- Coordinated management of / response to disturbances

ARIZONA CORPORATION COMMISSION

DISTRIBUTED GENERATION and INTERCONNECTION WORKGROUP

ACC DOCKET NO. E-00000A-99-0431

SITING, CERTIFICATION & PERMITTING

COMMITTEE REPORT

NOVEMBER 22, 1999

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Executive Summary

The Siting, Certification and Permitting Committee of the Distributed Generation & Interconnections Workgroup was formed to review issues relating to siting, certification and permitting of distributed generation (DG) projects within the State of Arizona under the jurisdiction of the Arizona Corporation Commission. There is currently no written set of state-wide requirements, or process for DG manufacturers to facilitate a smooth entrance to providing an alternative source of power. Each Utility Distribution Company (UDC) has individual requirements dating back to the Public Utilites and Regulatory Policies Act (PURPA).

The Siting, Certification and Permitting Committee was formed for the purpose of considering the siting, certification and permitting of new DG projects. The primary focus of its investigation was to include, but not limited to the following:

1. Identify thresholds for which siting is a public issue regarding:
   - Air quality
   - Fuel Supply
   - Noise
   - Safety

2. Establish how the above siting thresholds are affected by:
   - Type of Unit
   - Unit Size
   - Location of Project
   - Intended Operational Uses (Self-providing, emergency backup, sell excess to others, etc.)
   - Residential vs. Commercial Applications

3. Recommend circumstances warranting training, certification or licensing of personnel or pre-certification of distributed generation system packages.

4. Recommend a standardized application process and identify required information.

5. Recommend jurisdiction appropriate for each siting, certification and permitting issue.

Recommendations

1. A statewide-standardized application process/requirements would have a positive impact, since it would help to ensure DG is installed correctly, safely, and expeditiously.

2. Educational information needs to be available to DG applicants listing other government entities, which might have requirements, or require approval of DG projects.

3. Certification of DG equipment should be an option. This allows manufacturers to pursue approval, if they feel that certification would be beneficial because of multiple installations. The committee did not feel that the "installation" itself should be certified since unique conditions might exist at each site.

4. No ACC regulatory oversight is required for siting, permitting, or personnel issues. The committee found that government entities (federal, state and local) already exist and have jurisdiction over these issues.

Workscope Items

1. SITING:

Siting requirements were discussed and the following was agreed upon:

Types of units, location of project, types of distributed generation, intended operational use and residential vs. commercial applications could all impact air quality, fuel supply, noise and safety issues, and UDC operations, with each being site specific.

The committee found that government entities (federal, state and local) already exist and have jurisdiction over these issues.

Large power plants have to be reviewed by the State Power Plant Siting Committee.

No further action or regulation is required of the ACC at this time.

2. CERTIFICATION:

Certification of Personnel:

The group discussed training and certification of individuals installing DG equipment with a white paper submitted on this issue.

It is the consensus of the group that qualified contractors are required for distributed generation installations. Adherence to federal and state law ensure the safety of installers and operators. This is currently not applicable to homeowners for private use.

Certification of Equipment:

The Committee believes that certification should be an optional process since not all equipment is normally certified (e.g., larger generators). Applicants should be provided a flow chart outlining the agencies that would need to approve a product to have it certified. This could be provided by the Distributed Energy Association of Arizona, a non-profit organization. The Distributed Power Coalition of America might also be used a reference source.

The question came up as to whether a small generator, for example less than 10 kW, could be exempt from local jurisdiction for certification and permitting. The group in general, felt that residential units, 10 kW or smaller, should not require certification and permitting, other than a normal building permit required by the applicable city or jurisdiction.

Also discussed were the benefits of pre-certification of distributed generation system packages. Applicants who will be installing distributed generation equipment may find it advantageous to have their equipment certified by a 3rd party testing agency (i.e. UL/ETL, which is primarily testing for fire hazards) and then request that entities accept this certification for future installations. The UDC contends that this does not certify the internal protective functions, which are necessary for the UDC interface, or if the equipment will work at a specific site.

It is also not clear as to which approving agencies would accept certification. For example, the manufacturer of a 75 kW microturbine may desire certification from municipalities, Maricopa County and utility distribution companies (UDC's). However, one municipality may accept the certification, whereas a second may not. There are also situations where the installations, (of the distributed generation equipment and UDC required equipment) make each installation unique. UDC's do not certify equipment.

UDC's verify the interconnection requirements have been met on a site-specific basis, prior to interconnection with the distribution system.

Additional items for this discussion were presented in a white paper.

3. PERMITTING:

Permitting issues were discussed under "Siting". The group has identified which agencies are involved in the permitting process to be able to install and operate distributive generation based on specific type of units and site location.

It has been suggested that a list or flow chart outlining the agencies that would need to approve a product to have it certified and/or installed could be provided by the Distributed Energy Association of Arizona, a non-profit organization. The Distributed Power Coalition of America might also be used as a reference source.

4. APPLICATION PROCESS

Currently, no standardized, statewide, application process exists for an applicant wishing to install DG. Rather, the UDC can require the applicant to meet various criteria, which are not outlined in any statewide, specific document. There was general agreement that the application process should be handled expeditiously by both applicant and the UDC.

The general discussion is that a time frame of 30 days is sufficient for a sufficiency review by the UDC to evaluate, respond to an applicant and approve application, if all documents, switchgear, and other equipment that may be required to do the interconnect is in place.

APS is not in agreement that a specific number of days are appropriate. APS has stated that in the "real world" the process is an "interactive and iterative process".

Attached are several white papers explaining this "process" outlining the DG Application Process given to this Committee to discuss.

A lot of discussion ensued determining who needs to be contacted (government agencies, and/or the UDC), certified vs. non-certified units, are there any time frames involved to complete the UDC interconnection, etc. The Distributed Energy Association of Arizona could provide a listing of the various entities that may require approval or included as a reference on the statewide process. Manufacturers, the ACC and the UDC's could also provide a referral to the Distributed Energy Association of Arizona when a verbal request is made for this information.

5. OTHER ISSUES OF DISCUSSION:

DIRECT ACCESS SERVICE REQUEST (DASR):

The Committee discussed the Direct Access Service Request (DASR) process used to transition to direct access services under electric restructuring.

It was discussed that the DASR process might be used for distributed generation (DG) applications where the customer is exporting electricity on the UDC's distribution system.

Existing rules require an Energy Service Provider (ESP) to file a DASR to provide back-up, supplemental or maintenance power.

The DASR process is not needed if the DG is only providing power at the DG's premise.

Location Matching, Mapping:

A question presented to the Committee was "Can a location match be achieved for mutual benefit of the customer and UDC?" The Committee believes that instances may arise when installing distributed generation (DG) may benefit both the applicant and the utility distribution company (UDC). UDCs believe that they would be willing to consider such instances on a case-by –case basis and may offer a request for proposal in such an instance. A number of technical and economic issues would determine the viability of such a partnership.

Also discussed was the issue of who would keep an updated map of all DG units as they are installed. A proposal was made that the ACC could update and maintain such a map on their web site. The ACC is not favorable to this position.

The UDC's currently update maps showing DG units on their system for safety and system planning issues. It has been suggested that these maps could possibly be made public. Some UDC's consider this to be confidential, as they are proprietary information within their business and do not anticipate releasing for public use.

Fuel Preference Policy/Fuel Source

The Committee was asked to discuss the issue of whether a fuel preference policy is needed. Amanda Ormond, Director of the Arizona Department of Commerce Energy Office gave a presentation on this topic. Adopted State Energy Policy page is provided as Attachment E. Ms Ormond discussed the initial legislative resolution of 1977 and the State Energy Policy recommendations of 1990. In general, the policy indicates that energy must be efficient, affordable and environmentally sound. Renewable energy is "desirable" but not mandated. It was brought to the Committee's attention that renewables were now being discussed in deregulation meetings at the ACC. The group does not believe a preference policy for distributed generation was possible.

Another discussion that was to be presented by Ms Ormand was "Delivery of H2 as a By-Product of Fuel Cell Application". After further discussion, the group decided this issue is not an item that needs to be addressed by the ACC DGI Workgroup.

Committe Members

Name	**Representing**
Brian O'Donnell	DEAA-Chairman
James P Barry	Tucson Elec/IBEW 1116
Jana Brandt	SRP
Linda Bueczyinski	City of Tucson
Ann Cobb	Trico
Greg Czaplewski	Cummins Southwest
Randy Despain	City of Phoenix
Art Fregoso	Tucson Electric
Tom Friddle	APS
Bryan Gernet	Arizona Public Service
Jeff Hagen	SW Gas
Larry Holly	SW Gas
Barbara Keene	ACC
Warren Louis	Allied Signal
Sharon Madden	APS
Doug Mann	
Patti Morris	TEP
Bill Murphy	City of Phoenix
Doug Nelson	DEAA
Matt Puffer	Engine World
George Rash	New Energy
Brian Sievers	Empire Power Systems
Chuck Skidmore	City of Scottsdale
Jerry Smith	ACC
Scott Swanson	APS
Tony Turturro	ICG
Chris Weathers	APS
Ray Williamson	ACC

Distributed Generation & Interconnections Workgroup
Siting, Certification and Permitting Committee
August 30, 1999 Meeting Minutes

Attendees: Art Fregoso - TEP, Bryan Sievers - Empire Power Systems, Sharon Madden - APS, Doug Nelson - DEAA, Matt Puffer - Engine World, James Barry - TEP, Patti Morris - TEP, Larry Holly - Southwest Gas, Randy Despain - City of Phoenix, Warren Louis - Allied Signal Power System, Anne Cobb - Trico Electric Coop., and Barbara Keene - ACC.

Doug C. Nelson facilitated the meeting. Barbara Keene took the minutes.

The committee decided to table the selection of a chairperson until the next meeting.

The most convenient time for committee meetings was determined to be Thursdays at 10:00 a.m. The next meeting would be September 16, at 10:00 a.m. in the 2nd Floor Conference Room.

The group decided to divide the scope of the committee's work into three parts: siting, certification, and permitting.

The committee discussed the need to deal with overlaps of issues involving the other committees and with jurisdictional issues.

Draft definitions:

siting = address physical location and public issues.
certification = standardization of equipment and people.
permitting = government regulation.

The group decided that the committee's objectives are:

1) to produce a whitepaper that defines the current situation.
2) to produce a series of recommendations.

For each of the strawman issues, individuals are to:

1) determine whether the issue falls under siting, certification, or permitting.
2) list any objection to inclusion of the issue.
3) circulate a paragraph on the issue.

Approved 9/29

Siting, Certification, and Permitting Committee
APPROVED Meeting Minutes - September 16, 1999

Brian O'Donnell was elected Chairman
Chris Weathers took the minutes

The following individuals were present

Name	Representing	Phone	Email
Art Fregoso	TEP	520-884-3624	afregoso@tusconelectric.com
Barbara Keene	ACC Staff	602-542-0853	bkeene@cc.state.az.us
Brian O'Donnell	DEAA	602-395-4405	brian.odonnell@swgas.com
Bryan Gernet	APS	602-371-6959	
Chris Weathers	APS	602-371-6563	cweather@apsc.com
Chuck Skidmore	City of Scottsdale	480-312-7606	cskidmore@ci.scottsdale.az.us
Doug Nelson	DEAA	602-395-1612	dcn@netwrx.net
George Rash	New Energy Southwest	602-265-8558	grash@newenergy.com
Greg Czaplewski	Cummins Southwest	602-257-5981	gczaplew@notesbridge.cummins.com
James Barry	TEP	520-745-3490	
Larry Holly	Southwest Gas Corp	602-395-4082	larry.holly@swgas.com
Randy Despain	City of Phoenix	602-261-8504	
Sharon Madden	APS	602-250-2027	smadden@apsc.com
Tom Friddle	APS	602-371-7176	h36143@apsc.com
Tony Turturro	ICG	602-532-9606	

The August 30 meeting minutes were approved.

The group discussed training and certification of individuals installing the equipment. Jim Barry, who is representing IBEW Local 1116, presented a white paper discussing the need for certified and licensed contractors and the need for minimum hours of training. The group had several questions. In particular, the question of why additional certification would be required for users was asked since several cogeneration plants already exist, apparently without any special certification. Jim indicated that he was not referring to new certification requirements rather, only those requirements specified by existing federal or state laws. Jim agreed to try & bring an OSHA representative to the next meeting for a 15 minute overview of OSHA regulations and their potential impact on workers.

The group spent time discussing what entities were responsible for regulations. At the next meeting Brian O'Donnell volunteered to develop a list of entities who would be responsible for various certification and permitting functions. Brian will look at air quality, fuel supply, noise and safety so that the group can determine if any additional ACC involvement is required.

The question came up as to whether a small generator, for example less than 10 kW, could be exempt from certification and permitting. The group, in general, felt that residential units, 10 kW or smaller would not require certification and permiting, other than a normal building permit required by the applicable city or jurisdiction. APS felt that a utility review was still needed.

At the next meeting, Bryan Gernet offered to bring in the classification of generator sizes that APS, SRP, and TEP agreed to use for the purpose of describing levels of protection. The group will also review the State of Texas recommendations on sizing.

The question of pre-certification of distributed generation system packages was discussed. All representatives believe that an optional pre-certification program will benefit everyone. Manufacturers of larger generation equipment felt that pre-certification should not be mandatory since many larger components are not always certified by testing agencys. For example, only smaller generators are certified by UL.

APS indicated that their postion is that Public and Worker safety concerns required each generator project be reviewed by the local distribution company on a site specific basis.

The issue of "sale for resale" of electricity was discussed. APS felt that generally, one customer at his home site who sold to another user, would be covered by utility "sale for resale" regulations. However, it appears a company such as a grocery chain could produce electricty at on site and sell it to its other sites state wide. No firm conclusions were reached.

There was then some discussion of what we were trying to accomplish in the work shop. There seemed to be concensus that the purpose of the workshop was to determine what functions, if any, the ACC should regulate in the siting process. For example the ACC does not regulate fuel. There was concensus that the fuel regulation topic belonged in the Siting, Certification, and Permitting workshop, but that our recommendation would be that this was not an area the ACC should regulate.

At the next meeting, Bryan Gernet indicated he would bring in an example of an application form for use with distributed(or cogeneration) systems.

The group then went through the straw organization proposal and agreed with it, with the exception that we added, under the Safety heading, Standardized Safety Requirement Conforming to NEC/OSHA, etc.

The group agreed to meet again on Sept 29, at 10:00am, at 1101 W Washington. This is the large red building on the South side of the street, across from the ACC.

Distributed Generation & Interconnection Workgroup

Siting, Certification, and Permitting Committee
APPROVED Meeting Minutes - September 29, 1999

The following individuals were present

Name	Representing	Phone	Email
Art Fregoso	TEP	520-884-3624	afregoso@tusconelectric.com
Barbara Keene	ACC Staff	602-542-0853	bkeene@cc.state.az.us
Bill Murphy	City of Phoenix	602-262-7897	bmurphy@ci.phoenix.az.us
Brian O'Donnell	DEAA	602-395-4405	brian.odonnell@swgas.com
Bryan Gernet	APS	602-371-6959	h37614@apsc.com
Chris Weathers	APS	602-371-6563	cweather@apsc.com
Chuck Skidmore	City of Scottsdale	480-312-7606	cskidmore@ci.scottsdale.az.us
Doug Mann			drmann@ewst.com
Ernie Miller	OSHA	602-542-1690	ernest.miller@osha.gov
Greg Czaplewski	Cummins Southwest	602-257-5981	gczaplew@notesbridge.cummins.com
James Barry	TEP	520-745-3490	Jbarry@tusconelectric.com
Jerry Smith	ACC Staff	602-542-7271	jsmith@cc.state.az.us
Joe Gates	OSHA	602-542-1641	joe.gates@osha.gov
Larry Holly	Southwest Gas Corp	602-395-4082	larry.holly@swgas.com
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Matt Puffer			mannfred@earthlink.net
Ray Williamson	ACC Staff	602-542-0828	rwilliamson@cc.state.az.us
Scott Swanson	APS	602-250-2096	z93536@apsc.com
Tony Turturro	ICG	602-532-9606	icg.inc@ix.netcom.com

Chris Weathers took the 9/29/99 minutes

The September 16th Meeting Minutes were reviewed and corrected.

Joe Gates (OSHA Safety Training Officer) and Ernie Miller(Senior Compliance Officer) gave a presentation on OSHA requirements as they relate to generation. In Arizona they enforce State of Arizona law which is the same as Federal law. OSHA focuses on worker safety. They are not involved in residential compliance; except in cases where employees are involved. In some instances training may consist of manufacturer supplied training. A "qualified contractor" is needed to meet installation requirements. OSHA Standard 1910.269 covers power generation, transmission, and distribution. It can be viewed at http://www.osha.gov.

Brian O'Donnell/Tony Turturro gave a presentation regarding thresholds for siting. For example if equipment emits more than 50 tons of criteria pollutants, a Title Five permit is required. For air quality, fuel supply, noise and safety no additional actions or regulation are required by the ACC as rules already exist by other agencies or the ACC. However, applicants need to be informed that these issues exist, when preparing to install equipment. Thus we need to address the process for distributed generation installation.

Jerry Smith indicated that large power plants would have to be reviewed by the State Power Plant Siting Committee.

Individual Arizona Cities, Maricopa County, State of Arizona and the U.S. EPA already have jurisdiction for siting and permitting issues. No additional action is required by the ACC. Utility safety issues will be covered by the interconnection committee.

The process and jurisdiction for certification needs to be addressed. Larry Holly, Chris Weathers, Greg Czaplewski and Matt Puffer will try and address this item at the next meeting. Bryan Gernet reiterated the point that each installation needs to be looked at separately. Matt Puffer indicated that the Utility has no part in equipment certification.

Regarding the effects of certain items on Siting Threshold, the following was agreed upon: Types of unit, location of project, intended operational use and residential vs commercial applications could all impact air quality, fuel supply, noise & safety. But there is no need for additional ACC jurisdiction as other authorities already exercise authority. Unit size has been established for protection issues by the Interconnection Workshop.

Jerry Smith indicated he thought the Siting Certification, and Permitting Committee should concentrate on the process, whereas the other Distributed Generation workshops would concentrate on the technical details.

The Distributed Power Coalition of America could address certification on a national basis.

Bryan Gernet gave a presentation on the application form being reviewed by the Interconnection Workshop. Brian O'Donnell, Chris Weathers and Tony Turturro will try and review the application process and present their findings at the next meeting.

Jerry Smith will give an overview of the DSAR process at the next meeting

The meeting on October 7th, at 10:00 am will be at the Pipeline & Safety Conference rooms. All other meetings will be at the upstairs conference room

Distributed Generation & Interconnection Workgroup

Siting, Certification and Permitting Committee
Approved Meeting Minutes – October 7, 1999

The following individuals were present

Name	Representing	Phone	E mail
Jana Brandt	SRP	602-236-5028	jkbrandt@srpnet.com
Anne Cobb	TRICO	520-744-2944	acobb@trico.org
Randy Despain	City of Phoenix	602-261-8504	rdespain@ci.phoenix.az.us
Art Fregoso	Tucson Electric	520-884-3624	afregoso@tucsonelectric.com
Larry Holly	SW Gas	602-395-4082	larry.holly@swgas.com
Barbara Keene	ACC	602-542-0853	bkeene@cc.state.az.us
Sharon Madden	APS	602-250-2027	smadden@apsc.com
Brian O'Donnell	DEAA	602-395-4058	brian.odonnell@swgas.com
Matt Puffer	Engine	818-353-3617	mannfred@earthlink.net
George Rash	New Energy	602-265-8558	grash@newenergy.com
Chris Weathers	APS	602-371-6563	cweather@apsc.com
Ray Williamson	ACC	602-542-0828	rwilliamson@cc.state.az.us

The September 29th meeting minutes were approved with the comment that Art Fegosos' name should be changed to Art Fregoso.

Chris Weathers gave a presentation and handout on a proposed application process for distributed generation. The following was agreed upon:

1. A sufficiency review needs to be performed by the wires company. The wires company should turn this around in 10 working days. This review will tell the applicant if information is missing from the application.
2. The wires company should review an application within 30 calendar days. The sufficiency review will be a part of the 30 calendar days. If documentation is found missing, this stops the clock.
3. Resubmittals to obtain comments should be performed by the wires company in 5 working days.
4. Currently, APS indicates there will be no additional cost to the applicant for submitting an application. But if the wires company handled many applications with time constraints, there may have to be a charge for the service. If wheeling onto the distribution system is proposed, there will be a cost for the engineering study required by the wires company.
5. The ACC staff indicated that there would not be fines for failure of the wires company to review applications in a timely fashion. But if they saw a pattern of complaints, they would ask for an explanation.
6. The wires company will interface with the ACC to keep the ACC informed of all distributed generation projects. The means to accomplish this needs to be worked out.

Chris Weathers(cont)

7. The wires company will handle the mapping functions for DG pojects installed within their service territory. The ACC will be given a copy of the map for access by the public.
8. At the time an application is submitted, the wires company will give the applicant a reference sheet, listing additional agencies (e.g., county, state, municipalities, U.S. EPA, etc.) that may have additional requirements that the applicant must meet (e.g., air quality, noise, fuel requirements, safety, siting and permitting). The ACC will keep the list updated and available for the public. The ACC web site may be used for that purpose.

The following items were also discussed:

1. The interconnections committee needs to address the item as to whether 10 kW and smaller distributed generation projects need to file an application with the wires company. Chris Weathers re-iterated the APS position that all interconnections need to be approved by the wires company. The use of transfer switches was also discussed.
2. Sharon Madden will check on the appeals process within APS for the case where an applicant does not agree on the application requirements given by the wires company. The use of a 3rd party to review requirements was discussed; but no conclusion was reached.
3. The use of the yellow tag by the Utility lineman was discussed. It appears that a distributed generation project would follow the standard practices already in place.

The next meeting of the committee will be October 19th at 10:00 – 12 noon at the ACC. Items to be presented will be the DSAR process by Jerry Smith and the Process & Jurisdiction for Certification by Larry Holly & his subcommittee. If time permits we will also begin preliminary discussions of fuel preference policy (solar, wind, etc.) and delivery of hydrogen as a by-product of fuel cell applications.

Distributed Generation & Interconnection Workgroup

Siting, Certification and Permitting Committee
Approved Meeting Minutes – October 19, 1999

The following individuals were present

Name	Representing	Phone	E mail
James P Barry	Tucson Elec/IBEW 1116	520-745-3490	jbarry@tucsonelectric.com
Jana Brandt	SRP	602-236-5028	jkbrandt@srpnet.com
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Greg Czaplewski	Cummins Southwest	602-257-5981	gczaplew@notesbridge.cummins.com
Art Fregoso	Tucson Electric	520-884-3624	afregoso@tucsonelectric.com
Bryan Gernet	Arizona Public Service	602-371-6959	h37614@apsc.com
Larry Holly	SW Gas	602-395-4082	larry.holly@swgas.com
Barbara Keene	ACC	602-542-0853	bkeene@cc.state.az.us
Sharon Madden	APS	602-250-2027	smadden@apsc.com
Bill Murphy	City of Phoenix	602-262-7897	bmurphy@ci.phoenix.az.us
Brian O'Donnell	DEAA	602-395-4058	brian.odonnell@swgas.com
Matt Puffer	Engine World	818-353-3617	mannfred@earthlink.net
Jerry Smith	ACC	602-542-7271	jsmith@cc.state.az.us
Tony Turturro	ICG	602-532-9606	icg.inc@ix.netcom.com
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Ray Williamson	ACC	602-542-0828	rwilliamson@cc.state.az.us

The October 7th meeting minutes were approved.

Jerry Smith indicated that at the last meeting it was indicated that the ACC would keep a copy of distributed generation (DG) mapping and keep other DG information at the ACC. Jerry indicated that no decision regarding the ACCs role has been reached at this time.

Jerry Smith gave a presentation and handout on the Direct Access Service Request (DASR) process. The following was agreed upon:

1. The DASR process is not needed if the distributed generation (DG) customer is not selling electricity on the wires company's distribution or transmission systems.
2. The DASR process will be required if the customer is exporting electricity on the wires company's system.
3. The DASR process will be required if the DG customer is not selling electricity on the wires company system, but is using a Energy Service Provider (ESP) other than the wires company for back-up, supplemental or maintenance power.

Matt Puffer/Larry Holly gave a presentation and handout on the process & jurisdiction for certification of distributed generation equipment and system packages. The following was generally agreed upon:

1. Certification of equipment should be optional.
2. Various parties could certify DG including consulting engineers, UL, DPCA, etc.

Matt Puffer/Larry Holly will present a listing of agencies that would need to be involved in certification at the next meeting. These may include cities, counties, UDC for interconnection requirements, State of Arizona, Federal government, fuel suppliers, etc.

The following items were also discussed:

1. Sharon Madden would like to suggest the following change to item 8 of the October 7, 1999 minutes.

   > "8. At the time an application is submitted, the wires company will include within the Interconnect Agreement package, a reference sheet, listing additional agencies (e.g., county, state, municipalities, U.S. EPA, etc.) that may have additional requirements that the applicant must meet (e.g., air quality, noise, fuel requirements, safety, siting and permitting). This information may also be obtained through various entities such as the gas company, city, etc. The ACC will keep the list updated and available for the public. The ACC web site may be used for that purpose.

   There was no opposition to Sharon's suggestion.

2. Bryan Gernet indicated that he missed the last meeting but would like to indicate that from APS's prospective the application process for DG is more like an iterative process rather than the committee's agreed upon timeline discussed at the October 7, 1999 meeting.

The next meeting of the Workgroup is Monday, October 25th at 10:00 am - 12 noon at the ACC.

The next meeting of the committee will be Monday, October 25th at 1:00 PM – 3:00 PM at the ACC. Items to be presented will be the Fuel Preference Policy by the State of Arizona Department of Commerce Energy Office, discussion of delivery of Hydrogen as a product of fuel cell applications, APS appeals policy (Sharon Madden), listing of agencies involved in certification (Matt Puffer/Larry Holly) and Bryan Gernet's concerns on the application process for DG

Distributed Generation & Interconnection Workgroup

Siting, Certification and Permitting Committee
Approved Meeting Minutes – October 25, 1999

The following individuals were present

Name	Representing	Phone	E mail
James P Barry	Tucson Elec/IBEW 1116	520-745-3490	jbarry@tucsonelectric.com
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Randy Despain	City of Phoenix	602-261-8504	rdespain@ci.phoenix.az.us
Art Fregoso	Tucson Electric	520-884-3624	afregoso@tucsonelectric.com
Larry Holly	SW Gas	602-395-4082	larry.holly@swgas.com
Barbara Keene	ACC	602-542-0853	bkeene@cc.state.az.us
Sharon Madden	APS	602-250-2027	smadden@apsc.com
Brian O'Donnell	DEAA	602-395-4058	brian.odonnell@swgas.com
Matt Puffer	Engine World	818-353-3617	mannfred@earthlink.net
Chuck Skidmore	City of Scottsdale	480-312-7606	cskidmore@ci.scottsdale.az.us
Ray Williamson	ACC	602-542-0828	rwilliamson@cc.state.az.us

The October 19th meeting minutes were approved.

The group decided that the issue "Delivery of H2 as By Product of Fuel Cell Application" is not an item that needs to be addressed by the ACC DGI Workgroup.

Sharon Madden of APS gave a presentation on the APS appeals procedure that APS would use to dispute APS requirements on a cogeneration or distributed generation project. First there is no written procedure for appeal. APS does not have an arbitration or 3rd party review process. The applicant would have to file a complaint with the ACC if they didn't agree with the stipulated requirements. APS believes this should not change.

Matt Puffer/Larry Holly continued their presentation on certification. The following was generally agreed upon:

1. Certification of equipment should be optional.
2. There should probably be a flow chart given to applicants who desire certification outlining the potential agencies that would need to approve a product to have it certified.
3. Installations should not be certified. Brian O'Donnell was the only dissenting member. Randy Despain felt that the building permit process makes each installation unique.

Sharon Madden passed out two papers she would like to discuss at the next meeting. They present APS' position regarding the DG application process.

At the next meeting, Sharon Madden will present information on the topic "Can a location match be achieved for mutual benefit of Customer and UDC ? "

The next meeting of the Workgroup is Thursday, November 4th at 10:00 am - 12 noon at the ACC.

Distributed Generation & Interconnection Workgroup

Siting, Certification and Permitting Committee
Approved Meeting Minutes – November 4, 1999

The following individuals were present

Name	Representing	Phone	E mail
James P Barry	Tucson Elec/IBEW 1116	520-745-3490	jbarry@tucsonelectric.com
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Bryan Gernet	Arizona Public Service	602-371-6959	h37614@apsc.com
Larry Holly	SW Gas	602-395-4082	larry.holly@swgas.com
Barbara Keene	ACC	602-542-0853	bkeene@cc.state.az.us
Sharon Madden	APS	602-250-2027	smadden@apsc.com
Brian O'Donnell	DEAA	602-395-4058	brian.odonnell@swgas.com
Amanda Ormond	Dept of Commerce Energy	602-280-1401	amandao@ep.state.az.us
Chuck Skidmore	City of Scottsdale	480-312-7606	cskidmore@ci.scottsdale.az.us
Tony Turturro	ICG	602-532-9606	icg.inc@ix.netcom.com
Chris Weathers	APS	602-371-6563	cweather@apsc.com
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The October 25th meeting minutes were approved.

Amanda Ormond, Director, Arizona Department of Commerce Energy Office gave a presentation on the topic " Is a fuel preference policy needed (gas, solar, wind, H2, etc.) ? " Amanda discussed the initial legislative resolution of 1977 and the State Energy Policy recommendations of 1990. In general the policy indicates that energy must be efficient, affordable and environmentally sound. Renewable energy is "desireable" but not mandated. Sharon Madden indicated that renewables were now being discussed in deregulation meetings at the ACC. The group didn't see how we could implement any preference policy for distributed generation applications.

Sharon Madden presented a paper on the topic "Can a location match be achieved for mutual benefit of Customer and UDC. The paper discussed such items as:

1. Need for case by case evaluation
2. Capital budget deferment for the UCD
3. Sites available on the feeder to locate DG
4. Can the UDC schedule/control the DG ?
5. Counting on DG reliability
6. Loss of UDC revenue
7. Cost/benefit

Sharon also discussed the potential to have the UDC offer RFPs for a specific site, as well as technology and economic issues.

There was no objection to any of the information presented by Sharon. However, the group did feel that we should recommend that DG be considered in the ACC Distribution Planning Process.

Ray Williamson pointed out that it may be necessary for the ACC to also take a closer look at transmission because of the many proposed inter ties into the distribution system proposed by ESPs.

Sharon Madden reviewed the application process previously reviewed by the group. Bryan Gernet indicated that APS prefers an interactive and iterative approach with the customer working with the UDC commencing at the beginning of the project, as opposed to a "time stamp" approach. The remainder of the group felt that a reasonable time line was necessary and fair. Greg Czaplewski indicated that time lines ensure that project can be completed in a reasonable time. Bryan suggested that he and Tony Turturro take another look at this issue.

Sharon Madden wanted to clarify two previous items. First, the October 7, 1999 minutes indicated that currently there is no additional cost for an application. Sharon indicated that this may only be true for APS ; not other utilities. Second, in the October 19th minutes APS had indicated that they would provide a reference sheet listing agencies (e.g., Maricopa County) that may have additional requirements for DG. The APS legal Department feels that this is not possible because of liability concerns. APS is willing to reference the Distributed Energy Association of Arizona, a non-profit organization which could provide the check list to DG applicants.

Jim Barry asked that the heading "qualified contractors" be added to the check list for applications.

Brian O'Donnell and Chris Weathers will try to have an outline for our Committee's final report prepared for the next meeting.

The next meeting of the committee will be Tuesday, November 16th at 10:00 am – 12:00 noon at the ACC. Items to be presented are a 5 to 10 minute presentation on the application process for DG presented by Bryan and Tony and an outline for submitting our committee's report.

Distributed Generation & Interconnection Workgroup

Siting, Certification and Permitting Committee
Draft Meeting Minutes – November 16, 1999

The following individuals were present

Name	Representing	Phone	E mail
James P Barry	Tucson Elec/IBEW 1116	520-745-3490	jbarry@tucsonelectric.com
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Art Fregoso	Tucson Electric	520-884-3624	afregoso@tucsonelectric.com
Tom Friddle	APS	602-371-7176	H36143@aps.com
Bryan Gernet	Arizona Public Service	602-371-6959	h37614@apsc.com
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Barbara Keene	ACC	602-542-0853	bkeene@cc.state.az.us
Sharon Madden	APS	602-250-2027	smadden@apsc.com
Doug Nelson	DEAA	602-395-1612	dcn@netwrx.net
Brian O'Donnell	DEAA	602-395-4058	brian.odonnell@swgas.com
Matt Puffer	Engine World	818-353-3617	mannfred@earthlink.net
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The November 4th meeting minutes were approved.

