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Arizona Corporation Commission
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DEC 28 1999

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From: "DeCorse, Chuck" <CDecorse@TucsonElectric.Com>
To: "Jerry Smith (E-mail)" <jsmith@cc.state.az.us>
Date: 12/22/99 7:45pm
Subject: TEP Comments to ACC Interconnection.

Jerry:
I am submitting the following comments.

Thanks,
Chuck

<<Comments to Interconnection.doc>>

Tucson Electric Power
(520) 745-3251

CC: "Bill Murphy (E-mail)" <bmurphy1@ci.phoenix.az.us>

Tucson Electric Power Company
P.O. Box 711, Tucson, AZ 85702
3950 East Irvington Road
Tucson, Arizona 85714

Charles F DeCorse, PE, CEM
Senior Electrical Engineer
Technical Advisor Group (SC110)

520-745-3251
Fax: 520-571-4014
E Mail: cdecorse@tucsonelectric.com

December 22, 1999

Jerry Smith
Utilities Engineer
Arizona Corporation Commission
1200 W Washington
Phoenix, AZ 85007
Dear Mr Smith

Tucson Electric Power has reviewed the three ACC Interconnection committee standards. I am addressing the Interconnection Standards only and referring the other two committees to others in TEP.

There were several issues that were not covered adequately in the process due to time constraints or hard line positions taken by committee members. The key issues were connection to networks, power quality standards, financial responsibilities, and agreement on which standards are acceptable technically.

Manufacturers are attempting to have the state of Arizona accept testing standards they have had on their equipment but have not provided these standards to the committees. Standards such as ETL and some UL standards were discussed but there was not any information provided on what these standards were, dispite requests of the committee members. These standards should be provided prior to accepting equipment that is to paralleled to the grid.

On the subject of networked systems, there seems to be a great deal of concern with the safety of workers. There were technical issues but I believe these issues can be resolved. However when there is a safety concern, networked systems should not be allowed to have DG until these issues have been resolved to the satisfaction of concerned parties. For example, Texas may have dealt with networked systems but Texas also believes natural gas is a renewable resource. We should not do what other states are doing just because it's done somewhere else. If there are seminars to be conducted, I would like to have input from utilities who may have trouble implementing DG in networks.

The financial issue remains a debatable topic. Whenever a DG unit is installed on the system, it is for the benefit of the customer. This is the only reason the DG is installed, not for the benefit of the others on the grid. These reasons for installing DG is power quality or reducing bills of the customer. The resulting load flow to the grid is probably negligible and would probably cause potential for more harm than benefits. There has been a suggestion that DG would provide voltage support but if the DG is lost and the utility is depending on this voltage support, other customers may be impacted. Voltage could drop to a low enough value to burn up motors. Who would be responsible for this? If the DG customer is agreeable to accepting responsibility, there is not issue. The voltage support argument is weak. If there is validity to this argument, the DG provider should prove this to the utility. This should be the "cost of doing business". However, there should be support from the utilities to do this study. Phrases such as "new technology", or "new way of doing business", or "deregulation" should not change all rules and force utilities to pay for upgrades to feeders because of DG installations. These costs should be negotiated.

There were two vital missing links on the committees. One was representatives of building inspectors and inverter manufacturers. Although efforts were made to have these areas attend there was no attendence.

One of the problems we have experienced at TEP is installation of microturbines without knowledge of TEP. These systems were installed and paralleled to the grid. There must be some accountability and course of action if this practice continues. Safety and system integrity are risked due to these installations. Arizona Public Service, Salt River Project, Tucson Electric Power, and SSVEC are all willing to work with DG customers and installers. However this must be a two way street. Already there are two sides building up. As a utility we want to avoid this.

As final comments TEP, from a systems standpoint has the following concerns:

1.) Will the DG/QF coordinate with the Southern Island Off Nominal Frequency Plan ? How will compliance be monitored ?
2.) In parallel operations how will the UDC know how much load it will have to pick up ?, How will the UDC be updated as load is increased ?
3.) Should UDC facilities need to be upgraded to back up the DG/QF how will this be handled ?
4.) Are there provisions for 7x24 communications?
5.) The DG/QF should be required to operate at unity or be assessed a penalty

Distributed Generation will become a part of the grid. This is not an opinion but a fact. Utilities are aware of this fact and have accepted this. However it should be done in an orderly fashion. The system grid has been in existence and maintained by the utilities. That's where experience lies and this too is a fact.

In conclusion I recommend that the oversite committee consist of 1/3 utility representatives, 1/3 from manufacturers, and 1/3 from other sectors. The "other sector" should consist of any other areas who can contribute meaningfully to the document(s). There should not be a conflict with the IEEE standard that will be implemented.

Thank you for the opportunity to work with this committee.

Charles F DeCorse, PE, CEM
Senior Electrical Engineer.

Arizona Utility
Investors Association

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O. Smith

BEFORE THE ARIZONA CORPORATION COMMISSION

CARL J. KUNASEK
CHAIRMAN
JAMES M. IRVIN
COMMISSIONER
WILLIAM A. MUNDELL
COMMISSIONER

IN THE MATTER OF THE RECOMMENDATIONS OF THE DISTRIBUTED GENERATION AND INTERCONNECTIONS WORKGROUP.) DOCKET NO. E-00000A-99-0431

COMMENTS
OF THE ARIZONA UTILITY INVESTORS ASSOCIATION
ON THE REPORT OF THE ACCESS, METERING AND
DISPATCH (AMD) COMMITTEE OF THE DGI WORKGROUP

1. Introduction

The Arizona Utility Investors Association (AUIA) has been a participant in the deliberations of the above-referenced AMD Committee. In general, the Committee's report is a sincere attempt to delineate the issues that will confront the Commission if it institutes rulemaking on the subject of distributed generation (DG).

AUIA has no philosophical objection to distributed generation, but AUIA believes that the AMD report understates the difficulties the Commission may encounter in enabling some applications of distributed generation in the context of electric competition.

DG proponents have expressed the view that it is a natural outgrowth or follow-on to retail electric competition. However, a careful reading of the AMD report discloses that DG may clash directly with ACC competition rules and FERC equal access directives, create cost shifting among electricity users and cause revenue deficiencies for utilities that are now locked into future rate treatments under Commission orders.

2. DG issues

The potential for conflict is relatively less for stand-alone self-generators that are disconnected from the electric grid. The key issues raised by unconnected generators are revenue deficiencies for the utility distribution companies (UDCs) and resultant cost shifting.

The UDCs and their distribution systems continue to be regulated as public service corporations and are authorized to earn specific rates of return. As a matter of first impression, any loss of load to self-generation would reduce the revenue stream required to support the operation of the distribution system. Since a utility can't shrink its distribution system or shut it down, the lost revenue must be shifted to other users as an added cost.

Further, Arizona Public Service Co. (APS) and Tucson Electric Power (TEP) are committed to continuing rate reductions by the terms of their stranded cost and unbundled tariff settlements and they are prevented from filing new rate cases for several years.

Thus, other users eventually will have to absorb the loss of revenues to DG, but in the short term, utility shareholders will suffer a lowered rate of return and the UDCs may experience a higher cost of capital. This is the worst of all worlds for everyone except the DG provider and user.

Comments within the AMD report equate these potential revenue deficiencies with the stranded costs associated with competitive generation. The Commission should not accept that proposition.

Power generation was declared competitive en masse, creating the need for a temporary fix to simulate the recovery of fixed costs and regulatory assets which would go unrecovered in a competitive market. It should be noted that self-generators are purposely exempted by Commission rules from any requirement to contribute to a utility's recovery of fixed costs related to generation.

The regulated distribution system is a different matter. It must continue to operate reliably and serve the vast majority of electric customers. In addition, the UDC deserves the opportunity to earn its authorized rate of return irrespective of the impact of distributed generation.

In other words, revenue shortfalls that may result from DG cannot be stranded. They can only be shifted among users.

The same revenue issues may or may not occur with DG units that are connected to the grid, depending on the applications. But, other potential problems increase significantly when the DG application is designed to interact with the distribution and transmission systems. A partial list of such problems would include these:

- A DG unit that is connected to the grid for back-up or peaking purposes places the same requirement on the distribution system as if it were using it every hour. It has to pay its way, even if it isn't consuming kWh. Some sort of facility-based demand distribution rate might be appropriate, but that would necessitate revamping UDC tariffs completely.

- Except for stand-alone self-generation, the ACC electric competition rules do not distinguish among types of commercial generators. Therefore, any generator that wants to market its output must be a certificated electric service provider (ESP) or it must sell its output to an ESP.

- Some combination of "wheeling" and access charges will be an issue for DG providers who want to move excess power across the grid, even to their own affiliates. In particular, this would arise when they cross service area boundaries into territory that isn't under Commission jurisdiction.

- Where energy movement is concerned, the laws of physics don't distinguish between the distribution and transmission systems. Therefore, DG operators who want to wheel power would be subject to the rules of the transmission operators and would have to function through Scheduling Coordinators.

- Although it is less than certain, the above condition and others may place off-site DG transactions under the jurisdiction of the Federal Energy Regulatory Commission (FERC) and its direct access regulations.
- Uner the equal access dictates of this Commission and FERC, there is no basis for owners of DG units to make special deals that would give them guaranteed access to the grid ahead of other commercial generators.
- The economics of some DG applications may require a sell-back to the UDC. Such negotiated sales apparently would conflict with Commission requirements that UDCs acquire power supplies in the open market and with prohibitions against UDCs engaging in competitive activities.

3. Summary and Recommendation

The Corporation Commission is only now finishing an excruciating, five-year process of bringing retail competition to the electric industry. The dust hasn't settled on the new competition rules.

While distributed generation may offer intriguing opportunities to an elite group of electric customers, the Commission would have to rewrite or reinterpret the competition rules and reconfigure UDC tariffs to accommodate the complete array of DG applications.

AUIA recommends that the Commission proceed cautiously in opening the market to distributed generation. Some DG applications are feasible under current conditions, but those that require extensive rules support should be held in abeyance, at least until there is some experience with retail competition.

Even the simplest DG application raises the issue of cost shifting. In our view, the Commission should begin exploring the pros and cons of shifting from distribution rates based on consumption to some kind of demand rate applicable to partial or intermittent requirements.

This concludes AUIA's comments.

RESPECTFULLY SUBMITTED,
this 22nd day of December ,1999.

Walter W. Meek

WALTER W. MEEK, PRESIDENT

CERTIFICATE OF SERVICE

Original and ten (10) copies of the referenced Comments were filed this 22nd day of December, 1999, with:

Docket Control
Arizona Corporation Commission
1200 W. Washington Street
Phoenix, AZ 85007

Copies of the referenced Comments were hand-delivered this 22nd day of December, 1999, to:

Deborah Scott, Utilities Division
Jerry Smith, Utilities Division
Arizona Corporation Commission
1200 W. Washington
Phoenix, AZ 85007

Copies of the referenced Comments were mailed electronically this 22nd day of December, 1999, to AMD Committee members of record.

Walter W. Meek

WALTER W. MEEK

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From: "David Townley" <dtownley@newenergy.com>
To: CC.UTIL(jsmith)
Date: 12/22/99 5:10pm
Subject: David Townley (New Energy) Comments on the DG Committee Reports

Jerry,
Here are my comments on the DG Committee Reports and Workshop observations.
Thank-you for the opportunity to comment.

Have a Happy Holiday and Prosperous New Year.

David Townley

Chuck Miessner: If we need to get a hard copy to Jerry, would you print and deliver a copy on "official" letterhead?

CC: CC.SMTP("BGERNET@apsc.com","cdecorse@tucsonelectri...

newenergy

December 22, 1999

Jerry Smith, P.E.
Utilities Engineer
Utilities Division
Arizona Corporation Commission
1200 West Washington
Phoenix, AZ 85007

SUBJECT: Comments on the Final DG Committee Reports

Dear Mr. Smith:

After participating actively in the Interconnection Requirements Subcommittee and after reviewing the published reports of the other two Subcommittees, I make the following general observations:

- The new role of the UDC as a distribution service provider has not yet permeated the positions as articulated in the Subcommittee Reports. The implication of this new role should be made clearer by the ACC. Customers have equal access to the distribution system for power transactions regardless of the direction of power flow to the Customer. The UDC's role is to facilitate those power flows (transactions) efficiently, reliably, and at reasonable cost.
- The prevailing position/bias in the subcommittee discussions (and reflected in the Interconnection Requirements Subcommittee) is that a Distributed Generation (DG) Customer regardless of whether a partial requirements customer or an exporter has different rights to the distribution system than does a Customer who has no on-site generation. This bias is reflected in the process for interconnection, and language on which costs are borne by whom. Generally in the Subcommittee Reports, the DG Customer is assumed to bear all direct costs for siting reviews and system changes/upgrades (in spite of any positive distribution impacts or savings). Meanwhile the Customer who does not have site generation will have operational reviews, system changes and upgrades made at no cost to the Customer. This is a hold-over from the era of the vertically integrated utility and the reaction to Federally mandated interconnections. The utility resistance, barriers, and cost positioning regarding on-site generation from that era are still embedded in the processes, tariffs, and culture of today's UDC. These biases will require a recognition of their existence by the UDC and the ACC and an active review of the positive role of DG in the evolution of providing competitive, reliable, and low-cost power for end-users.
- As described in the Access, Metering, and Dispatch Subcommittee, even the system planning process <u>explicitly</u> ignores the positive impacts of DG by removing all DG from the system and then building the system – including reserves—to serve the load AS THOUGH NO DG IS PRESENT including power factor effects. This is just not the way to plan a system, but it is a way to erect a barrier to DG <u>especially</u> when the tariff would then reflect that the <u>DG Customer</u> (not all Customers) must bear the additional costs of the reserve capacity (A,M,&D

Subcommittee Report II.F.4.b.2 and II.F.4.c.3). This is NOT equal access to the distribution system and is a refusal to support/recognize the positive benefits of DG.

- No mention was made of the "Standard Interconnection Contract". This document is important in reducing the transaction cost for both parties to the Interconnection Agreement. The 3 page document recently approved by the Texas PUC for use throughout Texas is recommended for your review and approval.
- Significant penetration of DG into the distribution system will require revised operational and planning procedures, revised maintenance and restoration procedures, and will invite new technologies/tools for monitoring and controlling the distribution system and the Customer interfaces connected with it. This will be an evolution of the distribution system toward providing a system more adept and efficient at facilitating power transactions regardless of the direction of the power flow.

Following are some specific comments

- In the Siting, Certification, & Permitting Committee Report, Location Matching, Mapping, page 9, there is reference to the fact that some UDCs consider DG installation on their distribution systems to be proprietary. Given the comments about multiple units on a feeder line being a reason for rejecting the application, the potential DG owner should be able to ascertain whether they have been precluded from interconnecting before proceeding to conceptually plan site generation and interconnection to a particular feeder. ACC Staff is asked to review this question considering the needs of both the Customer and the UDC.
- As part of the Siting process, the UDC should make public its review of its distribution planning conclusions regarding constrained areas that could benefit from load management/curtailment to defer construction or upgrading of distribution facilities. The UDC could benefit by the market's response to the UDC need, especially if there is a tariff that provided an incentive (e.g. a curtailable tariff).
- The general comments above cover the reaction to the general tone of the Access, Metering, & Dispatch (A,M,&D) Subcommittee Report. The Section on the UDC Potential Planning Remedies most clearly show the over-hanging bias against recognizing and benefiting from DG use by the distribution Customer.
- Although only briefly referred to in the A,M,&D Report, the UDC should be required to "unbundle" its distribution costs from its generation and retail costs. The "bundled" Customer should not benefit from imbedded generation sources at the expense of the direct access customers that get their generation for the market. The UDC should be required to procure its generation from the market also, immediately.
- SRP should be encouraged to develop a tariff or rider for a partial requirement service for residential and small commercial customers.
- A curtailable/interruptable (non-firm) distribution tariff should be encouraged for all classes of customers.
- I refer to other comments made by Chuck Miessner on behalf of New Energy.
- At numerous points in the Interconnection Requirements Report the document states that the "cost shall be borne by the Customer". Per the comments in the general statements above, these statements are a hold-over from a different regulatory period and, in fact, are NOT part of the technical requirements for interconnection. Further attention should be given by the ACC in balancing the costs and benefits for the distribution system vs penalizing the DG Customer relative to the non-DG Customer.

- I recommend that the ACC accept the advice to hold a workshop with other experts to review the solutions for interconnecting DG within secondary networked systems. This approach had some benefit as Texas found and it would be helpful to the Arizona process.
- Technology is evolving and will continue to develop. These changes will require that the interconnection requirements be reviewed from time to time to upgrade the language or reference to accommodate new technology. The intent with the Interconnection Subcommittee document was to spell out the functional requirement but we were not always successful. One example is the "visible" disconnect switch. The functional requirement would be to provide a method to assure that the unit is disconnected from the grid. That requirement was translated into a specific technology today ("visible" disconnect switch) but as technology evolves (especially solid-state switches and communications), that verification could be electronic. Along with revisions to the maintenance procedures (allowing for isolating two way flows) the new technology could be incorporated safely and efficiently.
- An efficient dispute resolution process would still be helpful as we move forward in this process.
- Acceptable field testing procedures to demonstrate functionality for the new solid-state and integrated interconnection protection equipment needs to be developed. Manufacturers could be very helpful for this effort.
- More work needs to be done on the "pre-certification" of DG equipment so that can it can be installed more rapidly at a particular site after confirming through field/start-up testing that the protection equipment is functioning properly.

Thank you for the opportunity to comment on the Reports. I want to express appreciation to the ACC for moving quickly on this important opportunity to improve the electricity delivery process. Thank you for your coordination of the Workshop and its committees. This effort required patience, persistence, and leadership. As you assemble the Advisory Committee, I am available to participate in this very important process, should you so desire.

Sincerely,

David L. Townley
Vice President, Business and Product Development

CC: Chuck Miessner
Aaron Thomas
Chuck DeCorse
Bill Murphy
Bryan Gernet
Linda Buczynski

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From: <bmurphy1@ci.phoenix.az.us>
To: CC.UTIL(jsmith)
Date: 12/22/99 9:12am
Subject: Some more thoughts on the process

Jerry and Chuck- Here are my thoughts after reviewing all our work.
bill

CC: CC.SMTP("dtownley@newenergy.com","CDECORSE@TUCSONE...

Distributed Generation

After months of intense effort this may be a good time to review our work.
Safety and economics were extensively discussed, but only in the context of old technology. Almost all of the devices that were discussed in each of the experiences that were shared were technologies that existed in the '40's and '50's. I think is an interesting experience to review these anecdotes, but nothing is gained if we still view them through eyes focused on old technology.

It will be helpful to review the basic assumptions that are the basis for this work:

The utility mind set is a carry over from the PURPA days and is based on the following assumptions:
= Dg will not benefit distribution
= DG will decrease reliability.
= DG will increase distribution investment
= Even if DG is placed on the feeder, it will be in the worst location.
= DG can't be managed with our existing (old) technology

= The present system is optimum—
Arizona utilities have missed the technology on generation by a factor of 2 (existing costs 100% over current generation methods). But we are constantly assured that they were right on the button on distribution costs. (I doubt it)

DG requires newer tools and should be analyzed with newer design and operating tools, such as:
= Real time meters (on loads, generators, and feeders)
= A true GIS
= Design and operate the distribution system to maximize investment in it (power can flow both ways like in transmission)
= Utilize new software that will continuously determine optimum power flows and recommend/cause changes.
=It should be noted that all of the work on these committees was done by
1 defenders of the present system (not designers)
2. rate people (defend status quo)
3. Amateurs not expert in this field.

Now how do we get access to those who will design the distribution system of the future? I think we all agree they were missing from the process.

To illustrate the disconnect please note what the centerpiece of the interconnection plan. It is a visible open disconnect switch. This was possible used by Thomas A. Edison or for sure Nickola Tesla at the turn of the century. This switch will require a utility employee to visit the DG site and personally look to determine if it is open! Isn't there newer technology that can be trusted?

Lastly, all the way thru the process APS told us that DG was disruptive to the wires business and it couldn't be integrated. Then Jack Davis in a newspaper article on Nov.21st mentions that these technologies will be "widely used".

Happy new millenium!!

E-00000A-99-0431

CITY OF TUCSON
DEPARTMENT OF OPERATIONS

Technical Planning & Resources Division

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1999 DEC 28 P 3:21

AZ CORP COMMISSION
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December 17, 1999

Jerry Smith, P.E.
Utilities Engineer
Utilities Division
Arizona Corporation Commission
1200 West Washington
Phoenix, AZ 85007

SUBJECT: Docket No. E-00000A-99-0431

Dear Mr. Smith:

The following are comments from the City of Tucson on the Arizona Corporation Commission's (ACC) Distributed Generation (DG) and Interconnection Workgroup process, to be filed in ACC Docket Control per Docket No. E-00000A-99-0431.

Turning first to the Draft Interconnection Requirements for Distributed Generation, Section 4, Overview of Distributed Generation Issues, the introductory paragraphs imply that the Public Utility Regulatory Policies Act (PURPA) of 1978 is the driver of the present trend to interconnect. If for any reason the ACC Staff intends to provide an historical perspective with its prospective rulemaking, it is recommended that regulatory developments since PURPA be included to update the wording, and that furthermore Statewide rulings be added to the Federal for the sake of completeness.

Moving on to Section 8, Interconnection Technical Requirements, 8.6, Labeling Requirements, we might consider adding the following to augment this section:

"Warning Signs and Markings

Permanent legible diagrams shall be installed near the Interconnection (or Service Entrance) showing (1) a block diagram for each cubicle, (2) a single line distribution diagram, (3) all possible sources of feedback potential, and (4) interlocks and their functions."

By the time we suggested the wording it was too late in the process to have all Committee members review, revise, and approve, but hopefully it will pose no undue inconvenience to the Customer, while providing an enhanced margin of safety and convenience to electrical maintenance workers on both sides of the meter.

When the Interconnect Standards Committee was reviewing Section 6, General Information & Requirements, you made a suggestion regarding the first paragraph, which essentially put the entire financial burden for the interconnection with the Customer. You recognized that this was not a question that the Committee could resolve in one session, but asked that we give it some thought, in view of the possible mutual benefits from DG. As it turned out, this and other sections (Section 4 second to last paragraph, Section 8 introductory paragraph) remain essentially in their original form of referring all such costs to the Customer.

Meanwhile, final reports from the other two committees go further in recognizing possible mutual benefits from DG. The Siting , Certification, and Permitting Committee Report refers to this on Page 8 in its discussion on Location Matching, Mapping. A DG handout distributed with the Report contains a section entitled "Benefits of DG Applications by Stakeholder Group, accompanied by Table 3, which breaks out benefits by Stakeholders and Applications. The Access, Metering, & Dispatch Committee Final Report suggests on Page 9, in F, 4, c, 2 that the Utility Distribution Company (UDC) may be able to use a DG unit to improve voltage regulation. There is a Section G, Potential Benefits of DG to the Grid on Page 10, providing viewpoints from both DG providers and UDCs. On Page 12, B, 2, e, the report suggests "tangible system benefits" from the use of DG for peak shaving purposes on the distribution system. Section F, Compensation for Grid Benefits of DG, provides viewpoints from DG providers as well as those from UDCs.

A conscientious review of the above sections reveals that providers and UDCs have valid points, and would indicate that the exact circumstances and to what extent DG might be mutually beneficial is yet to be demonstrated. For this reason we ask that no part of the pending ruling gets passed under the assumption that potential DG benefits accrue solely to the Customer, and that the Customer necessarily pays all. It may be that we need further definition as to when the Customer shall absorb the cost of studies or installation elements.

Perhaps the most controversial issue for the Interconnect Standards Committee is whether to allow DG to interconnect to a networked system, or to restrict its installation to radial lines. Both viewpoints were adequately represented in the document forwarded to ACC Staff, but the issue itself begs further resolution. We would suggest that the ACC sponsor a workshop specifically designed to further research the matter before any ruling prescribes one solution versus another. The Access, Metering, & Dispatch Committee Final Report, on Page 10, F, 4, e, 5 recognizes that the addition of DG to the current distribution system in effect creates a quasi-looped system. Would it follow that by definition no DG may go in anywhere now, because only radial systems are acceptable? Or are we prescribing a limit of ONE DG Customer per feeder?

One very important missing piece, discussed in Committee, is a provision to periodically revisit, review, and refresh any Statewide DG Interconnect Standard. The largest unresolved questions and issues relate to outcomes which have yet to be determined, such as DG benefits and network connections. Power Quality, Section 8.4, may need to be strengthened with higher DG saturation or merely more experience with DG. After more experience with DG in Arizona Service Territories, the Application Process may need to be refined or adjusted. It is anticipated that technological advancements such as packaged protection versus discrete relays and refinements telemetry and control will widen horizons of feasibility. A provision for periodic revision would allow Statewide Standards to be implemented initially on the basis of what is known at this time without precluding consideration of future developments.

In the Siting, Certification, & Permitting Committee Report, on Page 9, under Location Matching, Mapping, there is reference to the fact that some UDCs consider DG installation on their distribution systems to be proprietary, and do not anticipate releasing that information to the public. This brings up a question of customer due diligence in conducting a technical and economic feasibility study before proceeding to even conceptually plan interconnection to a feeder. As we all learned in Committee, the size, number, and configuration of existing DG installations will be a factor in adding additional units. If this information is secret, potential DG customers may find it difficult to intelligently arrive at a first approach. ACC Staff is asked to review this question with the intent of balancing both Customer and UDC interests.

The DG handout package, distributed with the Siting, Certification, & Permitting Committee Report, contains a letter from Jim Corbin, IBEW Local 1116 President, dated September 14, 1999. According to the letter, the Local was asked by the Committee to state its position on worker training and certification. The second page of the letter implies that "untrained, uncertified, and unlicensed contractors" will "come to Arizona to install and operate distributed generation that is connected to our electrical system" thereby "inviting disaster to the most critical element of our infrastructure." Addressing installation first, it is unlikely that any Authority Having Jurisdiction would sporadically permit an installation which did not comply with existing life safety codes, thereby exposing itself to the attendant liabilities. Refer also to Section 10 of the Draft Interconnect Requirements, Testing and Startup Requirements. If this section is to be implemented, it is again unlikely that now the UDC itself will permit an unsafe installation. Now addressing operation, nowhere is it anticipated that DG operators will be derived from a pool of "untrained, uncertified, unlicensed" out-of-state contractors. Again please refer to the Draft Interconnect Requirements, Section 11, Operational and Maintenance Requirements, which puts responsibility for operation and maintenance on the Customer, "with the requirements of all applicable safety and electrical codes, laws and governmental agencies having jurisdiction."