Tony Turturro/Bryan Gernet outlined an alternate procedure for the application process. Tony indicated that this procedure could be used for larger sized distributed generation units. Bryan Gernet indicated that applications for smaller sized units could be completed in 20 to 30 days. Tony and Bryan will re-work their procedure and send it to the committee preparing the final committee report by the morning of Friday, November 18th.

Chuck Skimore indicated:

Whether considering rules regarding siting, permitting or certification the actual granting of permits, certifications, or siting is not within the jurisdiction of the Commission. There are legislative and regulatory bodies that have jurisdiction.

The job of the Commission in these issues is to assure that all parties are fairly treated and that a healthy energy market exists while treating the utilities fairly as they discharge their obligation to serve. Commissioners need to consider the following.

- Utilities have both a right and an obligation to be involved in permitting and certification related issues for technical, commercial, and safety reasons.

Chuck Skidmore (Continued)

- The fact that utilities must be involved also presents an opportunity to abuse the process and to slow it down. The market can be affected by the added development costs and the cost of capital associated with less than expeditious review action by a utility.

- The utilities cannot reasonably be forced to a fixed turn-around time for review because of the technical issues involved and unique nature of each DG installation. However DG applicants have a right to a timely review.

The Commissioners' job is to make rules that assure that all this happens … not to site, certify and permit.

Brian O'Donnell presented a draft outline of the Siting, Certification & Permitting Committee, which had been sent out to all members. Sharon Madden presented a draft report that could not be sent to all members because of time constraints. The following was decided:

1. A committee consisting of Brian, Sharon (or Chris Weathers), Greg Czaplewski, and Matt Puffer will prepare the report on Friday, November 19th.
2. The report will have an executive summary, purpose (with bulleted items), final recommendations and review assigned work scope items. Meeting minutes, white papers and other exhibits handed out at the meetings will be attached to the document.
3. 75 copies are required for the November 22nd meeting.

Jerry Smith gave an overview of the ACC process that will follow the submittal of the three- (3) committee reports

The next meeting of the committee will be Monday, November 22nd at 10:00 am at the ACC.

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DISTRIBUTED GENERATION FORUM

The Role of Distributed Generation in Competitive Energy Markets

Distributed Generation:

Small power generation units (typically less than 30 MW) strategically located near consumers and load centers that provide benefits to customers and support for the economic operation of the existing power distribution grid.

This paper describes the role of distributed generation (DG) in current and emerging energy markets. The discussion focuses on the following topics:

March 1999

When Thomas Edison built the Pearl Street Power station to provide the first electric service to customers in New York City, he was essentially following a strategy that today would be called distributed generation – building power generation within the localized area of use. As the young industry grew, many industrial facilities built their own power plants both to serve their own needs and to sell to customers around them, another example of distributed generation. Rapid technological development led to larger and more efficient generating plants built farther and farther from the end-user. Large regional power transmission networks delivered this power to the local distribution systems and finally to the end-user. The industry was regulated so that these changes could occur efficiently without wasteful duplication of facilities, and the economic role of distributed generation became much more limited.

Since the 1970s, however, large central nuclear and coal-fired power stations have become increasingly expensive and more difficult to site and to build. At the same time, technological development has improved the cost and performance of smaller, modular power generation options – from 300 megawatt (MW) gas-fired combined cycle power plants down to individual customer generation of as little as a few kilowatts. The industry is also restructuring to allow customers to competitively select the optimum combination of energy resources to meet their needs.

Distributed Generation Technologies

Energy service providers and consumers can select from a wide range of distributed power generation technologies. Commercial technologies such as reciprocating engines and small combustion turbines already are used in a variety of applications from emergency power to combined heat and power. Emerging technologies such as fuel cells, microturbines, and photovoltaics will provide additional options for distributed power generation.

Reciprocating Engines

Reciprocating internal combustion (IC) engines (Figure 1) are a widespread and well-known technology. North American production tops 35 million units per year for automobiles, trucks, construction and mining equipment, lawn care, marine propulsion, and, of course, all types of power generation from small portable gen-sets to engines the size of a house, powering generators of several megawatts. Spark ignition engines for power generation use natural gas as the preferred fuel – though they can be set up to run on propane or gasoline. Diesel cycle, compression ignition engines can operate on diesel fuel or heavy oil, or they can be set up in a dual-fuel configuration that burns primarily natural gas with a small amount of diesel pilot fuel and can be switched to 100% diesel. Current generation IC engines offer low first cost, easy start-up, proven reliability when properly maintained, good load-following characteristics, and heat recovery potential. IC engine systems with heat recovery have become a popular form of DG in Europe. Emissions of IC engines have been reduced significantly in the last several years by exhaust catalysts and through better design and control of the combustion process. IC engines are well suited for standby, peaking, and intermediate applications and for combined heat and power (CHP) in commercial and light industrial applications of less than 10 MW.

Combustion Turbines

Combustion turbines (CT) (Figure 2) are an established technology in sizes from several hundred kilowatts to hundreds of megawatts. CTs are used to power aircraft, large marine vessels, gas compressors, and utility and industrial power generators. In the 1-30 MW size relevant to distributed generation applications, over 500 CTs were shipped worldwide last year, totaling over 3,500 MW for electric power generation. Most of these units are sold overseas; the North American market represents an 11% share of these totals. CTs produce high quality heat that can be used to generate steam for additional power generation (combined cycle) or for industrial use or district heating. CTs can be set up to burn natural gas or a variety of petroleum fuels or can have a dual-fuel configuration. CT emissions can be controlled to very low levels using dry combustion techniques, water or steam injection, or exhaust treatment. Maintenance costs per unit of power output are among the lowest of DG technology options. Low maintenance and high quality waste heat make CTs an excellent choice for industrial or commercial CHP applications larger than 5 MW.

Figure 1
Skid-mounted, Gas Engine Generator
Courtesy of Caterpillar, Inc.

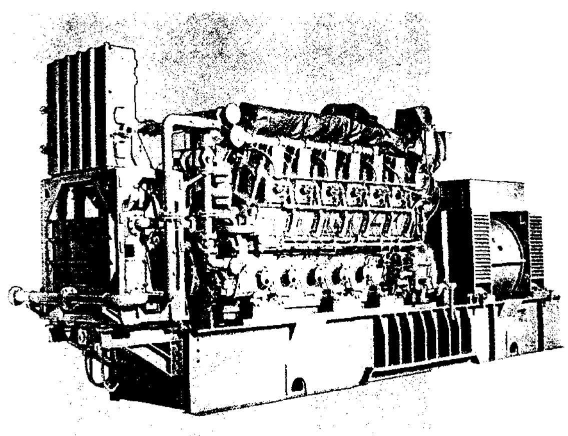
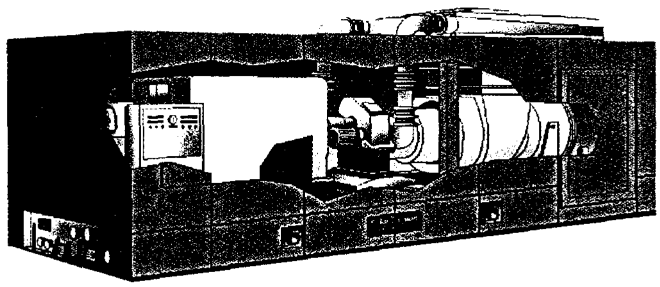


Figure 2
Typical Small Combustion Turbine Generation Plant
Courtesy of Solar Turbines, Inc.



Microturbines

Microturbines or turbogenerators (Figure 3) are very small combustion turbines with outputs of 30 kW to 200 kW. Individual units can also be packaged together to serve larger loads. Several companies are developing systems with targeted product rollout within the next two years. Turbogenerator technology has evolved from automotive and truck turbochargers, auxiliary power units for airplanes, and small jet engines used for pilotless military aircraft. Recent development of these microturbines has been focused on this technology as the prime mover for hybrid electric vehicles and as a stationary power source for the DG market. In most configurations, the turbine shaft spinning at up to 100,000 rpm drives a high speed generator. This high frequency output is first rectified and then converted to 60 Hz (or 50 Hz). The systems are capable of producing power at around 25-30% efficiency by employing a recuperator that transfers heat energy from the exhaust stream back into the incoming air stream. Like larger turbines, these units are capable of operating on a variety of fuels. The systems are air-cooled and some even use air bearings, thereby eliminating both water and oil systems. Low-emission combustion systems are being demonstrated that provide emissions performance comparable to larger CTs. Turbogenerators are appropriately sized for commercial buildings or light industrial markets for cogeneration or power-only applications.

Fuel Cells

Fuel cells (Figure 4) produce power electrochemically like a battery rather than like a conventional generating system that converts fuel to heat to shaft-power and finally to electricity. Unlike a storage battery, however, which produces power from stored chemicals, fuel cells produce power when hydrogen fuel is delivered to the negative pole (cathode) of the cell and oxygen in air is delivered to the positive pole (anode). The hydrogen fuel can come from a variety of sources, but the most economic is steam reforming of natural gas – a chemical process that strips the hydrogen from both the fuel and the steam. Several different liquid and solid media can be used to create the fuel cell's electrochemical reactions – phosphoric acid fuel cell (PAFC), molten carbonate fuel cell (MCFC), solid oxide fuel cell (SOFC), and proton exchange membrane (PEM). Each of these media comprises a distinct fuel cell technology with its own performance characteristics and development schedule. PAFCs are in early commercial market development now with 200 kW units delivered to over 120 customers. The SOFC and MCFC technologies are now in field test or demonstration. PEM units are in early development and testing. Direct electrochemical reactions are generally more efficient than using fuel to drive a heat engine to produce electricity. Fuel cell efficiencies range from 35-40% for the PAFC up to 60% with MCFC and SOFC systems under development. Fuel cells are inherently quiet and extremely clean running. Like a battery, fuel cells produce direct current (DC) that must be run through an inverter to get 60 Hz alternating current (AC). These power electronics components can be integrated with other components as part of a power quality control strategy for sensitive customers. Because of current high costs, fuel cells are best suited to environmentally sensitive areas and customers with power quality concerns. Some fuel cell technology is modular and capable of application in small commercial and even residential markets; other technology utilizes high temperatures in larger sized systems that would be well suited to industrial cogeneration applications.

Figure 3

Microturbine Generator

Courtesy of Allied Signal Corporation

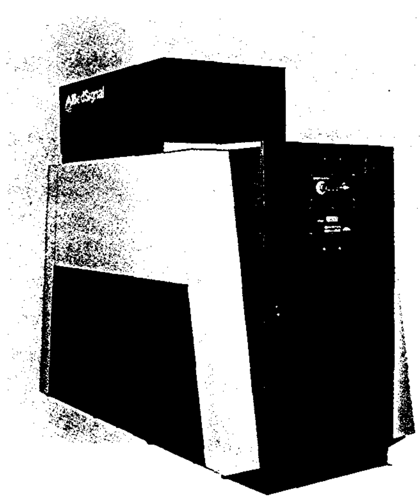
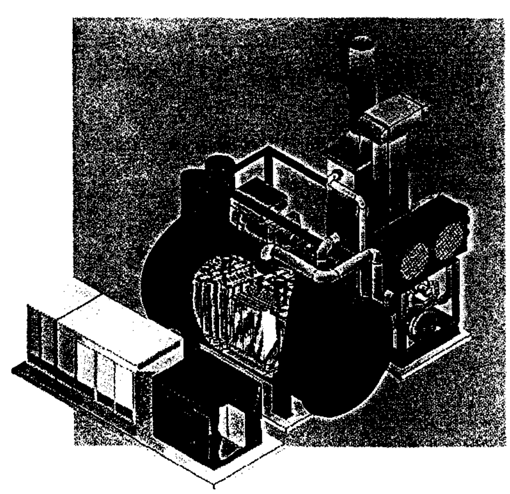


Figure 4

Advanced Fuel Cell Power Plant in Combined Cycle with Gas Turbine

Courtesy of Siemens-Westinghouse, Inc.



Photovoltaics

Photovoltaic power cells (Figure 5) use solar energy to produce power. Photovoltaic power is modular and can be sited wherever the sun shines. These systems have been commercially demonstrated in extremely sensitive environmental areas and for remote (grid-isolated) applications. High costs make these systems a niche technology that is able to compete more on the basis of environmental benefits than on economics.

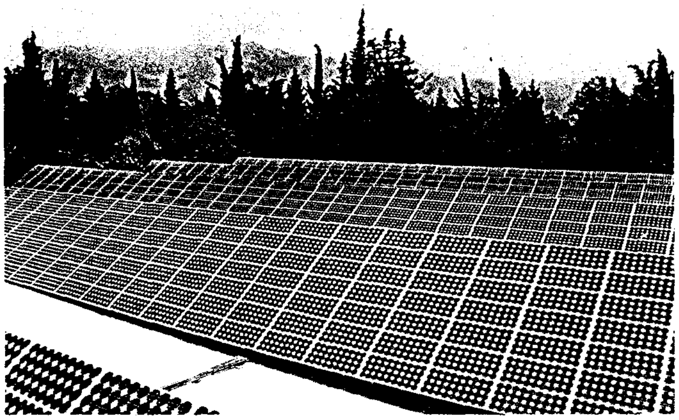


Figure 5

Photovoltaic Power Array in DG Service

Courtesy of Edison Technology Solutions, Inc.

Technology Comparison

In a broad sense, all of these technologies compete with each other and with utility and merchant power generation options. In a narrow sense, each technology is aimed at specific and often different market segments, so side-by-side comparisons must be viewed cautiously. Power generation economics depend on first cost, running efficiencies, fuel cost, and maintenance costs. Site suitability depends on size, weight, emissions, noise, and other factors. Table 1 shows the basic system performance characteristics for engines, turbines, turbogenerators, fuel cells, and photovoltaics.

Table 1

Economic Comparison of Distributed Generation Technologies

Technology Comparison	Diesel Engine	Gas Engine	Simple Cycle Gas Turbine	Microturbine	Fuel Cell	Photovoltaics
Product Rollout	Commercial	Commercial	Commercial	1999–2000	1996–2010	Commercial
Size Range (kW)	20–10,000+	50–5,000+	1,000+	30–200	50–1000+	1+
Efficiency (HHV)	36–43%	28–42%	21–40%	25–30%	35–54%	n.a.
Genset Package Cost ($/kW)	125–300	250–600	300–600	350–750*	1500–3000	n.a.
Turnkey Cost – no heat recovery ($/kW)	350–500	600–1000	650–900	600–1100	1900–3500	5000–10000
Heat Recovery Added Costs ($/kW)	n.a.	$75–150	$100–200	$75–350	incl.	n.a.
O&M Cost ($/kWh)	0.005–0.010	0.007–0.015	0.003–0.008	0.005–0.010	0.005–0.010	0.001–0.004

*Commercial target price

Applications for Distributed Generation

To understand how distributed generation fits into the overall energy market, it helps to look at the nature of the service provided, location on the grid, and the benefits to customers, transmission and distribution (T&D) companies, and energy service providers. Competition has brought a greater awareness that electric service is, in fact, a bundle of services that can be provided and priced separately (i.e., unbundled) in a competitive market. The services provided can be described as follows:

- Energy – providing all the customer's kilowatt-hours
- Capacity – meeting the customer's peak load requirements
- Reserve – maintaining additional capacity for fluctuations and emergencies
- Reliability – the end result of the level of investment in facilities and labor and management
- Power quality – voltage and frequency support and reactive power
- Back-up and standby service – support for customers with partial generating capability.

As customers and energy service providers develop the freedom to contract separately for these individual services, there may be a greater opportunity to use distributed generation as a means to optimize the sum of services required.

DG applications can be designed to meet a wide variety of service requirements and fulfill the needs of many customers and energy service providers. The applications categories defined below represent typical patterns of services and benefits provided by DG.

Combined Heat and Power

Power generation technologies create a large amount of heat in the process of converting fuel into electricity. For the average power plant, two thirds of the energy content of the input fuel is converted to heat. This heat can be utilized by customers, but only if the power generation is located at or near the customer's site. Combined heat and power (CHP), also called cogeneration, can significantly increase the efficiency of energy utilization, reduce global emissions, and lower costs. CHP is best for mid to high thermal use customers: process industries, hospitals, health clubs, laundries, etc. The approach has been successful in large industrial markets that use significant quantities of steam.

The application of CHP was greatly expanded by the Public Utilities Regulatory Policies Act of 1978 (PURPA). In the past twenty years, over 50,000 MW of CHP capacity has been built. The cogeneration rules in PURPA were designed to increase efficiency of fossil fuel utilization and stimulate the market by requiring utilities to interconnect with cogenerators and buy power at avoided costs that were calculated according to regulated procedures. Some of these rules implemented at the individual state level have resulted in contracts with cogenerators that contained pricing and operating terms and conditions that accommodated the vertically integrated power system but are not economic under current market conditions. In a competitive power market, more flexible rules will be required to ensure that customers, developers, and utilities can negotiate appropriate relationships that optimize the benefits of CHP for each of the participants. In addition, CHP can provide social benefits in the form of overall reduction of air and water pollution, reduction of emissions of greenhouse gases that contribute to global warming, and local and regional economic development.

Standby Power

The electric power system in North America is extremely reliable. Customers count on uninterrupted electric service 24 hours a day, seven days a week, week in and week out. Outages do occur, of course, most of which are the result of storm or accident damage to overhead T&D systems. With few exceptions, such outages tend to be brief and infrequent. Nevertheless, some customers are so sensitive to outages that they have standby generators onsite to supply power themselves until utility service is restored. Some standby generators are required by law to maintain public health and safety, such as for hospitals, elevators, and water pumping stations. For other customers like telecommunications, retail, and process industries, the installation of standby generators is an economic choice based on extremely high outage costs.

Standby generators are a highly underutilized generating resource. They hardly ever run, they aren't counted as either utility or non-utility generating capacity, and they usually are specifically isolated from grid connection. Still, there may be upwards of 40,000 MW of standby capacity in place today. Some utilities recruit customers with standby generation for peak load reduction programs offering payments or rate relief for limited operation during utility peak periods – generally fewer than 200 hours per year.

Customer choice of competitive power suppliers may stimulate the economic competitiveness of standby generators and increase the run hours for units in the field. Standby generation can be part of an optimal strategy that minimizes power costs and maximizes reliability through combinations of firm and interruptible power and onsite standby capability.

Peak-Shaving

The costs for power vary hour by hour depending on the demand and the availability of generating assets. Utilities see these variations, but customers typically do not. Larger customers often pay time-of-use (TOU) rates that convert these hourly variations into seasonal and daily categories such as on-peak, off-peak, or shoulder rates. With the advent of wholesale and retail competition in certain markets, more of these cost variations will be transmitted directly as price signals. Both TOU customers and those participating in competitive power markets could select distributed generation options during high-cost peak periods. Using DG for peak-shaving could reduce the customer's overall cost of power. In turn, this customer capability could reduce the need for the energy service provider to generate or contract to receive and redistribute very high cost power. TOU customers may find that their DG systems are cheaper than the peak TOU rates for much of the year. The closer that the price paid for power matches the actual hourly costs, the greater are the economic benefits to both the customer and the energy service provider in developing a peak-shaving strategy.

Grid Support

The power grid is an integrated system consisting of generation, high voltage transmission, substations, and local distribution. Selected use of distributed generation can provide system benefits and reduce the need for investment in other parts of the system. Potential DG benefits include:

- Voltage and frequency support to enhance reliability
- Avoidance or deferral of high cost, high lead time T&D system upgrades
- Reduction of line losses
- Reactive power control
- Transmission capacity release
- Reduced central generating station reserve requirements
- Fuel use reductions when solar, renewable, or high efficiency DG is applied in place of central station power.
- Emissions reduction from photovoltaics, fuel cells, and clean cogeneration

The evaluation of these benefits and the development of mechanisms whereby DG can provide grid support is an ongoing process. This process will likely occur more quickly in areas where the power industry is being restructured and costs are being unbundled.

Stand Alone (Grid Isolated)

In selected situations, grid isolated DG may be more economic than integration with the power grid. This would be true in very isolated or remote applications. In some cases, customers with CHP systems have separated from the grid due to an inability to negotiate economic back-up power from their energy service provider. It is expected that competitive power access would reduce the need for these customers to isolate from the grid.

Table 2 compares the applications described above with the individual service characteristics defined at the beginning of this section.

Table 2

Distributed Generation Applications and Services Provided

Services Provided	Combined Heat and Power	Standby Power	Peak-Shaving	Grid Support	Stand Alone
Energy	Simultaneous production of electricity and useful heat provide low cost energy to customers	Energy production is minimal and a small part of overall value	Provides alternative to high cost peak period energy	Reduces line losses, can be important in remote or congested parts of the T&D system	Must provide customer full requirements
Capacity	Provides capacity when running	Customer reserve capacity	Avoids high peak period system capacity costs	Can help to avoid T&D capacity constraints	Must provide customer full requirements
System Reserve	If the system is running at full load, by definition there is no reserve	Possible extension of current applications, but not part of most current standby systems	Could provide spinning and standby reserve during off-peak periods	Could provide spinning and standby reserve during off-peak periods	Must provide customer full requirements
Reliability	Systems are generally as reliable or more so than individual utility generators. Synchronous generators increase customer reliability by 90+% but don't contribute materially to system reliability	The primary purpose of these systems is to approach 100% reliability for health and safety reasons and to avoid economic losses from grid power outages	Increases customer reliability and can be part of a utility program to reduce shortage based outages	Increases reliability due to supply shortages, T&D constraints, and storm related outages	Must provide customer full requirements
Power Quality	Provides customer some protection from grid problems; can be part of a premium quality customer system	Not a primary issue but can be part of a premium quality customer system	May help customer to avoid voltage sags and brownouts that occur during system emergencies	Can be used for power factor correction and voltage support	Must provide customer full requirements
Back-up Service	For every 1% drop in generator availability, the system requires 87 hours of back-up service. Back-up for maintenance during off-peak periods, but forced outages can occur anytime	The system is the back-up service so separate back-up service is not required	Peak-shaving can be an extension of back-up service	Grid support enhances T&D system in general, not specific to back-up service	Must provide customer full requirements

Benefits of DG Applications by Stakeholder Group

The different DG applications provide various benefits to the stakeholders. Not all stakeholders benefit directly in all applications. CHP most directly benefits customers by providing lower energy costs. Social benefits from CHP include environmental benefits associated with combined heat and power production and economic benefits of higher productivity. Integrated electric utilities have, for the most part, not benefited from customer-operated CHP. However, in a competitive electric supply market, the T&D companies will be less affected by customer CHP and may receive grid support benefits. Standby systems meet customer reliability needs, but may be used by the T&D companies or energy service providers (ESPs) to provide peak load support for both supply and T&D constraints. Peak-shaving systems appear to provide large benefits to both customers and the T&D companies and may be the first market stimulated by electric industry restructuring. Grid support systems can optimize operations for T&D companies, thereby providing benefits to customers and operators in affected areas. Historically, stand alone or grid isolated systems were often the result of adversarial negotiations on customer generation projects and could have provided larger benefits to both if the system had remained grid connected. In the future, grid isolated systems may be less likely unless stranded cost recovery rules allow customers to avoid high payments by leaving the system altogether.

Table 3 summarizes potential stakeholder benefits for the various applications discussed in this paper.

Table 3

Distributed Generation Applications and Benefits by Stakeholder Group

Stakeholder	Combined Heat and Power	Standby Power	Peak-Shaving	Grid Support	Stand Alone
Customer	Lower energy costs, higher overall reliability	Avoid economic loss due to system outage and satisfy critical life support requirements	Lower peak period energy costs	Customers generally benefit from the enhanced service provided, but may be isolated from competitive markets as a result	Customer option to avoid high cost back-up service for CHP system; remote communica-tions and control systems
T&D System	Positive to negative depending on situation	Can be integrated with utility needs to provide both customer and grid benefits	Can be integrated with utility needs to provide both customer and grid benefits	Enhances grid stability and economic customer service	Loss of customer load and associated revenues
Energy Service Provider	Power and heat can be separately marketed, ESPs can also provide ancillary services to CHP customers	Can facilitate ESP marketing of interruptible power supplies, widely used strategy of municipal power systems	Can aggregate and sell customer peak period generation	Possible benefits as an owner-operator of the system	Possible benefits as an owner operator of the system
Natural Gas Industry	Benefit from high gas consumption, possible fuel switching benefit for oil-fired boilers	Minimal impact, but cost to service customers is high	Good match of gas off-peak period with electric on-peak period	Generally similar to peak-shaving benefits	Benefit from high gas consumption
Society	Environmental benefits, conserva-tion, economic development	Public health and safety	Environmental benefits, economic development	Environmental benefits, economic development	Less likely in a competitive market to represent an optimum allocation of resources

Electric Industry Restructuring

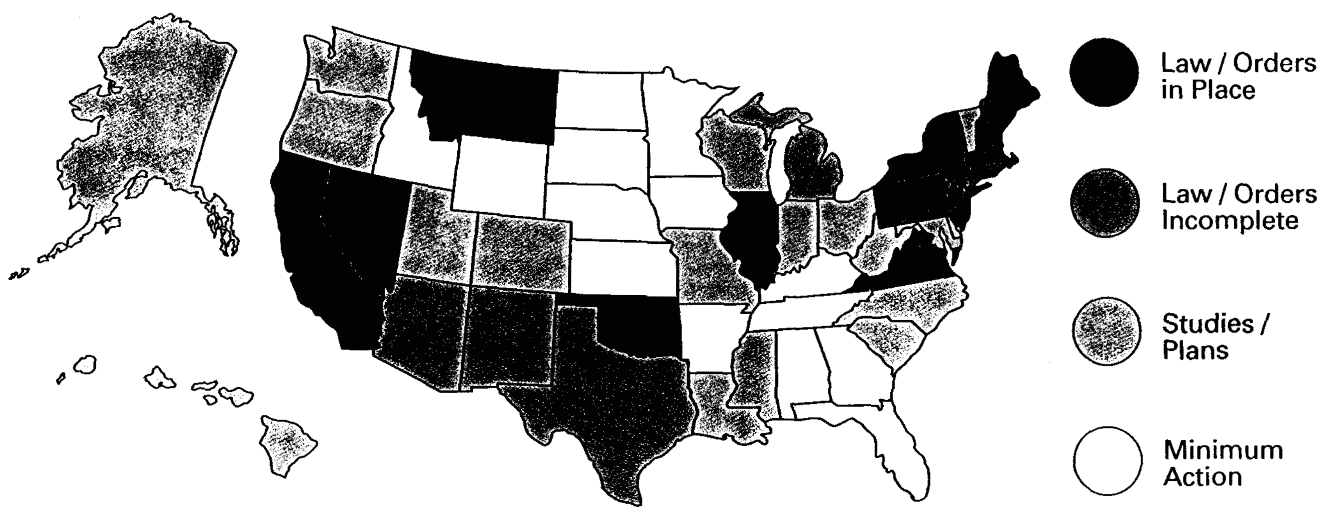
Restructuring of the electric power industry is underway with the objective of allowing customers to choose among competing power suppliers. The Federal Energy Regulatory Commission has already established rules to make wholesale power markets competitive. Retail competition is being enacted or proposed by many states, and generation is becoming an unregulated, competitive business. Six states have already initiated customer choice, and eight others have legislation or orders in place for implementation at a later date (see Figure 6). With some exceptions, the most activity has occurred in the high power cost regions of the country – namely California, the Northeastern and New England states, and Illinois.

In other states, especially the lower cost regions, the industry, the public, and regulators appear to be delaying a decision until more information can be gained from the experiences of the leading states – especially as transition problems emerge. This situation could well continue for several years, and it may be up to ten years before all states are restructured to allow competitive access. This delay will result in a high level of uncertainty among all parties to the process and a reluctance to proceed with investment at any level until the uncertainties are removed. Some critics have pointed to recent occurrences in the power industry, such as the blackout in the West in 1996 and the capacity shortage and high prices in the Midwest in 1998, as evidence that restructuring will threaten power reliability.

The changes underway are leading to a new industry structure as depicted in Figure 7. The changes will generally separate the generation, transmission, and distribution functions of the industry into separate entities with new functions. Critical aspects of restructuring are as follows:

- To ensure equal access to wholesale markets, transmission facilities are being placed under the control, but not ownership, of independent system operators
- Utility generating assets are being separated from the distribution companies and are being deregulated in order to develop a competitive market for power.
- Power marketers have emerged, creating an active power trading market.

Figure 6
Status of Deregulation by States (as of 3/1/99)



Source:
George C. Ford & Associates

- Utilities are to be compensated for stranded assets – investments made and costs incurred prudently under the existing regulatory compact that must be written off during the transition to competition.
- New mechanisms are being evaluated for maintaining public interest programs after restructuring such as research and development, conservation, support for renewables, and social programs previously administered by utilities.

At the same time that utilities are changing their vertically integrated structure, many are seeking to integrate horizontally through mergers with other power companies, gas companies, and other energy service providers in order to increase their customer access and expand the products and services that they provide.

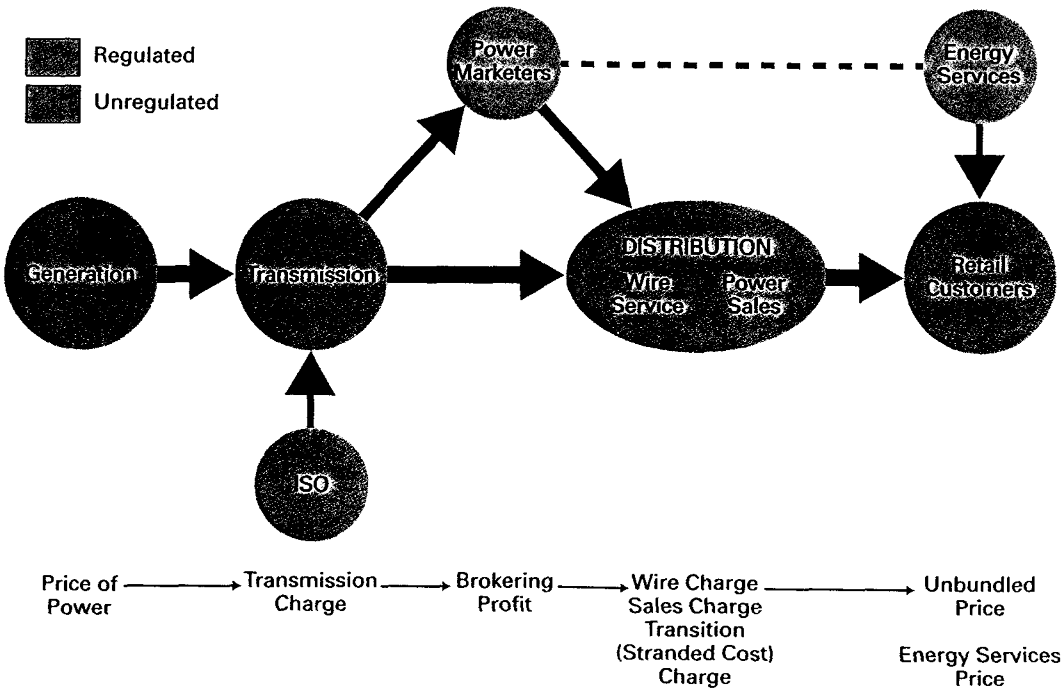
These industry changes are leading to new strategies by traditional utilities, independent unregulated new players, and customers in order to compete or take advantage of the new market:

- Competition for customers will lead to greater attention to customer needs. The regulated and unregulated industry players must respond to demands for choice of supplier and lower energy cost, better power quality, and overall energy services tailored to specific needs of each customer or customer class.
- In the commodity business of producing electric power, low cost will be the primary goal. Market risks must be avoided by minimizing capital investment and maintaining short lead-time for capacity additions.
- The potential attractiveness of small, dispersed sources has led to greater efforts to develop these technologies, including more efficient small gas engines, combustion turbines, microturbines, and fuel cells.

The electric capacity requirements during this ten-year transition period will depend on the future industry growth rate and the ability of restructuring to make more effective use of existing capacity, to cut reserve margins without affecting reliability, and to keep marginally economic plants operating. The future power requirements over the next ten years to meet new load growth and to replace retired capacity could range from 60,000 to 120,000 MW. This power will come from a combination of new central station generation plants, independent and merchant plants, and distributed generation.

Figure 7

U.S. Electric Industry – Expected Future Structure



The Potential Role of Distributed Generation in the New Electric Markets

Distributed generation will play a role in supporting available capacity to meet peak power demands, provide critical customer loads with emergency standby power, improve user power quality, and provide low-cost total energy in CHP applications. Potential customers include commercial and industrial users, distribution utilities, power marketers, and possibly even residential customers as well. Specific applications will be discussed in more detail below.