Lastly, but perhaps most ominously, there is a concern about much of the language in the Metering, Access, & Dispatch Committee's Final Report, Section III, Tariff and Policy Issues. There is apparently considerable uncertainty on tariff issues as they pertain to DG. The point is well taken on Page 18, D, 2, d of DG Provider Concerns that both the APS and the TEP Settlement Agreements were executed in full knowledge that DG could be utilized by customers. With the prospect of Standard Offer and Direct Access rate redesign arising while the ink is not yet dry on these Agreements, it can be expected that potential critics will be looking at these issues a great deal more closely.

Thank you for your consideration of these comments, and for your diligent coordination of the Workshop and its committees. Looking forward, as you assemble members of the Advisory Committee, I would be interested in participating in that regard. With a conservative foundation in sound engineering practice and a conviction that new technologies should be accommodated, I feel that I would bring a certain balance to that Committee.

Lastly, please see the attached flyer from the University of Wisconsin College of Engineering. "Interconnecting Distributed Generation to Utility Distribution Systems" will be held in March in Los Angeles. You might want to distribute this flyer to certain "interested" parties.

Sincerely,

Linda Buczynski, P.E.
Electrical Engineer

C: Jim Perry
Loretta Humphrey
Vinnie Hunt
Sandy Elder
Ron Ballard
Mark Crum
Randy Schuler
Chuck DeCorse
Bryan Gernet
David Townley

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From: Ed Gieseking <ed.gieseking@swgas.com>
To: "Jerry D. Smith" <JDS@CC.STATE.AZ.US>
Date: 12/22/99 2:58pm
Subject: Southwest's December 22 Comments

Attached are Southwest's comments in both Microsoft Word format and Adobe Acrobat PDF format.

Happy Holidays.

SOUTHWEST GAS CORPORATION

December 22, 1999

Jerry Smith
Arizona Corporation Commission
1200 West Washington Street
Phoenix, AZ 85007

Mr. Smith:

Subject: Docket No. E-00000A-99-0431

Pursuant to your instructions during the workshop in the above referenced docket, Southwest Gas Corporation hereby provides its comments on the Workgroup Committee Reports. In addition to mailing a copy of the comments to you, a copy will be transmitted by email.

Yours truly,

/s/ Ed Gieseking

Ed Gieseking
Manager, State Regulatory Affairs

Enclosure

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BEFORE THE ARIZONA CORPORATION COMMISSION

CARL J. KUNASEK
Chairman
JIM IRVIN
Commissioner
WILLIAM A. MUNDELL
Commissioner

IN THE MATTER OF THE GENERAL INVESTIGATION OF DISTRIBUTED GENERATION AND INTERCONNECTIONS FOR POTENTIAL RETAIL ELECTRIC COMPETITION RULES CONSIDERATION.	)	DOCKET NO. E-00000A-99-0431

COMMENTS OF SOUTHWEST GAS CORPORATION

Southwest Gas Corporation (Southwest) hereby submits the following comments on the Final Workgroup Reports of the Siting, Certification, and Permitting Committee, the Access, Metering and Dispatch Committee, and the Interconnection Committee.

Southwest appreciates this opportunity to provide Arizona Corporation Commission Staff (Staff) with these comments. Additionally, Southwest applauds the effort Staff put forth during this process working with the Distributed Generation and Interconnections Workgroup (Workgroup) and its three committees, keeping participants focused and reminding the committees of their goals and responsibilities. This is especially appreciated considering the various and sometimes diametrically opposed viewpoints on the issues discussed during this process. Southwest believes that the Staff process of forming an Advisory Committee with the task of consolidating the committee reports is a logical next step towards the development of distributed generation (DG) interconnection rules.

Benefits derived from distributed generation have the potential to extend to a variety of stakeholders. The customers or end-users of DG may benefit from reduced energy costs and increased reliability. Customers, especially those with a small tolerance to voltage bumps, can increase power quality with "inside-the-fence" DG. When the electric utility distribution company (UDC) evaluates high voltage transmission line and distribution system requirements, DG provides additional planning options. The UDC could benefit if provided the opportunity to purchase energy services from DG units to support its wires business. These types of contractual services could include interruptible rates in exchange for running a peaking plant or standby generator, or ancillary services that the distribution system may need in addition to those services provided by the transmission system.

Southwest first provides general comments regarding the workgroup workshop process and thereafter comments on each of the workgroup committee reports.

I. WORKSHOP PROCESS

Staff's leadership and ability to resolve disputes on contentious issues enabled the committees to complete their investigations and provide reports in the allotted time frame. From the first day of the workshop on June 28, 1999, through the last meeting on November 22, 1999, Staff kept the participants focused on the task of identifying issues related to the development of DG.

The Workgroup identified over 70 different, but interrelated, issues to discuss in preparation of the final report. These issues were consolidated and grouped into three categories which ultimately formed the three committees: Interconnection; Siting, Certification and Permitting; and Access, Metering and Dispatch (AMD). In most cases, committees did not infringe upon other committees' responsibilities. However, there was one major responsibility transgression by the Interconnections Committee into one of the AMD Committee responsibility assignments. Southwest aligns itself with the comments provided by the AMD Committee on the issue of the applicability of the Public Utility Regulatory Policies Act of 1978 (PURPA) requirements to the Commission's DG efforts.

II. WORKGROUP COMMITTEE REPORTS

Southwest participated in all three of the workgroup committees. Although consensus building was given different priority in each of the workgroups, the objective of presenting all viewpoints in the committee reports was universal. Southwest provides the following comments to assist the Advisory Committee in its efforts of preparing a final report.

A. Interconnection Committee

Experience in other states has shown that interconnection standards can be designed that maintain the current level of safety for UDC employees, its contractors and the general public, while at the same time allowing customers to install DG economically.

In order to facilitate consensus on some of the interconnection issues, this committee limited its discussion to interconnection at the distribution system level. Although this limitation did allow the parties to reach general agreement on many issues, much more work is needed before all encompassing interconnection standards can be developed and presented for Commission consideration. Each UDC defines its transmission/sub-transmission voltages at different levels: APS-21kV; TEP-46kV and SRP-12kV. Given the wide variation in the distribution/transmission system definitions among the UDCs, uniform interconnection standards at the distribution level will be difficult to develop. Non-standard interconnection requirements between the UDCs could severely affect the potential for DG deployment. For example, if a hospital is located in SRP's service area and wanted to interconnect a DG project to the distribution system at above 12 kV, the standards developed by this committee could not be used. A lack of standards for interconnection to the UDC system could have a significant impact on the economics of small DG projects and a significant share of Arizona's electric load could be denied access to DG opportunities. Standard requirements must be adopted that address distribution, sub-transmission and transmission interconnections before DG potential can be fully realized.

Under Section 6, General Requirements of the Interconnections Committee report, several references are made regarding UDC charges for administrative and other costs. The UDC should only have the opportunity to recover, from a DG interconnection applicant, the incremental costs over and above costs already established in the existing UDC's rates. If there is any DG-specific identifiable and quantifiable incremental cost, it should be established up front and published in the tariff of each UDC. Just as important is the timeline under which the UDC is required to perform certain tasks so that transaction costs are held to a minimum. Defining the costs and processing timeline will help eliminate discriminatory treatment of customers interested in installing DG.

B. Siting, Certification and Permitting Committee

One of the issues discussed early in the workgroup process was the need to streamline the application process with the UDC and with other governmental agencies. This streamlining includes certifying DG units that meet the technical requirements for deployment. If the UDC has no desire or is unable to pre-approve a packaged DG unit, then the DG manufacturer could receive a pre-certification from Underwriters Laboratories or another third-party testing organization. The need for streamlining is of particular economic concern for the smaller size units, i.e., 500 kW and below.

Once a particular product has been pre-certified to state-adopted standards, both the manufacturers and customers would be assured that the UDC would have no concerns about the ability of the DG equipment to perform on their system. This should facilitate an expedited UDC review process.

The Advisory Committee should address the application process between the DG owner and the UDC. The application process with the UDC should not be unnecessarily complicated and should be expeditious and time certain. The UDC should be able to provide the customer with all required forms, a listing of services and costs within time frames that are consistent with a new customer service request.

The application requirements and process should be different for residential, small commercial, large commercial and industrial customers. The review of smaller applications should be a simpler process compared to a 1 MW commercial application. Appropriate time frames need further discussion.

One of the products of the DG interconnection rules should be a requirement for each UDC to maintain a "roadmap" for the customer. This roadmap should detail all the required permits with local governmental agencies, application steps with the UDC, and potential costs. The permitting process to install DG may be different if you are located in Yuma, Kingman or Phoenix and a roadmap would assist potential DG applicants in their project evaluation and development.

This committee did not address an expedited complaint process. The Commission is the appropriate agency to address complaints regarding a violation of Commission rules, but the existing Commission complaint process does not resolve issues in a manner timely enough for the resolution of issues arising during a project. The Advisory Committee should address the formation of a process by which complaints can be heard and expeditiously resolved. A Federal Energy Regulatory Commission (FERC) alternate dispute resolution process may be helpful in these circumstances.

C. Access, Metering and Dispatch Committee

The AMD Committee report discussed issues regarding FERC jurisdiction and filing requirements for DG owners that export power. Mandatory filings with the FERC for a "market rate tariff", or to be classified as "Exempt Wholesale Generators", by potentially thousands of residential and small commercial customers will dampen or strangle that segment of the DG market. Additionally, the imposition of a transmission charge by the UDC on transactions totally contained within the distribution grid may diminish DG economics for small transactions. Consequently, the Advisory Committee should address these issues and obtain legal opinions from various parties to ascertain any legal requirements at the FERC. Additionally, the Commission itself should prepare a filing with the FERC that factually addresses these issues and requests the FERC provide an opinion or ruling concerning jurisdictional and filing requirements for distributed generation projects in Arizona. At a minimum, the Commission should request a waiver from specific requirements for DG projects below a specific threshold size to reduce any unnecessary regulatory and bureaucratic burdens. The issue of jurisdiction could be a potential barrier to the deployment of DG in Arizona.

The current UDC rate schedules assume that all non-UDC generators are operating as QFs as defined in PURPA. In order to provide non-QFs the same services that QF generators receive (back-up, maintenance and supplemental energy services) modifications must be made to remove such assumptions and requirements from existing regulations, rules and tariffs.

A subject which should have received more attention is "mapping." Mapping of all DG units within the UDC's territory will provide necessary information the UDC needs to operate its system safely and reliably. The UDC has a requirement to know the location of DG units for the purpose of system planning. The mapping should be accomplished for all DG installations whether separate from the grid, grid-connected for backup purposes, or grid-connected and exporting power. The mapping should include the name and address of the DG owner/operator, emergency contact information, size and type of unit, whether connected to the grid or not, any contractual arrangements between the UDC, the DG and any other ESP, telemetry information, if any, and any other pertinent and relevant information.

Throughout the committee report, there are references to "certain size of DG", "larger DG units" and "significant units of DG." These references should be more specific, identify the recommended sizes and define what is meant by "significant".

The Committee report contains several paragraphs discussing distribution system planning and the impact DG will have on this business practice. The UDCs need to identify the differences between connecting and losing load and connecting and losing DG before the impact of DG on system planning can be calculated. Several questions need to be answered. What does the UDC do now when a new customer applies for new service or when customers request incremental service or if they close their doors and move to New Mexico? How would the answer to those questions differ if the customer were a DG customer rather than load? UDC connection requirements for DG and load should only differ where UDC actions vary .

III. CLOSING REMARKS

The deployment of Distributed Generation technologies in the state of Arizona should be encouraged by the Commission through the development and adoption of regulations that: 1) protect the safety and reliability of the electric distribution system and the safety of the employees and customers of the electric system; 2) remove artificial barriers that hamper customer access to DG; and 3) encourage DG manufacturers and developers to participate in the Arizona market place. It was recognized in all three committees that the recently adopted Arizona electric industry restructuring rules will have to be taken into account during the development of DG interconnection rules, and may need to be modified to accomplish these goals. The benefits to the State and its citizens include increased energy efficiency, increased electric reliability, growth of electric generation competition, lower prices and increased customer choice.

The competitive market, not the UDCs, should dictate how and what DG technologies are utilized. Although several manufacturers have DG units ready for deployment today, smaller, more efficient and more reliable DG technologies are predicted to be available in the very near future. However, continued DG research and development hinges on the existence of a market for the products. The Commission and its Staff should continue its work on providing the tools that will allow the market to grow and mature under a restructured competitive business model.

Southwest respectfully requests that it be provided a position on the Advisory Committee. Southwest, through its participation in the previous committee activity and through its contributions to the committees' reports, was able to provide a unique perspective on the issues of distributed generation. Southwest will continue to dedicate the resources necessary to assist with this investigation through participation on the Advisory Committee.

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ARIZONA CORPORATION COMMISSION
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DEC 22 1999
Director of Utilities

December 21, 1999

Arizona Corporation Commission
Attn: Jerry D. Smith
1200 West Washington
Phoenix, Arizona 85007

Re: Oversite Committee

Dear Jerry:

Here are my comments for your "Super-ACC DG" committee (3 pages). Is it possible for me to serve on this committee?

Sincerely,

BALTES/VALENTINO ASSOCIATES, LTD.

R. T. Baltes

Robert T. Baltes, P.E.
Principal

RTB/ma

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Comments to Arizona Corporation Commission on Distributed Generation and Interconnection Workgroup

Siting, Certification & Permitting Report

1. Certification –

Utility Distribution Companies (UDCs) should certify both equipment and protective schemes for small distributed generation (DG) equipment. For installations of 1MW and smaller, DG installers should know in advance the typical protective relaying to be required by the UDC. The UDC may require additional protection at any particular site; however the DG installer that intends to install repeat products should be able to know in advance that his equipment (e.g., 75 kW microturbine) meets UDC requirements before the sale to customers.

2. Application Process –

The application process for DG installers should be simple and expeditious. Residential applications (10 kW or smaller) if requiring an application should be approved within 3 working days. Commercial applications (100 kW or smaller) should be approved within 5 working days. Small industrial applications (1000 kW or smaller) should be approved within 30 days. Larger industrial applications should be approved within 30 to 60 days. The review of smaller applications is a relatively simple engineering process and shouldn't require the expertise required for applications that might impact the UDC's distribution system.

Access Metering & Dispatch Committee Report

1. Size of Distributed Generation –

The impact on the distribution system should impact the demarcations for the size of DG installations and not vice versa. Or another method would be to separate the installations by the anticipated classes of users. There appears to be no logic for a 300 kW cutoff. I would suggest the following:

Residential Class – 10 kW or smaller
Commercial Class– Above 10 kW -100 kW
Small Industrial – Above 100 kW – 1000 kW
Industrial Class - Above 1000 kW
Large Industrial Class – Above 10 MW

The reason for the break points would be:

Residential Class applications should require a minimal or no review.
Most *Commercial Class* applications would be 100 kW or smaller.
Small Industrial Class users of 1000 kW or smaller wouldn't impact most distribution feeders that have a capacity of 5 –10 MW.
Industrial Class users above 1000 kW would have more of an impact on distribution feeders.
Large Industrial Class users above 10 MW would typically be connected to the transmission grid.

Interconnection Requirements for Distributed Generation Final Report

1. Generator Class Protective Requirements -

   100 kW or smaller generators – Minimum protection is under voltage contactor.
   100 kW – 1000 kW generators - Minimum protection for under voltage, over voltage, over frequency and under frequency.
   1000 kW – 10 MW generators – Utility grade protection devices and equipment required.

   It is not clear why break points shown in the report are for 50 kW and 300 kW. It would seem that all commercial class applications would have sufficient protection with under voltage contactors. Also utility grade devices seem to be over kill for 300-1000 kW units.

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AZ CORP COMMISSION
DOCUMENT CONTROL

From: "Madden, Sharon R(Z61960)" <SMADDEN@apsc.com>
To: "'Jerry D. Smith'" <JDS@CC.STATE.AZ.US>
Date: 12/22/99 4:44pm
Subject: APS Comments on DG & Intercon. Workshop

Here's our comments. Please let me know if you have any problems opening.
Thanks

<<DG Summary 12_15.doc>> <<DG Summary 12_15.doc>>

Sharon R. Madden
Ext. 602-250-2027
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The Arizona Corporation Commission formed a workshop on Distributed Generation & Interconnection to consider advancements in distributed generation technology and requirements for interconnection to the electrical grid from an Arizona Retail electric competition paradigm. This workgroup was then further disseminated into three workgroups: Siting, Certification, and Permitting; Access, Metering & Dispatch; and Interconnection.

On November 22, 1999 the three workgroups presented their results to ACC Staff on the status of their findings and any recommendations formulated by each workgroup. Staff has now requested comments from individual participants on each of the documents submitted by December 22, 1999, if they so desire.

A review board will be formed consisting of Jerry Smith, ACC Staff, each of the Chairs, Co-Chairs and members of the three groups that submitted comments, to formulate a proposal to submit to the Commissioners for their review and possible hearing on this matter.

Arizona Public Service feels that this project has produced a good start in the direction of setting procedures and guidelines in the state of Arizona. However, it is evident by the papers submitted on November 22nd, as well as at the national level (EEI), that there are still considerable issues that need to be resolved, and that the Group should continue to move forward to accomplishing a final process. Two additional items APS would like to emphasize is 1) Regardless of what type of DG is installed, safety issues surrounding this equipment will always have a substantial impact, and 2) Even if "substantial" DG is not in place, protocols still have to be developed to address DG.

APS hereby submits their comments on these documents:

SITING, CERTIFICATION AND PERMITTING WORKGROUP

RECOMMENDATIONS:

1) No Change

2) No Change

3) "Certification of DG equipment should be an option."
There is still no clear or precise meaning to the word "certification". There should be a definition to clarify what is meant by this.
We also recommend incorporating the language from the "Interconnection Requirements Document" for consistency between the documents. Utility "blanket approval" is not extended to any specific type of generator or generator schemes since each project is site specific and needs to be reviewed on a case-by-case basis.

4) Where it is stated that no additional jurisdiction by the ACC should be required, the comments submitted by Mr. Chuck Skidmore (meeting minutes of November 16, 1999,) reflect the true overview of the role of the ACC and should be incorporated into this section of the Recommendations.

Chuck Skidmore's Comments

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.

- 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.

1. SITING:

Paragraph 2: "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."

This is confusing as to meaning, as it appears we are discussing the units, not the sites. Therefore we recommend changing the language to read:

Every installation must be site specific to verify all the requirements of every entity involved are met. This would include review of the following:

Type and description of Unit
Location of Project
Intended operational use
Residential vs. Commercial applications
Impact to air quality, fuel supply, noise and safety issues
UDC operations, safety and protection

2. CERTIFICATION:

Paragraph 2: This paragraph suggests that possibly, a small generator, as in this example less than 10 kW, should not require certification and permitting, other than a normal building permit required by the applicable city or jurisdiction. This does not address the issue of an UDC review; therefore we request the following language be added following " applicable city or jurisdiction." This does not exempt any unit from interconnection review by the UDC to assure all safety, protection, and other items of concern are completed prior to interconnection.

4. APPLICATION PROCESS:

Paragraphs 2 & 3:

This has been an area of contention with much discussion from all parties. APS would like to clarify its position on this area. APS did not have an objection to implementing some type of completion time guideline, provided, other relevant aspects were taken into consideration.

Prior to this summary a whitepaper was submitted by Bryan Gernet on October 25, 1999 on the DG Application Process. This document explained the process whereby a customer would follow a procedure working with the UDC to evaluate everything that must be in place prior to the actual interconnection. This is presented as a typical process, with the guidelines, rather than a definitive turn around time due to the complexity of some of these projects.

Brian O'Donnell requested that Bryan Gernet and Tony Turturro prepare a joint document that would address concerns by all parties. This document was attached to the minutes from the Interconnect Workgroup on 12/01/99.

Therefore it is the recommendation of APS to include the document attached to the Interconnection Workshop's summary, incorporating the third draft of this document to be the Interconnection Process. This will accommodate the concerns addressed by both the UDC's and the Customers.

5. OTHER ISSUES OF DISCUSSION:

Direct Access Service Request (DASR):

APS feels that the DASR should not be considered to track DG information. The current DASR was subject to months of review and is specifically designed for UDC's and ESP's to track what services are being supplied by each entity for direct access customers.

Location Matching, Mapping:

Paragraph 3: UDC's must be protective regarding location and configuration of its electric system and equipment. This information is for the safety of their personnel and the prevention of sabotage to their equipment, which could jeopardize the reliability of the system.

Therefore APS would like to change the last sentence to read:
UDC's consider much of their system and distribution documentation confidential, and as such, will not release this information for public use.

INTERCONNECTION WORKGROUP

The Interconnection Workgroup has worked diligently to compile a document that may be utilized statewide by interested parties. However, with the time available to complete this task, there are still portions of this document where a consensus was not reached.

SCOPE:

The intent of this workgroup was to address the issues involved in connection to a distribution system (that is, transmission connection was not considered). If a customer wishes to connect to a transmission system, transmission related issues would also need to be addressed to complete an installation. These interconnections must be in compliance with all rules and regulations by FERC, WSCC, AZ-ISA, Desert STAR, NERC, and other utility or transmission owner requirements

OVERVIEW OF DISTRIBUTED GENERATION ISSUES

APS is in a unique situation as it is the only UDC in Arizona that has network systems in some areas. If ACC staff desires to pursue the topic of "interconnection with network systems," then APS suggests further investigation is required.

There have also been discussions on re-design or upgrades that may be required to accommodate DG interconnections. APS would like again to stress that the current system was not designed for this purpose.

GENERAL INFORMATION & REQUIREMENTS

It has been argued that DG, in certain circumstances, could be of benefit to both UDC's and providers of DG, therefore, costs associated with such an installation could be borne by the UDC. In such situations, an agreement would be reached that would benefit both parties. However, in the vast majority of cases the DG benefits only the customer, and in fact places additional costs on the UDC. APS currently has ACC approved tariffs for the purpose of recovery of costs associated with DG studies, interconnection requirements, and service requirements which allow APS to collect such additional costs from the customer installing and/or benefiting from this interconnection. We oppose any change to this that would require other customers and shareholders to subsidize DG.

INTERCONNECTION TECHNICAL REQUIREMENTS

EXHIBIT 3: DG APPLICATION PROCESS:
APS is supportive of having an application process in place for DG activities and recognize this is a collective process of the Interconnection Workgroup. APS is also in agreement with other utilities and committee members that certain aspects of the interconnection process are not always suited to enable a fixed time frame. Therefore, while this document outlined by the Interconnect Workgroup presents a strong foundation, it should be used as a guideline for what needs to be accomplished prior to the final interconnection inspection, with time frames agreed upon by both the UDC and customer. The customer may appeal to the ACC if they feel they are being delayed unreasonably. This will also address the comment on page 34 of the Interconnection paper regarding the concern for proper staffing requirements needed to meet any set timeline.

ACCESS, METERING & DISPATCH WORKGROUP

I. INTRODUCTION:

C. Definitions and Abbreviations

APS understands these definitions were prepared to clarify the issues in this document. We suggest however, to the extent possible, *where a definition already exists* in the "Electric Competition Rules" (Rules), such definition be used to retain consistency in definitions to anyone using these documents.

APS suggests

1) Distributed Generation ("DG")
   Suggest using the definition from page 5 of the "Interconnection Requirements" document:

   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 electrical system. A distributed generator is sometimes referred too simply as "generator".

2) Change to definition in "Rules" as the UDC does not necessarily "manage the transmission grid". In fact, under FERC's Order 2000 issued 12/15/99, all UDC's will likely relinquish transmission control to an independent RTO.

   "Utility Distribution Company" (UDC) means the electric utility entity regulated by the Commission that operates, constructs, and maintains the distribution system for the delivery of power to the end user point of delivery on the distribution system.

3) Change definition of Energy Service Provider to definition as stated in Rules".

   "Electric Service Provider" (ESP) means a company supplying, marketing, or brokering at retail any Competitive Service pursuant to a Certificate of Convenience and Necessity.

6) Standard Offer Customers should be redefined as: Customers purchasing "Standard Offer Service" as defined in Section R14-2-1601(38) of the "Rules."

Standard Offer Service means Bundled Service offered by the Affected Utility or Utility Distribution Company to all consumers in the Affected Utility's or Utility Distribution Company's service territory at regulated rates including metering, meter reading, billing and collection services, demand side management services including but not limited to time-of-use, and consumer information services. All components of Standard Offer Service shall be deemed noncompetitive as long as those components are provided in a bundled transaction pursuant to R14-2-1606(A).

D. Approach and Report Organization

5) APS would like to stress that while not everyone agreed with all the views, there were many common issues and agreements as well. Therefore we would like to include additional language after this sentence.

"Providers agree with all of the views expressed by their representing groups." However, it is important to note that both the DG Provider and UDC's had common understandings and agreements on many issues.

II. POTENTIAL IMPACTS OF DG ON THE PLANNING AND OPERATION OF THE UDC DISTRIBUTION GRID

A. Overview:

1) The statement that "the overall experience with DG in Arizona is relatively low," does not accurately describe APS's, experiences. We have had long-term experience, spanning many years with relatively small number of installations, as well as dealing with DG's owned by a few large industrial customers. We suggest the end of this sentence read:

"typically backup emergency generators, small QF facilities, and a few large industrial installations".

4) The grid shown in this document is incomplete. Even though this provided the framework for the committee's analysis the grid itself is probably not helpful and should be eliminated.

B. Application 1: DG is separate from Grid:

3a) By definition a DG used for emergency back-up would operate when the grid fails or is not available, therefore, if the emergency DG fails to operate, the customer has no back-up.

Even if a DG is operated non-parallel to the UDC grid, when the DG fails, the UDC could be expected to pick up the additional load.

3b) For clarification purposes APS would like to add language at the end of this sentence as follows (This information needs to be consistent throughout these sections):

No additional metering requirements for this scenario, unless a contractual relationship is developed to run generator in parallel with UDC grid.

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

3c) New section to be added as referenced in (B.3b).
Additional metering equipment would be required even though the DG did not intend to sell back excess power.

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

3a) APS would like to reiterate that there is no obligation for a UDC to purchase DG power. Therefore, we recommend adding the following statement after this sentence:

UDC's have no obligation to purchase except from Qualified Facilities. DG's may be able to participate in a competitive bid process when UDC's auctions for power to serve standard offer customers. Also, DG's may sell to other wholesale entities that are not ESP's in Arizona.

3b) APS believes that all DG sales, regardless of size, would always be included in purchasers' schedule.

3c) It is the recommendation of APS to delete the words "at least above a size threshold" from the first sentence of this paragraph.