The key success factor for DG in a competitive situation can be best described as "providing the customer with the lowest cost solution to meet his particular needs." In some cases, this may be lowest initial or production cost; in others, it might be the lowest cost after considering site-specific or strategic factors. Distributed generation faces a challenge due to generally higher specific capital costs ($/kW) and production costs ($/kWh) than larger generating systems. These challenges must be balanced against positive factors such as the opportunity for waste heat utilization, increased reliability at the site, avoidance of peak load constraints and price spikes, reduction of transmission and some distribution charges, avoidance of energy line losses, improved power quality, and greater flexibility to react to market changes. Providing a specific valuation and a market for these services will allow DG to compete effectively where the system needs are greatest.

Distributed generation has traditionally faced obstacles from lack of technology maturation, integrated utility use of its own generating capacity, and a number of technical and regulatory obstacles to launching a new project. These other obstacles include interconnection requirements, permitting and siting, and building and electrical codes. Industry restructuring will remove structural obstacles to DG and will provide greater incentive to developing strategies for implementation.

Certain details of the restructuring process will have a big impact on DG's role during the transition period and beyond:

- Charges for utility stranded cost recovery – Utilities are being permitted to recover stranded assets using various types of tariffs including exit fees, competitive transition charges, access charges, and other means. Policies for application of these charges to distributed generation could significantly delay the benefits of these projects. Regulators are generally concerned with fairness toward all ratepayers and reluctant to subsidize one group at the expense of others. However, certain social benefits such as environmental protection and regional economic development may justify special treatment. Most states intend to apply the stranded cost charge only to power purchased from the grid.
- Standby charges for connection to the utility power grid – Customer-owned generation requires in most cases a back-up source of power to meet load requirements during generation outages. Utilities now charge not only for the power used but for the standby generation and distribution capacity. In the future deregulated market, the generation back-up charge will be negotiated between the user and the generation supplier, and the distribution charge negotiated with the utility as it is now. Regulators will be involved only with the distribution charge and must try to balance the utility and user positions on what is a reasonable charge that is fair to all ratepayers. A somewhat related issue is the treatment of customers who "take" power from the grid for which they have not contracted. Appropriate penalties need to be developed to keep customers that purchase from the competitive market from jumping back to the utility during periods of very high prices.
- Utility ownership of distributed generation – The separation of generation functions from T&D functions provides for equal access to competitive markets. However, regulators in some cases have supported selected DG investments by electric distribution companies that can provide grid support for localized areas.

Stakeholder Roles and Perspectives

Distributed generation is one piece of the larger picture that will emerge as a more efficient and competitive power market. Uncertainty concerning the direction of change in the electric power industry in this country and the potential magnitude of these changes combine to delay a strong focus on distributed generation.

Large customers are waiting for expected lower energy rates; many would like to outsource responsibility for managing their energy needs to a competent provider so that they can focus their resources on their core business needs. Small customers are concerned about how they will share in the benefits of deregulation. The regulated electric power industry and the regulators have too many other priorities right now – sale of generating assets, stranded asset recovery, and restructuring. Independent power providers (IPPs) are focusing their efforts on large merchant power plants and renegotiation of existing contracts. Power marketers and energy service providers are busy building the structure of the new market and gaining customer and power access. ESPs and energy service companies (ESCOs) are looking to build multilevel service capability, and they do see distributed generation as an important component of a complete line of customer services and products.

Recognizing that all of these goals compete for the attention of these market participants, an important purpose for this paper is to focus attention on the benefits of distributed generation and to define active roles for the main stakeholders.

Federal Government

While electric industry restructuring is proceeding without a clear federal position, there are a number of federal initiatives that could facilitate the emergence of competition in both wholesale and retail power markets. The administration has prepared a comprehensive proposal, the Federal Energy Regulatory Commission has outlined its proposals to Congress, and there are at least 16 bills before Congress that address a wide range of issues. The expected aspects of a federal program are as follows:

- Federal directive for states to implement retail consumer choice programs by a certain date (January 1, 2003, in the administration proposal)
- Repeal of the Public Utilities Holding Company Act of 1935, which was designed to protect against market abuses foreseen in the 1930s but which, today, is an impediment to the type of restructuring needed to promote competition
- Repeal of the requirement for utilities to buy power from cogenerators and renewable sources at avoided costs (Section 210 of the Public Utilities Regulatory Policies Act of 1978) and establishment of a new policy toward renewable energy
- Establishment of a federal authority for determining reliability standards for the electric power industry
- Support for stranded cost recovery under state laws including nuclear decommissioning costs
- Extension of competitive access rules to federal power marketing administrations and to municipal utilities, including facilitation of sale of generating assets funded with municipal bonds
- Establishing a procedure for resolving disputes among states and regions and requiring reciprocity between states on power access
- Research and development to support cleaner and more efficient technologies
- Development of initiatives that promote environmental and conservation benefits from CHP projects. The recommended CHP initiatives include streamlined environmental permitting, nondiscriminatory grid access, and tax incentives.

State Governments

As defined in the opening discussion on restructuring activity, the 50 states differ widely on their progress toward competitive access. Restructuring legislation has been enacted in 12 states, but progress has been slow in other parts of the country. In a position paper issued by the National Governors' Association, the state roles are defined as follows:

- Ensure fair competitive access to the electricity transmission and distribution grid for electric generators
- Determine the amount and method for recovery of stranded costs resulting from the transition
- Continue to regulate the local distribution systems and ensure their reliable operation
- Evaluate the impact of competition on the fuel mix for power generation and assess associated environmental impacts
- Define a basis for continuing public interest programs in conservation, renewable energy, and other technologies that will benefit the customer.

States that have already begun implementation of restructuring have found specific operational issues emerging that need to be addressed as part of a smooth transition. These issues include revising the state tax codes to avoid revenue loss based on the new modes of purchase and sale of power, development of procedural requirements, and determination of appropriate affiliate relationships. The two most important roles at the state level that could exert a beneficial impact on DG development are:

- Examine and consider utility ownership of distributed generation assets or incentives for DG implementation where system benefits can be achieved by their implementation
- Encourage exemptions from stranded asset recovery for distributed generation projects that have overriding economic, environmental, and social benefits.

Electric Power Companies

The traditional electric utility industry is evolving in various directions to meet the changing needs of a competitive market. Many of the larger investor owned utilities are developing deregulated power generation activities, power and fuel marketing, and energy service companies. At the same time, mergers with gas companies and other power companies are providing the customer access and total service that is believed to be the cornerstone of a healthy restructured company. The suggested roles for the distribution business are:

- Aggressive efforts to minimize stranded assets – e.g., sale of generating assets and settlement of above-market power contracts
- Cost and value analysis in preparation for the development of unbundled services
- Evaluation of constrained areas and ancillary services and alternative means, like distributed generation, that can effectively provide grid support
- Integration of customer generating equipment into interruptible and load management programs to provide greater peak-load reliability
- Development of uniform rules for interconnection.

Independent System Operators

Independent system operators (ISOs) are taking over many of the decision-making functions of regional power systems including, in many cases, operating a competitive power market, deciding on peak power requirements and implementing emergency power programs, and defining and valuing ancillary services. ISOs are defining peak load control programs for customers with standby generation, creating rules for DG participation in the power market, defining ancillary services, and even developing demand-side customer bidding options.

Natural Gas Industry

DG provides a way for gas distribution companies to participate in the evolving power generation market and derive benefits such as growing gas load, increased asset utilization, and additional service opportunities through unregulated affiliates. The gas industry role includes:

- Participation in regulatory proceedings to ensure that gas interests are considered
- Participation with the electric power industry, regulators, and consumers in the development of uniform grid interconnect standards
- Education of key decision-makers regarding gas related issues
- Assistance in the development and deployment of DG technology and application demonstrations
- Communication with DG developers and manufacturers to ensure compatibility with gas systems.

Energy Service Providers / Energy Service Companies

ESPs and ESCOs are aggressively moving to become the source of "one stop" energy shopping for a wide customer base from large industrial and national accounts to the residential retail customer. These companies will provide fuel, power, energy services, project development and operation, management of customer energy facilities, risk management, and financing. Distributed generation represents an important part of this complete portfolio of services designed to improve the competitive position of these companies in the eyes of their customers.

In this context, ESPs and ESCOs will be the market-makers for distributed generation. Their roles will include market development; joint development of demonstration projects with customers, manufacturers, and utilities; development of improved matching of systems to site needs; and reduction in the costs associated with project development. In addition, public education on the uses and benefits of distributed generation is important, as is increasing the awareness of the issues and obstacles inhibiting electricity users from realizing the full potential benefits.

Equipment Manufacturers

The engine, turbine, and fuel cell makers and other manufacturers of generation systems need to work with the market-makers (distributors, ESCOs, and ESPs) to better target system performance, emissions, and life-cycle cost to customer needs. Ancillary equipment makers are also important in this process in the area of controls, communications, dispatch, fuel gas compression, power electronics, and emissions clean-up. They need to participate with the market-makers in project development, demonstration, and education activities. For the developers of emerging technology, the development of manufacturing capability and a sound marketing and service network is of critical importance. Equipment manufacturers should also assume the responsibility to work with agencies setting standards and certification procedures.

Customers

Customers will be faced with new responsibilities in the management of their energy use in a competitive market. Customers that do not prepare will be bombarded with a bewildering array of claims and choices from competing energy suppliers. Many large industrial and commercial customers already have energy management groups that control purchasing and operation of all energy matters. In some cases, customers want to outsource this activity on a contract basis so that they can focus on their primary business responsibilities. Customers can prepare for competitive access by undertaking the following activities:

- Evaluate energy requirements to determine cost-effective energy alternatives
- Identify load shifting or load shedding opportunities
- Quantify outage costs to determine if additional standby generation capacity is needed
- Identify opportunities for using existing or new generation to contract for lower cost interruptible power.

Finally, all potential beneficiaries from distributed generation have a stake in this process and can contribute to achieving the goal of maximizing the benefits from these advancing technologies.

Distributed Generation Forum

The Distributed Generation Forum is a membership organization composed of representatives from electric and gas utilities, their affiliate marketing and development companies, and manufacturers and developers of distributed generation and ancillary equipment. In addition, the Forum includes invited participation from government and private research and development, industry, and marketing organizations that have an interest in distributed generation. The mission of the Forum is to provide its members with technical, regulatory, and market information for their use in strategic planning, market development, internal and external education, and information exchange with trade allies, customers, and regulators. This paper represents the consensus view of the Forum based on the work undertaken during the previous two years, but may not represent the opinions of individual members. Gas Research Institute manages the Forum.

For further information on Forum activities contact:

Dan E. Kincaid
Gas Research Institute
8600 West Bryn Mawr Avenue
Chicago, Illinois 60631-3562
773/399-8338; FAX: 773/399-8100
E-mail: dkincaid@gri.org

299.10,500 Miller Johnson
GRI-99/0054

DATE: September 14, 1999

MEMO TO: ACC DGI Work Groups

FROM: Jim Corbin
President, IBEW Local 1116
(502) 792-1475

SUBJECT: Training and Certification

We have been asked by the Siting, Certification and Permitting Committee to state our position on worker training and certification. Some of these issues may overlap with discussions in the Interconnection Standards Committee and consultation with those groups may be necessary.

Safe construction, maintenance, and operational practices in the Electric Utility industry are the key components to a safe and reliable electric supply. The United States has one of the most reliable and low cost electrical supply systems in the world. The key factor to our successful system has been the people that build, maintain and operate the Generation, Transmission, and Distribution segments of the industry.

Many of the jobs involved are extremely technical and hazardous and thus require a high level of training and expertise to prevent accidents to workers and the public and keep unplanned outages to commercial and residential customers at a minimum. For these reasons, a high level of skill and ability should be maintained by the incumbent utilities and required of any future participants to prevent degradation of our existing system.

For example, the training required to become a Journeyman Lineman/Cableman entails a State and Federally overseen four-year apprenticeship program. The curriculum includes a minimum of 144 hours of classroom time (math, electrical theory, National Electrical Safety Code) per year, and a minimum of 2000 hours in the field demonstrating competency in on-the-job training (pole climbing, proper connection practices, clearances and lock-out procedures.) If at any point during the apprenticeship the applicant fails to meet attendance, minimal test scores, or any on-the-job training requirements, they are removed from the program.

This enormous amount of training and responsibility is paralleled on the Generation side of the industry. On average, a six-year training program is required to become a Control Room operator, from starting as new operator to being able to operate the control panel unassisted.

Allowing untrained, uncertified, and unlicensed contractors to come into the State of Arizona to install and operate distributed generation that is connected to our electrical system is inviting disaster to the most critical element of our infrastructure. The customers of Arizona's electrical utilities deserve and should expect the people that bring power into their homes and businesses to be qualified and knowledgeable in all facets of safety and reliability. Because this very issue was overlooked in drafting distributed generation language in California, regulators and staff are presently trying to correct sub-standard construction practices by retroactively implementing minimum standards for workers and contractors. We should not make the same mistake. We need to have minimum standards of 160 hours classroom time per year and 2000 hours field related work for electricians that will be involved in electric construction work i.e distributive generation work, protecting our customers and our system from unqualified personnel before any damage can occur.

Possible language could require minimum hours for exposure to the National Electrical Code, OSHA training such as rescue procedures, traffic control, lockout/tagout, Personal Protective Equipment, medical and first aid, fall protection, fire fighting and prevention, drug and alcohol, noise exposure, and excavations.

Third party certification should be required from a state or federal agency, verifying training requirements and minimum standards have been met, as is currently being done with the apprenticeship programs.

Please contact our office at the above number if we can answer any questions or assist you in any way. Thank you for your interest in this important topic.

Siting, Certification & Permitting Committee

Thresholds for which siting is a public issue:

Air Quality – Air quality issues are handled by Maricopa County, State of Arizona Department of Environmental Air Quality and U.S. Environmental Protection Agency. No new action required by ACC.

Fuel Supply – Fuel supply issues are handled by regulations already in place. State of Arizona, Arizona Cities, and ACC may all have regulations. No new action required by ACC.

Noise – Noise issues are handled by local zoning ordinances or OSHA. No new regulations required by ACC.

Safety – Safety issues are already covered by existing building codes and equipment standards. Utility safety issues will be covered by Interconnection Committee.

Jurisdiction appropriate for siting, certification & permitting issues:

Individual Arizona Cities, Maricopa County, State of Arizona and the U.S. Environmental Protection Agency have jurisdiction for siting, certification and permitting issues.

Siting is a local, county, state and U.S. EPA issue. No new action is required by the ACC.

Permitting is a local, county, state and U.S. EPA issue. No new action is required by the ACC. Merchant plants ___ MW or larger in size should require ACC review for system compatibility.

Jurisdiction(cont)

Certification is an issue that can be addressed by the ACC and local jurisdictions. Equipment suppliers should have the option of having equipment pre-certified for use in the State of Arizona. Pre-certification should be allowable for installations of ___5 MW or smaller. The advantage of pre-certification would be that the ESP and local wires company would simply be notified that the pre-certified equipment was to be installed. Similarly, equipment and equipment protective devices(i.e., all devices downstream of the meter) should be able to be certified as a package. The certification process would consist of an independent test of the equipment and/or package by an independent testing authority(e.g., UL, etc.). A copy of the approval would be sent to the ACC, State Chapter of the International Conference of Building Officials and Building Official of the jurisdiction where the unit is to be installed. The ESP and local wires company could have access to the report through the ACC.

Siting Thresholds affected by:

Type of Unit – Air quality, fuel supply, noise & safety are all impacted by type of unit; but there is no need for added ACC jurisdiction as other authorities already exercise authority.

Unit Size – To be discussed at meeting

Location of Project – Air quality, fuel supply, noise & safety could all be impacted by the location of project; but there is no need for added ACC jurisdiction as other authorities already exercise authority.

Intended Operational Uses(Self –providing, emergency back-up,sell excess to others, etc.) Air quality, fuel supply, noise & safety could all be impacted by the intended operational use; but there is no need for added ACC jurisdiction as other authorities already exercise authority. The safety issue also needs to be addressed by the Interconnection Committee.

Siting Thresholds(cont)

Residential vs Commercial Applications - Air quality, fuel supply, noise & safety could all be impacted by the intended operational use; but there is no need for added ACC jurisdiction as other authorities already exercise authority.

DISTRIBUTED GENERATION APPLICATION PROCESS

Customer – can select either process

Preliminary Process

Submit Application to ACC/UDC
With General Information
- Type of Equipment
  - Synchronous
  - Induction
  - Inverter
- Size
- Location
- Special Requirements

3 week turn-a–round

UDC informs applicant of
Final Process requirements,
Copy to ACC

User begins Final
Application Process

Final Process

Submit Application to ACC/UDC
with Detailed Form
Filled Out

3 week turn-a-round

UDC informs applicant
of comments, copy to
ACC

If necessary, resubmit-
tal to ACC/UDC

2 week turn-a-round,
ACC/UDC approves application

DEAA 10/4/99

DG Application Process

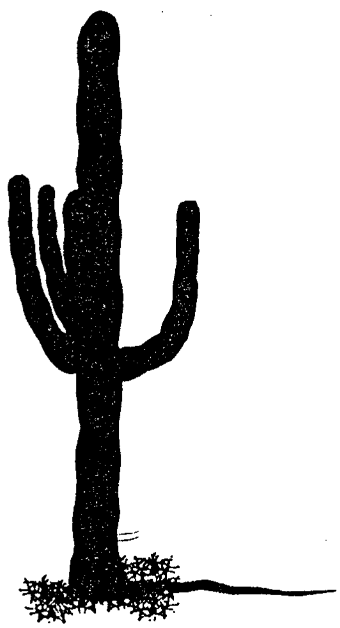
Who	What	Comments
DG Installer	Notifies UDC of intent to interconnect.	Should DASR be used, or other notification process?
UDC	UDC sends Interconnection Requirements package.	Who should send checklist with addresses and telephone numbers of other agencies that need to be involved
DG Installer	DG sends required interconnection documents to UDC. DG and UDC work together throughout design process. When the project is completed a site inspection is scheduled.	This is an iterative process with documents submitted and reviewed as the project goes forward. The Interconnect Workshop is working on the technical details
UDC	UDC verifies that all the interconnection requirements are met and notifies DG that they can parallel with UDC.	The Interconnect Workshop is working on the technical details
DG Installer		

Chris Weathers 10/6/99

Attachment #2

State of Arizona

Direct Access Service Request Handbook



Final Version will be dated 10/14/99

09/01/99

Table of Contents

Appendices

Team Charter

Background

This document was developed by interested parties at the request of the Arizona Corporation Commission to assist in the transition to Direct Access services under Electric Restructuring. The DASR Team is a subcommittee of the Billing and Collections Working Group sponsored by the Arizona Corporation Commission. This team met on a regular basis from May 1998 through October 1998 to assess and develop statewide processes for the multitude of transactions between the existing utilities and their support services and the new entrants and their support services. This Direct Access Service Request Handbook was developed in alignment with the August 5, 1998 Arizona Corporation Commission Emergency Rules. Each team member actively pursued the best interests of their represented company while recognizing the needs of the other key players.

It is the intent of the DASR Team to meet in subsequent quarters to refine the statewide processes. The core team members involved in the development of this handbook are representatives of:

Arizona Public Service
Citizens Utilities Company
Navopache Electric Cooperative
RW Beck, consultant for Enron, et al
Salt River Project
Tucson Electric Power

During preliminary development, the DASR Handbook was presented to the Billing and Collections Working Group for feedback. Attendees included representatives from affected utilities and market participants (i.e., ESPs, consultants, and consumer groups).

Future Process Management

Team Objective is to be a focal point for the Arizona DASR process. This will be accomplished by:

- Meeting as needed to refine the state wide DASR processes
- Maintaining and updating DASR handbook
- Keeping membership open to all market participants

Process evaluation and changes are needs driven, governed by group process, based upon agreement and ability of participating market entities.

Introduction

The purpose of this handbook is to provide a process overview and basic instructions for completing the Direct Access Load Aggregation Submittal (DALAS) and the following Direct Access Service Request (DASR) transactions:

Request	(RQ) DASR
Cancel	(CL) DASR
Termination of Service Agreement	(TS) DASR
Physical Disconnect	(PD) DASR
Update / Change	(UC) DASR

Arizona Affected Utilities and Interested Parties agreed at the onset of Commission meetings that the DASR was a communication mechanism between an Energy Service Provider (ESP) and a Utility Distribution Company (UDC); that it was in the best interest of all parties to develop a common format, to be adopted by all Affected Utilities for processing the Direct Access Service Requests. The guidelines of this handbook were based on the following:

- A Letter of Authorization (LOA) will be signed by the customer and retained by the ESP as proof that the customer made a legitimate request for a new service provider
- The current service provider is responsible for submitting 12-months (or available) of customer-specific consumption history to the new service provider
- Customer always bears the burden of contacting their present service provider regarding any changes to their service agreement
- One DASR is required for each requested transaction
- The effective Direct Access (DA) switch date will occur on the customer's scheduled meter read date or the date of meter installation
- The minimum format to be used for these transactions is comma delimited value: character values are left justified; numeric values are right justified zero filled
- DASR's may initiate the meter exchange process; for specific meter exchange protocols contact the UDC
- Until January 1, 2001, load aggregation eligibility is determined within individual UDC service territories
- The Direct Access Load Aggregation Submittal (DALAS) needs to be validated by the UDC prior to the submission of DASR's for each of the services listed on the DALAS
- DASR/DALAS transactions may require additional specific details refer to individual UDCs

This handbook contains a detailed description of the five basic transactions to be used including responsibilities of the ESP, UDC, and Customer; a communication process flowchart for each of the five basic transactions; a Submittal/Response table for each of the five basic transactions; and the DASR Field Definitions. Where aggregation is desired, a similar structure and a sample form for the DALAS is included.

Consumer Protection References

R14-2-212	Administrative and Hearing Requirements
R14-2-1613	Service Quality, Consumer Protection, Safety, and Billing Requirements
R14-2-1618	Disclosure of Information

Request (RQ) DASR

Purpose: Used to initiate enrollment in Direct Access; used to request a change in Electric Service Providers.

ESP Responsibility:
- Prior to submitting the DASR, the ESP will obtain a signed Letter of Authorization (LOA) from the customer requesting Direct Access electric service and authorizing release of customer consumption history to the ESP
- Retains customer Letter of Authorization
- Submits DASR form with UDC required fields completed
- Submits DASR to the UDC a minimum of 15 calendar days prior to requested change date
- Notifies prospective / new customer of ineligibility, acceptance, or status of DASR request
- ESP will coordinate with UDC any meter exchange activity

UDC Responsibility:
- Determines eligibility of customer
- When acting as current ESP, responds to new ESP with customer's 12-month consumption history and DASR status within 5 business days
- Upon new Request DASR acceptance, issues Termination of Service Agreement DASR to ESP of record (now prior ESP) notifying them of customer's request to switch providers
- Assigns Universal Node Identifier (UNI) if first time Direct Access customer
- Coordinates with ESP, or their designated affiliate, any meter exchange activity and/or meter reading requirements as necessary

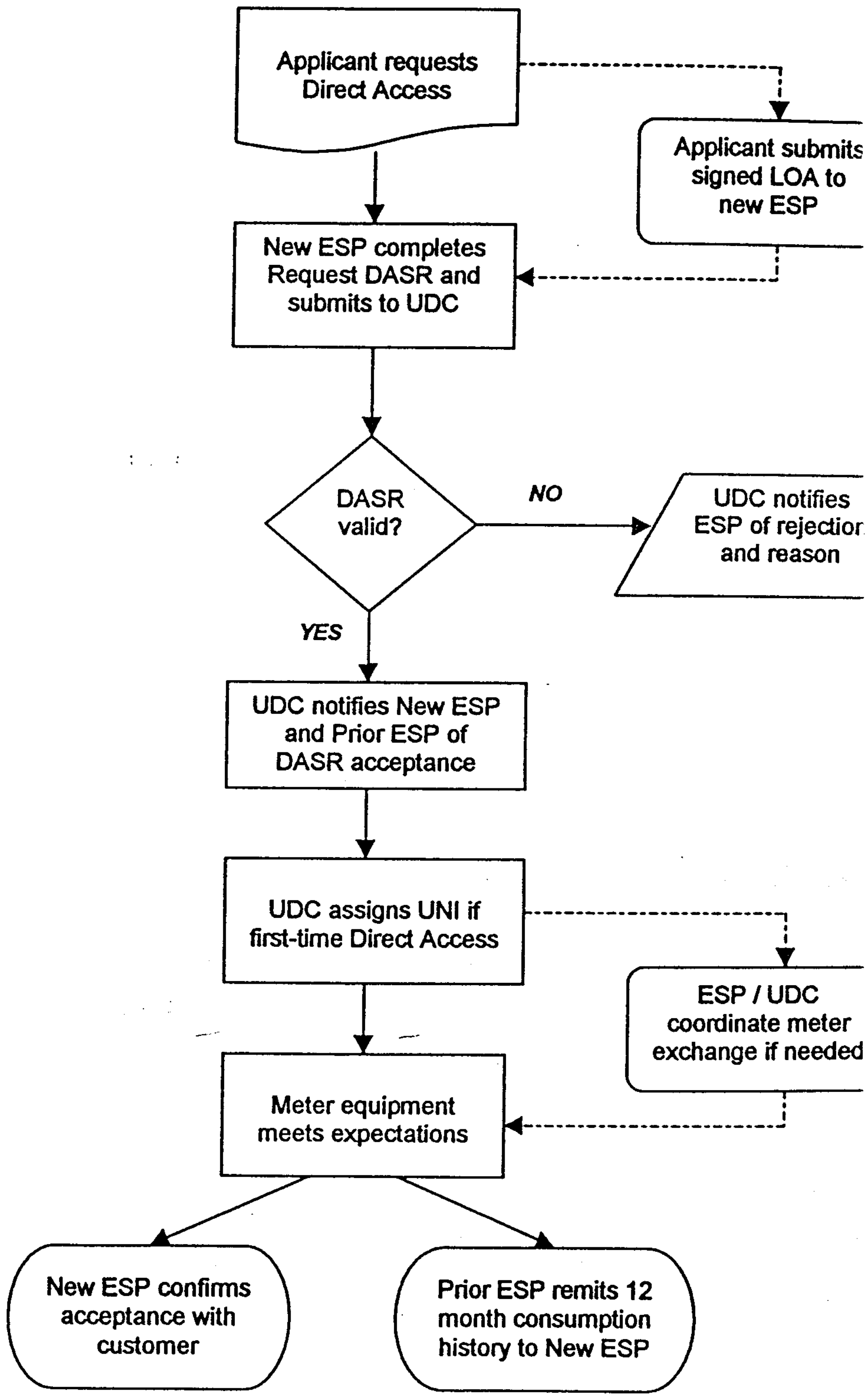
Customer Responsibility:
- Customer makes application with ESP
- Signs LOA that permits ESP to request 12-month consumption history from UDC or prior ESP and indicates customer is requesting change of electric service provider
- Provides free and unassisted access to the electric meter

General Information:

- Within the established time frame, when more than one Request DASR is received for a service delivery point, only the first DASR received will be processed; all subsequent DASRs will be rejected
- New connect and current service Request DASRs must be submitted 15 calendar days prior to the requested [move in date] effective change date

In accordance with R14-2-203.D4, the following standards are also in place;
- When a meter exchange is *not* required, the switch date to Direct Access will occur on the customer's next scheduled meter read date provided that the DASR is processed [received and validated by the UDC] 15 calendar days prior to that date
- When a meter exchange is required, the switch date will occur on the meter install date
- The customer switch date may occur earlier for a fee

Request (RQ) DASR Process Flowchart



Request (RQ) DASR Submittal / Response

This table demonstrates the **R**equired, **O**ptional, and **C**onditional (based upon UDC business rules) fields necessary to complete this DASR transaction type. ***Response will include both submittal and response fields.***

Field	Submittal – Field Description	Req'd	Field	Response – Field Description	Req'd
1	DASR Tracking #	R	20	Quarter Eligible	O
2	ESP Business Name	R	22	UDC Medical Code	R
3	Date & Time Sent	R	25	Congestion Zone	R
5	Transaction Type	R	28	DASR Status	R
6	ESP Customer Account #	R	29	Reason Code	O
7	Customer UDC Account Name	R	31	UDC Comments	O
8	UDC Customer Account #	R	33	Effective Change Date	R
9	Service Street Address	R	42	UDC Meter Read Cycle	R
10	Service City	R	43	Universal Node ID (UNI)	R
11	Service State	R	45	Universal Meter ID (UMI)	C
12	Service Zip	R	55	Load Profile	O
13	Mail Address	R	56	UDC Bill Cycle	O
14	Mail City	R	58	Recipient ID	O
15	Mail State	R	59	Recipient Name	O
16	Mail Zip	R			
17	Contact Phone #	R			
18	UDC ID	R			
19	UDC Business Name	O			
21	ESP Medical Code	O			
23	Scheduling Coordinator Duns #	R			
24	Scheduling Coordinator Name	R			
26	UDC Customer Eligibility	R			
27	DA Load Aggregation Submittal ID	C			
30	ESP Comments	O			
32	Requested Change Date	R			
34	Billing Options	R			
35	Billing Calculation	C			
41	Meter #	R			
43	Universal Node ID (UNI)	C			
44	Meter Ownership	R			
45	Universal Meter ID (UMI)	O			
46	MSP ID	C			
47	Meter Service Provider Name	C			
48	MRSP ID	R			
49	Meter Reading Service Provider Name	R			
54	ESP Rate Code	C			

Submittal

Response

Cancel (CL) DASR

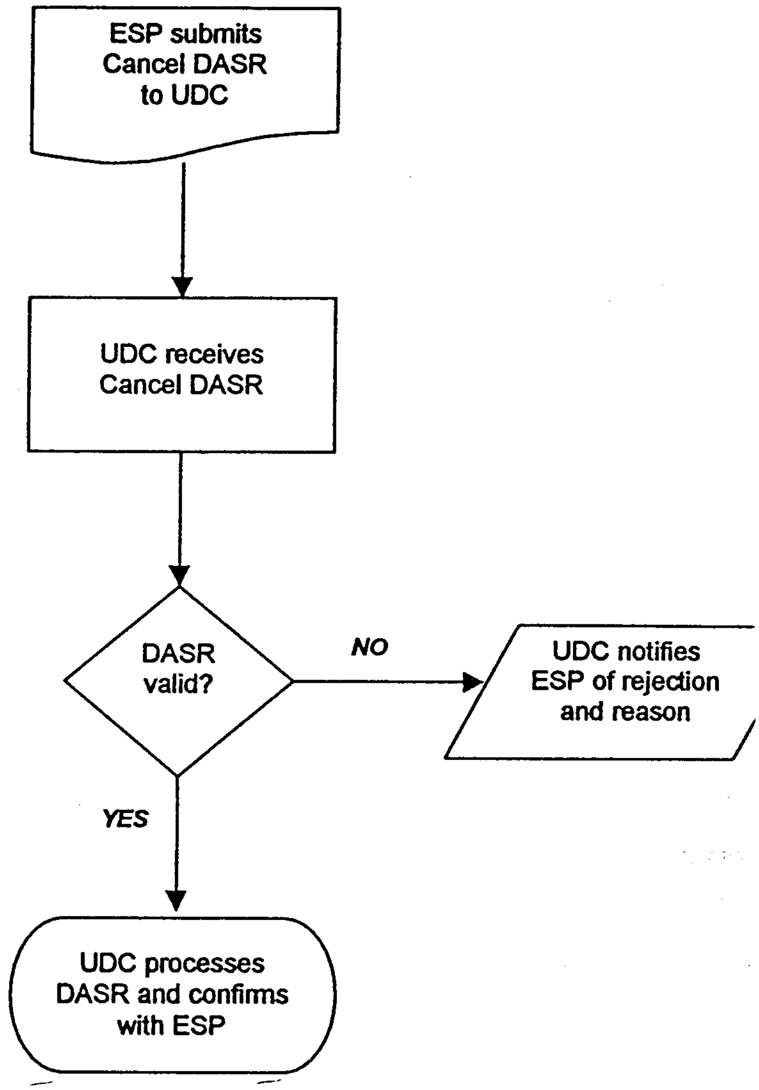
Purpose: Used to cancel a previously submitted Request (RQ), Physical Disconnect (PD), or Termination of Service Agreement (TS) DASR prior to the effective change date.

ESP Responsibility:
- Originator of DASR submits Cancel DASR to stop activation of the transaction

UDC Responsibility:
- Accept and respond with confirmation

Customer Responsibility:
- To promptly notify their ESP of any change of decision

Cancel (CL) DASR Process Flowchart



Cancel (CL) DASR Submittal / Response

This table demonstrates the **R**equired and **O**ptional fields necessary to complete this DASR transaction type. ***Response will include both submittal and response fields.***

Field	Submittal – Field Description	Req'd	Field	Response – Field Description	Req'd
1	DASR Tracking #	R	28	DASR Status	R
2	ESP Business Name	R	29	Reason Code	O
3	Date & Time Sent	R	31	UDC Comments	O
5	Transaction Type	R	33	Effective Date	O
6	ESP Customer Account #	R	58	Recipient ID	O
7	Customer UDC Account Name	R	59	Recipient Name	O
8	UDC Customer Account #	R			
9	Service Street Address	R			
10	Service City	R			
11	Service State	R			
12	Service Zip	R			
18	UDC ID	R			
19	UDC Business Name	O			
30	ESP Comments	O			
41	Meter #	R			
57	Original DASR Tracking #	R			

Termination of Service Agreement (TS) DASR

'urpose: Used by ESP to advise UDC that the service agreement with a customer is being erminated; used by the UDC to notify the existing ESP of a customer change to a new ESP.

:SP Responsibility:

Provide minimum of 5 calendar days notice to customer of intent to terminate service agreement

Provide 15 calendar days notice prior to the next scheduled read date, via Termination of Service Agreement DASR, to UDC regarding intent to terminate the service agreement with their customer

When switching to a new ESP, current ESP submit customer's 12-month consumption history to new ESP; not necessary if customer is returning to a Standard Offer

IDC Responsibility:

When a Termination of Service Agreement DASR has been received and a new ESP has not been identified with a pending Request DASR, UDC will send notification to customer they are being returned to UDC Standard Offer

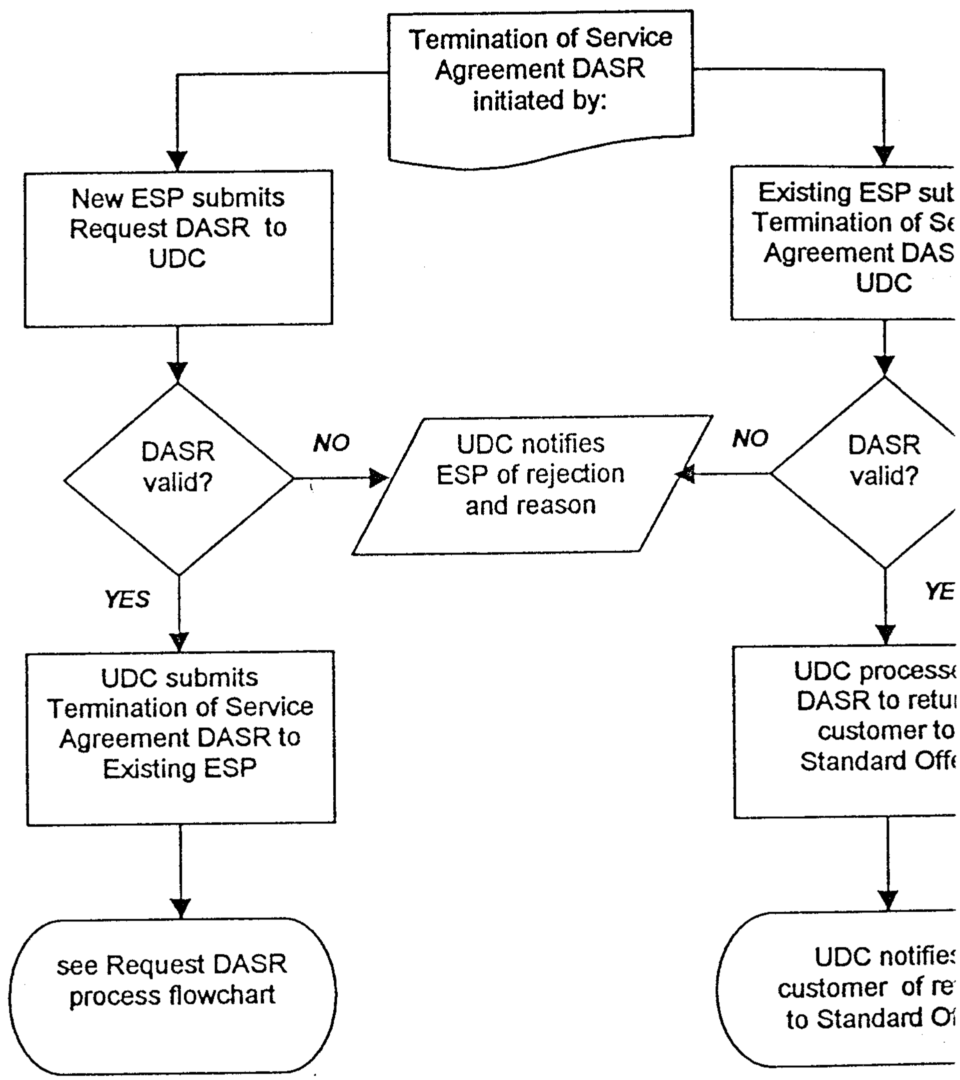
Send Termination of Service Agreement DASR to prior ESP upon receipt of a Request DASR from a new ESP for a customer; prior ESP is not required to respond

:ustomer Responsibility:

When customer is requesting termination of the service agreement, they must contact their present ESP for submittal of Termination of Service Agreement DASR or new ESP for submittal of Request DASR

The customer will be returned to UDC Standard Offer unless another Request DASR is received within the established time frame

Termination of Service Agreement (TS) DASR Process Flowch



Termination of Service Agreement (TS) DASR Submittal / Response

Bi-Directional

This table demonstrates the **R**equired and **O**ptional fields necessary to complete this DASR transaction type. ***Response will include both submittal and response fields.***

Field	Submittal - Field Description	Req'd	Field	Response - Field Description	Req'd
1	DASR Tracking #	R	28	DASR Status	R
2	ESP Business Name	R	29	Reason Code	O
3	Date & Time Sent	R	31	UDC Comments	O
5	Transaction Type	R	33	Effective Change Date	R
6	ESP Customer Account #	R	58	Recipient ID UDC	O
7	Customer UDC Account Name	R	59	Recipient Name UDC	O
8	UDC Customer Account #	R			
9	Service Street Address	R			
10	Service City	R			
11	Service State	R			
12	Service Zip	R			
18	UDC ID	R			
19	UDC Business Name	O			
30	ESP Comments	O			
31	UDC Comments	O			
32	Requested Change Date *	R			
43	Universal Node ID (UNI)	R			
50	New ESP #	O			
51	New ESP Business Name	O			
58	Recipient ID UDC	O			
59	Recipient Name UDC	O			

* *When the UDC is submitting the Termination of Service Agreement DASR, this will be the requested change date that was present on the Request DASR submitted by the new ESP*

Physical Disconnect (PD) DASR

Purpose: Used to communicate a customer request for physical disconnection of their electric service, which may or may not include physical removal of meter equipment.

ESP Responsibility:

- When receiving customer request for physical service disconnection, ESP should obtain:
  - Customer forwarding address for final bill
  - Customer contact telephone number
  - Verification of access to meter
  - Requested disconnect date
- Issues Physical Disconnect DASR to UDC on the same date the customer request is received for physical disconnection of electric service
- When ESP or their agent is the MSP, the ESP will schedule the physical disconnect order and notify UDC with a Physical Disconnect DASR

UDC Responsibility:

- When customer contacts UDC to request physical disconnect of ESP provided service, UDC will refer customer to their ESP for processing the Physical Disconnect DASR
- When UDC is the MSP, the UDC will schedule the physical disconnect order upon receipt of Physical Disconnect DASR from the ESP

Customer Responsibility:

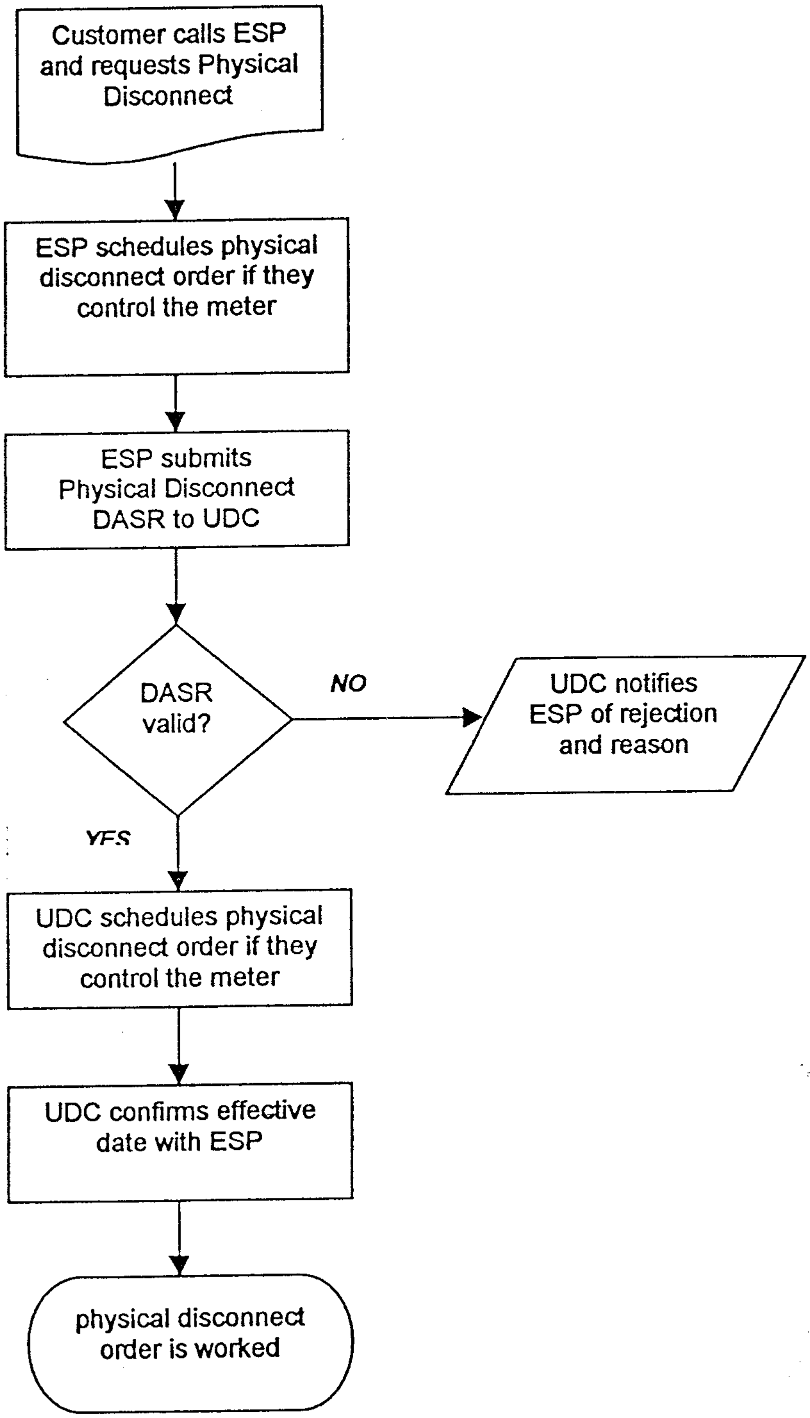
- Customer must contact their ESP directly to request physical disconnect of electric service

General Information:

In accordance with R14-2-210.I,

- To order service discontinued or to change occupancy, the customer must give the utility at least 3 working days advance notice in person, in writing, or by telephone
- The outgoing customer shall be responsible for all utility services provided and/or consumed up to the scheduled tumoff date
- The outgoing customer is responsible for providing access to the meter so that the utility may obtain a final meter reading

Physical Disconnect (PD) DASR Process Flowchart



Physical Disconnect (PD) DASR Submittal / Response

This table demonstrates the **R**equired and **O**ptional fields necessary to complete this DASR transaction type. ***Response will include both submittal and response fields.***

Field	Submittal – Field Description	Req'd	Field	Response – Field Description	Req'd
1	DASR Tracking #	R	28	DASR Status	R
2	ESP Business Name	R	29	Reason Code	O
3	Date & Time Sent	R	31	UDC Comments	O
5	Transaction Type	R	33	Effective Change Date	R
6	ESP Customer Account #	R	58	Recipient ID	O
7	Customer UDC Account Name	R	59	Recipient Name	O
8	UDC Customer Account #	R			
9	Service Street Address	R			
10	Service City	R			
11	Service State	R			
12	Service Zip	R			
17	Contact Phone #	O			
18	UDC ID	R			
19	UDC Business Name	O			
30	ESP Comments	R			
32	Requested Change Date	R			
36	Disconnect Requested By	R			
37	Forward Mail Address	R			
38	Forward City	R			
39	Forward State	R			
40	Forward Zip	R			
41	Meter #	O			
43	Universal Node ID (UNI)	R			
45	Universal Meter ID (UMI)	R			

Update / Change (UC) DASR

Purpose: Issued whenever a change in customer information or a service relationship has occurred.

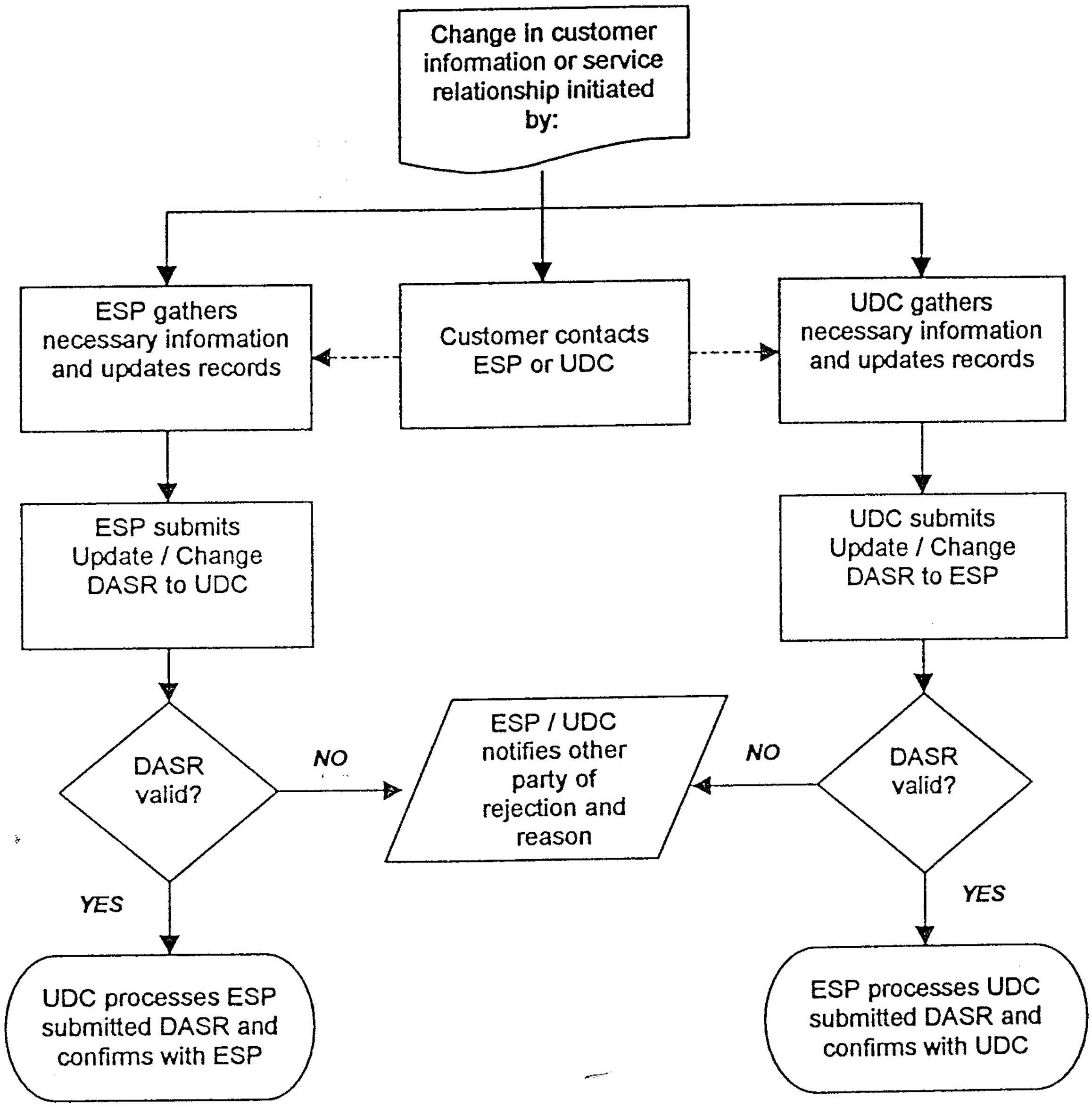
ESP Responsibility:
- To promptly notify the UDC of any change of customer information or change in service relationship for the customer

UDC Responsibility:
- To promptly notify the ESP of any change of customer information including a change in scheduled or effective change date of a previous DASR

Customer Responsibility:
- To notify their ESP of any change in mail address or medical needs status

General Information:
- When communicating a change to the *scheduled or effective change* date, the original DASR Tracking # should be used
- When communicating a change to *customer information* (such as a new mail address, change of billing options, or metering relationships), a newly assigned DASR Tracking # should be used
- Legal change of name or service address needs to be communicated directly to the UDC/ESP contact
- Where the transaction necessitates any change in contractual agreement, the Update/Change DASR is *not* the mechanism

Update / Change (UC) DASR Process Flowchart



Update / Change (UC) DASR Submittal / Response

This table demonstrates the **R**equired and **O**ptional fields necessary to complete this DASR transaction type. ***Response will include both submittal and response fields.***

Field	Submittal – Field Description	Req'd	Field	Response – Field Description	Req'd
1	DASR Tracking #	R	28	DASR Status	R
2	ESP Business Name	R	29	Reason Code	O
3	Date & Time Sent	R	31	UDC Comments	O
5	Transaction Type	R	33	Effective Change Date	R
6	ESP Customer Account #	R	58	Recipient ID	O
7	Customer UDC Account Name	R	59	Recipient Name	O
8	UDC Customer Account #	R			
9	Service Street Address	R			
10	Service City	R			
11	Service State	R			
12	Service Zip	R			
13	Mail Address	O			
14	Mail City	O			
15	Mail State	O			
16	Mail Zip	O			
17	Contact Phone #	O			
18	UDC ID	R			
19	UDC Business Name	O			
21	ESP Medical Code	O			
23	Scheduling Coordinator Duns #	O			
24	Scheduling Coordinator Name	O			
30	ESP Comments	O			
31	UDC Comments	O			
32	Requested Change Date	R			
34	Billing Options	O			
35	Bill Calculation	O			
41	Meter #	O			
42	UDC Meter Read Cycle	O			
43	Universal Node ID (UNI)	R			
44	Meter Ownership	O			
45	Universal Meter ID (UMI)	O			
46	MSP ID	O			
47	Meter Service Provider Name	O			
48	MRSP ID	O			
49	Meter Reading Service Provider Name	O			
52	New ESP Customer Account #	O			
53	New UDC Customer Account #	O			
54	ESP Rate Code	O			
56	UDC Bill Cycle	O			
57	Original DASR Tracking #	O			
58	Recipient ID	O			
59	Recipient Name	O			

Direct Access Service Request (DASR)
Field Definitions

Field #	Name	DASR Field Definition and Format			Size maximum	Type Character or Integer
1	DASR Tracking #	Unique number assigned by the originator submitting the DASR. First 13 (9 + 4) digits are the originator's Duns # followed by 9 user-specified digits. All future communication about this DASR will contain this tracking number.			22	C
2	ESP Business Name	Business name of Energy Service Provider as recorded on their Certificate of Convenience and Necessity Docket #.			30	C
3	Date & Time Sent	Date and time DASR was sent CCYYMMDDHHMM.			12	I
4	Date & Time Received	Date and time DASR was received CCYYMMDDHHMM. All time frames for response will be based on this date/time.			12	I
5	Transaction Type	RQ	Request	Identifies that a customer should be switched to Direct Access or is requesting a change in Energy Service Provider.	2	C
		CL	Cancel	Identifies that a previously submitted RQ, PD, or TS DASR needs to be canceled.		
		TS	Termination of Service Agreement	Identifies that the ***customer or ESP*** has chosen to terminate the current service agreement.		
		PD	Physical Disconnect	Identifies that the ***customer*** has requested the electrical service to their premise be shut off.		
		UC	Update / Change	Identifies that a change in customer information or service relationship has occurred.		
6	ESP Customer Account #	Customer account number of the ESP submitting the DASR.			20	C
7	Customer UDC Account Name	Customer's name as it appears on the Utility Distribution Company's bill.			42	C
8	UDC Customer Account #	Customer account number of the UDC where service is provided.			20	C
9	Service Street Address	Street address (or physical location) for the premise where service is being provided.			30	C
10	Service City	City for the premise where service is being provided.			30	C
11	Service State	State for the premise where service is being provided.			2	C
12	Service Zip	Zip code for the premise where service is being provided.			9	C
13	Mail Address	Street / post office box address for the customer where service is being provided.			30	C
14	Mail City	City for the customer where service is being provided.			30	C

Field #	Name	DASR Field Definition and Format		Size maximum	Type Character or Integer
15	Mail State	State for the customer where service is being provided.		2	C
16	Mail Zip	Zip code for the customer where service is being provided.		9	C
17	Contact Phone #	Area code and 7-digit phone number where customer can be contacted.		10	I
18	UDC ID	Utility Distribution Company's Duns # or the DOE's designator for the UDC.		13	I
19	UDC Business Name	Business name of the Utility Distribution Company as recorded on their Certificate of Convenience and Necessity Docket #.		30	C
20	Quarter Eligible	Identifies the ***first*** quarter a customer can switch to direct access at the beginning of this quarter CCQYY.		5	I
21	ESP Medical Code	**Y or N.** Indicates a residential customer has obtained a verified document from a licensed medical physician stating that discontinuance of service would be dangerous to the customer's health. Documentation to be obtained and retained by the UDC.		1	C
22	UDC Medical Code	**Y or N.** What the UDC has on record to indicate a residential customer has obtained a verified document from a licensed medical physician stating that discontinuance of service would be dangerous to the customer's health. Documentation to be obtained and retained by the UDC.		1	C
23	Scheduling Coordinator Duns #	Scheduling Coordinator's Duns # as recorded on the UDC agreement with the Scheduling Coordinator.		13	I
24	Scheduling Coordinator Name	Business name of the entity that provides schedules for power transactions though the transmission or distribution system to the party responsible for the operation and control of the transmission grid.		30	C
25	Congestion Zone	Identifies a geographic area that requires power which exceeds capacity of the transmission system.		8	C
26	UDC Customer Eligibility	**1** Residential Load Profile **2** Residential greater than 20kW **3** 40kW aggregate **4** 1 MW or greater		1	I
27	DA Load Aggregation Submittal ID	ESP assigned tracking number on the ESP submitted Direct Access Load Aggregation Submittal (DALAS).	*during phase-in, required if field 26 is 3*	20	C
28	DASR Status	**A** Accepted **P** Pending **R** Rejected	*for Pending and Rejected reason codes, see field 29*	1	C

Field #	Name	DASR Field Definition and Format		Size maximum	Type Character or Integer
29	Reason Code	***PENDING*** **CW** Completion of Work **MC** Meter Change **PD** Physical Disconnect **SI** Site Investigation **OT** Other (comments)	*a DASR returned with a "Pending" code is not closed until notification from the UDC or ESP confirms all processes involving this DASR have been satisfied* *see field 31 for Comments or additional information*	2	C
29		***REJECTED*** **01** Blank or Incorrect Required Field **02** Incorrect Format **03** Not Eligible (comments) **04** Field Information Not in ESP Service Agreement **05** Blocked By Pending DASR **06** Not registered with UDC **07** Insufficient ESP Financial Security **08** Duplicate (comments) **09** Other (comments)	*UDC comments will contain reject information. Rejected DASR cannot be processed* *see field 31 for Comments or additional information*		
30	ESP Comments	Additional information to clarify request.		240	C
31	UDC Comments	Additional information to clarify request.		240	C
32	Requested Change Date	Date submitter would like the request to occur CCYYMMDD.		8	I
33	Effective Change Date	Date the request will be honored CCYYMMDD, typically the scheduled meter read date.		8	I
34	Billing Options	Identifies selected billing option: **SB** Separate Bills **EC** ESP Consolidated **UC** UDC Consolidated	*requires bill calculation data – see field 35*	2	C
35	Bill Calculation	Required field if UDC Consolidated billing option is selected. **B** Bill ready data provided **U** UDC will calculate	*required if field 34 is UC*	1	C
36	Disconnect Requested By	Name of individual residing at service premise requesting the disconnect.		42	C
37	Forward Mail Address	Street / post office box address for the customer where future mail is to be delivered.		30	C

Field #	Name	DASR Field Definition and Format	Size maximum	Type Character or Integer
38	Forward City	City for the customer where future mail is to be delivered.	30	C
39	Forward State	State for the customer where future mail is to be delivered.	2	C
40	Forward Zip	Zip code for the customer where where future mail is to be delivered.	9	C
41	Meter #	Individual meter number at the service delivery point.	11	C
42	UDC Meter Read Cycle	Indicates the cycle in which the meter is read.	2	C
43	Universal Node ID (UNI)	Identifies a unique, permanent number assigned to the last service point of the UDC's distribution network to which energy is delivered. The ESP is responsible for the energy delivered to that service point. *required if field 41 is blank*	34	C
44	Meter Ownership	Indicates the owner of meter. E ESP U UDC C Customer	1	C
45	Universal Meter ID (UMI)	Identifies a universal meter number assigned to every meter by the manufacturer.	17	C
46	MSP ID	Meter Service Provider's Duns # as recorded on the UDC agreement with the Meter Service Provider.	13	I
47	Meter Service Provider (MSP) Name	Business name of the entity providing Metering Service.	30	C
48	MRSP ID	Meter Reading Service Provider's Duns # as recorded on the UDC agreement with the Meter Reading Service Provider.	13	I
49	Meter Reading Service Provider (MRSP) Name	Business name of the entity that reads meters, performs validation, editing, and estimation on raw data to create validated meter data; translates validated data to an approved format, this posts to a Server for retrieval by billing agents; manages the Server; exchanges data with market participants; and stores meter data for problem resolution.	30	C
50	New ESP #	Duns # for the new Energy Service Provider.	13	C
51	New ESP Business Name	Business name of the Energy Service Provider as recorded on their Certificate of Convenience and Necessity Docket #.	30	C
52	New ESP Customer Account #	Customer account number assigned by the ESP.	20	C
53	New UDC Customer Account #	Customer account number assigned by the UDC where service is provided.	20	C
54	ESP Rate Code	Identifies the rate code assigned by the ESP. *required if field 34 is UC*	25	C
55	Load Usage Profile	An estimate of a customer's hourly energy consumption based on measurements of similar customers.	5	C

Field #	Name	DASR Field Definition and Format	Size maximum	Type Character or Integer
56	UDC Bill Cycle	Identifies the cycle in which the UDC account is billed.	2	C
57	Original DASR Tracking #	Identifies the unique number assigned by the originator of the DASR being canceled or updated/changed.	22	C
58	Recipient ID	Recipient's (ESP) Duns # as recorded on the UDC agreement with the Energy Service Provider.	13	I
59	Recipient Name	Business name of the recipient (ESP) of the TS or UC DASR submitted by the UDC.	30	C

Direct Access Load Aggregation Submittal (DALAS)

Purpose: Used by an ESP to identify a group of customers greater than 40kW per single premise who are interested in aggregating with others to achieve a 1 MW or greater load to participate in Direct Access within an individual UDC service territory.

ESP Responsibility:
- Prior to submitting the DALAS, the ESP will obtain a signed Letter of Authorization from each customer requesting Direct Access
- Submits DALAS to the UDC for validation that customers identified meet load requirements of a single premise peak of 40kW prior to submission of individual DASRs
- Submits all DASRs associated with a single DALAS within 3 business days of the acceptance of the DALAS
- Assigns a DA Load Aggregation Submittal ID to the DALAS which will be used on all associated DASRs

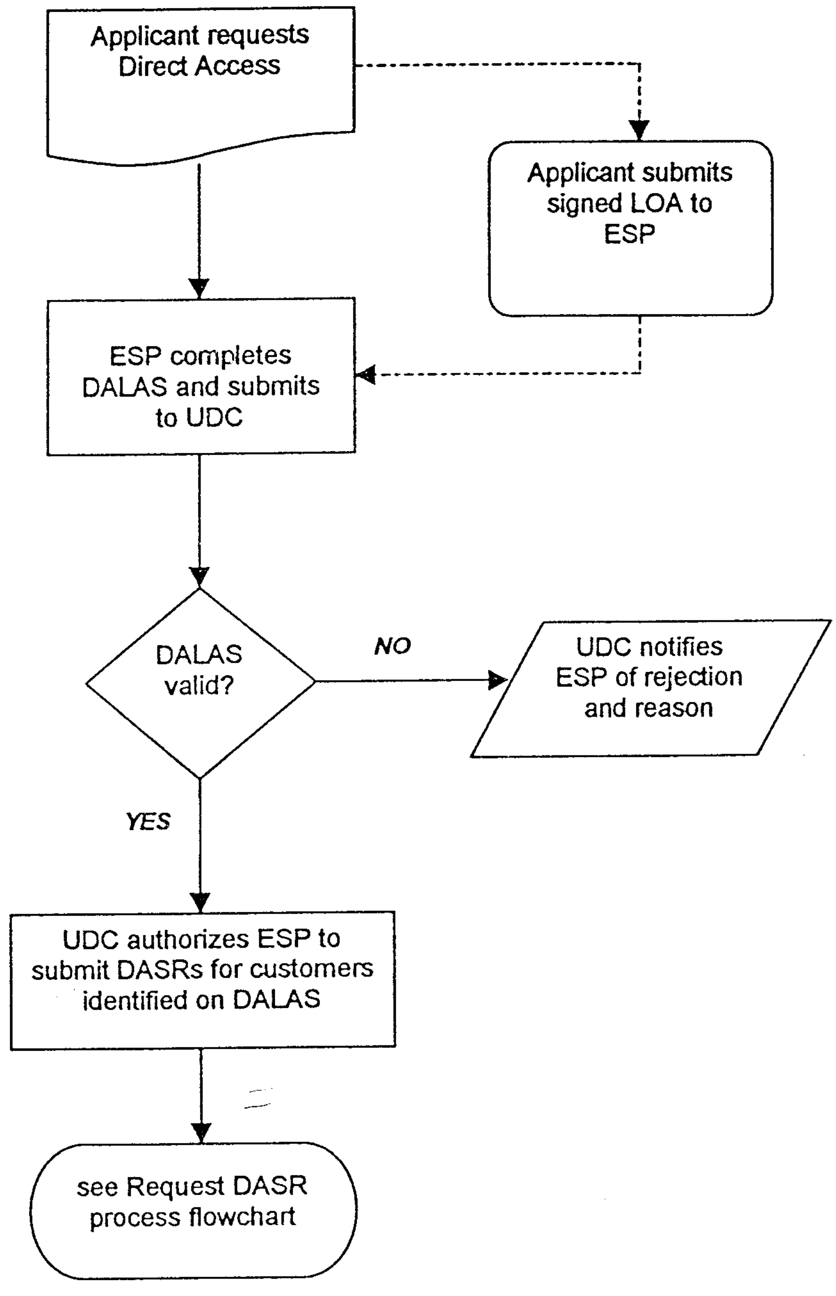
UDC Responsibility:
- Verifies identified customers are eligible and the DALAS submittal totals at least 1 MW
- Responds to ESP with status (accepted or rejected) of DALAS within 3 business days

Customer Responsibility:
- Customer makes application with ESP

General Information:
- DALAS will be used during Phase-In period only (until January 1, 2001)
- After the ESP has a valid DALAS form on file and all associated DASRs have been submitted, an ESP may submit DASRs to add new locations to the load pool; the DA Load Aggregation Reference ID must be present on each associated DASR
- DASRs submitted prior to validation of a DALAS will be rejected

In accordance with R14-2-1604
- Customers with single premise non-coincident peak load demands of 40kW or greater are eligible for aggregation into a combined load of 1 MW or greater

DALAS Process Flowchart



State of Arizona
Direct Access Load Aggregation Submittal (DALAS)

One DALAS to be completed and submitted by an ESP on behalf of an aggregated set of eligible customers prior to submission of individual DASRs. Field definitions will conform to those used for the DASR, where applicable, or according to contractual agreement between affected parties.

ESP Name ________________ Date & Time Sent ________

ESP Duns # ________________ Date & Time Received ________

UDC ID ________________ ESP / UDC Contract # ________

DA Load Aggregation Submittal ID ________________

Customer Account Name	Customer UDC Account #	Meter #	Projected Load (kW)	Actual Load

Direct Access Service Request (DASR)
Field Validation

The following table was developed to assist Direct Access market participants in Arizona. It identifies the validation rules that are currently in place at the identified UDCs. These rules apply to the field regardless of the DASR type. It is a high level overview of the validation rules, the specifics are contained in each UDCs protocols. It is a point-in-time document. As the market develops and UDC systems are updated, this data may change. The DASR Team will be charged with the update responsibility. Other UDCs will be encouraged to include their validation rules in this table.