Timed, two-way metering is required to accommodate inadvertent input of excess power to the UDC grid, or detents be installed on standard meters to prevent backwards operations.

E. Application 4: Size of DG

2g) APS is concerned this section may lead to an incorrect conclusion that small DG's could almost be ignored. The third sentence "DG Providers expressed that units in this size range should be a lower concern for UDCs." This statement is incorrect as UDC's have concerns that, regardless of size, each DG unit must be considered on a site-specific basis. Potential impacts are not necessarily eliminated due to small sized units. For example, DG's in this size range can easily support islanded feeder operation, especially in rural areas.

UDC's also disagreed that DG would have the same impacts to the delivery system as customers increasing or reducing loads permanently or intermittently. As a generation source, DG would increase the available fault current, and should be evaluated on that basis, as well as to ensure proper protection coordination.

Also, if the DG customer had no back-up requirement from the UDC, then the impact would be similar to having the load permanently removed. In reality, most DG installations do rely on the UDC for back-up with anticipated usage requirement significantly different than a normal customer load.

3a) To be consistent with our previous comment (D.3.a) APS recommends adding the following to end of sentence.: UDC's have no obligation to purchase except from Qualified Facilities. DG's may be able to participate in a competitive bid process when UDC's auctions for power to serve standard offer customers. Also, DG's may sell to other wholesale entities that are not ESP's in Arizona.

3b) To be consistent with our previous comment (D.3.b) APS recommends the exclusion of the words "above a certain size" and "typically" in this sentence. There must be a schedule to credit the imbalance account of the ESP or UDC.

F. Potential remedies for UDC Distribution Planning

1) General Concerns

b) To meet this requirement, UDC's generally believe that DG installations should impose no additional costs that would be recovered from other customers or paid by shareholders.

2) Rules of Thumb

b) APS has specific objections to the "Rules of Thumb":
- No support for 50% of feeder capacity.
- Each DG installation is site and location specific. (DG size and location on feeder)
- Potential for unintended islanding, specifically at end of line.
- Minimum feeder load requirement.
- Emergency feeder re-configurations.
- In most cases there is not enough units to bank on diversity.

G. Potential Benefits of DG to the Grid

3) Again we must emphasize that APS is willing to look for these types of benefits as long as they are economic. UDCs or unaffected UDC customers should not be required to subsidize the installation and/or operation of a DG. This has been addressed in the white paper submitted by the Siting, Certification, and Permitting Workgroup and needs to be incorporated into any recommendation by ACC Staff.

III. TARIFF AND POLICY ISSUES

A. Backup Service for DG

2) The current competition rules (R14-2-1606) permit UDCs to provide standard offer service (bundled) and non-competitive services. The provision of back-up generation to direct access customers is a competitive service, which cannot be provided by a UDC. Any change to these rules would require a full hearing by the ACC to re-open the Rules prior to any such change.

B. Tariffs for Standby, Maintenance, and Supplemental Power

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

a) APS currently has partial requirements rates in place for non-residential customers. A new standard offer partial requirements tariff applicable to residential customers would need to be developed.

c) The last sentence of this section reads: "Furthermore, the rates should not act as a disincentive to the deployment and utilization of DG by customers." APS agrees that if the opportunity exists for DG, we will support it. However, if the true cost of DG reflects it may be "a disincentive", we will protect our customers and shareholders against subsidizing DG.

2) DG Owners Choosing Direct Access – APS -TEP

c) APS would like to clarify its meaning of "number of hours" as it is referred to in this paragraph. The intent is to show the emphasis on the fact that metered kW and kWh will be reduced with installation of a DG, thus reducing the revenue for the UDC. We understand that the number of hours are not changed.

d) This Direct Access rate should also include applicable transaction costs.

e) The use of DG for peak shaving purposes may not reduce the number of hours the distribution system is used. However, the reduction in the volume of kWhs and kWs flowing over the distribution system causes a reduction in revenues and in return reduces the amount of fixed cost contribution to the affected UDC.

f) This potential growth offset would only apply to areas of customer growth and distribution system expansion. Revenue deficiencies incurred by installing DG in a stagnant growth area of the distribution system would not be offset from new customer growth.

g) This emphasizes our comments for Section (III.B.2.c) and (III. 2.d).

C. Selling excess Power from DG to UDCs

1) General Obligations and Options

a) APS believes non qualifying facilities DG's selling power to a UDC or any entity would have to meet all applicable state and federal requirements as a wholesaler of power.

D. Selling Excess DG in the Open Market

2) FERC Requirements

c1) APS has not found any citations within PURPA or PUHCA which identify exceptions regarding sale for resale. However, a DG can become an EWG which would give them an exception to several FERC regulations.

c3) APS disagrees with this statement. A distribution wheeling charge applied together with a distribution access charge (direct access rate for delivery) would be appropriate if priced in a way which only recovers costs for services provided.

Page 17 of the document appears to be erroneously labeled. It appears it should be Section E, not D again. *Therefore we are referring all comments as Section E to differentiate between the two sections.*

E. UDC Recovery of Distribution Costs

2) DG Provider Concerns

c) APS recommends adding the following language to the end of the sentence: Typically, the installation of DG in these instances reduces the volume of kWs and kWhs flowing over the distribution system. This causes a reduction in revenues to the UDC and reduces the customer's contribution to the UDC's fixed costs. This statement reiterates the comments made in Section D.

APS would like to note that when using the term "hours used", the interpretation by others was being used in a different context than our intent.

e) APS is not in agreement with this section. Under this scenario, UDC stockholders would be inappropriately paying these costs until the next general rate case. This subsidizes the DG at the expense of the shareholders. The UDC would then be offered the opportunity, not the guarantee, to justify these costs for recovery of this deficiency, in order to collect from customers in the future.

j) Same concern as Section (III.2.c.3):
APS disagrees with this statement. A distribution wheeling charge applied together with a distribution access charge (direct access rate for delivery) would be appropriate if priced in a way which only recovers costs for services provided.

Page 20: Section E - Metering should be renumbered to Section F. *APS is referring all comments as Section F to differentiate between the two sections.*

F. Metering

4c) APS recommends adding the following language to the end of the sentence: In this instance the meter will need to be detented to prevent it from inadvertently running backwards.

Page 20: Section F – Compensation for Grid Benefits of DG (Avoided Distribution Costs) Should be Renumbered *to Section G.*

Additional Areas not Discussed and need to be included:

There is an entire section that APS does not feel has been addressed relevant to DG. The topics of discussion should fall into the following categories:

1) The need to look at DG in terms of permanency or obligations.
2) Standards and reliability.
3) How long is it required to stay is service?
4) Repercussions if DG suppliers decides to leave. Who must supply their customers and at what cost?
5) Increased uncertainty and increased risks to the UDC for these repercussions.

E-00000 A-99-0431

Land & Water Fund

December 15, 1999

1999 DEC 28 P 3:21

AZ CORP COMMISSION
DOCUMENT CONTROL

TO: Jerry Smith, Utilities Division, Arizona Corporation Commission

FROM: Rick Gilliam, Senior Technical Advisor, Land and Water Fund of the Rockies

Re. Comments on Distributed Generation and Interconnection issues, Docket No. E-00000A-99-0431

The LAW Fund is a regional environmental law and policy center founded in 1990 to provide legal and policy assistance to community groups throughout the Rocky Mountain and Desert Southwest region. The LAW Fund's Energy Project was established in 1991 to advocate for sustainable energy policy and practices in a variety of state and national forums. Our interest in distributed generation and interconnection issues is relatively narrow in scope and relates primarily to the removal of barriers to the development of small-scale distributed renewable resources, such as photovoltaics (PV) and wind micro-turbines.

Anyone who visits Arizona is immediately struck by the state's most prominent natural resource – the sun. The public policies established by this Commission should promote development of technologies in Arizona that capture this abundant resource. A good example is the Solar and Environmentally-Friendly Portfolio Standard proposal of Chairman Kunasek that contains provisions promoting the development of distributed renewable resources in Arizona. Such public policies proposed by this Commission should not be compromised by other policies or practices that place undue cost burdens on these same resources.

The Benefits of Renewable Resources

Renewable resources can provide many benefits that inure to the people of Arizona directly or indirectly. These resources can aid in the state's economic development in a number of ways, provide significant benefits to the utility system itself, and provide assistance to low-income and rural Arizonans in addition to the benefits to the environment.

Development of solar and other small scale electric technologies will bring economic development benefits to the state in the form of rural development and jobs. Many Native Americans living in Arizona have limited access to grid-based electric power. Such power, when it is available, is expensive. Effective distributed generation policies will allow rural peoples to supplement grid-based purchases with small scale distributed resources. Employment and business opportunities are a by-product of this type of rural development.

In addition, the growth in demand for off-grid renewable resources, especially in developing countries, is so great that substantial new manufacturing facilities will be needed in the near future. Two billion people around the world lack electric power, and many governments around the world see electrification of rural areas using renewable resources as a means of improving quality of life and reducing urban crowding. Indeed, three-fourths of the 20% annual growth in solar electric resources is occurring in developing nations.

By creating local demand through consistent public policy, Arizona has an opportunity to increase its share of the expanding global manufacturing capacity requirement. A solid portfolio standard, along with removal of barriers to small scale distributed electric resource development, will provide solar electric developers and manufacturers of renewable technologies with the assurance they need to commit resources to manufacturing and related operations. Such a policy will bring jobs to Arizona in a clean industry.

The existing electric utility systems also benefit by strategically placed distributed resources that capture cost and risk benefits[1] for both generation and wires businesses. On the generation side, these benefits include resource diversification and fuel cost risk management. For example, if fossil fuel costs rise in the future or if environmental regulations are tightened, then renewable resources can potentially provide a cost effective and attractive alternative. On the wires side, transmission and distribution cost reductions can occur as a result of deferring or eliminating line and substation upgrades in localized (and sometimes constrained) areas. Other benefits to the electric supply system include reliability enhancement and reduction in line losses.

Finally, small scale distributed resources, and especially solar electric technologies, would produce electricity at various times of day that will offset the burning of fossil fuels. From an environmental perspective, encouraging the use of these renewable resources will help reduce emissions from traditional fossil fuel power plants. For example, a typical 2 kilowatt residential PV system will produce about 4,400 kWh each year. This should reduce CO_2 emissions by about 4,400 pounds per year, SO_2 emissions by about 175 pounds per year, and NO_X emissions by about 235 pounds per year. This is equivalent to not driving an automobile nearly 9,000 miles per year. In the long run, when one, two, and five kW standardized PV systems are readily available from the local hardware store, widespread use will increase these annual emission reduction figures dramatically.

Comments on the Interconnection Requirements Committee Report

As an initial comment, we point out that the Institute of Electrical and Electronics Engineers (IEEE) has in place a recommended practice known as ANSI/IEEE STD 929-1988, "IEEE Recommended Practice for Utility Interface of Residential and Intermediate PV Systems." This standard is currently being revised. In addition, IEEE is currently developing a more comprehensive standard (SCC21 P1547) that establishes uniform criteria and requirements for interconnection of distributed resources with electric power systems, providing requirements relevant to the performance, operation, testing, safety considerations, and maintenance of the interconnection. This document should be complete in early 2000. It is the intent of the IEEE standards to meet all legitimate utility concerns with safety and power quality so that there will be no need for additional requirements in developing utility specific guidelines. Indeed, it would be inefficient and potentially costly to adopt any standards that are inconsistent with those developed by the IEEE. These uniform standards should be adopted by this Commission.

The Interconnection Requirements Committee Report is geared towards distributed electric generators larger than the typical size for residential or small commercial customer-sited renewable resources -- the smallest class size, i.e. Class I, has a ceiling of 50 kW. While we don't take issue with the minimum protective relaying requirements for Class I, we believe the nine step DG application process outlined in Exhibit 3 is cumbersome for small generators, i.e. less than 10 kW, and may inhibit development of this important resource. The process requires extensive utility involvement (and cost, no doubt), and ultimately utility approval of the project. This is simply not workable for small installations. An extra $1,000 in expense to a 2 kW solar installation will increase costs by over 22¢/kWh in the first year.

Other states have adopted standardized application forms and contracts for small systems. For example, Rhode Island utilities have adopted a one-page document that captures the pertinent information to initiate a small DG solar project (although it could be modified to encompass other renewables). Similarly, California has developed a standardized interconnection agreement for residential and small commercial solar and wind facilities 10 kW or smaller. Both of these documents are attached as Appendices A and B, respectively.

[1] See Hoff, Thomas, "Identifying Distributed Generation and Demand Side Management Investment Opportunities," Energy Journal 17(4): 89-105 (1996); and also Farmer, Hoff, and Wenger, "Measuring the Value of Distributed Photovoltaic Generation: Final Results of the Kerman Grid-Support Project," December, 1994.

We recommend first that a sub-category of Class I be established for systems under 10 kW.[2] Second, small systems should be exempt from the process described in Exhibit 3, and abbreviated procedures should be adopted that provide for minimal administration of projects under 10 kW whose output is not expected to exceed the host facility's load on an annual basis. In this regard, we support the use of standardized application forms and contracts.