Validation Types:
1 - Data Present
2 - Validated per UDC Records; refer to the protocols of each individual UDC for specifics
3 - Validated per expected values or ranges found in the DASR handbook (exception SRPs 814 protocol)
0 - Outbound from UDC

Field #	Name	All	SRP	TEP	APS	CZN	NEC
1	DASRTracking #	2					
2	ESP Business Name		N/A	2	2	2	2
3	Date & Time Sent	3					
4	Date & Time Received	0					
5	Transaction Type	3					
6	ESP Customer Account #		1	1	2	1	1
7	Customer UDC Account Name	2					
8	UDC Customer Account #	2					
9	Service Street Address		1	2	2	2	2
10	Service City		1	2	2	2	2
11	Service State		1	2	2	2	2
12	Service Zip		1	2	2	2	2
13	Mail Address		N/A	1	1	1	1
14	Mail City		N/A	1	1	1	1
15	Mail State		N/A	1	1	1	1
16	Mail Zip		N/A	1	1	1	1
17	Contact Phone #		N/A	1	1	1	1
18	UDC ID	2					
19	UDC Business Name	1					
20	Quarter Eligible	0					
21	ESP Medical Code		N/A	3	N/A	1	3
22	UDC Medical Code	0					
23	Scheduling Coordinator Duns #	2					
24	Scheduling Coordinator Name		N/A	2	2	2	2
25	Congestion Zone	0					
26	UDC Customer Eligibility		N/A	3	3	3	3
27	DA Load Aggregation Submittal ID		N/A	2	2	2	2
28	DASR Status	0					
29	Reason Code	0					
30	ESP Comments						
31	UDC Comments	0					
32	Requested Change Date	3					
33	Effective Change Date	0					
34	Billing Options	3					

Field #	Name	All	SRP	TEP	APS	CZN	NEC
35	Bill Calculation		3	3	3	N/A	3
36	Disconnect Requested By		N/A	2	2	2	2
37	Forward Mail Address	1					
38	Forward City	1					
39	Forward State	1					
40	Forward Zip	1					
41	Meter #	2					
42	UDC Meter Read Cycle	0					
43	Universal Node ID (UNI)		N/A	2	2	1	2
44	Meter Ownership		N/A	3	3	3	3
45	Universal Meter ID (UMI)		N/A	2	1	2	2
46	MSP ID	2					
47	Meter Service Provider (MSP) Name		N/A	2	2	2	2
48	MRSP ID	2					
49	Meter Reading Service Provider (MRSP) Name		N/A	2	2	2	2
50	New ESP #	1					
51	New ESP Business Name	1					
52	New ESP Customer Account #	1					
53	New UDC Customer Account #	0					
54	ESP Rate Code		N/A	2	2	N/A	2
55	Load Usage Profile	0					
56	UDC Bill Cycle	0					
57	Original DASR Tracking #	2					
58	Recipient ID	0					
59	Recipient Name	0					

All – all UDCs participating in above validation matrix
SRP – Salt River Project
TEP – Tucson Electric Power
APS – Arizona Public Service
CZN – Citizens Utilities Company
NEC – Navopache Electric Cooperative

SITING CERTIFICATION OUTLINE

Currently, there are several existing bodies responsible for certifying the distributed generation unit, the installation, and the interconnect. The physical installers are typically governed by Standards set by the NEC and OSHA. There are efforts being taken on the national level by the IEEE to establish certain standards that may lead to certification.

National certifying standards, such as UL and CSA, have been broached, but it needs to be understood that these bodies certify primarily for safety hazard and not unit performance. Most of the electrical interconnect systems can be and will usually be UL certified. It is difficult to certify the genset both based on cost and the constant need to upgrade and improve technology.

The sizing, operation, and quality of the genset are the responsibility of the manufacturer, which is subject to civil liability. The interconnect is the responsibility of the installer/customer and the UDC. It is generally acknowledged that as long as the interconnect is built and operated to the satisfaction of the UDC, that there is little interest regarding the type and operation of the genset. This precludes a need for UDC certification of the unit similar to the UDC not having a certifying interest in the type of air conditioning unit installed by a customer. Even if the genset and the interconnect are designed for net metering, the only concern is for the interconnect and power quality.

The genset installation and the interconnect are also certified, or permitted, by existing local jurisdictions through the city or county permitting process. This includes the safety of the unit, siting location, interconnect, gas plumbing, and other mechanical areas. Emissions are also certified through the State air quality programs on a case-by-case basis.

DG unit installations are performed by licensed electrical, mechanical and plumbing contractors (this does not discuss the small, at home < 10 kW sets). They are certified by their respective professional organizations and subject to OSHA requirements. There are national organizations that provide general certification for service technicians (not specific to DG) and according to OSHA, manufacturers can provide for certification of its technicians (and carry the liability).

The general conclusion is that there are already several certifying bodies in place to assure genset safety and basic performance. The UDC and local jurisdictions assure the quality and performance of the interconnect. Other jurisdictions have oversight of other operational aspects of the DG unit. The State may have a compelling interest for consumer protection to pre-certify DG units. The outline below points to several areas of certification and opportunity.

1. GENERAL
   - A. Unit certification
     - i. Whole genset
     - ii. Emissions
     - iii. Interconnect
   - B. Install/Site certification
   - C. Installer certification
   - D. Service technician certification

2. CERTIFYING BODIES
    A. Underwriter's Laboratories (UL)
    B. Canada (CSA)
        i. Phoenix
    C. 3rd party engineer
    D. Manufacturer (self)
    E. National Electric Code & other construction trade codes
    F. UDC
        i. Not traditional
        ii. Interest past interconnect?
    G. ACC
        i. Not traditional
        ii. Jurisdictional issues
    H. State
        i. Emissions
3. WHY CERTIFY?
    A. Product safety
    B. Consumer confidence
    C. Facilitate permitting
        i. Local planning/permitting
        ii. UDC interconnect
    D. Installation training & qualifications
    E. Technician training and qualifications
    F. UDC interconnect
        i. Safety
        ii. Application
        iii. Net metering
4. PRODUCT CERTIFICATION PROCESS
    A. Manufacturer
        i. Applies and pays certifying agency (UL)
        ii. Units built by certified UL contractor
        iii. Provides unit(s) for testing
        iv. Receives or is rejected for certification
        v. Major modifications must be resubmitted for testing and certification
        vi. Similar process for interconnect electronics (most off the shelf and generally certified)
            (1) Disconnect switch
                (a) Fused
                (b) Unfused
            (2) Utility tie box
            (3) Additional switch gear

    B. Planning/permitting
        i. Desires UL listing
        ii. Allows for 3rd party engineering certification
        iii. Process review and permitting
            (1) Zoning
            (2) Structural
            (3) Electrical
            (4) Plumbing

C. Utility
   i. Case-by-case
   ii. Few consistent standards
      (1) Gensets
      (2) Interconnection
      (3) Peak shaving
      (4) Base loading
      (5) Stand alone

D. Emissions
   i. Size threshold
   ii. PPM standards
   iii. Unit & site certification

E. 3RD Party
   i. Distributed generation organizations
   ii. Gas Research Institute
   iii. EPRI
   iv. IEEE
   v. Other National Standards

(3) The studies shall consider both the costs incurred and the benefits realized as a result of the interconnection of distributed generation to the utility's system.

(4) The customer, at its request, shall receive an estimate of the study cost before the utility initiates the study.

(j) **Communications concerning proposed distributed generation projects.** In the course of processing applications for interconnection and parallel operation and in the conduct of pre-interconnection studies, customers shall provide the utility detailed information concerning proposed distributed generation facilities. Such communications concerning the nature of proposed distributed generation facilities shall be made subject to the terms of §25.272 of this title (Relating to Code of Conduct for Electric Utilities and their Affiliates), §25.273 (Relating to Contracts between Electric Utilities and their Competitive Affiliates), and §25.84 (Relating to Annual Reporting of Affiliate Transactions for Electric Utilities). A utility and its affiliates shall not use such knowledge of proposed distributed generation projects submitted to it for interconnection or study to prepare competing proposals to the customer that offer either discounted rates in return for not installing the distributed generation, or offer competing distributed generation projects.

(k) **Equipment pre-certification.**

(A) **Entities performing pre-certification.** – The commission may approve one or more entities that shall pre-certify equipment as defined pursuant to this section.

(B) **Standards for entities performing pre-certification.** – Testing organizations and/or facilities capable of analyzing the function, control, and protective systems of distributed generation units may request to be certified as testing organizations.

(B) **Effect of pre-certification.** – Distributed generation units which are certified to be in compliance by an approved testing facility or organization as described in this subsection shall be installed on a company utility system in accordance with an approved interconnection control and protection scheme without further review of their design by the utility.

(l) Designation of utility contact persons for matters relating to distributed generation interconnection.

(1) Each electric utility shall designate a person or persons who will serve as the utility's contact(s) for all matters related to distributed generation interconnection.

(2) Each electric utility shall identify to the commission its distributed generation contact person(s).

(3) Each electric utility shall provide convenient access through its internet web site to the names, telephone numbers, mailing addresses and electronic mail addresses for its distributed generation contact person(s).

(m) Time Periods for Processing Applications for Interconnection with the Utility System. In order to apply for interconnection customer shall provide the utility a completed application for interconnection and parallel operation with the utility system as described in subdivision (b) of this Rule. The interconnection of distributed generation to the utility system shall take place within the following schedule:

(1) For a facility with pre-certified equipment, interconnection shall take place within four weeks of the utility's receipt of a completed interconnection application.

(2) For other facilities, interconnection shall take place within six weeks of the utility's receipt of a completed application.

(3) If interconnection of a particular facility will require substantial capital upgrades to the utility system, the company shall provide the customer an estimate of the schedule and customer's cost for the upgrade. If the customer desires to proceed with the upgrade, the customer and the company will enter into a contract for the completion of the upgrade. The interconnection shall take place no later than two weeks following the completion of such upgrades. The utility shall employ best reasonable efforts to complete such system upgrades in the shortest time reasonably practical.

(4) A utility shall use best reasonable efforts to interconnect facilities within the time frames described in this subsection. If in a particular instance, a utility determines that it can not interconnect a facility within the time

frames stated in this subsection, it will notify the applicant in writing of that fact. The notification will identify the reason or reasons interconnection could not be performed in accordance with the schedule, and provide an estimated date for interconnection.

(5) All applications for interconnection and parallel operation of distributed generation shall be processed by the utility in a non-discriminatory manner. Applications will be processed in the order that they are received. It is recognized that certain applications may require minor modifications while they are being reviewed by the utility. Such minor modifications to a pending application shall not require that it be treated as a new or separate application.

(n) **Reporting requirements.** Each electric utility shall maintain records concerning applications received for interconnection and parallel operation of distributed generation. Such records will include the date of receipt of each such application, documents generated in the course of processing such applications, correspondence regarding such applications, and the final disposition of such applications. Annually each electric utility shall file with the commission a distributed generation interconnection report that will identify each distributed generation facility interconnected with the utility's distribution system. In addition, the report shall provide the new distributed generation facilities interconnected with the system since the previous year annual report, distributed generation facilities no longer interconnected with the utility's system since the previous year's annual report, the capacity of each facility, and the feeder or other point on the company's utility system where the facility is connected. The annual report shall also identify all applications for interconnection received during the previous one-year period, and the disposition of such applications. Each report shall cover the preceding calendar year, and shall be submitted to the commission no later than March 30 of the subsequent calendar year.

Arizona Public Service Company
White Paper Regarding Issues Set Forth by Siting, Certification and Permitting Committee
Submitted as an Attachment to the Meeting Minutes of October 25, 1999

APS is submitting a proposed process that outlines a realistic approach to the Application Process for Distribution Generation projects within the State of Arizona. It attempts to emphasize desired utility-customer interaction and a team-work approach throughout the interconnection and design process that would facilitate a timely and successful interconnection project, as opposed to a few simplistic "time-stamp" type requirements at the end of the design process.

Application Process

a. The Customer initially contacts the utility for the interconnection information and briefly outlines/discusses his proposed project. The utility then forwards the appropriate information to the Customer and provides the Customer with a contact name and number should he decide to proceed with the project.

b. If the Customer decides to proceed, then he is encouraged to work closely with the utility contact at the conceptual stage of the design to ensure that the interconnect requirements are met, the project proceeds smoothly and in a timely fashion, and to ensure that there are no surprises at the end. The utility either meets with, or works closely with the Customer during the initial stages, and explains the interconnect process and applicable requirements with the Customer as it will apply to his specific project. The utility informs the Customer if any utility or other studies may need to be performed or if any special requirements apply.

c. The Customer proceeds with the design and prepares the utility-required information - application form, electrical diagrams, protective relaying and settings, site and equipment layout plans, etc. It is strongly suggested that these be submitted to the utility as they are developed, so that the utility can make any comments or recommendations as early on in the design process as possible. On larger projects the utility may often participate in the design team meetings. On smaller projects, the design and review can normally be expediently accomplished. Depending on the size, scope and complexity of the project, as well as any special situations or requirements, timeframes may be worked out between the Customer and the utility so the project proceeds smoothly. The utility will generally also begin preparing applicable interconnection documents and site inspection/testing checksheets at this time.

(This is normally a very iterative and desired process, often involving a close working relationship between the utility and the Customer and/or his designers or consultants. It generally includes forwarding marked-up prints or written/verbal comments back and forth, or actually meeting as required. It may also involve performing and sharing any study results with the Customer, and could involve initiating work on the utility system to accommodate the Customer's generation. The utility may also need to forward distribution system characteristics to the Customer for fault current calculations and coordination studies).

d. Upon completion of the design, the Customer submits the final design information package (as specified in the Application Form of the Interconnect Requirements manual) to the utility for final review and approval. Upon completion of a satisfactory final review, the utility responds in writing to the Customer that all utility interconnection requirements have been satisfied, and again outlines the final steps that still need to be taken prior to bringing the generating facility on line. The utility prepares and forwards final interconnection/electric service agreements to the Customer.

e. Following construction/installation of the generating facility, the Customer notifies the utility (the utilities request at least 5 days notice) as to when the utility can perform the site inspection, and when the relay calibrations/functional tests, as applicable, are to be performed so that the utility may witness and/or review them.

f. Upon the satisfactory completion of the site inspection and protective testing, the utility notifies the Customer in writing that the generation facility may be operated in parallel with the utility grid per the agreed terms and conditions.

Distributed Generation & Interconnection Workgroup

Siting, Certification and Permitting Committee

APS Comments to Meeting Minutes of October 7, 1999
Submitted October 25, 1999 as attachment to Meeting Minutes

1. A sufficiency review needs to be performed by the wires company. The wires company can turn this around in 10 working days. This review will tell the applicant if information is missing from the application.

   Concern:
   This does not reflect the discussion surrounding the sufficiency review, what it needs to include, or at what point in the application process the "sufficiency review" is performed. Interaction with the UDC is crucial prior to this point, as opposed to the customer waiting until the project is designed and equipment ordered to avoid any delays, especially if any studies or special requirements apply.

2. The wires company will review an application within 30 calendar days. The sufficiency review will be a part of the 30 calendar days.

   Concern:
   This does not include the discussion clarifying that the customer **must** have all prerequisite information and details in place to allow the UDC to meet a thirty day review requirement.

3. Resubmittals to obtain comments can be performed by the wires company in 5 working days.

   Concern:
   My understanding is that the **Customer** would have 5 days to resubmit their application after returned by the UDC in order to continue with the 30 day commitment on behalf of the UDC. Why would the UDC only have 5 days after resubmittal, when total allowed time is 30 days?

APS submits that the proposed process as outlined in Steps 1 through 3 is presented in a very simplistic and unrealistic approach. APS is therefore submitting a White Paper describing the desired process and steps required to facilitate a timely and successful interconnection project, in lieu of these three items above. (Attached as separate document)

4. Currently, there will be no additional cost to the applicant for submitting an application. If wheeling onto the distribution system is proposed, there will be a cost for the engineering study required by the wires company.

   This statement is not valid as it only pertains to APS, not all UDC's. Also, the comment that "there **will** be no additional cost to the customer, is misguided. Currently, APS has not charged customers that interconnected with the grid for expenses incurred, other than when hardware has been required to be installed on the utility system. APS however, retains the right to charge customers for all expenses incurred in interconnecting any future projects, including any required engineering studies. Such studies may be required (eg. fault and coordination studies) irrespective of whether or not the customer actually wheels power onto the distribution system.

5. The Wires Company will interface with the ACC to keep the ACC informed of all distributed generation projects. The means to accomplish this needs to be worked out by the ACC.

   Concern:
   Discussion on this was that the ACC already had reporting requirements in place, and if they felt a need to modify this procedure, they would initiate. Reporting requirements should not be included in the Interconnection Standards Process unless it becomes a requirement for the installer or operator to provide any information to ACC.

6. The ACC will handle the mapping functions for DG projects installed within their service territory. The ACC will be given a copy of the map for access by the public.

   Concern:
   This should be a not be required function of the ACC as APS out of necessity for system load and safety of field personnel, maps the location of each DG unit interconnected with the APS distribution system today. This will continue to be an internal function of APS for business purposes and system/feeder configurations and maps not released as a public document.

7. At the time an application is submitted, the wires company will give the applicant a reference sheet, listing additional agencies (e.g., county, state, municipalities, U.S. EPA, etc.) that may have additional requirements that the applicant must meet (e.g., air quality, noise, fuel requirements, safety, siting and permitting). The ACC will keep the list updated and available for the public. The ACC web site may be used for that purpose.

Concern:
In further discussion with others within APS, this is not a viable procedure. Once a document is included within a "package", there is an assumed liability to APS, especially if new requirements or contacts were not updated.

APS would be in favor of including language in the State Standards for Interconnection Process (if it does get established) that would direct the customer to go to the ACC website or the Arizona Distributed Generation Society, to get a listing of permits and contacts they may need to get.

Attachment E

adopted

~~Recommended~~ State Energy Policy

Whereas, the state of Arizona's population and energy use are projected to grow for the foreseeable future; and

Whereas, conservation and the efficient use of energy are expected to continue to be the preferred overall economic and environmental strategies; and

Whereas, energy is a key determinant of the way we live, environmental quality and the vitality of the economy of the state of Arizona; and

Whereas, energy supply, energy demand and the natural environment are at a point of conflict which will continue into the foreseeable future; and

Whereas, the effect of this conflict can be mitigated through the development of a state energy policy which balances supply, demand, environment and economic issues;

Therefore, be it resolved by the House of Representatives of the state of Arizona, the Senate concurring, that the energy policy of the state of Arizona shall be to:

1. Assure sustainability of Arizona's energy supply and environmental quality through efficient use and conservation of energy resources; utilization of a diversity of energy resources; promotion of energy research, development, and demonstration projects; adoption and implementation of mechanisms to assure energy-efficient communities, buildings, equipment and transportation systems; and promotion of the optimum utilization of renewable energy resources.
2. Assure the environmental quality of the state of Arizona through environmentally sound energy utilization.
3. Establish and utilize appropriate measures of the total cost and benefit to society while maintaining an adequate, affordable and environmentally sound supply of energy for all Arizonans.
4. Assure economic development and well-being that is sustainable through implementation of a balanced energy policy; efficient use of all energy resources; and with help from renewable energy and energy-efficient products and processes.
5. Establish a long-range comprehensive planning system incorporating integrated least cost energy planning, mitigation measures to avert supply disruptions and means to incorporate anticipated energy supply, demand and technological changes.
6. Encourage individual, local, and statewide action through the implementation of energy education programs to overcome institutional, structural, and individual obstacles to beneficial changes in the energy system.

ACC DGI WORKSHOP
ORGANIZATIONAL PROPOSAL

Location and Types of Distributed Generation Connections:

Prepared for The Siting, Certification and Permitting SubCommittee

November 4, 1999

Can a location match be achieved for mutual benefit of Customer and UDC?

- Under the former paradigm of a vertically integrated utility, UDC's had the sole responsibility to provide reliable, cost efficient and basically "guaranteed" electric service to any customer that desired such service in a CC&N service territory. In order to accommodate such requirements, UDC's planned for future load growth, whether by population or technology related, to make this guarantee of power available as needed. In order that the UDC is also sufficiently compensated for such guarantees, the Arizona Corporation Commission allows a fixed rate of return for providing these services.

- With the onset of "electric competition" UDC's continue to remain a regulated entity and allowed a fixed rate of return on its investment to guarantee a reliable, safe, and efficient means of providing power for anyone wishing to use its distribution system. Therefore, it is in the best interest of the UDC, and it's customers, to keep its facilities fully utilized.

- Under this new paradigm, providing safe, reliable power is entering into an era of development and possible opportunities for both UDC's and Distributive Generation manufacturers. As a result of this changing environment, the ACC has requested that we, as a group, look at the benefits of a mutual location match for DG to assist the UDC's and customers.

- Using the current planning decisions for the UDC's, DG has not been a major consideration for system relief. This is mainly due to the fact that most DG units are cost prohibitive as compared to upgrading current systems or installing new distribution lines and equipment. In the future, however, the possibility for utilizing DG resources may prove to be an amicable solution. In order to make this determination, here are some items of consideration that must be determined prior to that choice.

    1. Each possible opportunity must be evaluated on a case by case basis. (Site specific)

    2. What capital budget deferment would the UCD be making.

    3. Are there sites available on the feeder to locate DG.

    4. Can the UDC schedule/control the operation of these DG units.

    5. Can the UDC count on the unit's reliability. (Both day to day operation, as well as long term)

    6. Will the UDC lose any revenue entitled to be recovered by distribution customers when the DG unit is online.

    7. Can the cost benefit be obtained without the requirement of any type of subsidy to the DG supplier.

<u>This should really be the prevailing determination as to mutual benefits:</u>

- As technology advances, the type and efficiency of DG's should increase, with the price to provide DG decreasing. This would then dictate what market will prevail to determine the mutual benefits to customers and the UDC.

- If an opportunity should arise, the UDC could offer to accept RFP's for a specific site, requesting all interested DG suppliers to bid. The UDC would detail the requirements of the system upgrade, with a cost they must incur to provide services themselves. If a DG supplier is able to offer their services for a better price, and supply a cost backup for deliveries, there is no reason for a UDC to not be willing to contract for such services.

- As this is still a new arena with multiple players, technology today has been unproven to advocate any benefits, one way or another. As we progress in the future, a new awareness of possible choices must be included when planning on reliability or availability of the distribution system, as well as cost recovery to ensure the UDC is not held accountable to promote DG just for the sake of DG. It must stand on its own merit, without subsidy to make it happen. If this can happen, the *mutual benefits* will be seen by all involved, whether it is the manufactures, suppliers, UDC's or customers.

DRAFT #1

DG Application Process

Step 1 - DG notifies UDC of intent to interconnect

Step 2 – UDC reviews nature of request as to:

1. Location
2. Type of system
3. Applicable interconnect requirements

Step 3 – UDC forwards appropriate Interconnection Requirements and Information package including “Application Form” to DG within five (5) working days.

Step 4 – DG submits application and associated information to UDC for review. DG notifies UDC that interconnect information has been submitted, and UDC confirms to DG receipt of application within five (5) working days. UDC will review information submitted for completeness and and feasibility, and determines if any special studies may be required Several exchanges of information may occur between UDC and DG until application is complete, any special studies are completed, or consensus is agreed upon. (Due to the nature of the request, review may require up to thirty (30) working days of UDC tenure for agreement)

Step 5 – UDC commences review of complete “ Application for Interconnect”. Request review will include; Assessment of technical feasibility, Utility interconnect requirements, interconnection agreement (etc). UDC will inform DG within thirty (30) working days for endorsement of application.

Step 6 – DG will forward completed design package for review to UDC. UDC will review for conformance to endorsed application and will forward any further interconnect, or safety, requirements to DG within twenty (20) working days of receipt, unless other time frames are agreed to between UDC and DG This notice will conclude UDC acceptance of DG facility for construction. (Adjust time to final requirements of Interconnect Workshop)

Step 7 – DG approved “Facility” construction will commence in accordance to Step 6 accepted design package.

Step 8 – DG facility is tested to design standards before interconnect agreement can commence. (Interconnect Workshop to fill in the rest)

DRAFT #2

Tony Turturro (ICG)
Byran Gernet (APS)
November 18,1999

DG Application Process

Step 1 – Customer contacts Utility for interconnection information package and outlines proposed project. Utility forwards appropriate information to Customer within five (5) working days and provides a Utility contact name and number should Customer decide to proceed with project.

Step 2 – (OPTIONAL STEP) If Customer decides to proceed with project, Customer is strongly encouraged to contact Utility at conceptual stage of project and discuss proposed installation/design options with the Utility. Customer is encouraged to meet with Utility and discuss the type and size of system, location and proposed operation. A preliminary electrical one-line diagram would be very helpful at this stage. This step will help ensure that :

1. The project proceeds smoothly and in a timely fashion helping to mitigate any surprises later on.
2. It will help the Utility determine upfront if any special studies may be required, which could be initiated as early on as possible.
3. Applicable interconnect and protective requirements are properly understood and implemented.

Step 3 – Customer proceeds with design and prepares the utility-required information – application form, electrical diagrams, protective relaying and settings, site equipment and layout plans, etc. It is strongly suggested, especially on large projects (above 50 kW) that these be submitted/discussed, normally on an informal basis, with the Utility as they are developed, so the Utility can make any comments or recommendations as early on in the design process as possible – this is normally an interactive and iterative process, at which point Customer may need to submit data to the Utility if any special studies are required, and Utility may also need to submit fault/coordination information to Customer as required. Due to the diverse nature of projects, timeframes may need to be worked out between the Customer and the Utility, especially if special studies are required.

Step 4 – Upon completion of the design, the Customer submits the final design information package (as specified in the Application Form of the Interconnect Requirements manual) to the Utility for final review and approval. Customer notifies Utility interconnection contact that information has been submitted, and Utility reviews information and informs Customer within ten (10) working days of receipt as to sufficiency of information and whether any information is missing.

Step 5 – Upon receipt of completed and sufficient application information, Utility reviews the application for conformance to the interconnect requirements within twenty (20) working days, unless other timeframes are mutually agreed upon.Utility will respond to Customer within this time as to whether the submitted design information complies with the interconnect requirements or if there are any issues in non-compliance. (In the event of non-compliance, Customer will re-submit corrected information and Step 5 will be re-initiated).

Step 6 – Upon Customer receiving approval of the Utility for the design, construction of the facility commences, and the Utility prepares the required interconnection agreements and site checklist. Customer notifies Utility as to anticipated starpup/testing date.

Step 7 – Utility forwards completed interconnection documents/agreements to Customer for signature prior to anticipated startup date given in Step 6 above.

Step 8 – Following construction/installation of the facility, Customer provides the Utility with at least ten (10) working days notice as to when the Utility can perform the site inspection and when the protective device tests, as applicable are to be performed so that the Utility may witness and/or review them.

Step 9 – Upon satisfactory completion of the site inspection, protective relay testing, and signed interconnect documents, Utility notifies Customer in writing within two (2) working days that the facility may be operated in parallel with the Utility grid per the agreed terms and conditions.

Arizona Corporation Commission
Distributed Generation and Interconnections Workgroup

ACCESS, METERING & DISPATCH COMMITTEE FINAL REPORT

November 22, 1999

I. INTRODUCTION

A. Objectives

1. As part of the overall ACC workgroup formed to investigate issues concerning distributed generation, the Access, Metering, and Dispatch Committee ("Committee") to:

    a. Develop a framework for distributed generator customers accessing the energy market to acquire supplemental power, sell excess power to others, and contribute to ancillary services.

    b. Identify a means of accurately scheduling and accounting for the related transactions to protect system constraints.

    c. Develop an operating protocol to efficiently manage system disturbances in the presence of distributed generation.

    d. Identify technical requirements associated with these functions.

    e. Identify conditions where system benefits or stranded cost may result, that warrant pricing consideration.

    f. Develop tariff concepts that facilitate the above transactions in a consistent and equitable fashion.

B. Participants

1. The Committee was represented by a variety of stakeholders of distributed generation including, the ACC Staff, RUCO, utilities, competitive energy service providers, equipment manufacturers, distributors, contractors and other interested parties.

2. A list of participants is provided in Appendix B.

C. Definitions and Abbreviations

1. Distributed Generation ("DG"). The Committee did not develop a formal definition of DG. We recognized that DG equipment and applications could be very broad, from very large units attached at to transmission grid and selling excess power over the system, to very small generators for loads completely separated from the utility. However, for the purposes of assessing potential impacts to the utility distribution grid and policies for back-up and buy-back tariffs and other issues, we generally considered DG to mean generation placed on a customer's site or close to a load center, and smaller than the traditional merchant plants, which sell into the wholesale market.

2. Utility Distribution Company ("UDC"). The wires portion of a traditional vertically integrated utility, which is accountable for managing the distribution grid, managing the transmission grid in coordination with the ISA or ISO, and procuring power for standard offer service.

3. Energy Service Providers ("ESPs"). Competitive providers of energy services including generation, aggregation, billing, and metering.

4. DG Providers. Parties involved in implementing DG projects including ESPs, Gas suppliers, DG manufacturers, contractors, and customers purchasing DG equipment.

5. Direct Access Customers ("DA"). Customers purchasing competitive energy services from an ESP at market prices.

6. Standard Offer Customers. Customers purchasing traditional bundled energy services from the UDC at regulated tariffs.

7. Arizona Public Service ("APS"), Salt River Project ("SRP"), Tucson Electric Power ("TEP").

D. Approach and Report Organization

1. The Committee formed two subgroups to analyze (1) operation and UDC planning issues and (2) tariff and policy considerations.

2. In addition to the regular Committee meetings, the Committee met with the planning and operation staff of APS, SRP, and TEP to investigate the issues discussed in this report.

3. The report first addresses the potential impact of DG on the distribution grid, next it discussed potential remedies to these impacts, and lastly, it reviews various tariff and policy issues.

4. The Committee discussed the issues, attempted to understand the concerns of other parties, and to reach a general understanding of the issues and potential solutions. However, the Committee did not strive to reach consensus on each issue or to vote for a particular policy recommendation. Instead, the Committee's goal was to educate the Commission and other interested parties about the key issues, and to articulate the concerns and viewpoints of the various stakeholders.

5. Shareholder concerns are often labeled in the report as the viewpoints of UDCs and DG Providers. Please be advised that those are general statements; not all of the UDCs or DG Providers agree with all of the views expressed by their represented group.

II. Potential Impacts of DG on the Planning and Operation of the UDC Distribution Grid

A. Overview

1. The potential effects of DG on the planning and operations of the UDC distribution grid were discussed within the Committee and also assessed with a broader group of transmission and distribution planning and operations personnel from APS, SRP, and TEP. While most of the UDCs are beginning to assess, test and pilot DG applications, the overall experience with DG in Arizona is low. Most UDCs report only a few existing customer DG installations, typically back-up emergency generators or small QF facilities.

2. Many of the potential impacts on the UDC distribution system depend on several factors including the size of the DG or aggregate DGs relative to the size of the relevant distribution circuit, the location of the DG on the system, whether the DG is connected to the grid, and whether the DG is selling power back over the grid, and the timing of DG installations.

3. Given this, the Committee assessed the planning and operational issues for four scenarios: (1) the DG is separate from the grid, (2) the DG is grid connected, but is not putting excess power back on the grid, (3) the DG is selling excess power over the grid and (4) the DG or aggregate DGs reach certain size thresholds. For each of these applications, the Committee assessed the potential impacts on the grid operations and design, scheduling, operating profile, information, and metering needs, and the potential for dispatching the DG unit.

4. Below is a brief summary of the issues for each of these factors.

DG Applications and Issues

Application	Potential Operation and Design Impacts	Scheduling, Information, metering Needs	Dispatch, Automation
Separate			
Grid Connected			
Sell back			
Size			

B. Application 1: DG is Separate from Grid

1. Description
   a. DG is not connected to the grid;
   b. Customer load could be connected to, or separate from, the grid and able to reconnect through a transfer switch;
   ~~b.~~c. Typically used as emergency backup;
   ~~c.~~d. Can be used for peak-shaving or other operation.
   ~~d. Customer load could be connected to, or separate from the grid and able to reconnect through a transfer switch.~~

2. Distribution Operation and Design Impacts
   a. For emergency back-up applications, there would be low or no impacts on the design and operation of the distribution grid.
   b. UDCs could call upon emergency generation to be run to ~~off load~~ "shed" customers' load during high peak times.