Comments on the Access, Metering, and Dispatch Committee Final Report

This committee somewhat arbitrarily demarcated DG sizes differently than did the Interconnection Requirements Committee. The smallest class reaches all the way to 300 kW. While we don't understand why the classes are different, it may be irrelevant since "the UDCs had a lower level of concern for the 0-300 kW DG applications from a planning and operational perspective."[3]

The key issue for small (10kW and under) renewable resources in this report is net metering. The report makes no recommendation, but does identify differences among the participants on the committee. In a nutshell, the UDCs recommend that net metering (allowing the meter to run backwards) is not well suited to a competitive environment, and will not be offered to DG customers. On the other hand, the DG Providers recommended that net metering would not be a typical solution, except perhaps for a special program for very small technologies, such as a residential solar program. (emphasis added).

The competitive environment is about customer choice. Commission and utility policies and practices should encourage grassroots energy resource options such as small-scale renewables. Any of the other metering options in the report would increase the transaction costs to the point of killing this important market. Net metering (allowing the meter to run backwards) is the low-cost and simple solution to encouraging renewable resources, as recognized by the DG Providers. Moreover, we would point out that 29 states have sponsored net metering programs (two are in the proposal stage). Nearly all states limit the size of the generator subject to net metering to 100 kW, with about one-fourth limited to under 10 kW.

Perhaps the key net metering policy issue is the treatment of excess generation, i.e. generation that exceeds the load of the host facility. There are two broad categories of treatment. The first involves reconciliation of any excess generation at the end of each monthly billing cycle. The second allows

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[2] Public Service Company of Colorado has established *seven* classes of customer-sited facilities for specifying protective relaying requirements, the smallest of which is 10 kW and under. Section 5.2 describes the requirements placed on these small systems, and is attached as Appendix C.

[3] Report, page 7.

excess generation credits to be carried forward to offset energy consumption in the following month, with reconciliation occurring at the end of a twelve month period to allow for seasonal variations.

In either case, the most favorable policy for the customer is for the utility to buy any excess generation at the customer's retail rates. However, only two states have adopted this policy. At the other extreme is for excess generation to be simply "granted" or given to the utility without compensation to the customer that generated it. Nine states have adopted this policy, although in nearly all cases the granting occurs at the end of a twelve month period such that excess generation in one month can be credited against consumption in another month. The most prevalent practice is for utilities to purchase net excess generation at avoided cost rates, and that is what we recommend here.

We urge the Commission to establish a net metering policy that provides for excess generation to be carried forward from month to month, with any excess remaining at the end of a twelve month period purchased by the UDC or ESP at avoided cost rates.

Comments on the Siting, Certification, and Permitting Committee Report

With respect to siting, we agree with the report that existing government entities already have appropriate and sufficient regulations in place, and that nothing further is needed by this Commission. The report also indicates that no special certification and permitting, other than a normal building permit required by the applicable city or jurisdiction should be required for residential units of 10 kW and smaller. First, we would add small commercial units under 10 kW to this exemption, but clearly still subject to local building permit requirements as there is no real difference in the application. Additionally, one key requirement of National Electric Code Article 690 (dealing directly with PV) is that all equipment must be listed by a recognized listing agency such as UL. We believe that these requirements are sufficient certification for small (under 10 kW) renewable distributed generators, and that nothing further should be required by this Commission.

Finally, a brief comment with respect to ultra small generators. There is an emerging class of renewable generators, (PV and wind) under 1000 watts (1 kW), that generate so few kilowatt-hours that exemption from all interconnection standards is appropriate. From the energy supplier's perspective, such resources would be akin to a customer replacing an older refrigerator with a new more efficient unit, thereby reducing consumption. These ultra-small renewables would never generate more energy than is consumed by the host, and thus would not create any of the safety and system stability concerns raised by these committees. In our view, ultra small generators should be entirely exempt from these requirements, provided that they meet appropriate UL and NEC requirements.

Summary & Recommendation

In recognition of the economic, system, and environmental benefits of small, i.e. under 10kW, DG applications, the Commission should adopt consistent policies that promote their implementation. These policies should be geared towards minimizing unnecessary requirements and costs. Therefore, based on the above discussions, the Land and Water Fund makes the following recommendations:

1. Establish two new subcategories of distributed generation: ultra-small generators for those under one kW, and small generators for those between one and 10 kW.

2. Ultra-small generators should be entirely exempt from interconnection, siting, permitting, access, and metering requirements, provided that they meet applicable UL and NEC standards.

3. For distributed generation projects between one and 10 kW whose output is not expected to exceed the host facility's load on an annual basis, adopt abbreviated interconnection procedures that minimize administrative burdens such as standardized applications and contracts. The application can be as short as one page and the contract concise as in the case of California.

4. Adopt a statewide net-metering policy that allows excess generation in one month to be applied to excess consumption in future months. Excess generation that remains at the end of a twelve month period can be purchased by the UDC or ESP at avoided cost rates.

5. Adopt a policy that recognizes that distributed generation resources under 10 kW require no further certification than meeting UL and NEC standards.

Respectfully submitted this 15th day of December, 1999.

/s/ James (Rick) Gilliam, Senior Technical Advisor
Land and Water Fund of the Rockies Energy Project
2260 Baseline Road, Suite 200
Boulder, CO 80302
303-444-1188 ext 218
rgilliam@lawfund.org

Appendix A

Rhode Island Distributed PV Application

Post-it® Fax Note 7671	Date 12-16	# of pages ▶ 16
To Jerry Smith	From Rick Gilliam	
Co./Dept. ACC	Co. LAW Fund	
Phone # 602-542-7271	Phone # 303-444-1188	
Fax # 602-542-2129	Fax # x 218	

DIST. GEN. COMMENTS

Appendix A

Rhode Island Distributed PV Application

PROJECT SUNRISE INTERCONNECT APPLICATION

Section 1. Customer Information

Name: ____________________

Mail Address: ____________________

City: ____________________, RI, Zip Code: __________

Street address (if different than above): ____________________

Daytime Phone #: ____________________

Distribution Utility: ____________________ Account#: ____________________

Section 2. PV System Information

System Name: __________ Nameplate ac rating: _____

Module Type: __________ Inverter: __________ Batteries: __________

Module Location: __________ Inverter Location: __________

AC Disconnect location: __________ Permission to monitor? __________

Section 3. Installation Information

Master Electrician: ____________________ RI License #: __________

Mail Address: ____________________

City: ____________________, RI, Zip Code: __________

Daytime Phone #: ____________________ Proposed installation date: __________

Section 4. Certifications

1. The system hardware is in compliance with Underwriters Laboratories (UL) standard 1741, "Standard for Static Inverters and Charge Controllers for Use in Photovoltaic Power Systems"

Signed(Vendor): ____________________ Date: __________

Name (printed) ____________________ Company: ____________________

2. The system has been installed in compliance with IEEE P929, "Recommended Practice for Utility Interface of Photovoltaic (PV) Systems" and the National Electrical Code (NEC).

Signed (Electrician): ____________________ Date: __________

Name (printed) ____________________ Company: ____________________

3. The system has been installed to my satisfaction and I have been given system warranty information, an operation manual, and have been instructed in the operation of the system.

Signed (Owner): ____________________ Date: __________

Section 5. Utility Approval & State Electrical Inspection

1. Application Approved: ____________________ Date: __________
2. System Inspection by : ____________________ Inspection Date: __________

Appendix B

California Standard Small Renewable Generation Interconnection Agreement

CALIFORNIA

INTERCONNECTION AGREEMENT FOR NET ENERGY METERING FROM RESIDENTIAL AND SMALL COMMERCIAL SOLAR OR WIND ELECTRIC GENERATING FACILITIES OF 10 KILOWATTS OR LESS

INTERCONNECTION AGREEMENT FOR NET ENERGY METERING FROM RESIDENTIAL AND SMALL COMMERCIAL SOLAR OR WIND ELECTRIC GENERATING FACILITIES OF 10 KILOWATTS OR LESS

TABLE OF CONTENTS

INTERCONNECTION AGREEMENT FOR NET ENERGY METERING FROM RESIDENTIAL AND SMALL COMMERCIAL SOLAR OR WIND ELECTRIC GENERATING FACILITIES OF 10 KILOWATTS OR LESS

__________________________("Customer-Generator"), and __________________________ (UTILITY NAME), referred to collectively as "Parties" and individually as "Party", consistent with the provisions of Section 2827 of the California Public Utilities Code agree as follows:

CUSTOMER-GENERATOR:
SOLAR OR WIND ELECTRIC GENERATING FACILITY:

1.1 Operating Option

Customer-Generator has elected to interconnect and operate its solar or wind electric generating facility in parallel with the electric grid. The solar or wind electric generating facility is intended primarily to offset part or all of the Customer-Generator's own electrical requirements.

1.2 Identification Number:
(PVID = Photovoltaic/Solar; WID = Wind Turbine)

1.3 Photovoltaic/Solar ("PV") Array Rating: __________________kW
Wind Turbine (WT) Rating: __________________________kW

1.4 Site Address:

1.5 Facility will be ready for operation on or about:__________________
(date)

2. NET ENERGY

2.1 The Energy Charge on the regularly filed tariff schedule shall normally be computed based upon Net Energy where Net Energy is energy supplied by the utility, minus energy generated by the customer and fed back into (UTILITY NAME)'s grid over a 12-month period. In the event the energy generated exceeds the energy consumed during the 12-month period, no payment will be made for the excess energy delivered to (UTILITY NAME)'s grid. If (UTILITY NAME) is the customer's Electric Service Provider (ESP), this condition may be modified where the customer has a signed contract to sell any portion of the customer generated energy to the utility.

2.2 If (UTILITY NAME) is the customer's ESP, (UTILITY NAME) shall provide the Customer-Generator with the net electricity consumption information on each regular bill. The consumption information shall include the current monetary balance owed to (UTILITY NAME) for net electricity consumed since the last 12-month period ended.

(UTILITY NAME) upon request of the Customer-Generator, shall permit the Customer-Generator to pay monthly for net energy consumed.

3. INTERRUPTION OR REDUCTION OF DELIVERIES

3.1 (UTILITY NAME) shall not be obligated to accept or pay for and may require Customer-Generator to interrupt or reduce deliveries of available energy:

a. when necessary in order to construct, install, maintain, repair, replace, remove, investigate, or inspect any of its equipment or part of its system; or

b. if it determines that curtailment, interruption, or reduction is necessary because of emergencies, forced outages, force majeure, or compliance with prudent electrical practices.

3.2 Whenever possible, (UTILITY NAME) shall give Customer-Generator reasonable notice of the possibility that interruption or reduction of deliveries may be required.

3.3 Notwithstanding any other provision of this Agreement, if at any time (UTILITY NAME) determines that either (a) the Facility, or its operation, may endanger (UTILITY NAME) personnel, or (b) the continued operation of Customer-Generator's facility may endanger the integrity of (UTILITY NAME)'s electric system, (UTILITY NAME) shall have the right to disconnect Customer-Generator's Facility from (UTILITY NAME)'s system. Customer-Generator's Facility shall remain disconnected until such time as (UTILITY NAME) is satisfied that the condition(s) referenced in (a) or (b) of this Section 3.3 have been corrected.

4. INTERCONNECTION

4.1 Customer-Generator shall deliver the available energy to (UTILITY NAME) at the utility's meter.

4.2 The Customer-Generator shall be responsible for all expenses involved in purchasing and installing a meter that is able to measure electrical flow in two directions. A dual meter socket with separate meters to monitor the flow of electricity in each direction may be installed with the consent of the Customer-

Generator, at the expense of (UTILITY NAME). If the Customer-Generator refuses consent for dual metering, and due to billing purposes a single bi-directional meter cannot be installed, (UTILITY NAME) shall have the right to refuse interconnection.

4.3 Customer-Generator shall not commence parallel operation of the Facility until written approval of the interconnection facilities has been given by (UTILITY NAME). (UTILITY NAME) shall provide written approval within ten (10) working days from the utility's receipt of the inspection clearance of the governmental authority having jurisdiction. Such approval shall not be unreasonably withheld. (UTILITY NAME) shall have the right to have representatives present at the initial testing of Customer-Generator's protective apparatus. Customer-Generator shall notify (UTILITY NAME) five (5) working days prior to the initial testing.

5. MAINTENANCE AND PERMITS

Customer-Generator shall: (a) maintain the Facility and interconnection facilities in a safe and prudent manner and in conformance with all applicable laws and regulations including, but not limited to, (UTILITY NAME)'s Appendix A, and (b) obtain any governmental authorizations and permits required for the construction and operation of the Facility and interconnection facilities. Customer-Generator shall reimburse (UTILITY NAME) for any and all losses, damages, claims, penalties, or liability it incurs as a result of Customer-Generator's failure to obtain or maintain any governmental authorizations and permits required for construction and operation of Customer-Generator's Facility.

6. ACCESS TO PREMISES

(UTILITY NAME) may enter Customer-Generator's premises: (a) to inspect, at reasonable hours, Customer-Generator's protective devices and read or test meters; and (b) to disconnect, without notice, the interconnection facilities if, in (UTILITY NAME)'s opinion, a hazardous condition exists and such immediate action is necessary to protect persons, or (UTILITY NAME)'s facilities, or property of others from damage or interference caused by Customer-Generator's solar or wind electric generating facilities, or lack of properly operating protective devices.