   ~~e.~~c. For peak-shaving applications, if DG goes down and load is not separated from grid, then the grid will have to pick up the customer's entire load. If distribution facilities were designed to accommodate the customer's total ~~customer~~ load, absent the peak shaving, then there would be few or no distribution design impacts. However, an issue remains regarding recovery of the distribution costs. ~~this impact becomes more of a cost recovery issue, rather than a design issue.~~
   c.
   d. Adding baseload DG to an existing customer could cause load to drop below minimum level for a distribution feeder, which could result in voltage regulation problems ~~issues~~. This could be a design issue if the size of the DG unit is ~~a~~ significant ~~size~~ relative to the total load on the circuit. (This is discussed below under size criteria section.)

3. Scheduling, Information, Metering
   a. If a DG used for emergency backup fails, the grid would have to pick up the load during an emergency situation. Such situations could arise when…(Please describe.) Therefore Mapping of DG locations may be important because they may impact emergency feeder switching practices. Question: Didn't the need for mapping arise from the idea that some types of DG units/installations would remain in operation when the grid went down?

   b. No additional metering requirements for this scenario.

4. Dispatch, Automation
   a. Emergency, Backup DG applications could be strategically run to reduce load during UDC peak periods. This would occur when the customer separated from the grid via a transfer switch, and met its electricity needs using DG.

C. Application 2: DG is Grid Connected, but not Selling Excess Power over the Grid

1. Description
   a. DG is connected to the grid;

   b. Customer may be purchasing power from the grid and self generating the rest.

   c. Customer is using DG for own site load, and no power is ~~intentionally~~ intentionally [underline intentionally] being delivered or sold back to the grid.
   d. Could be used for a variety of applications including emergency, baseload, cogeneration, and peak-shaving.

2. Potential Distribution Operation and Design Impacts
   a. Potential for ~~load~~ DG customer to "lean" on the grid if the DG unit goes down.

   b. Same issues as under "Separate" case.

   c. Switching requirements

3. Scheduling, Information, Metering
   a. Some emergency applications run parallel when a storm is ~~eminent~~ imminent to protect continuity of supply; they notify the UDC by phone. Another notification system may be needed if the number of such applications increases significantly.

   b. The UDC ~~M~~ may also need to map locations for same issue discussed under "Separate" case.

4. Dispatch, Automation
   a. The UDC ~~C~~ could dispatch or incent the customer to run the DG via contract arrangements ~~DG to run and~~ to reduce load during grid emergencies.

D. Application 3: DG is Selling Excess Power over the Grid

1. Description
   a. DG is connected to the grid;
   b. Customer is selling power back to the grid or transporting power over the grid for use on another site.
   c. Could be used for a variety of applications including emergency, baseload, cogeneration, and peak-shaving.

2. Potential Distribution Operation and Design Impacts
   a. UDCs were concerned that the CAO typically addresses transmission issues; distribution transactions may not be adequately considered.
   b. UDC may need to know additional information, on top of the ESP schedule, on where the ~~load~~ power [? ☺] is being put on the system, especially above a size threshold.

3. Scheduling, Information, Metering

a. Sales would typically have to be made to the UDC or to an ESP.

b. Grid sales to ESPs, above a certain size, would typically have to be included in an ESP's schedule.

c. Sales to grid should be metered through an interval meter, at least above a certain size threshold. UDC metering could be accomplished through several techniques, which are described below in the Metering section under Tariffs and Policy.

4. Dispatch, Automation
   b. Could dispatch or incent DG to run and reduce load during grid emergencies. Such items could be handled through contracts.

E. Application 4: Size of DG

1. Description
   a. The committee discussed a variety of size demarcations for DG, which could ~~determine the~~ be used as a guide for potential impacts on the distribution grid. Although ~~T~~ the size categories were somewhat arbitrary, ~~however,~~ the Committee generally divided discussions into the following bins:
      - 0 - 300 kW
      - 300 kW - 1 MW
      - 1 MW - 10 MW
      - Above 10 MW

2. Potential Distribution~~,~~ Operation and Design Impacts
   a. The size impact depends on several other factors: the capacity of the distribution circuit, proximity to UDC generation source, e.g., a substation, and whether the customer is served from a radial circuit, transfer switch, or spot network.

   b. The size issue also depends on the size of the DG relative to customer's service drop [?].

   c. The DG impact also depends on the operating hours of the DG relative to daily and seasonal peak of the feeder

   d. DG applications above 10 MW would typically be connected to the transmission grid, not the distribution grid. These applications would require individual project coordination with the UDC, including grid impact studies and other informational needs. Given the customized nature of this category, it was not assessed in detail by the Committee.

   e. UDCs were concerned about DG applications above 1 MW, connected to the distribution grid. The capacity for most distribution circuits are in the 5 - 10 MW range, therefore, DGs above 1 MW can be significant relative to size of the circuit. These units ~~could affect~~ raise the operational issues discussed above, such as feeder capacity, emergency or seasonal switching, and minimum voltage issues.

f. In general, the UDCs had a lower level of concern for the 0-300 kW DG applications from a planning or operational perspective. The concern would increase, however, if multiple, small DGs were added to the same circuit, so that the aggregate ~~generation~~ DG became substantial.

g. There was mixed discussion concerning DG applications in the 300 kW - 1 MW range. UDCs expressed that there could be situations where DGs in this range could be a concern for distribution planning and operations. These potential impacts would depend on the factors discussed herein. DG Providers expressed that units in this size range should be a lower concern for UDCs. Furthermore, the potential impacts would be similar to many existing customer issues such as customers increasing or reducing load either permanently or intermittently.

3. Scheduling, Information, Metering
   a. Sales would typically have to be made to the UDC or to an ESP.

   b. Grid sales to from DG operators to ESPs, above a certain DG size, would typically have to be included in an ESP's schedule.

   c. Sales to grid should be metered through an interval meter, at least above a certain size threshold. UDC metering could be accomplished through several techniques, which are described below in the Metering section under Tariffs and Policy.

4. Dispatch, Automation
   a. Could dispatch or incent DG to run and reduce load during grid emergencies. Could be handled contractually.

F. Potential Remedies for UDC Distribution Planning and Operations

1. General Concerns

   a. UDCs are generally concerned that grid design and operation issues ~~are~~ be adequately addressed as more DG units are installed and DG excess power is transmitted onto the distribution system. In this section, UDCs discuss possible solutions to address the concerns described above.

   b. DG providers are concerned that UDCs' planning processes adequately accommodate DG installations and that they are (1) forward looking, (2) streamlined, (3) reasonable and fair, and (4) not unduly costly to DG projects.

   c. One of the DG Providers felt strongly that DG should not impose a substantial threat to distribution system planning in the near term and was generally concerned that new rules imposed by the ACC regarding such planning could adversely ~~is~~ impact the implementation of DG in Arizona. They felt that the restructuring of the electric industry and changes in technology and safety requirements all affect distribution system planning. Although distribution system planning~~,~~ by the distribution UDC~~,~~ could be impacted by significant penetration of DG units on the specific UDC's system, this is not expected to occur in the near term. Distribution system planning should not be adversely affected by the addition of a relatively small number of small DG units dispersed throughout the distribution system. The addition of DG to the mix of factors that distribution system planners must be cognizant of, should not be used as a basis to erect barriers to deployment of DG and customer choice and should not be construed as a basis to impose higher costs on DG owners/operators.

d. TEP expressed the concern that, since the responsibility for managing the presence, dynamics, impacts, etc., of DG units of significant size connected to the grid will fall on the UDC as the operator of the T&D system, that the UDC be allowed to recover the costs of doing so in rates. One reason the UDC may have to monitor the operation of significant DGs is because they could impact the Control Area Operator's/UDC's ability to meet ability to meet North American Reliability Council (NERC) standards. Such management costs include training of troublemen and other personnel, mapping where significant DGs are located, and modeling their potential impacts on the system.

e. TEP also expressed the concern that arrangements be made contractually for such things as i) the 24-hour-a-day, sevens-days-a-week contacts at the UDC and the DG site if a problem arises either with the grid or the DG unit, ii) maintenance or contingencies on the grid where the DG is located, and iii) protection/coverage for damage to the UDC's equipment, the DG customer's equipment and product, and other affected customers' equipment and product. Generally, such concerns could be couched as the "rules of engagement" for disconnecting and re-establishing service, etc., to on-grid DGs.

f. TEP pointed out that all parties should recognize the dynamics of the weather in southern Arizona because of their potential impacts on the operation of the grid and concomitant effect on DG.

2. Rules of Thumb

   a. The Committee discussed two possible rules of thumb to determine when DGs would be considered substantial relative to the capacity of a feeder and, therefore, would require increased information and design considerations by the UDCs.

      - The size of ~~A~~ a single ~~unit~~ DG unit should not exceed ~~would be considered substantial if its capacity were over~~ 50% of the feeder capacity. Aggregate DG capacity on the same feeder could go above this level before being considered ~~substantial~~ prohibitive due to the diversity of the units.

- Aggregate DGs would be considered substantial if they caused ~~existing~~ actual loads to drop below the minimum load level for a feeder.

b. While, these rules of thumb generally seemed reasonable, the UDCs expressed concerns about adopting them as policy decisions. Their concerns were twofold. First, there is uncertainty on the potential grid impacts from DG, and second, there could be important exceptions where these rules of thumb would not be prudent for a particular feeder.

3. When does DG Impose a Substantial Impact ~~to~~ on the Grid?

Below, the UDCs describe potential planning actions that could be taken to address the DG concerns. This discussion is relevant to (1) DG units attached to the distribution grid and (2) for "substantial" potential impacts. The UDCs have recognized that the potential impact of DG increase with larger DG units, ~~or~~ and with the number of units on a circuit. The point at which the DG comprises a "substantial" share of circuit capacity is still an open discussion.

4. UDC Potential Planning Remedies

a. While the Committee is not recommending specific planning requirements at this time, the UDCs have generally explored potential actions that could be taken to address the various concerns. The UDCs generally describe their planning process and potential impacts from DG as follows. Using a detailed criterion, the distribution system planning process is used to identify capital improvements that are necessary to maintain high quality, reliable, and safe electric service to ~~our~~ customers. The purpose of this section is to identify possible changes to the current distribution planning process precipitated by the addition of substantial amounts of DG to the UDC grid, assuming that most new generating facilities are distributed on the UDC grid in relatively small units.

b. Facility Loading (transformers, wires, and, switches)

1) With substantial amounts of DG connected to the system, facility loading would be determined by adding each DG unit (watt and var output) to a computer model.

2) Two separate cases would probably need to be run (all DG off-line and all DG on-line). In the "all DG off-line" case, ~~we~~ UDCs would ~~still~~ be required to ~~supply the feeder load~~ serve all load on the feeder. Since ~~we~~ UDCs will still ~~supply~~ have to meet the total load, the DG owners should be required to pay for this reserve capacity.

3) There would be no way of verifying the load flows "downstream" from the substation, since no such metering is in place downstream of the substation. ~~because there is only one metering point at the substation bus.~~ If this became significant it could be mitigated by adding telemetry to the significant DG facilities.

4) Providers feel ~~I~~ it is important to keep the "permitting" time short for new DG installations. This may cause a problem if there isn't enough time to adequately study the different system configurations.

c. Voltage profiles (from the substation to the end-of-line)

1) Voltage planning is required for the "peak" load case as well as the "minimum" load case since ~~we~~ UDCs have HIGH voltage and LOW voltage targets. The "all DG off-line" case would be used to determine the feeder voltage profile during the "peak" load condition. The "all DG on-line" case would be run during the "minimum" load condition.

2) Voltage control on a circuit ~~w~~ could be complicated ~~because~~ if ~~we~~ the UDC ~~would~~ were not ~~be~~ scheduling the DG units. If it became significant, partnering with the customer ~~and~~ could allow the UDC to use the unit to improve voltage regulation.

3) The ~~Distribution~~ UDC would still be required to provide Power Factor correction for the "all DG off-line" case. DG owners should be required to pay for this reserve capacity.

d. System protection (breakers, reclosers, sectionalizers, and fuses)

1) Depending on the size, ~~and~~ location of the DG unit, and the time of day it operates, the ~~distributed generator~~ DG may back-feed through a protective device, causing an ~~misoperation~~ unintended power flow. Larger size DG units may add to the system available fault current, thereby exceeding the ratings of existing devices. In addition, larger DG units would require "inrush" analysis to limit short-term voltage dip to other customers. All these conditions can be mitigated with the appropriate added system analysis.

e. Contingency planning (load transfers)

1) Equipment failures, storms, dig-ins, and accidents typically cause most outages on the system. There would be no reduction in the frequency of outages as a result of DG additions to the system. In addition, the outage duration may be increased because repair time will be increased. In order to make repairs~~;~~, the operations personnel will need to verify that no sources remain connected to the system. This must be done by observing a "visible" open switch.

2) The most difficult problem facing the operations personnel will be the feeder load transfer operation. When a block of load is to be moved from one feeder to another, ~~feeder~~ all the above-mentioned concerns must be addressed by field personnel.

3) The following questions will need to be answered by field personnel and/or engineering staff concerning any ~~distributed generators~~ DGs:

- Will the distributed generators be "on" or "off"?

- What is the true load to be picked up by the ~~secondary~~ feeder?

- How is the protection scheme effected?

4) The engineering staff can answer these questions after the appropriate analysis. But these questions will not be answered by the field personnel at 7:00 P.M. on a Saturday Evening during a summer windstorm.

5) Generally, ~~T~~ the current distribution system is a simple radial system. The addition of DG to the current distribution system in effect creates a quasi-looped system. The transmission system is a looped system and as such requires ten times the amount of computer analysis as a radial system. Looped systems require a more complex computer program and require that all contingencies (load transfers) be modeled. In other words, the installation of DG increases the level of complexity of the distribution system tenfold while at the same limiting control of the DGs coming onto the system ~~components (DG)~~.

6) If larger DG units at strategic locations ~~are installed and~~ are controlled by UDCs ~~at strategic locations~~, either directly or contractually, many of the planning issues can be minimized or eliminated.

G. Potential Benefits of DG~~g~~ to the Grid

1. The Committee discussed potential benefits that DG could provide to the distribution grid. These include voltage support, reliability, lower losses, power quality improvements, and potential deferral or avoidance of UDC distribution investments. These issues have been explored in significant detail in other industry publications and, therefore, the Committee did not go beyond a general discussion.

2. The UDCs emphasized that these benefits were potential and not yet proven. Many of the benefits could be on the customer's side of the meter, some could be on the UDC side. However, UDC benefits would likely be very specific to each DG installation. Furthermore, any UDC cost avoidance or deferral would also be case specific, and would have to coincide with the timing and location of load growth on the system. This is discussed further in the Policy section below.

3. DG Providers opined that the UDCs should be actively looking for these types of benefits, whether the DG is owned by the utility, owned by the customer and "dispatched" by the UDC, or owned by the customer and incented contractually by the UDC to operate in such a manner as to provide benefits to the grid.

III. TARIFF AND POLICY ISSUES

A. Backup Service for DG

1. The Committee generally envisions that under the new world of retail competition, the UDC would provide backup service for standard offer customers, through a bundled generation, transmission, and distribution tariff. Direct access customers would obtain backup generation service from an ~~competitive energy service provider~~ ESP via the market. ~~, through competitive prices~~. The direct access customer would also acquire UDC-provided distribution and transmission services for the backup power, either through general direct access tariffs, or partial requirements direct access tariffs.

2. The Committee believes that under the current ~~Competitive~~ Competition Rules, the UDC would not have an obligation or opportunity to provide backup generation service to direct access customers ~~service~~. This is because standard offer service is defined as a bundled service. However, some DG Providers felt that the ~~Competitive~~ Competition Rules most likely did not fully contemplate the policies concerning DG, and that it could make sense to change the Rules to allow UDCs the opportunity (but not the obligation) to provide backup generation service to direct access customers.

B. Tariffs for Standby, Maintenance, and Supplemental Power

1. Standard Offer Partial Requirements Service for DG – APS & TEP

   a. The UDCs believe that if the DG owner chooses to be a standard offer customer, the distribution UDC is obligated to provide back-up, maintenance, and supplemental power under the provisions of a partial requirements tariff. APS already has these types of rates and related provisions in place. These rates would be applicable to any residential or non-residential customer requiring partial requirements services (DG). TEP has such rates in place for Qualifying Facilities (QFs) only. TEP has also designed and received ACC approval for a rate applicable to a small commercial, non-QF customer using DG in parallel with the UDC. TEP plans to model rates for other customers using DG after this initial rate.

   b. The economics of partial requirements tariffs (both existing and proposed) will need to be addressed to ensure that the rates appropriately recover the costs, including transmission and distribution (T&D) costs, associated with providing bundled partial requirements electric service to the DG customer.

   c. DG Providers suggested that the existing partial requirements tariffs were developed under the "bundled regime" of the past. These tariffs should be reviewed and revised, where appropriate, to ensure conformance with an "unbundled" world. Only the actual costs associated with providing the requested partial requirements service should be considered in developing the tariffs. Furthermore, the rates should not act as a disincentive to the deployment and utilization of DG by customers.

2. DG Owners Choosing Direct Access – APS & TEP

a. As stated above, the Committee believes that the Competition Rules do not allow a UDC to offer back-up, maintenance, and supplemental power to DG owners choosing direct access. They must contract for these competitive direct access services with a certified ESP.

b. The current direct access tariffs do not specifically address distribution delivery service to partial requirements (DG) customers.

c. UDCs emphasized that the under the current direct access tariff structure, the rates charged a direct access DG owner for any supplemental, backup, and/or maintenance power delivered are based on full requirements service. The installation of DG reduces the number of hours (or load factor) the distribution system is being used by a specific customer and reduces the amount of revenues collected by the distribution UDC under the provisions of the applicable direct access tariff.

d. UDCs added that partial requirements direct access rate should be designed to properly recover T&D and any other relevant plant investment from customers utilizing DG, because current direct access service rate design relies largely on energy, i.e., "volumetric" charges, rather than fixed charges, to recover costs~~is priced using demand and energy charges~~.

e. DG Providers argued that the number of hours the distribution system is used by a DG owner/operator is not necessarily reduced. DG used solely as back-up or as emergency generation would not reduce the number of hours the distribution system is used by that customer. Additionally, if DG is installed by the customer to meet new or increased load, the number of hours the distribution system is being used would not be affected. The use of DG for peak shaving purposes, although reducing the volume of kilowatt-hours and kilowatts flowing over the distribution system, would not reduce the number of hours the distribution system is used, and this application could also provide tangible system benefits to the ~~distribution~~ UDC. TEP agreed with the Providers' perspective with regard to the issue of distribution system "hours of use," since it turns on how costs are recovered, i.e., kwh charges vs. fixed charges such as a monthly contract demand or customer charge.

f. Furthermore, DG providers opined that there may not be a revenue deficiency. Absent significant market penetration by DG in a particular distribution UDC's service area, a revenue deficiency may be insignificant and could potentially, over time, be offset by revenues from distribution system load growth from new customers.

g. The rate should be fair and reasonable and based solely on those costs actually incurred by the distribution UDC to provide the specific service. The rates developed should not act as a disincentive to the deployment and use of DG by customers nor should it be a direct subsidy for DG owners/operators.

h. Some DG providers believe that a partial requirements, direct access tariff may not be necessary. The existing direct access tariffs could be used and any UDC distribution company revenue deficiency associated with the installation of DG could be recovered through the existing direct access rate structure. However, according to the UDCs, this implies that any revenue shortfalls will need to be recovered from other customers after rates are adjusted in a subsequent rate case. To ensure proper revenue recovery, the existing rate design will need to be modified to recover distribution system costs through customer charges, contract demand charges, and/or ratcheted demand charges instead of the current commodity based kWh charges.

3. Single Tariff For Standard Offer and Direct Access Rates – SRP

   a. SRP has a single set of unbundled tariffs, rather than separate standard offer and direct access rates.

   b. SRP provides standby (partial requirements) service to large commercial and industrial customers served on the E-60 series price plans (over 1 MW and 300,000 kWh annually) under provisions of the standby electric service rider. The standby service rider applies to customers receiving electric service from SRP or an ESP. Unlike the Affected UDCs, SRP may provide generation service to direct access customers.

   c. The rate design of the E-60 series price plans with the standby service rider is intended to appropriately recover fixed costs from all customers based on cost of service, not just customers with DG. Rate designs may be examined and modified by SRP in future rate adjustments, but SRP would not likely decrease the level of fixed cost recovery in any future rate design change, unless such a change is supported by actual cost changes.

   d. SRP does not have a tariff or rider to provide partial requirements service to residential or small business customers. If the market penetration of DG becomes significant within these rate classes, SRP may consider developing an appropriate tariff or rider.

   e. DG Providers suggest that customer choice and competition would be enhanced by the development of a tariff or rider for partial requirements firm or interruptible service to the residential and small commercial rate classes.

C. Selling Excess Power from DG to UDCs

1. General Obligations and Options

   a. The Committee concurred that UDCs should not be required to buyback excess generation from DG from either standard offer or direct access customers, except as required under existing PURPA rules. However, at their option, UDCs could elect to offer a DG buyback service as part of a standard offer service, with requirements, restrictions, and limits as determined by the distribution UDC. The Committee also believes that UDCs could also (at their option) buyback excess DG power from direct access customers, as part of their generation procurement process.

   b. UDCs suggested that under the current ACC competition rules and the APS <u>and TEP</u> settlement agreement<u>s</u>, the UDC will eventually be required to purchase generation for its standard offer customer through a competitive bidding process. To obligate a UDC to purchase surplus power from a DG would be detrimental to a competitive market and could increase costs to other Standard Offer customers.

c. DG Providers agreed that the buyback of excess power from DGs should not, in general, be made mandatory. However, this assumes effective competition is present such that an ESP or other provider can and will contract with DG owners/operators to purchase their excess power. Absent effective competition, the ACC may need to review this provision. If the purchase of excess power from DGs is solely at the discretion/election of UDCs, the ACC should emphasize and monitor that the UDC fairly includes DG power when it competitively procures power for standard offer service.

d. The election by the UDC to offer a DG buyback service should be based on requirements, restrictions, and limits as determined jointly by the DG owner/operator and the distribution UDC based on current market conditions.

e. DG Providers also commented that the DG should be considered as part of the portfolio of supply side resources and distribution UDC purchases of DG should be subject to the competitive bidding process. For the competitive market to function efficiently, the distribution generation owner, as a seller to the market, should participate in the competitive bid process if they wish to sell excess or "merchant" power.

2. UDC Tariffs

a. Buy-back Tariffs for QFs

1) UDCs currently have standard offer purchase rates for qualified cogeneration facilities, qualified small power production facilities, qualified solar\photovoltaic facilities, and facilities utilizing renewable resources. Distributed generators meeting the requirements of a "qualified facility" under the provisions of the existing tariffs will be able to sell excess power to the distribution UDC under the provisions of these tariffs.

2) DG Providers argue that the existing QF buyback tariffs were developed under the "bundled regime" of the past. These tariffs should be reviewed and revised, where appropriate, to ensure conformance with an "unbundled" world.

3) TEP intends to modify its buy-back rates to be more consistent with market principles. Such buy-back rates will also be more easily adjustable to market prices, e.g., perhaps adjusted monthly or quarterly. In addition, TEP does not intend ~~t~~ to continue to offer long-term buy-back contracts.

4) SRP intends to purchase power from residential, commercial, or large industrial cogeneration and small power production customers under the provisions of the Buyback Service Rider. The buyback credit is indexed to the day-ahead hourly California PX prices for Palo Verde delivery less $0.00017/kWh, which is the cost to provide scheduling, system control, and dispatch services under SRP's retail Open Access Transmission Tariff.

b. Buy-back provisions for Non-QF DG power

1) In general, the UDCs believed that voluntary buyback of DG by UDCs should be priced at the lower of the distribution UDCs short-run avoided cost or the hourly market rate. However, in the near future, the UDC's current calculation of avoided cost will need to be based on market prices instead of the current methodology which is based on the UDC's own production costs.

2) DG Providers suggest that the buyback of excess power from distributed generators should be priced at a competitive market rate or as established by contractual agreement between the DG owner/operator and the distribution UDC.

c. Firm Vs. Non-firm Power

1) UDCs maintain that excess DG power cannot be considered firm power and may be supplied to the distribution grid at any time. This excess DG is unscheduled and could be detrimental to the current loading on generation plants as well as transmission and distribution facilities. This affects the value of excess DG to the distribution UDC on an hourly basis. APS pointed out that, for power to be considered "firm," it must meet certain requirements.

2) DG Providers assert that excess DG power may or may not be considered firm power depending on any contractual arrangement between the DG owner/operator and the distribution UDC.

D. Selling Excess DG in the Open Market

1. General Obligations and Options

a. The Committee believes that under the current Competition Rules, DG owners cannot sell excess power to other retail customers unless they become a licensed ESP or sell to an ESP. The legal requirements for such sales are currently being debated in other jurisdictions and are being reviewed by the legal staffs of Committee members. At this time no definitive conclusion has been reached, therefore, the Committee recommends additional follow-up on this issue.

b. DG Providers commented that the current Competition Rules ~~ACC rules~~ should be reviewed to determine if modifications are necessary to allow sales of excess power to others, such as the ~~distribution~~ UDC or entities or properties under common ownership and/or control that are non-contiguous. The modifications may be necessary to allow increased customer choice and greater competition.

2. FERC Requirements

a. The FERC classification and requirements for DG sales of excess power to an ESP or to another customer are currently being debated in several jurisdictions. Some Committee members have performed an initial review and opinion of this issue. However, the Committee recommends that the ACC continue to resolve this issue. Below is a summary of preliminary opinions by UDCs and DG Providers. Please note that not all UDCs and DG Providers necessarily share these opinions.

b. DG sales to an ESP (UDC Viewpoint)

1) In accordance with Section 201 (d) of the Federal Power Act the sale of electric energy at wholesale is defined as:

"a sale of electric energy to any person for resale."

2) DG sales to an ESP is considered a wholesale transaction subject to FERC jurisdiction. The DG owner would need a market rate tariff (filed with FERC) to sell excess generation to an ESP.

3) OATT charges apply for all sales of excess power from the DG owner to an ESP. ESPs will pay transmission charges even if the ESP elects to sell excess DG power to customers located on the same substation ~~or~~ feeder as the DG unit from which energy is purchased.

4) If an ESP elects to purchase power from the DG, ~~distributed generator,~~ an applicable FERC jurisdiction direct assignment charge for the distribution wheeling will apply. In order for the appropriate wheeling charge to be determined a direct assignment study will need to be done (in accordance with the provisions of the current OATT).

c. DG sales to an ESP (Viewpoint of DG Providers)

1) The determination that DG sales to an ESP are wholesale transactions subject to FERC jurisdiction has not been confirmed. If the determination is made that these wholesale transactions are subject to FERC jurisdiction, a ruling regarding this issue should be requested from FERC to exempt DG units under a particular size threshold from this burdensome and unnecessary requirement. Both PURPA and PUHCA identify exemptions regarding sales for resale.

2) Transmission charges are not applicable in all cases. The use of only the distribution system to sell excess DG to customers does not involve any physical use of the transmission system, particularly when the distributed generator and the customers are on the same substation ~~and/or~~ feeder. Consequently, OATT charges should not apply and ~~Arizona electric restructuring rules~~ the Competition Rules may need to be adjusted.

3) A distribution wheeling charge should not be applied together with a distribution system access charge. The customer should be charged only once for use of the distribution system.

d. DG sales to other retail customers (UDC Viewpoint)

1) DG owners must become, or sell to, an ESP to sell excess power directly to other retail customers, and meet all ACC and local UDC ESP certification requirements.

2) DG owners attaining an ESP status would also be considered to be an EWG or IPP and must meet requirements under 18 C.F.R Part 365.

3) As an ESP, the DG owner must provide 100% of the load requirements for its retail customers (pursuant to the terms of APS's Schedule 1, Section 3.5.2 as approved by the ACC). This includes contracting for backup, supplemental, and maintenance power on behalf of these retail customers.

4) Retail customers contracting with the DG owner for excess DG power will become Direct Access customers and take service under the distribution UDC's applicable Direct Access rate.

e. DG sales to other retail customers (DG Provider opinion)

1) The current Competition Rules ~~ACC rules~~ should be reviewed to determine what modifications are necessary to promote greater flexibility and fairness for DG, especially concerning the ability to sell back power to the UDC, and the ability to provide excess DG power to other sites owned by the same business proprietor, e.g., McDonalds, Quick Stop, etc. ~~retail customer.~~

2) Exemptions exist within 18 C.F.R Part 365 that waive FERC requirements to register as an EWG or IPP. The filing requirements would be onerous and burdensome for residential and commercial customers.

D. UDC Recovery of Distribution Costs

1. UDC Concerns

a. The installation of DG after the area load has been established, and the delivery system has been installed, could lead to unrecovered distribution costs for the ~~distribution~~ UDC. DG customers should not be subsidized, either through UDC shareholder or ratepayer funding of costs which are unrecovered due to the DG installation, i.e., cost-shifting should be minimized.

b. The DG owner will not have as many hours of use compared with a full requirements customer. Because the UDC's ~~distribution company's~~ current recovery of fixed costs is largely through commodity charges ~~are commodity based~~, this causes a reduction in the revenues to be collected by the ~~distribution~~ UDC without an equivalent reduction in costs. This distribution UDC revenue reduction also reduces the fixed cost contribution to distribution plant (which is unrecovered).

c. Under the terms of the current APS Settlement Agreement, over the next five years distribution UDC rates (both Standard Offer and Direct Access) will be decreasing. APS will not have the ability to increase existing Standard Offer or Direct Access rates. With fixed rate reductions the ~~distribution~~ UDC will not be able to collect any reduction in fixed cost contribution associated with the installation of DG ~~distribution generation~~ for at least five years unless new rate designs are permitted . Any lost fixed cost contribution equates to unrecovered distribution costs. To address this issue, TEP intends to require all customers with DG running in parallel with the UDC to take service under tariffs specifically designed to recover the costs of T&D facilities in place to serve such customers. Such tariffs are akin to traditional "standby" service only in this case the focus is on the UDC's T&D facilities that are standing by to serve the customer.

d. Under this scenario, shareholders of the distribution UDC company will be required to absorb this reduction in fixed cost contribution and will not have an opportunity to earn a fair rate of return on their investment. TEP intends to address this issue as stated in item c. above.

e. The derivation of distribution related stranded costs associated with the installation of DG must be quantified and recovered through use of one of the following methods:

   1) A distribution stranded cost charge paid by the DG customer.

   2) Redesign the current commodity based Standard Offer and Direct Access rates to include more fixed cost recovery of revenues (i.e. recover distribution related costs through a fixed distribution charge or contract capacity charge rather than a kW or kWh charges).

f. The rate design of SRP's large industrial tariffs, in conjunction with the standby electric service rider, is intended to recover fixed distribution facilities, distribution delivery, and transmission costs, based on the customer's reserved capacity on SRP's electric system. To the extent that DG becomes significant within the small business or residential classes, SRP may adjust current rate designs to accommodate that situation.

g. As discussed above, the rate design of SRP's large industrial tariffs, in conjunction with the standby electric service rider, is intended to recover fixed distribution facilities, distribution delivery, and transmission costs, based on the customer's reserved capacity on SRP's electric system.

h. To the extent that DG becomes significant within the small business or residential classes, SRP may adjust current rate designs to accommodate that situation.

2. DG Provider Concerns

   a. DG providers recognize that UDCs are concerned over proper recovery of distribution assets, and their desire to move towards fixed-charge vs commodity-based recovery. However several concerns arise:

   b. In the short-term, DG may cause under-utilization of the distribution system leading to the under-recovery of fixed distribution costs. In the longer term, the electric distribution UDC has the responsibility to promote system utilization that maximizes the available capacity of the system. Opportunity exists for increases in revenue recovery as system utilization is maximized and as new products are introduced by the regulated distribution UDC. The objective should be to facilitate and promote increased customer choice and greater competition.

   c. There are several instances where the use of DG will not result in a reduction in the hours the distribution system is utilized.

   d. The Settlement Agreement was entered into by APS with full knowledge that DG could potentially be utilized by customers. APS willingly agreed to a rate freeze. Additionally, Standard Offer and Direct Access rates could potentially be increased based on the provision in the Settlement Agreement that allows for rate increases based on conditions or circumstances which constitute an emergency. TEP also entered into a Settlement Agreement with full knowledge of DG and the Settlement Agreement contains the same provision for rate increases related to emergencies.

   e. It has not been established that there will be stranded or unrecovered distribution-related costs directly related to the installation of DG. If there were any revenue deficiencies, including deficiencies due to the installation of DG, the distribution UDC has the opportunity to recover those revenues in its next general rate case.

   f. Some UDCs have rate freezes or mandatory reductions in standard offer tariffs. Therefore any changes to the design of distribution tariffs for DG, without changing the tariff design for all customers and applications could be unfair and create an uncompetitive bias.

   g. Reduces price signals for energy efficiency, which is being emphasized by some ESPs.

   h. Could create rate shocks or windfalls for some customers.

   i. May not be consistent with other customer situations in which load is reduced, e.g. energy efficiency, non-electric end uses, reducing business activity in an existing site, or sub classes of customers with unique load characteristics. UDCs are currently collecting commodity-based average distribution costs from these customer groups, even <u>though</u> these activities reduce their contribution to the recovery or total distribution costs.

   j. A distribution wheeling charge should not be assessed in conjunction with any distribution access charge. This is duplicative and requires a DG owner/operator to pay twice for the same service. A distribution wheeling charge, if any, should only be assessed against one party to the transaction. The appropriate party could be determined by where the ESP takes title or ownership to the excess power.