7. INDEMNITY AND LIABILITY

7.1 Each Party as indemnifier shall defend, save harmless and indemnify the other Party and the directors, officers, employees, and agents of such other

Party against and from any and all loss, liability, damage, claim, cost, charge, demand, or expense (including any direct, or consequential loss, liability, damage, claim, cost, charge, demand, or expense, including attorneys' fees) for injury or death to persons including employees of either Party and damage to property including property of either Party arising out of or in connection with (a) the engineering, design, construction, maintenance, repair, operation, supervision, inspection, testing, protection or ownership of, or (b) the making of replacements, additions, betterments to, or reconstruction of, the indemnifier's facilities; provided, however, Customer-Generator's duty to indemnify (UTILITY NAME) hereunder shall not extend to loss, liability, damage, claim, cost, charge, demand, or expense resulting from interruptions in electrical service to (UTILITY NAME)'s customers other than Customer-Generator. This indemnity shall apply, notwithstanding the active or passive negligence of the indemnified. However, neither Party shall be indemnified hereunder for its loss, liability, damage, claim, cost, charge, demand, or expense resulting from its sole negligence or willful misconduct.

7.2 Notwithstanding the indemnity of Section 7.1, and except for a Party's willful misconduct or sole negligence, each Party shall be responsible for damage to its facilities resulting from electrical disturbances or faults.

7.3 The provisions of this Section 7 shall not be construed to relieve any insurer of its obligations to pay any insurance claims in accordance with the provisions of any valid insurance policy.

7.4 Except as otherwise provided in Section 7.1 neither Party shall be liable to the other Party for consequential damages incurred by that Party.

7.5 If Customer-Generator fails to comply with the insurance provisions of this Agreement, Customer-Generator shall, at its own cost, defend, save harmless and indemnify (UTILITY NAME), its directors, officers, employees, agents, assignees, and successors in interest from and against any and all loss, liability, damage, claim, cost, charge, demand, or expense of any kind or nature (including attorney's fees and other costs of litigation) resulting from the death or injury to any person or damage to any property, including the personnel and property of (UTILITY NAME), to the extent that (UTILITY NAME) would have been protected had Customer-Generator complied with all such insurance provisions. The inclusion of this Section 7.5 is not intended to create any expressed or implied right in Customer-Generator to elect not to provide any such required insurance.

8. INSURANCE

8.1 To the extent that Customer-Generator has currently in force all risk property insurance and comprehensive personal liability insurance, Customer-Generator agrees that it will maintain such insurance in force for the duration of this Agreement in no less amounts than those currently in effect. (UTILITY NAME) shall have the right to inspect or obtain a copy of the original policy or policies of insurance prior to commencing operation.

8.2 Customer-Generators shall meet the standards and rules set forth in Section 5, have the appropriate liability insurance required in Section 8.1 and shall not be required to purchase any additional liability insurance.

Such insurance required in Section 8.1 shall, by endorsement to the policy or policies, provide for thirty (30) calendar days written notice to (UTILITY NAME) prior to cancellation, termination, alteration, or material change of such insurance.

9. GOVERNING LAW

This Agreement shall be interpreted, governed, and construed under the laws of the State of California as if executed and to be performed wholly within the State of California.

10. AMENDMENTS, MODIFICATIONS OR WAIVER

Any amendments or modifications to this Agreement shall be in writing and agreed to by both Parties. The failure of any Party at any time or times to require performance of any provision hereof shall in no manner affect the right at a later time to enforce the same. No waiver by any Party of the breach of any term or covenant contained in this Agreement, whether by conduct or otherwise, shall be deemed to be construed as a further or continuing waiver of any such breach or a waiver of the breach of any other term or covenant unless such waiver is in writing.

11. APPENDIX

This Agreement includes the following Appendix A, which is attached and incorporated by reference:

Appendix A: (UTILITY NAME)'s Interconnection Standards for Residential and Small Commercial Solar or Wind Electric Generating Facilities of 10 kW or Less

12. NOTICES

INTERCONNECTION AGREEMENT FOR NET ENERGY METERING FROM RESIDENTIAL AND SMALL COMMERCIAL SOLAR OR WIND ELECTRIC GENERATING FACILITIES OF 10 KILOWATTS OR LESS

All written notices shall be directed as follows:

(UTILITY NAME)
(UTILITY ADDRESS)

CUSTOMER-GENERATOR:______________________(name)

Address______________________

City______________________

Customer-Generator's notices to (UTILITY NAME) pursuant to this Section 12 shall refer to PVID and WID Numbers set forth in Section 1.1.

13. TERM OF AGREEMENT

This Agreement shall become effective as of the last date set forth in Section 14 and shall continue in full force and effect until terminated by either Party providing 30-days prior written notice to the other Party in accordance with Section 12. This Agreement may be terminated prior to 30 days by agreement of both Parties.

14. SIGNATURES

IN WITNESS WHEREOF, the Parties hereto have caused two originals of this Agreement to be executed by their duly authorized representatives. This Agreement is effective as of the last date set forth below.

"Customer-Generator Name"______________________

By (Signature):______________________

Type/Print Name:______________________

Title:______________________

Date:______________________

(UTILITY NAME)

INTERCONNECTION AGREEMENT FOR
NET ENERGY METERING FROM RESIDENTIAL AND SMALL COMMERCIAL
SOLAR OR WIND ELECTRIC GENERATING FACILITIES OF 10 KILOWATTS OR LESS

By (Signature)______________________________

Type/Print Name:______________________________

Title:______________________________

Date:______________________________

APPENDIX A

A. GENERAL

This Appendix sets forth the requirements and conditions for interconnected non utility-owned, solar or wind electric generation where such generation may be connected for parallel operation with the service of (UTILITY NAME). For purposes of this Appendix, the interconnecting entity shall be designated Customer-Generator.

B. DESIGN REQUIREMENTS

1. Customer-Generator shall conform to all applicable solar or wind electrical generating system safety and performance standards established by the National Electrical Code (NEC), the Institute of Electrical and Electronics Engineers (IEEE), and accredited testing laboratories such as Underwriters Laboratories, and where applicable, rules of the Public Utilities Commission regarding safety and reliability, and applicable building codes. A customer-generator whose solar or wind electrical generating system, or a hybrid system of both, meets those standards and rules shall not be required to install additional controls, perform or pay for additional tests, or purchase additional liability insurance.

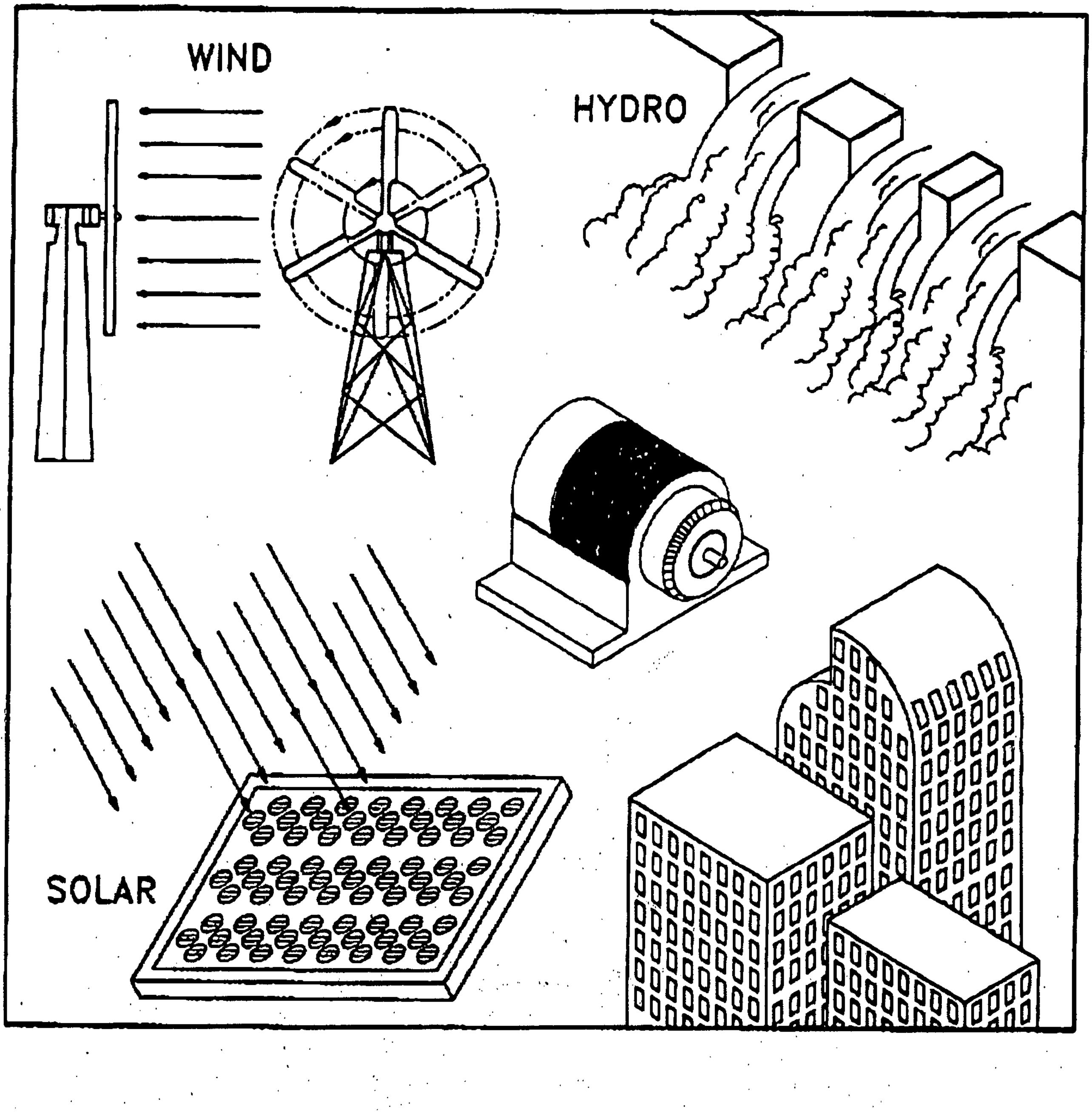
Appendix C

Public Service Company of Colorado
Protective Relaying Requirements
for
Small Customer-owned Generators

Appendix C

Public Service Company of Colorado Protective Relaying Requirements for Small Customer-owned Generators

SAFETY, INTERFERENCE AND INTERCONNECTION GUIDELINES FOR COGENERATORS, SMALL POWER PRODUCERS AND CUSTOMER-OWNED GENERATORS



Public Service®

Public Service Company of Colorado

5.1 GENERATION CLASSIFICATION...continued

a) Meets or exceeds ANSI/IEEE Standards for protective relays (i.e., C37.90-1989, C37.90.1-1989, and C37.90.2-1995)

b) Extensive documentation covering application, testing, maintenance, and service.

c) Positive indication of what caused a trip (Targets).

d) A means of testing that does not require extensive unwiring (e.g. a draw out case, test blocks, FT-1 switches, etc.).

5.2 INSTALLATIONS UNDER 10 kW

All installations in this class will require a design and relay review by PSCo (i.e., metering and relaying one-lines, protection and control schematics, relay setting sheets and name plate data of the generator(s) and breaker(s)/disconnect switch(es) will be provided to PSCo by the Producer, see Section 4.7). PSCo will determine if a relay and site inspection (i.e., witnessing the calibration and testing of the relays and operation of the generator and breakers (see Section 7) is also required. Most installations in this class feature a standard protection package offered by a manufacturer. Each package will be reviewed. As long as no changes are made in configuration or equipment, no further review of that package will be required for additional installations. All installations that are not a standard package must be reviewed individually.

The protective relaying settings and details, are shown in Figure 10.1. The installation must be permanently wired into a suitable load center and a lockable disconnect switch must be provided that is readily accessible to PSCo personnel. This switch is to be at the metering point unless an alternate location is readily accessible and easily identifiable. The alternate location must be approved by PSCo.

5.3 INSTALLATIONS FROM 10 kW TO LESS THAN 100 kW

All installations in this class will require a design and relay review by PSCo (i.e., metering and relaying one-lines, protection and control schematics, relay setting sheets and name plate data of the generator(s) and breaker(s)/disconnect switch(es) will be provided to PSCo by the Producer, see Section 4.7). PSCo will determine if a relay and site inspection (i.e., witnessing the calibration and testing of the relays and operation of the generator and breakers, see Section 7) is also required.

Those installations which are a standard package will be reviewed once. No further package review will be required for additional installations provided no changes in configuration or equipment are made to the package. All installations that are not a standard package must be reviewed individually.

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From: Dave Drummond <ddrummond@newenergy.com>
To: CC.UTIL(jsmith)
Date: 12/22/99 2:13pm
Subject: Comments from DPCA

Please find attached comments submitted on behalf of the Distributed Power Coalition of America (DPCA) on the Final Committee Reports of the Arizona Distributed Generation Docket No. E-00000A-99-0431. Sarah McKinley, Peter Chamberlain, Mark Skowronski and Dave Drummond contributed to the drafting of this document. The Arizona Corporation Commission is to be congratulated for the work it is doing to further the development of distributed generation in Arizona. DPCA looks forward to continuing its involvement in the process.

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Arizona Corporation Commission Workshop on Distributed Generation

Docket No. E-00000A-99-0431

<u>COMMENT ON THE FINAL COMMITTEE REPORTS</u>
DECEMBER 22, 1999

The Distributed Power Coalition of America (DPCA) offers the following comments to the three subcommittee reports on distributed generation submitted to the Arizona Corporation Commission in November. We applaud the Commission for opening the discussion with stakeholders, and welcome this opportunity for a comprehensive public discussion of the issues.

The Distributed Power Coalition of America

The DPCA is a coalition of companies and organizations whose mission is to advocate the adoption of DR that will benefit the electric system and energy consumers. Currently the DPCA has over 60 members, which include equipment manufacturers, electric and gas distribution utilities, natural gas pipelines, energy service companies, consultants and educational/research organizations. Begun in 1997, the DPCA is technology and fuel neutral, and its members represent a balance of interests in the DG community.