E. Metering

1. General

a. The Committee discussed various options concerning the metering of DG power. The requirements should depend on the size of the DG and whether the DG is selling excess power to the grid. For larger installations, which are selling excess power, the UDCs wanted to have hourly metered data. For very large installations, they desired dynamic (real time) data. DG providers generally concurred with real time data for DGs selling excess power; real-time data could be collected at the UDC expense.

b. Below is a review of metering options and recommendation by the UDCs and DG Providers.

2. Summary of Metering Options

a. Net metering (i.e. the meter running backwards). DG excess power sales to the UDC effectively offset customer purchases from the UDC. Could be time of use meter of monthly consumption meter.

b. Simultaneous buy-sell agreement. DG owners with on-site generation are required to sell 100% of their generation to the ~~distribution~~ UDC at avoided cost while purchasing 100% of their load requirements from the ~~distribution~~ UDC (or an ESP).

c. Traditional metering equipment with devices which prevent power to flow backwards through the meter. This would apply to DGs which are not intending to sell excess power.

d. Bi-directional metering equipment, which could facilitate excess power sales on a monthly-consumption, time-of-use or hourly-interval basis.

3. UDC Recommendations

a. Net metering (i.e. the meter running backwards) ~~as a device~~ is not well suited ~~in~~ to a competitive environment, and will not be offered to DG ~~distribution generation~~ customers.

b. DG owners ~~with on-site generation~~ will not be required to sell 100% of their generation to the distribution UDC at avoided cost while purchasing 100% of their load requirements from the distribution UDC (or an ESP). This situation is known as a simultaneous buy-sell agreement.

c. The installation of a bi-directional meter (either timed or un-timed) to record hourly sales to the customer and hourly excess power supplied to the distribution grid will be required for all DG ~~distribution generation~~ owners.

d. Excess energy sales to the customer and excess DG power supplied to the distribution grid will be separately metered and treated as separate transactions.

   1) Hourly sales from the ~~distribution~~ UDC to the DG ~~distribution generation~~ owner will be priced at the applicable standard offer or direct access retail rate.

   2) Any hourly excess DG purchased by the ~~distribution~~ UDC will be priced in accordance with an applicable buy-back ~~standard offer partial requirements~~ tariff, ~~(~~if available~~)~~.

   3) The distribution UDC will charge an appropriate distribution wheeling charge for any excess distribution generation sold to an ESP.

e. SRP's Buyback Service Rider requires that the customer provide sufficient metering service entrances and pay for sufficient metering to segregate load between firm service and buyback service.

4. DG Providers Recommendations

   a. DG providers concur that net metering would not be a typical metering solution, except perhaps for a special program for very small technologies, such as a residential solar program.

   b. DG Providers generally concur that a bi-directional meter could typically be required for larger DG units that are selling excess power.

   c. However, if the DG does not sell excess power, there should be no requirement for a bi-directional meter.

   d. In addition, the pricing could be determined by contractual agreement between the DG and the UDC. The contract would determine the required metering equipment.

5. Ownership of information

   a. UDCs and DG Providers agree that the ownership of metering and other related information concerning DG should be consistent with the ACC Competition ~~r~~ Rules.

F. Compensation for Grid Benefits of DG (Avoided Distribution Costs)

1. DG Provider Viewpoint

   a. DG could provide avoidance of costs, as well as system benefits for the ~~distribution~~ UDC's distribution system. DG can provide many benefits to the distribution system as noted below. Additionally, there are many examples of DG applications that will result in the distribution infrastructure being used as many hours as it was originally anticipated.

b. Strategic placement of DG resources on the transmission or distribution systems can provide many system benefits to the ~~distribution~~ UDC. These benefits include improved system reliability, reduced transmission and/or distribution system line losses, the avoidance or deferral of transmission and/or distribution system improvements and upgrades, relief to constrained transmission and/or distribution systems, and environmental benefits depending on the type of technology employed and the type of fuel used.

2. UDC Viewpoint

a. In almost all instances DG will not provide any "avoided wires cost" unless the distribution system will never be used to provide backup power. If backup power is required ~~for~~ at any time, the local UDC must design ~~have~~ the delivery system with adequate capacity to provide backup delivery service in case the DG customer's unit goes down. The UDC must install the same distribution infrastructure if they are providing normal distribution delivery service or backup delivery service. The only difference is that the distribution system will be delivering lower demand ~~less power~~ and less energy than originally anticipated.

b. Distribution facilities provide a customer with the option of purchasing electricity through the distribution company's wires. The cost to the distribution company / option value to the customer does not change because fewer electrons are flowing to the DG owner. A fixed "pipeline" of a certain size to the customer exists regardless, and the costs should be recovered. Cost-shifting should also be minimized.

c. Multiple distributed generators on a single feeder, if properly included in the original planning of the distribution system, could affect the sizing of the feeder. Specifically, the size of the feeder installation could be reduced due to the reduction in distribution load caused by the distributed generators, which have sufficient diversity in potential outages. There could be some "avoided wires cost" in this instance. Cases such as these would be infrequent and should be addressed on a case by case basis. Furthermore, the avoidable costs of the distribution system that can be avoided (such as by using smaller conductors) are typically small, relative to the ~~fixed~~ costs of distribution facilities such as ~~distribution~~ transformers and service drops.

APPENDIX A

ACCESS, METERING & DISPATCH COMMITTEE

ASSIGNED QUESTIONS AND KEY TOPICS

OPERATIONS SUBCOITTEE

Questions 4,5,6,7,8,9,10,11,12,13,15,16,17,21

TOPICS

A set of operating scenarios were developed, with power generating entities defined as follows:

- System Support – Any DG that is operated for the principal purpose of bringing benefit or value to the system.
- End use customer only – Any DG, connected with the grid, that is operated for the principal purpose of self-generating to offset internal power consumption.

Disconnected from the grid – Any DG that is not capable of being interconnected with the grid, consequently for self-generation purposes ONLY.

1. UDC role, obligations for system management and interconnection
2. Jurisdiction issues for interconnection and control
3. Control of DG (UDC, CAO)
4. Relay requirements
5. Ancillary services
6. Disturbances, outages
7. Reliability issues
8. DG benefits to grid
9. Emergency generators
10. Metering requirements

TARIFF AND POLICY SUBCOMMITTEE

Questions 1,2,3,13,15,18,19,20,22, sellback policy

TOPICS

1. Distribution Costs
   Proper cost recovery in competitive environment
   Consistent and fair treatment for DG

2. UDC role/obligation
   Standby, maintenance power
   Supplemental commodity power
   Buyback excess DG power
   Tariff design – energy vs. monthly connection charges

3. PURPA issues

4. Selling DG power
   Over the fence (selling to neighbor)
   Self provision, multiple sites
   UDC grid vs. customer grid
   ESP role/obligation

5. Jurisdiction Issues

6. Net metering

7. Coordination policy
   Dispatch, control
   CAO scheduling
   Ancillary services

8. Value to grid

9. Information ownership and access

10. Tariffs
    Rules, policies
    Rate schedules
    Supplemental fees
    Maintenance fees
    Standby fees
    Buy-back charges
    Metering information
    Compensation for benefits and costs to the system

APPENDIX B

ACCESS, METERING & DISPATCH COMMITTEE

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Arizona State

Draft

Interconnection Requirements

For

Distributed Generation

TABLE OF CONTENTS

1. FORWARD

This revised document entitled "Arizona State Draft Interconnection Requirements for Distributed Generation" (Revision 3), is presented to the Arizona Corporation Commission by the Interconnect Standards Committee with the intent of recommending interconnection standards to the Commission for eventual adoption and implementation within the State of Arizona. It replaces the Draft Revision 2 previously submitted on 11/22/99.

The methodology initially agreed to and employed by the committee was to begin with a strawman document, based on existing Arizona utility standards. It served as a basis for discussion and subsequent modification in order to develop this document, once consensus by the committee members on the various issues had been achieved. Interconnection documents from other states were also reviewed.

Committee members initially agreed that a user-friendly document would be desirable. Hence, an attempt has been made to incorporate descriptive and explanatory language throughout the document.

With this revision broad consensus has been achieved on all sections. In an effort to present a document which was representative of the various view points expressed, and where consensus was not achieved on specific items in the sections, additional notes have been included outlining major differing views by inserting as comments **(IN BOLD CAPITALS)** within the sections.

Section 9, Metering Requirements, previously determined to fall into the scope of work of the Metering, Access, and Dispatch Committee, has now been removed from the document.

Members of the interconnect standards committee appreciate being afforded the opportunity by commission staff to further refine and complete this document. It is generally felt that by bringing this document to a satisfactory conclusion, in as much as consensus can be achieved, will be beneficial to the distributed generation industry and utilities as a whole in the state.

2. SCOPE

This document specifies the Arizona utility (UDC) requirements for safe and effective interconnection of distributed generation with a utility radial distribution system. **(THE COMMITTEE HAS NOT REACHED A CONSENSUS ON ALLOWING DISTRIBUTED GENERATORS ON NON-RADIAL SYSTEMS.)** Interconnection requirements as outlined here are for those installations that will be connected to the utility electric power distribution system and do not backfeed onto the utility transmission system. Installations that interconnect to, or backfeed onto, the transmission system may have additional utility requirements and will also need to comply with all applicable WSCC (Western Systems Coordinating Council), AZ-ISA (Arizona Independent Scheduling Administrator), Desert STAR Independent System Operator, NERC (North American Electric Reliability Council) and RTO (Regional Transmission Operator) requirements as applicable. Facilities that will be connected directly to the transmission system will be reviewed by the utility on an individual basis.

For the purpose of simplicity, the term "Customer" will be used here to refer to a utility customer who installs, owns or operates a distributed generator, cogenerator or small power producer, even though the Customer may not actually be a purchaser of power from the utility, and includes any independent party or entity that either invests in, owns or operates a distributed generator or generation facility.

The required protective relaying and/or safety devices and requirements specified in this document are for protecting only utility facilities and other utility customers' equipment from damage or disruptions caused by a fault, malfunction or improper operation of the distributed generating facility. They are also necessary to ensure the safety of utility workers and the public. The requirements specified herein do not include additional relaying, protective or safety devices as may be required by industry and/or government codes and standards, equipment manufacturer requirements and prudent engineering design and practice to fully protect Customer's generating facility or facilities; those are the sole responsibility of the Customer. In addition to all applicable regulatory, technical, safety, and electrical requirements and codes, Customers will also be subject to contractual and other legal requirements, which will govern over the general provisions in this document.

Customers and utility personnel shall use this document when planning the installation of distributed generation. Note that these requirements may not cover all details in specific cases. The Customer should discuss project plans with the utility before designing the facility or purchasing and installing equipment. This document must be applied in conjunction with applicable utility rate tariffs and electrical service schedules and requirements that pertain to the operation of distributed generation with the utility electrical distribution system.

3. DEFINITIONS

3.1 Clearance Point: A clearance point is the physical location on a piece of line or equipment that is to be de-energized from all known sources of power. It is at this physical piece of line or equipment that tags will be installed.

3.2 Cogeneration Facility: Any facility that sequentially produces electricity, steam or forms of useful energy (e.g., heat) from the same fuel source and which are used for industrial, commercial, heating, or cooling purposes.

3.3 Customer: Any utility customer who installs, owns or operates a GF, even though the customer may not actually be a purchaser of power from the utility, and includes any independent party that either invests in, owns or operates a distributed generator or generating facility.

3.4 Distributed Generator: Any type of electrical generator or static inverter producing alternating current that (a) has the capability of parallel operation with the utility distribution system, or (b) is designed to operate separately from the utility system and can feed a load that can also be fed by the utility electrical system. A distributed generator is sometimes referred to simply as "generator".

3.5 Electric Supply/Purchase Agreement: An agreement, together with appendices, signed between the utility and the Customer (Generating Facility) covering the terms and conditions under which electrical power is supplied and/or purchased to/from the utility.

3.6 ESP (Electric Service Provider): A company supplying, marketing or brokering at retail any competitive services pursuant to a Certificate of Convenience and Necessity.

3.7 Generating Facility (GF): All or part of the Customer's distributed electrical generator(s) or inverter(s) together with all protective, safety, and associated equipment necessary to produce electric power at the Customer's facility. A GF also includes any Qualifying Facility (QF).

3.8 Hold Tag (also called Contact Tag): The method used as an aid in protection of personnel working on or near energized equipment, whereby automatic or remote re-closing of a line is disabled. When a hold (or contact) tag is in effect, if the circuit trips open, it will not be re-closed until it is verified that all personnel are in the clear. As it relates to distributed generation, circuits with hold tags shall have all potential sources of backfeed removed by opening, locking and tagging the appropriate disconnect switch.

3.9 Interconnect Agreement: An agreement, together with appendices, signed between the utility and the Customer (Generating Facility) covering the terms and conditions governing the interconnection and operation of the Generating Facility with the utility.

3.10 Islanding: A condition occurring when a generator and a portion of the utility system separate from the remainder of the utility system and continue to operate in a energized state (copyright EPRI).

3.11 Metering Service: All functions related to measuring electricity consumption.

3.12 MSP (Meter Service Provider): An entity providing Metering Service, as that term is defined herein.

3.13 Parallel Operation: The operation of a GF that is electrically interconnected to a bus common with the utility electrical system, either on a momentary or continuous basis.

3.14 Points of Interconnection: The physical location where the utility's service conductors are connected to the Customer's service conductors, at which point the power transfer occurs between the Customer's electrical system and the utility distribution system, also commonly referred to as the Point of Common Coupling.

3.15 Qualifying Facility (QF): Any Cogeneration or Small Power Production Facility that meets the criteria for size, fuel use, efficiency, and ownership as promulgated in 18 CFR, Chapter I, Part 292, Subpart B of the Federal Energy Regulatory Commission's Regulations.

3.16 Relay: An electric device that is designed to interpret input conditions in a prescribed manner and after specified conditions are met to respond to cause contact operation or similar abrupt change in associated electric control circuits.

3.17 Small Power Production Facility: A facility that uses primarily biomass, waste or renewable resources, including wind, solar, and water to produce electric power.

3.18 Utility: The electric utility entity that constructs, operates and maintains the electrical distribution system for the receipt and/or delivery of power, also referred to as the Utility Distribution Company (UDC).

3.19 Utility Grade Relays: Relays specifically designed to protect and control electric power apparatus, tested in accordance with the following ANSI/IEEE standards:

(a) ANSI/IEEE C37.90-1989 (R1994), IEEE Standard for Relays and Relay Systems Associated with Electric Power Apparatus.
(b) ANSI/IEEE C37.9.01-1989 (R1994), IEEE Standard Surge Withstand (SWC) Tests for Protective Relays and Relay Systems.
(c) ANSI/IEEE C37.90.2-1995, IEEE Standard Withstand Capability of Relay Systems to Radiated Electromagnetic Interference from Transceivers.

4. OVERVIEW OF DISTRIBUTED GENERATION ISSUES

Any Customer qualified under the Public Utility Regulatory Policies Act (PURPA) of 1978, may operate his generating equipment in parallel with the utility provided the Customer provides equipment that will:

(a) not present any hazards to the utility personnel, other customers or the public,
(b) minimize the possibility of damage to the utility or other customer equipment,
(c) not adversely affect the quality of service to other customers, and
(d) minimally hamper efforts to restore a feeder to service (specifically when a clearance or hold tag is required).

In addition, the Customer will also need to comply with the following:

(a) the generating facility meets all the interconnection, safety, and protection requirements outlined in this document,
(b) Customer signs an Interconnect Agreement, as well as an Electric Supply /Purchase Agreement, as applicable, with the utility, and
(c) Customer complies with and is subject to all applicable service and rate schedules and requirements, rate tariffs and other applicable requirements as filed with and approved by the Arizona Corporation Commission for regulated utilities.

Customer generating equipment that does not qualify under PURPA may also be operated in parallel with the utility provided that all of the conditions outlined above are complied with.

(IT IS GENERALLY EXPECTED BY COMMITTEE MEMBERS THAT A POLICY DECISION SHOULD BE MADE BY THE ACC REGARDING THE INTERCONNECTION OF GENERATORS NOT QUALIFIED UNDER PURPA.)

Due to relay coordination and potential backfeed and stability problems, a utility may not permit any distributed generation to be connected to a network system.

(THE COMMITTEE HAS NOT REACHED CONSENSUS ON ALLOWING DISTRIBUTED GENERATORS ON NETWORKED SYSTEMS. AT LEAST ONE OTHER STATE'S INTERCONNECTION REQUIREMENTS PROPOSED TO ALLOW CONNECTION TO NETWORK SYSTEMS, WITH CERTAIN LIMITATIONS. IT IS NOT CLEAR AS TO THE TYPE OF NETWORKS ADDRESSED HOWEVER. THE PROSPECT OF INTERCONNECTING WITH NETWORKED DISTRIBUTION SYSTEMS IS A POINT OF CONCERN WITH UTILITY ENGINEERS, FIELD SUPERVISORS AND OPERATORS. UTILITY COMMITTEE MEMBERS AND OPERATIONAL STAFF HAVE STRESSED THAT WITH THE EXISTING CONFIGURATION AND RELAYING, NETWORKS ARE NOT DESIGNED TO OPERATE IN CONJUNCTION WITH CUSTOMER GENERATION. SAFETY, LOSS OF RELIABILITY, IMPOSSIBILITY OF COORDINATING PROTECTIVE RELAYING, LIABILITY, OPERATIONAL CONSTRAINTS, AND COST OF RETROFITS WERE CITED AS BARRIERS. SOME NON-UTILITY MEMBERS FELT THAT RELAY AND PROTECTION REQUIREMENTS COULD TAKE INTO CONSIDERATION GENERATOR SIZE RELATIVE TO SERVICE SIZE AND ALSO GENERATION TYPE. IT WAS SUGGESTED THAT THE

ACC CONSIDER SPONSORING A WORKSHOP ON INTERCONNECTION OF DG TO NETWORK SYSTEMS AND SHOULD INVITE ADDITIONAL NETWORK EXPERTS TO DISCUSS THE ISSUES.

IT WAS ALSO SPECULATED THAT DISTRIBUTION SYSTEM (EVEN RADIAL) INSTALLATIONS AND UPGRADES IN THE FUTURE MIGHT NEED TO BE DESIGNED OR RE-DESIGNED FOR MULTIPLE-SOURCES AND BI-DIRECTIONAL OPERATION, REFLECTING TRANSACTIONS NOW OCCURRING ON THE LEVEL OF TRANSMISSION SYSTEMS AND EVOLVING TO FUNCTION MORE LIKE THOSE SYSTEMS. IT IS UNCLEAR, HOWEVER, WHO WOULD PAY FOR THIS OR HOW IT WOULD BE IMPLEMENTED).

The protective and safety devices (relays, circuit breakers, disconnect switches, etc.) specified in this document must be installed and placed into service before allowing parallel operation of Customer's generation facilities with the utility system. The purpose of these devices is to isolate the Customer's generating equipment from the utility system whenever faults or disturbances occur and for maintenance purposes. Modifications to the utility electrical system configuration or protective equipment may also be required, generally at the expense of the Customer, in order to accommodate parallel generation. Additional agreements may be required between the Customer and the utility before modifications to the distribution system are made.

The utility will not assume any responsibility for the protection of the Customer's generator(s), or of any other portion of the Customer's electrical equipment. The Customer is fully and solely responsible for protecting his equipment in a manner to prevent any faults or other disturbances on the utility distribution system from damaging the Customer's equipment.

The Customer must obtain all required permits and inspections indicating that the Customer's generating facility complies with local and other applicable safety codes. The utility can disallow the interconnection of a Customer's generating facility if, upon review of the Customer's design or facility, it determines that the proposed design or facility is not in compliance with applicable safety codes, or is such that it could constitute a potentially unsafe or hazardous condition.

5. DISTRIBUTED GENERATION TYPES

Distributed generation is any type of electrical generator or static inverter producing alternating current that (a) has the capability of parallel operation with the utility distribution system, or (b) is designed to operate separately from the utility system and can feed a load that can also be fed by the utility electrical system. A distributed generator is sometimes referred to simply as "generator".

Distributed generators include induction and synchronous electrical generators as well as any type of electrical inverter capable of producing A/C power. A **Separate System, or Emergency or Standby Generation System,** is designed so as to never electrically interconnect or operate in electrical parallel with the utility system. A **Parallel System, or Interconnected Generation System,** is any generator or generation system that can parallel, or has the potential to be paralleled via design or normal operator control, either momentarily or on a continuous basis, with the utility system.

The Customer may elect to run his generator as a separate system with non-parallel load transfer between the two independent power systems, or he may run it in parallel with the utility system. A description and the basic requirements for these two methods of operation are outlined below.

5.1 Separate System

A separate system is one in which there is no possibility of electrically connecting or operating the Customer's generation in parallel with the utility's system. The Customer's equipment must transfer load between the two power systems in an open transition or non-parallel mode. If the Customer claims a separate system, the utility may require verification that the transfer scheme meets the non-parallel requirements.

Emergency or Standby generators, used to supply part or all of the Customer's load during a utility power outage, are required by the National Electrical Code (NEC) to have transfer equipment designed and installed to prevent the inadvertent interconnection of normal and emergency sources of supply in any operation of the transfer equipment.

As such, these generators must be connected to the Customer's wiring through a double throw, "break-before-make" transfer switch specifically designed and installed for that purpose. The transfer switch must be of a fail-safe mechanical throw over design, which will under no circumstances allow the generator to electrically interconnect or parallel with the utility system. The transfer switch must always disconnect the Customer's load from the utility power system prior to connecting it to the generator. Conversely, the transfer switch must also disconnect the load from the generator prior to re-connecting it back to the utility system. These requirements apply to both actual emergency operations as well as to testing the generator. All transfer switches and transfer schemes must be inspected and approved by the jurisdictional electrical inspection agency.

Portable generators are not designed to be connected to a building's permanent wiring system, and are not to be connected to any such wiring unless a permanent and approved transfer switch is used. Failure to use a transfer switch can result in backfeed into the utility system – the generator voltage can backfeed through the utility transformer and be stepped up to a very high voltage.

This can pose a potentially fatal shock hazard to anyone working on the power lines or on utility equipment.

Other than the requirements outlined above in this section, the utility has no further technical interconnection requirements for a separate system.

5.2 Parallel System

A parallel, or interconnected, generator is connected to a bus common with the utility's system, and a transfer of power between the two systems is a direct result. A consequence of such interconnected operation is that the Customer's generator becomes an integral part of the utility system that must be considered in the electrical protection and operation of the utility system.

Parallel generators encompass any type of distributed generator or generating facility that can electrically parallel with, or potentially backfeed the utility system. Additionally, any generator system using a "closed transition" type transfer switch or a multi-breaker transfer scheme, or an electrical inverter that can be configured or programmed to operate in a "utility interactive mode" constitutes a potential backfeed source to the utility system, and is classified as an interconnected generator.

The utility has specific interconnection and contractual requirements that must be complied with, and information that needs to be submitted for all interconnected generators as is specified in the various sections of this document. In summary, these include a "visible open" disconnect switch meeting certain requirements to isolate the Customer's system from the utility system, as well as protective relaying, metering, special rate schedules, and other safety and information requirements. The Customer will be responsible for having the generation system protective schemes tested by qualified testing/calibration personnel. Utility personnel will inspect the system and the Customer will be required to sign an Interconnect Agreement and, as applicable, an Electric Supply/Purchase Agreement with the utility. Utility "blanket approval" is not extended to any specific type of generator or generator scheme since each project is site specific and needs to be reviewed on a case-by-case basis.

In addition to the various other requirements specified in this document, Parallel Systems shall specifically comply with the technical requirements outlined in the Interconnection Technical Requirements section (Section 8) of this document.

6. GENERAL INFORMATION & REQUIREMENTS

The Customer is responsible for all facilities required to be installed solely to interconnect the Customer's generation facility to the utility system. This includes connection, transformation, switching, protective relaying, metering and safety equipment, including a visibly-open Disconnect Switch and any other requirements as outlined in this document or other special items specified by the utility. All such Customer facilities are to be installed by the Customer at the Customer's sole expense. In the event that additional facilities are required to be installed on the utility system to accommodate the Customer's generation, the utility will install such facilities, generally at the Customer's expense. The utility may also charge the Customer for any administrative costs and/or the costs of studies required to interconnect the Customer's generation.

(IT WAS PROPOSED THAT THE ACC MAY YET ADDRESS THE ISSUE OF ALLOCATION OF THESE COSTS. UTILITY COMMITTEE MEMBERS EXPRESSED CONCERN AT THIS SUGGESTION. UTILITIES PRESENTLY HAVE TARIFFS APPROVED BY THE ACC TO RECOVER ALL REASONABLE COSTS OF INTERCONNECTION SUCH AS SWITCHING, METERING, TRANSMISSION, SAFETY PROVISIONS AND ADDITIONAL ADMINISTRATION. CUSTOMERS ARE ALSO FULLY RESPONSIBLE FOR THE COSTS OF DESIGNING, INSTALLING, OPERATING AND MAINTAINING INTERCONNECTION FACILITIES. THESE TARIFFS ARE EVEN MORE CRITICAL AS WE ENTER COMPETITION, AND COSTS SHOULD BE BORNE BY THOSE WHO STAND TO BENEFIT FROM DG, NOT THROUGH RATES PAID FOR BY STANDARD OFFER OR DISTRIBUTION CUSTOMERS.)

The Customer will own and be responsible for designing, installing, operating and maintaining:

(a) The generating facility in accordance with the requirements of all applicable electric codes, laws and governmental agencies having jurisdiction.

(b) Any control and protective devices, in addition to protective relays and devices specified in this document, to protect its facilities from abnormal operating conditions such as, but not limited to, electric overloading, abnormal voltages, and fault currents.

(c) Interconnection facilities on the Customer's premises as may be required to deliver power from the Customer's generating facility to the utility system at the Point of Interconnection.

6.1 Insurance

Customers interconnecting a generator with a utility may be required to maintain public liability and property damage insurance.

6.2 Interconnect Agreement

All interconnected Customers are required to sign, in addition to any other special agreements as may be applicable, an Interconnect Agreement with the utility.

6.3 Electric Supply/Purchase Agreement

Customers purchasing energy from either the utility or an ESP, utilizing an interconnected DG system, will be required to sign an agreement for backup, supplemental and maintenance power from their energy supplier.

The Customer must also sign an agreement/tariff with the appropriate utility for movement of power over the utility's distribution grid and transmission system.

For a Customer who wishes to sell power to others, the customer will be required to:

1) Choose a utility tariff that allows for the movement of power over the utility distribution grid and transmission systems;

2) Sign an agreement with the purchaser of the electric power , and/or

3) Become an ESP and sell power to retail customers. The Customer may sell power to the Customer's UDC, other utilities, ESPs, or electric wholesalers. These entities may or may not be obligated to purchase this power and any such sales would be made under the terms and conditions offered by the purchaser.

All tariffs under this Purchase/Supply Agreement are subject to change by the utility and approval of the ACC.

6.4 Interconnections

The utility will not install or maintain any lines or equipment on a Customer's side of the Point of Interconnection, except it may install its meter. Only authorized utility employees may make

and energize the service connection between the utility system and the Customer's service entrance conductors.

Normally, the interconnection will be arranged to accept only one type of standard service at one Point of Interconnection. If a Customer's generating facility requires a special type of service, or if sales to the utility will be at a different voltage level, the services will only be provided according to additional specific terms that are outlined in the Electric Supply/Purchase Agreement, applicable rate schedules, or other terms and conditions governing the service.

6.5 Easements and Rights of Way

Where an easement or right of way is required to accommodate the interconnection, the Customer shall provide, or obtain from others and provide, suitable easements or rights of way, in the utility's name.

6.6 Meter Installations

The utility has metering requirements for a GF that may depend on the electric rate tariff selected by the Customer. The Customer will need to contact the utility, or the ESP or MSP if applicable, for design requirements and installation details.

7. DESIGN CONSIDERATIONS AND DEFINITION OF CLASSES

Protection requirements are influenced by the size and characteristics of the parallel generator along with the nature and operational characteristics of the associated the utility system. Therefore, similar units connected to different lines could have different protection requirements based on varying load conditions, as well as on utility feeder and transformer characteristics.

7.1 Synchronous Units

Synchronous generators are generally capable of supplying sustained current for faults on the utility system. These units can also supply isolated utility load providing the load is within the units' output capability, and must be prevented from energizing a de-energized utility line.

Automatic reclosing by the utility may be either time-delayed or may be instantaneous. The utility will specify the maximum allowable protective relay time settings for a particular proposed distributed generator installation. The Customer is responsible for ensuring generator separation prior to utility circuit re-energization to prevent out-of-sync paralleling.

7.2 Induction Units

Induction generators are basically induction motors that are mechanically driven above synchronous speed to produce electric power. These units do not have a separate excitation system and, as such, require that their output terminals be energized with AC voltage and supplied with reactive power to develop the magnetic flux. Induction generators are therefore normally not capable of supplying sustained fault current into faults on the utility system. Such units are generally not capable of supplying isolated load when separated from the utility system; however, it is possible for an induction generator to become self-excited if a sufficient amount of capacitance exists at its output terminals. Under conditions of self-excitation, an induction generator will be capable of supplying isolated load, providing the load is within the units' output capability. In most cases when self-excitation occurs it will be accompanied by a sudden increase in terminal voltage. The utility and its other customers must be protected from out-of-sync closing and over-voltages that can occur whenever an induction generator becomes self-excited. Induction units shall therefore be designed to automatically separate from the utility system upon loss of utility voltage and prior to reclosing of the utility feeder.

7.3 Static Inverters

Static inverters convert DC power to AC by means of electronic switching. Switching can be controlled by the AC voltage of the utility's supply system (line-commutated) or by internal electronic circuitry (forced-commutated). Line-commutated inverters are generally not capable of operating independently of the utility's AC supply system and, as such, cannot normally supply fault current or isolated loads. Forced-commutated, or self-commutated, inverters are capable of supplying fault current and load independently of the AC supply system. Any forced-commutated inverter that is to be interconnected with the utility must be specifically designed for that purpose, i.e. it must be designed to accommodate parallel interfacing and operation. Static inverters must be designed to automatically separate from the utility system upon loss of utility voltage and prior to reclosing of the utility feeder.

7.4 Definition of Generator Size Classes

The following generator size classifications are used in determining specific minimum protective requirements for distributed generation facilities. Specified ratings are for each connection to the utility system. Customers must satisfy, in addition to the general requirements specified in this document, the minimum relaying requirements given in this document for each generator class.

(a) Class I -- 50 kW or less, single or three phase
(b) Class II -- 51 kW to 300 kW, three phase
(c) Class III -- 301 kW to 5,000 kW, three phase
(d) Class IV -- over 5,000 kW, three phase

8. INTERCONNECTION TECHNICAL REQUIREMENTS

The requirements and specifications outlined in this section are applicable to distributed generation interconnected for parallel operation with the utility distribution system, unless otherwise specified. The protection and safety devices and other requirements specified in the following sections are intended to provide protection for the utility system, utility workers, other utility customers and the general public. They are not imposed to provide protection for the Customer's generation equipment or personnel; this is the sole responsibility of the Customer.

With respect to the above protection objectives, it is necessary to disconnect the parallel generator when trouble occurs. This is to:

(a) ensure if a fault on the utility system persists, the fault current supplied by the Customer's generator is interrupted;
(b) prevent the possibility of reclosing into an out-of-synch isolated system composed of the utility distribution system, or a section thereof, and the Customer's generator; and
(c) prevent reclosing into the Customer's generation system that may be out of synchronization or stalled.

The protection requirements are minimal for smaller installations, but increase as the size of the Customer's generation increases. Small installations usually ensure that the generator is small compared with the magnitude of any load with which it might be isolated. Thus, for any fault on the utility system, utility protective devices will operate and normally isolate the generation with a large amount of load, causing under-voltage automatic shutdown of the generator. For larger installations the probability of isolated operation is higher since the available generation may be sufficient to carry the entire load, or part thereof, of the local utility circuit. In instances where the utility system arrangement is such that it is possible that the generators will not always be isolated with comparatively large amounts of load, additional protection and generator shutdown schemes are required.

The Customer is solely responsible for the protection of his equipment from automatic reclosing by the utility. The utility normally applies automatic reclosing to overhead distribution circuits. When the utility source breaker trips, the Customer must ensure that his generator is disconnected from the utility circuit prior to automatic reclosure by the utility the automatic reclosing time on the utility distribution varies by utility, and from utility feeder to feeder. Automatic reclosing out-of-synch with the Customer's generator may cause severe damage to Customer equipment and could also pose a serious hazard to Customer or utility personnel.

8.1 General Technical Requirements

8.1.1 Customer is responsible for obtaining and maintaining all required permits and inspections indicating that Customer's generating facility complies with all applicable codes, ordinances and statutes relating to safety and construction.

8.1.2 Multiple generator connections on the same utility service are permitted; however, a single Disconnect Switch for the facility will generally be required (normally located at the service entrance section).

8.1.3 In the event that a generator, or aggregate of generators, are of sufficient size to carry the entire (minimum) load of the utility distribution feeder, or if a generator size and physical location on a feeder is such that it could support an isolated (islanded) section of the feeder, then a transfer trip scheme may be required at the Customer's expense. If a transfer trip is required, a communication channel and telemetering may also be required, at the Customer's expense, to facilitate proper parallel operation. In certain instances, a dedicated utility feeder may be required.

8.1.4 For synchronous generators, the Customer shall ensure that any potential open points such as breakers, fused disconnect switches, etc, located between the generator breaker and utility service are appropriately equipped with either (1) keyed or other suitable mechanical interlocks to prevent them from being inadvertently opened when the generator breaker is closed, or (2) contacts that will instantaneously trip the generator breaker if any such switch were opened while the generator breaker was closed.

The intent of the above is to prevent the opening and subsequent (inadvertent) re-closing of such a breaker or switch onto an un-synchronized generator.

8.1.5 Customer shall ensure that the design and installation of electric meter(s) is such that the meter(s) are located on the utility-side of the generator breaker on a normally energized bus. Electronic meters are not designed to be de-energized for any length of time.

8.1.6 The Customer is responsible for the design, installation, operation and maintenance of all equipment on the Customer's side of the Point of Interconnection. It is strongly recommended that the Customer submit specifications and detailed plans as specified in the Application and Equipment Information Form (refer to Appendix A) for the installation to the utility for review and written approval prior to ordering any equipment. Written approval by the utility does not indicate acceptance by other authorities.

8.2 Disconnect Switch

The Customer shall install and maintain a visible open, manually-operated load-break disconnect switch ("Disconnect Switch") capable of being locked in a visibly "open" position by a standard utility padlock that will completely open and isolate all ungrounded conductors of the Customer's generating facility from the utility system. For multi-phase systems, the switch shall be gang-operated.

The Disconnect Switch blades, jaws and the air-gap between them shall all be clearly visible when the switch is in the "open" position. It is not acceptable to have any of the "visible open" components obscured by the switch case or an arc-shield, etc. Only switches specifically designed to provide a true "visible open" are acceptable. Such Disconnect Switch shall be installed in a place so as to provide easy and unrestricted accessibility to utility personnel on a 24-hour basis. The utility shall have the right to lock open the Disconnect Switch without notice to the Customer when interconnected operation of the Customer's generating facility with the utility system could adversely affect the utility system or endanger life or property, or upon termination of the Interconnect Agreement.

The Disconnect Switch will normally be required to be installed at the Customer's electrical service entrance section; however it may be located in the immediate vicinity of the generator, subject to utility approval.

The Disconnect Switch must be rated for the voltage and current requirements of the generation facility, and must meet all applicable UL, ANSI and IEEE standards. The switch shall meet the requirements of the National Electric Code (NEC), and the switch enclosure shall be properly grounded.

In cases where the Disconnect Switch will be installed on a line at a voltage above 500V, the utility may have specific grounding requirements that will need to be incorporated into the Disconnect Switch. Under certain circumstances (above 500V, switch located outdoors and underground fed), the utility may require the customer to install a rack-out breaker, along with a racking tool and grounding breaker, in lieu of a Disconnect Switch. In these cases, the utility will work with the Customer to determine the best option and ensure that the safety requirements are met.

8.3 Dedicated Transformer

Customer generators with a combined total rating of over 10 kW, as measured at the service entrance, may be required to be isolated from other customers fed off the same utility transformer by a dedicated power transformer connecting to the utility distribution feeder. The primary purpose of the dedicated transformer is to ensure that (a) the generator cannot become isolated at the secondary voltage level with a small amount of other-customer load, and (b) the generator does not contribute any significant fault current to other customers' electrical systems. It also helps to confine any voltage fluctuation or harmonics produced by the generator to the Customer's own system. The utility will specify the transformer winding connections and any grounding requirements based on the specific customer site location.

8.4 Power Quality

Customer shall exercise reasonable care to assure that the electrical characteristics of its load and generating equipment will maintain the serving utility's normal power quality requirements. Any deviation from sine wave form or unusual short interval fluctuations in power demand or production shall not be such as to result in impairment of service to other customers or in interference with operation of computer, telephone, television or other communication systems or facilities. Those power quality items will generally include the following:

- Power Quality
- Current Imbalance
- Harmonics
- Voltage Flicker

Exhibit 1 lists for general informational purposes currently available requirements for APS, SRP, TEP and SSVEC, and may be updated from time to time. The Customer should verify actual requirements with the serving utility prior to designing/installing a GF.

(CERTAIN COMMITTEE MEMBERS RECOMMEND THAT THE ACC SHOULD ADOPT A STATEWIDE STANDARD FOR POWER QUALITY ISSUES MEASURED AT THE POINT OF INTERCONNECTION, AND APPLICABLE WHETHER OR NOT A GF IS INSTALLED ON THE CUSTOMER SITE. OTHER COMMITTEE MEMBERS FEEL THAT THIS CAN NOT BE READILY STANDARDIZED DUE TO DIFFERENCES IN UTILITY SYSTEM DESIGN AND OPERATION.)

8.5 Voltage Requirements

Customer generating equipment must deliver at the Point of Interconnection, 60 Hertz, either single or three-phase power at one standard utility voltage as may be selected by the Customer subject to availability at the premises.

8.6 Labeling Requirements

8.6.1 General Requirements

The Customer shall conform to the NEC for labeling of generation equipment, switches, breakers, etc. The utility will assume the responsibility for labeling any utility equipment.

8.6.2 Disconnect Switch

The Customer shall label the Disconnect Switch “Interconnected Generator Disconnect Switch” (or “Interconnected Photovoltaic Inverter Disconnect Switch, Interconnected Wind Turbine Disconnect Switch”, etc., as the case may be) by means of a permanently attached placard with clearly visible and permanent letters. In addition, the utility may need to attach its own label to the Disconnect Switch.

8.6.3 Service Entrance

A sign shall be placed at the service entrance indicating type and location of onsite emergency power sources, legally required standby power sources, and onsite optional standby power sources, as defined by the NEC.

The NEC also requires a permanent directory, denoting all electrical power sources on or in the premises, shall be installed at each service equipment location and at locations of all electric power production sources capable of being interconnected. Installations with large numbers of power production sources shall be permitted to be designated by groups.

8.7 Protective Requirements

8.7.1 General Requirements

8.7.1.1 The Customer shall be solely responsible for properly protecting and synchronizing his generator(s) with the utility system.

8.7.1.2 Customer facility shall include an automatic interrupting device that is listed with a nationally recognized testing laboratory, and is rated to interrupt available fault (short circuit) current. The interrupting device shall be tripped, as a minimum, by all protective devices required herein.

8.7.1.3 Inherent characteristics of induction disk type voltage and frequency relays render their use unsuitable for some generator interface protection applications. Therefore, devices with definite level and timing characteristics (e.g., solid state type relays) will be necessary to meet the requirements established herein.

8.7.1.4 For generator classes II and above (>50 kW), utilizing discreet relays, separate and independent voltage and frequency relays and associated trip paths to the generator breaker (automatic interrupting device) are required. This is to ensure a redundant trip function in the event of a single relay failure or out-of-tolerance condition. It is acceptable however, for the over/under voltage functions to be integrated into a single o/u voltage relay, and for the over/under frequency functions to be integral to a single
o/u frequency relay. Protective relays or microprocessor based devices may be used provided that the required functionality described herein is demonstrated.

8.7.1.5 For generator protective schemes that utilize microprocessor based, multi-function relays, one of the following requirements must be met:

(a) Protective relay failure will not only alarm but will also trip the generator breaker/contactor.

(b) If relay failure alarms, but does not trip the generator breaker, then additional relaying which meets the requirements stated herein for each class must be provided.

8.7.1.6 With the addition of generation at a Customer site, the ground fault current magnitude might increase to the level where the grounding grid is insufficient to protect personnel from step or touch potentials. Therefore, a study may be required to ensure the adequacy of the Customer's grounding grid to keep the step and touch potentials at a safe level.

8.7.1.7 The Customer shall ensure that the GF protective relaying and controls are adequately protected from electrical surges that may result from lightning, utility switching or electrical faults.

8.7.2 Generator Class Protective Requirements

8.7.2.1 Class I (Single or Three Phase: 50 kW or less)

1. The minimum protection required is an under-voltage contactor.

2. For all synchronous generators and forced commutated inverters, either a manual or automatic synchronizing scheme is required.

8.7.2.2 Class II (Three Phase: 51-300 kW)

1. Protection for overvoltage, undervoltage, overfrequency, and underfrequency is required.

2. For all synchronous generators and forced commutated inverters, either a manual or automatic synchronizing scheme is required.

3. For installations interconnected to the utility through a transformer with connections that will not supply current to a ground fault on the utility system, a special ground fault detection scheme may be necessary. The utility will advise Customer of any such requirements after a preliminary review of the Customer's proposed installation.

4. Other equipment such as supervisory control and alarms, telemetering and associated communications channel may be necessary. This is especially the case when (a) the generator, or an aggregate of generators is large relative to the minimum load on a feeder or sectionalized portion of the feeder, (b) the GF is involved in power transactions requiring the grid, or (c) the GF is remotely controlled by, or dispatched by the utility. The utility will advise Customer of any communications requirements after a preliminary review of the proposed installation.

8.7.2.3 Class III (Three Phase: 301-5,000 kW)

1. For this class of installation, utility grade protection devices and equipment will be required.

2. Protection for overvoltage, undervoltage, overfrequency, and underfrequency is required.

3. For all synchronous generators and forced commuted inverters, either a manual or automatic synchronizing scheme is required.

4. For installations interconnected to the utility through a transformer with connections that will not supply current to a ground fault on the utility system, a special ground fault detection scheme may be necessary. The utility will advise Customer of any such requirements after a preliminary review of the Customer's proposed installation.

5. Other equipment such as supervisory control and alarms, telemetering and associated communications channel may be necessary. This is especially the case when (a) the generator, or an aggregate of generators is large relative to the minimum load on a feeder or sectionalized portion of the feeder, (b) the GF is involved in power transactions requiring the grid, or (c) the GF is remotely controlled by, or dispatched by the utility. The utility will advise Customer of any communications requirements after a preliminary review of the proposed installation.

8.7.2.4 **Class IV (Three Phase: Greater than 5,000 kW)**

Note: Induction Generators or Line Commuted Inverters (LCI) in this size range are not anticipated.

1. For this class of installation, utility-grade protective devices and equipment will be required.

2. Protection for overvoltage, undervoltage, overfrequency, and underfrequency is required.

3. For all synchronous generators and forced commuted inverters, either a manual or automatic synchronizing scheme is required.

4. A ground time overcurrent and instantaneous overcurrent relay, or for installations interconnected to the utility through a transformer with connections that will not supply current to a ground fault on the utility system, a ground fault detection scheme is required.

5. The following relays are also required:

   (a) Voltage-controlled time overcurrent relays, one per phase
   (b) Negative sequence time overcurrent relay
   (c) Overexcitation relay
   (d) Loss of excitation relay

6. Other equipment such as supervisory control and alarms, telemetering, and associated communications channel may be necessary. This is especially the case when (a) the generator, or an aggregate of generators is large relative to the minimum load on a feeder or sectionalized portion of the feeder, (b) the

GF is involved in power transactions requiring the grid, or (c) the GF is remotely controlled by, or dispatched by the utility. The utility will advise Customer of any communications requirements after a preliminary review of the proposed installation.

The minimum protective relaying requirements for parallel operation of distributed generation are summarized in the following table:

Summary of Minimum Protective Relaying Requirements

	Induction Generator/ Line Commutated Inverter	Synchronous Generator/ Forced Commutated Inverter
Class I 50 kW or less	Undervoltage contactor	Undervoltage contactor Synchronizing
Class II 51 to 300 kW	Overvoltage, Undervoltage Overfrequency, Underfrequency	Overvoltage, Undervoltage Overfrequency, Underfrequency Synchronizing
Class III 301 to 5,000 kW	Overvoltage, Undervoltage Overfrequency, Underfrequency	Overvoltage, Undervoltage Overfrequency, Underfrequency Synchronizing
Class IV Greater than 5,000 kW	No induction generators of this size anticipated	Overvoltage, Undervoltage Overfrequency, Underfrequency Synchronizing Ground Time Overcurrent Ground Instantaneous Overcurrent Voltage-controlled Time Overcurrent Loss of Excitation Overexcitation Negative Sequence Time Overcurrent

8.7.3 Relay Settings

Voltage and frequency relays needed for minimum interface protection for all classes will have setting limits as specified by the serving utility. Exhibit 2 lists for general informational purposes currently available settings for APS, SRP, TEP and SSVEC, and may be updated from time to time. The Customer should verify with the serving utility prior to designing/installing a GF.

9. APPLICATION PROCESS AND DOCUMENTATION REQUIREMENTS

9.1 Utility approvals given pursuant to the review and approval process and the Interconnection Agreement shall not be construed as any warranty of representation to Customer or any third party regarding the safety, durability, reliability, performance or fitness of Customer's generation and service facilities, its control or protective device or the design, construction, installation or operation thereof.

9.2 The "Application and Equipment Information Form" (see Appendix A) must be completed by the Customer and all supplementary information requested therein must be provided to the utility for review.

The utility strongly encourages each Customer to contact and work closely with the utility at the conceptual stages of the design to ensure that the project proceeds smoothly. The utility will generally require a single point of contact with which to coordinate the interconnection process and a single utility point of contact will be provided to the Customer. Exhibit 3 lists for general informational purposes the typical steps required to interconnect a DG with a utility.

9.3 In the event it is necessary for the utility to install interconnection facilities on its system (including but not limited to control or protective devices, or any other facilities), in order to accommodate or protect the Customer's generation facility or utility equipment, the utility will inform the Customer of the cost and generally the Customer must reimburse the utility for the costs incurred by the utility to the extent they exceed those normally incurred by the utility for customers who do not have self generation facilities.

9.4 Following the utility's approval of the Customer's proposed generating facility and associated facilities, the Customer cannot remove, alter or otherwise modify or change the equipment specifications, including, without limitation, the operational plans, control and protective devices or settings, and the generating facility system design, type, size or configuration. If the Customer desires to make such changes or modifications, the Customer must revise and resubmit to the utility plans describing the changes or modifications for approval by the utility. No change or modification may be made without the prior written approval of the utility.

10. TESTING AND START-UP REQUIREMENTS

10.1 Following the utility approval of the Customer's interconnection equipment and protective devices as specified herein, the Customer shall, at a minimum, have all specified interface equipment, shutdown and associated protective devices field tested and calibrated at the time of installation by qualified personnel and shall also perform functional trip testing of these relays and associated generator or inverter breaker. Calibration shall include on-site testing of trip setpoints and timing characteristics of the protective functions as required herein. Functional testing must demonstrate that each protective relay or device trip function as required herein, upon a (simulated) out of tolerance input signal will trip the generator breaker, and shall also include a simulated loss of control power to demonstrate that the generator breaker or contactor will open.

A trip timing test (simulated loss of voltage) will suffice for static inverters rated 50kW or less.

10.2 The Customer shall provide the utility with a copy of calibration and functional test results. Customer must also notify the utility at least five working days in advance that such tests are to be performed and allow utility personnel to witness such tests and/or conduct additional startup tests if necessary.

10.3 The Customer shall be required to have a signed Interconnect Agreement with the utility, and will need to provide the utility with a copy of the insurance certificate, as applicable, prior to electrically paralleling the generating facility with the utility system.

10.4 The Customer shall not commence interconnected operation of its generating facility until the installation has been inspected by an authorized utility representative and final written approval is received from the utility to commence interconnected operation, which approval shall not be unreasonably withheld. The Customer shall give the utility at least five working days notice as to when initial startup is to begin. The utility will have the right to have a representative present during initial energizing and testing of the Customer's system.

10.5 The Customer shall have all protective devices tested by qualified test personnel at the time of installation, prior to initial interconnection, and at intervals not to exceed four years. The Customer shall (i) notify the utility as to when such tests are to be performed at least five working days prior to such tests and allow the utility personnel to witness the testing, and (ii) provide the utility with a certified copy of the test results.

11. OPERATIONAL AND MAINTENANCE REQUIREMENTS

11.1 The Customer shall be responsible for operating and maintaining the generator facility in accordance with the requirements of all applicable safety and electrical codes, laws and governmental agencies having jurisdiction.

11.2 The Customer shall protect, operate and maintain the generating facility in accordance with those practices and methods, as they are changed from time-to-time, that are commonly used in prudent engineering practice and shall operate and maintain the generating facility lawfully in a safe manner and non-hazardous condition.

11.3 In the event the utility or its authorized agents lock open the Disconnect Switch, the Customer shall not remove or tamper with such lock.

11.4 The utility (including its employees, agents and representatives) shall have the right to enter the Customer's premises to (a) inspect the Customer's generating facility, protective devices, and to read or test instrumentation equipment that the utility may install, provided that as reasonably as possible, notice is given to the Customer prior to entering its premises; (b) maintain or repair the utility equipment; (c) disconnect the generating facility without notice if, in the utility's opinion, a hazardous condition exists and such immediate action is necessary to protect persons, the utility facilities or other customers' or third parties' property and facilities from damage or interference caused by the Customer's generating facility, or improperly operating protective devices; (d) open the Disconnect Switch without notice if an operating clearance or hold tag is required by utility personnel.

11.5 Following the release of a utility clearance or hold tag, where it was necessary for the utility to open the Disconnect Switch, utility personnel will not normally re-close the switch. It will normally be the Customer's responsibility to re-close the switch after ensuring that all generation sources that could potentially be energizing the Customer's side of the switch are off, so as to eliminate any possibility of re-closing the utility grid onto an out-of-sync generator.

However, utility personnel may, without liability, re-close the Disconnect Switch provided that (a) Customer requests, and agrees to allow, the utility to re-close the switch, following the release of a utility clearance or hold tag, and (b) there are means provided to conveniently allow utility personnel to verify that the Customer side of the Disconnect Switch is not energized.

11.6 Upon termination of the Interconnect Agreement, the Customer shall be responsible for ensuring that the Disconnect Switch is immediately opened, and that the electric conductors connecting the Customer's generator(s) to the Disconnect Switch are physically removed, so as to preclude any possibility of inadvertent interconnected operation in the future. The utility reserves the right to inspect the Customer's facility to verify that the generator is appropriately disconnected.

APPENDIX A

APPLICATION AND EQUIPMENT INFORMATION FORM

SITE AND CUSTOMER INFORMATION
(Complete all items)

Customer Name ______________________________ Telephone ____________________

Company Name (if applicable) ____

Mailing Address ____

Generating Facility Address ____

Project Contact ______________________________ Telephone ____________________

Utility Account Number ________________________ Electric Meter No. ____________

ESP (if different from serving utility) _______________________________________

MSP (if different from serving utility) ______________________________________

Completed By ______________________________ Telephone ____________________

PROPOSED OPERATION
(Answer all questions)

A. Is the Generation Facility a Qualifying Facility (QF) as defined in the Definitions section of the document? (Yes or No) _________.

B. Does the Generation Facility plan on being a net exporter of energy into the utility grid? (Yes or No)_____. If "Yes", explain the proposed operation and estimated power to be exported, and also provide name of proposed purchaser of this power:

____

____

C. If the Generating Facility will be used only to displace utility power, will it be operated as a peak-shaving or base-loaded unit?

____

____

____

GENERATOR INFORMATION
(Complete for each rotating generator only)

A. Manufacturer ______________________________

B. Type (Synchronous, Induction, D.C.) ______________________________

C. Nameplate rating
Voltage ______________ kW ______________
Power Factor ______________ Frequency ______________
Model No. ______________ Single or Three Phase______________

D. Type of Excitation System (Self or Separate)______________________________

E. Generator Electrical Characteristics (on the machine base, for Class II and above)

Synchronous Reactance (X'd)______________________________
Transient Reactance (X'd) ______________________________
Subtransient Reactance (X"d) ______________________________
Zero sequence reactance (XO) ______________________________
Negative sequence reactance (X2) ______________________________

PRIME MOVER
(Complete for rotating machinery only)

A. Manufacturer ______________________________
B. Manufacturer's Reference Number ______________________________
C. Energy Source (Natural Gas, Steam, etc.) ______________________________

INTERFACE EQUIPMENT
(Complete for each rotating generator only)

A. Synchronizer for Synchronous Generator:
Manufacturer ______________________________
Manufacturer's Model Number ______________________________
Automatic or Manual Synchronizer ______________________________

B. Inverter for DC generator:
Manufacturer ______________________________
Manufacturer's Model Number ______________________________
Line or Self Commutated Inverter ______________________________

STATIC INVERTER
(Complete for DC to AC Inverters only)

A. Manufacturer ______________________ Model No. ______________________
B. Terminal Voltage ______________________ Single, Split or Three Phase ___________
C. Nameplate kW ______________________ No. of Units ______________________
D. Frequency ______________________ Power Factor ______________________
E. Line or Self Commutated ______________________ Battery Back Up? ______________________
F. Total System kW Output ______________________
G. Energy or Fuel Source ______________________

PROTECTION EQUIPMENT
(Complete all applicable items, attach a separate sheet if necessary)

A. Manufacturer's Name for each Protective Device ______________________

____

____

B. Manufacturer's Model Number for each Protective Device ______________________

____

____

C. Range of Available Settings for each Protective Device ______________________

____

____

D. Proposed Settings (trip setpoint and time) for each Protective Device ______________________

____

____

E. Ratios of associated current transformer. If multi-ratio, state the available ratios and which ratio will be used ______________________

____

F. Describe operation for tripping of the interface or generator circuit breaker for both

1. Utility outage ______________________

   ____

   ____

2. Utility short circuit (three phase and single phase to ground) ______________________

   ____

   ____

SUPPLEMENTARY INFORMATION
(Information below to be submitted for all projects. All diagrams are to be professionally and neatly drawn. Generally, free hand drawn or illegible diagrams will not be accepted by utility).

A. Electrical One-Line Diagram:
Provide 5 sets, including any and all revisions or changes as they are made. Diagram(s) must also include project name and address, show generator size and all protective relaying and control equipment, as well as electric service entrance and utility meter.

B. Electrical Three-Line Diagram:
Provide 5 sets, including any and all revisions or changes as they are made. Diagram(s) must also include project name and address, show generator size and all protective relaying and control equipment, as well as electric service entrance and utility meter, and include all neutral and ground conductors and connections.

C. AC & DC Control Schematics:
Provide 5 sets, including any and all revisions or changes as they are made, for all projects comprising rotating machinery. Diagrams must show the detailed wiring of all protective relays and control functions, and include control power source and wiring.

D. Detailed Map:
Provide 5 sets of detailed maps, including any and all revisions or changes as they are made. Maps should show major cross streets and proposed plant location, and include the street address.

E. Site Plan:
Provide 5 sets of site plans, including any and all revisions as they are made, showing the arrangement of the major equipment, including the electric service entrance section and utility meter, location of generator and interface equipment, and location of the Disconnect Switch. Include the street address, and location of the any lock-boxes, etc.

F. Testing Company:
Provide the name of the company that will do the protective relay bench testing and the trip circuit functional tests and the anticipated start up date.

G. Point of Contact
If the interconnection and start-up process is to be coordinated through a party or individual other than the Customer, provide the name, company, address and phone number of that individual or party with whom the utility is to coordinate the interconnection.

EXHIBIT 1

LOAD CHARACTERISTICS FOR ARIZONA UTILITIES LAST UPDATE NOVEMBER, 1999

SETTING TYPE	APS	SRP	TEP	SSVEC
Power Factor [1]	90% lag 0% lead	85% lag to 90% lead	No Penalties	90% lag 90% lead
Phase Current Imbalance	10%	5%	[3]	10%
Voltage Characteristics	ANSI C84.1	[2]	ANSI C84.1	ANSI C84.1
Sine Wave Form	IEEE 519	[2]	IEEE 519	IEEE 519
Harmonics	IEEE 519 [2]	IEEE 519 [2]	IEEE 519 [2]	IEEE 519 [2]
Voltage Flicker	IEEE 519 [3]	IEEE 519 [3]	IEEE 519 [3]	IEEE 519 [3]

Notes:

[1] Provision to substitute kVA for kW in rates but not generally applied.

[2] Load characteristics shall not impair service to other customers.

[3] Need to consult utility.

EXHIBIT 2

UTILITY RELAY SETTINGS AND RE-CLOSING PRACTICES LAST UPDATE NOVEMBER, 1999

SETTING TYPE	APS	SRP	TEP	SSVEC
Over-frequency Time delay	62 Hertz 1 Second	[1]	61.1 Hz 0.1 Seconds	60.5 Hz 0.1 Seconds
Under-frequency Time delay [2]	58 Hertz 1 Second	[1]	58.9 Hz 0.1 Seconds	59.5 Hz 0.1 Seconds
Over-voltage Time Delay	120% 1 Second	120% 0 Seconds	105% 0 Seconds	110% 1 Seconds
Under-voltage Time Delay	80% 1 Second	90% [3]	95% 0 Seconds	90% 1 Second
Re-closing, first shot [4]	2 or 5 Seconds	Instantaneous	Instantaneous	1 to 2 Seconds [6]
Re-closing, second shot [4]	2 or 5 Seconds	15 Seconds	15 to 30 Seconds [5]	1 to 2 Seconds
Re-closing, third shot [4]	5 Seconds		165 Seconds	1 to 5 Seconds
Re-closing, fourth shot [4]	5 Seconds			

Notes:

[1] Guidelines do not specify a setting or time delay; they say "trip the circuit breaker when the frequency varies from the nominal 60 Hz."

[2] If generator is considered a WSCC generator, the under-frequency setting might be different to comply with WSCC guidelines.

[3] Per SRP guidelines, "Set the time delay (typically 3 to 5 seconds at zero voltage) to allow for motor starting and to coordinate with line protection devices."

[4] Times are for typical overhead/residential type feeders (not necessarily line reclosers), and are the time delay from the trip to the next reclosure. Actual number of re-close shots on a particular feeder may vary.

[5] Varies based on type of reclosing utilized.

[6] Reclosing on first shot transmission, and hence distribution, is instantaneous.

EXHIBIT 3

DG APPLICATION PROCESS

Step 1 – Customer contacts Utility for interconnection information package and outlines proposed project. Utility forwards appropriate information to Customer within five (5) working days and provides a Utility contact name and number should Customer decide to proceed with project.

Step 2 – (OPTIONAL STEP) If Customer decides to proceed with project, Customer is strongly encouraged to contact Utility at conceptual stage of project and discuss proposed installation/design options with the Utility. Customer is encouraged to meet with Utility and discuss the type and size of system, location and proposed operation. A preliminary electrical one-line diagram would be very helpful at this stage. This step will help ensure that :

1. The project proceeds smoothly and in a timely fashion helping to mitigate any surprises later on.
2. It will help the Utility determine upfront if any special studies may be required, which could be initiated as early on as possible.
3. Applicable interconnect and protective requirements are properly understood and implemented.

(REGARDING POINT 3 ABOVE, PERHAPS A REVIEW OF THE STATEWIDE INTERCONNECT STANDARDS AS APPLICABLE TO THE SUBJECT PROJECT WOULD BE APPROPRIATE AT THIS POINT.)

Step 3 – Customer proceeds with design and prepares the utility-required information – application form, electrical diagrams, protective relaying and settings, site equipment and layout plans, etc. It is strongly suggested, especially on large projects (above 50 kW) that these be submitted/discussed, normally on an informal basis, with the Utility as they are developed, so the Utility can make any comments or recommendations as early on in the design process as possible – this is normally an interactive and iterative process, at which point Customer may need to submit data to the Utility if any special studies are required, and Utility may also need to submit fault/coordination information to Customer as required.

(ALTHOUGH IT IS UNDERSTOOD THAT THE WORDS "INFORMAL BASIS" ARE USED TO RECOGNIZE THAT THE ITERATIVE PROCESS WILL BE MOST PRODUCTIVE, THE PRACTICES OF INSTITUTIONAL CUSTOMERS ALSO NEED CONSIDERATION. MOST OF THESE CUSTOMERS UNDERTAKE FREQUENT DESIGN, PROCUREMENT, AND CONSTRUCTION PROJECTS. MILESTONES FOR REVIEW SUBMITTALS ARE TYPICALLY IDENTIFIED ON EACH PROJECT TIMELINE. PLEASE EMPHASIZE THAT THE DISTRIBUTION COMPANY REPRESENTATIVE SHALL BE INCLUDED IN ANY SCHEDULED REVIEW SUBMITTALS. FORGETTING TO GET OUTSIDE CONTACTS IN THE LOOP IS A VERY COMMON AND OFTEN FATAL FLAW FOR INSTITUTIONAL PROJECT MANAGERS AND SHOULD NOT BE TOLERATED HERE.

THE UTILITY WILL NEED TO SUBMIT FAULT CURRENT AND COORDINATION REQUIREMENTS BEFORE THE CUSTOMER CAN PROCEED WITH DESIGN DEVELOPMENT. PERHAPS AT THE TAIL END OF THE CONCEPTUAL PHASE IF THE PROJECT IS TO PROCEED, OR AT THE LATEST AT THE VERY BEGINNING OF DESIGN DEVELOPMENT.)

Due to the diverse nature of projects, timeframes may need to be worked out between the Customer and the Utility, especially if special studies are required.

Step 4 – Upon completion of the design, the Customer submits the final design package (as specified in the Application Form of the Interconnect Requirements manual) to the Utility for final review and approval. Customer notifies Utility interconnection contact that information has been submitted, and Utility reviews information and informs Customer within ten (10) working days of receipt as to sufficiency of information and whether any information is missing.

Step 5 – Upon receipt of completed and sufficient application information, Utility reviews the application for conformance to the interconnect requirements within twenty (20) working days, unless other timeframes are mutually agreed upon.Utility will respond to Customer within this time as to whether the submitted design information complies with the interconnect requirements or if there are any issues in non-compliance. (In the event of non-compliance, Customer will re-submit corrected information and Step 5 will be re-initiated).

Step 6 – Upon Customer receiving approval of the Utility for the design, construction of the facility commences, and the Utility prepares the required interconnection agreements and site checklist. **(SUGGEST ALLOWING THE CUSTOMER TO PREVIEW A SAMPLE SITE CHECKLIST DURING STEP 2 CONCEPTUAL PHASE ABOVE, PERHAPS WHEN THE INTERCONNECT STANDARDS ARE REVIEWED.)** Customer notifies Utility as to anticipated startup/testing date.

Step 7 – Utility forwards completed interconnection documents/agreements to Customer for signature prior to anticipated startup date given in Step 6 above.

Step 8 – Following construction/installation of the facility, Customer provides the Utility with at least ten (10) working days notice as to when the Utility can perform the site inspection and when the protective device tests, as applicable are to be performed so that the Utility may witness and/or review them.

Step 9 – Upon satisfactory completion of the site inspection, protective relay testing, and signed interconnect documents, Utility notifies Customer in writing within two (2) working days that the facility may be operated in parallel with the Utility grid per the agreed terms and conditions.

(SEVERAL UTILITIES HAVE EXPRESSED THAT THEY ARE NOT IN AGREEMENT WITH THE TIME LIMITS IMPOSED IN THE STEPS ABOVE. SOME UTILITIES DO NOT HAVE THE ENGINEERING STAFF ON HAND TO MEET THE ABOVE TIMELINES. OTHER COMMITTEE MEMBERS BELIEVE THIS SHOULD BE AN INTERACTIVE AND ITERATIVE PROCESS TO ENSURE THAT PROJECTS PROCEED SMOOTHLY.)

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Template:	H:\MSOFFICE\TEMPLATE\NORMAL.DOT
Title:	Arizona State
Subject:	
Author:	APS
Keywords:	
Comments:	
Creation Date:	12/02/99 09:24
Change Number:	6
Last Saved On:	12/02/99 15:07
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