On the federal level DPCA activities have included legislative briefings, testimony before Congress, and education efforts with policy makers in federal agencies. On the state level, the organization—both through its members and as a separate body—has participated actively in interconnection proceedings in New York and Texas, and in legislative debates on electric restructuring in Virginia, New Jersey, Maryland, Ohio and Delaware. The DPCA is also in contact with state regulators to provide information about DR technology and policy issues, and has sponsored several national conferences to focus attention on DR issues, as well as a policy seminar exploring issues now before Congress.

DPCA has established *ex officio* ties with other organizations active in this field, including the California Alliance for Distributed Energy Resources, the Distributed Generation Forum of the Gas Research Institute, and the National Renewable Energy Laboratory. We have actively promoted collaboration between organizations, and sponsored a national meeting on interconnection in November, 1998, which brought together all the major organizations working on this issue. The DPCA also organized a national conference in conjunction with the California Alliance for Distributed Energy Resources in September, 1999 that brought together representatives from the major organizations working on the issue, as well as federal and state policymakers.

Introduction

The Arizona Corporation Commission's (ACC) role in the distributed generation (DG) rulemaking process is to ensure a healthy "customer choice" energy market in which all parties are treated fairly. One challenge lies in changing the focus of an established, conservative industry, which has traditionally viewed DG as a threat that justifies deterring implementation. During the first phase of the DG Workshop, safety and economic issues of DG were discussed in the context of old technology and the way things have always been done. The rules being formulated for the DG industry must take into account what is technically feasible today.

DPCA interprets the ACC's objectives to be:

1. The safe and reliable operation of the State's electric system;

2. The creation of statewide standards for the interconnection of Distributed Generating units;

3. The elimination of redundant and unnecessary costs of interconnection;

4. The incorporation of the latest technology, where appropriate, to enhance the operation of the utility system, and;

5. Non-discriminatory access to interconnection and application of tariffs, including tariffs that provide cost-based back-up and maintenance service to generators.

The reports recently submitted by the Siting, Certification & Permitting (SC&P) Committee; the Access, Metering & Dispatch (AM&D) Committee; and the Interconnection Requirements (IR) Committee should be viewed as the starting point in this process. These documents represent a considerable amount of effort by the parties in identifying the many issues surrounding the development and implementation of standard interconnection requirements for distributed generation resources.

However, substantial effort is still required to distill the many positions expressed in the reports into a final set of documents that can produce the benefits of standardization and maintain goals of safety and reliability. The reports, as written, do not provide meaningful standardization and do not facilitate the appropriate commercialization of distributed resources. Nor do they support the goals enumerated above.

The following represent some general observations:

1. The reports do not provide for the pre-certification or pre-approval of standard or identical equipment. (This is direct contrast to the pre-approval of certain relays and

circuit breakers already commonplace in the industry.) As a result, a valuable and obvious opportunity to reduce costs to customers and provide choice is ignored. Any attempt to standardize and streamline the installation of economic distributed resources must incorporate this essential component.

2. The reports should specify that all customers have access to non-discriminatory interconnection and tariff treatment to all customers. A facility's lack of QF status should not be used to deny interconnection or availability of cost-based back-up and maintenance power.

3. The reports do not clarify the jurisdiction and the role the Commission should have in DG transmission grid issues. This is important as larger onsite generating units will be connected either to the distribution system or the transmission grid, depending on the designations of these lines in various utility service territories. There may also be conflicts with other government agencies. Currently 100 MW plants are regulated by the State's Transmission & Line Siting Committee.

4. The Distributed Generation and Interconnection Working Group should evaluate interconnection activities in other states such as Texas and utilize commission-approved standards as a template to consolidate and structure a draft of proposed standards for Arizona.

5. The standards ultimately approved in Arizona should reflect the intended use and benefits of distributed generation. For example, if an installation is intended to provide grid support in a particular area of the system, the standards should not force it off of the system when it is needed the most as they might if the installation was treated more as an "appliance" or "negative load."

6. The working group reports preferentially treat induction and synchronous motors with respect to interconnection requirements. The reality is that both induction motors and synchronous motors are capable of generating power – at least for a brief period of time after they are shut off and coasting to a stop. Thus they are capable of providing fault current to the system in the event of a fault on the grid. Yet, DPCA is not aware of any requirements that a customer even inform the utility of the installation of a motor let alone a system impact study or relay coordination review. _

The Appropriate Use of the Working Group Reports in Meeting Objectives

The various working group reports cover many areas and report the positions of various parties on many issues. At least some consensus appears to have been achieved in several areas. These reports, however, are not sufficiently refined to clearly identify those areas of agreement, nor specifically how agreement is to be applied to any single application or unit.

While the division of labor into three groups was probably dictated and required by time constraints of the participants, it also created problems of consistency and coordination which must be reconciled as part of any final standard. Further, several unsubstantiated (and in DPCA's opinion, unsupportable) statements have been included in the report that are wholly inappropriate in a document purporting to be a set of standards.

DPCA offers the following discussion of how the considerable amount of work, evidenced by the working group reports, can be utilized to effect true standardization, consistent with the goals enumerated above. We offer these suggestions in the context of the ACC's objectives in this proceeding.

Meeting the Objectives of the ACC

Objective #1 – Safety and Reliability

DPCA strongly supports the Commission's objective of the safe and reliable operation of the utility grid. No member of DPCA is even slightly advantaged by a deterioration – or the perception of a deterioration – of the electric system in Arizona. DPCA's members have invested considerable resources and capital in the development of this exciting resource. That investment could be wiped out by a single incident resulting from inadequate or improper protective devices or schemes.

We are aware that there are parties to this proceeding that oppose standardization of, indeed, even the installation of distributed generators. We believe this opposition is misplaced and may reflect the economic issues of DG development more than the safety issues. We submit that a review of electrical worker injuries would reveal failure to follow established procedures as the primary cause of accidents.

System Mapping. System mapping, which would identify all existing DG units on the utility systems, as well as emergency contact numbers for each of these units, is a procedure that would eliminate many of these safety concerns. This has been accomplished successfully on natural gas pipeline systems, and similar procedures could be adapted easily for the electric industry.

While DPCA holds safety and reliability as an overriding objective of any installation, we reject the manner in which it is addressed in the working group reports. Safety and reliability seems to be used as a justification for almost any requirement - independent of other requirements discussed. Safety and reliability should be accomplished by the application of a standard in its whole – not by each of its parts.

Objective #2 – Standardization

In order for the work of these groups to have their desired affects, the reports must be reviewed and structures to provide meaningful standardization. Where standards need to vary by size, technology, feeder load or other unit characteristic, the standards should reflect those distinctions. The working group reports do not provide adequate structure in this regard and, in some cases, contradict statements in another report or elsewhere in the same report.

In addition, those existing utility requirements reported in various locations must be reviewed for legitimacy and possible standardization. This is not to say that a single State standard is always the most desirable result, however, it should always be the rebuttable presumption.

One example is the apparent prohibition to connect to a network system. Other states accommodate interconnection to network systems with relative ease. The considerations surrounding connection to a network system do not require the exponentially more difficult analysis opined by some utilities.

Objective #3 – Eliminate Unnecessary Costs

It is essential that any standards emanating from this effort accurately and definitively represent the actual requirements intended for a particular application. Standards that are too broad and fail to identify when and why they apply only reduce their effectiveness. Standards qualified by "...depending upon size..." or "...may be required..." that do not explain the distinctions in detail, DO NOT provide benefit to customers wishing to install distributed generation.

Precertification. The need for "pre-certification" of distributed generation units and systems is an essential and obvious objective. It provides manufacturers with the ability to mass-produce units based on standard design parameters which drive down the cost on a per-unit basis. Moreover, a utility should not need to re-assess the adequacy of a particular unit's design and functionality if it has already been approved elsewhere or on another electric system in the State as long as it meets the standards developed here. This eliminates duplicate review and unnecessary delays in the approval of customer applications.

Impact Studies. The imposition of impact studies can serve as another major deterrent to the deployment of DG, particularly for smaller units. Precertification of equipment should eliminate the need for individual studies for equipment. The Interconnection Policy should also indicate when a DG application triggers a distribution or transmission system study to establish the impact upon the utility grid. It should also include the various types of studies that might be needed, when they are required and who performs the studies. As indicated in the CC&P Committee Report, the Policy should put reasonable limits on the time frames allowed to conduct each of these studies.

Another issue is the importance of setting policy based on the relative impact of DG on the grid. Variables to consider include the size of the distribution line, the size of the generating unit, and where it is connected to the grid. For example, impact could be measured using the "50% of feeder capacity rule of thumb" to clarify the potential economic impact that DG is likely to have on the distribution grid. This would help minimize potential problems and save expenses by providing stakeholders with greater certainty of the likely impacts early on in the development process.

Best Planning Practices. The DG rules should also provide incentives for the electric utility to use DG in both the planning and operation of the distribution grid. The use of this technology can avoid more traditional upgrades of distribution systems, thereby creating substantial savings for ratepayers. The Commission should take note, however, that it may not be necessary for the utility to own the distributed generating units in order to benefit from their placement on the grid.

Standardized Procedures and Contracts. Another set of transaction costs that hinder deployment of DG is the lack of standardized commercial procedures and agreements. Texas, for example, created a standardized interconnection application, guidelines for their approval (with time limits) and a standardized interconnection contract. These documents reduce transaction costs for both the utility and the DG operator. The DPCA supports the adoption of this approach to reduce cost and time delays for projects.

Dispute Resolution. The rules also should identify an independent and equitable dispute resolution process that is separate from the ACC Staff and utility management. This would help to avoid costly legal proceedings for all parties. One possibility is assembling a panel comprised of utility representatives and independent industry experts.

Objective #4 – Accommodate technological innovation and advances.

Allowing Innovation. Substantial innovation and improvement in protective devices and operation have occurred since most utility specifications were substantially reviewed. Everyone can benefit from these improvements – including non-generating customers. The assumption that "what has worked for fifty years" is the best solution should be left at the door. All technologies must be given a fair chance to be incorporated. It may be necessary for the Commission to seek expert assistance in sorting through the parties' various positions on these and other technical matters.

Gaining Access to Technical Expertise. One difficulty in state proceedings is the need for technical expertise to make determinations about safety issues and the application of new technologies. In most cases, regulators have relied on the electrical engineering departments of the regulated utilities to provide that technical expertise. However, electrical engineers working with energy service companies and development companies bring a new perspective and should be consulted in the decision-making process.

Any proposed requirement by a particular utility must be subject to a meaningful opportunity for challenge. DPCA has observed that utility personnel are often skilled at applying existing utility standards but are less knowledgeable of the technical foundation of those standards. It is possible that a utility's position on a particular matter reflects more what has always been done, rather than what may be technically feasible.

One example in Arizona is the treatment of load balancing and back-flow prevention. On the Arizona Public Service Company (APS) system, network service is defined as two or more feeders from independent sources (each capable of meeting the full requirements of the load) tied 100% of the time in parallel to a buss bar in the customer's service entrance section. This kind of service requires sensitive load balancing and back-flow prevention. However, industry experts believe that technology now exists to allow DG to be safely applied to this kind of system.

Another example of this dilemma is the approach taken by the Interconnection Requirements Committee, which assimilated the existing standards of the various Arizona utilities. This committee assumed that utility-grade protection devices are required for applications starting at 300 kW when, in fact, technology now exists to provide adequate protection without creating an unnecessary economic burden on these relatively small DG applications.

The DPCA has recommended to New York regulators that a special panel of electrical engineering experts be available to regulatory staff to help them make technical decisions of this kind. This panel could include representation from both the utility, energy service and manufacturing communities. The ACC could also consider holding a separate technical workshop to consider the extent to which the precertification process addresses internal protective devices and other issues that arise in the proceeding.

Objective #5 – Non-discriminatory access to interconnection and Back-up service.

QF Status. There appears to have been considerable discussion and a fair amount of agreement that all potential installations should be treated equally – independent of QF status. This is particularly true with regard to access to cost-based rates for back-up and maintenance service. DPCA makes no statement as to the appropriateness of existing back-up service to QFs. These services should be made available to all generators who desire it and the rates for service should reflect the true costs of providing service to this class of customer, consistent with load diversity and characteristics of the class as a whole.

Fair and Reasonable Rates. In order for DG to be deployed, the Commission must also fashion fair and reasonable tariffs for interconnection and the ancillary services associated with onsite generation. Reasonable standby, backup and maintenance charges are essential if projects are economic and customers are to be encouraged to remain connected to the grid.

APS currently has both supplemental rate tariff and a partial requirements tariff. The Salt River Project (SRP) has a supplemental service rider that applies to the E-61, E-63, and E-65 rates (nothing for the residential or small commercial). However, supplemental rate rider is restricted to self-generation by qualified facilities.

AlliedSignal, a DPCA member, has prepared a white paper on rate structure that could serve as a starting point in the rate discussion. A copy is provided with this filing.

Other Issues to be Considered

Quantification of Potential Grid Benefits Arising Out of DG Installation

Other states, such as New York and California, have instituted processes designed to determine the value that distributed generation can provide the distribution system. Arizona's final proposal should consider these potential benefits as well. Customer choice cannot be fully optimized if customers are prohibited from obtaining the full economic benefits that their investment can provide to the electric system.

Mythology of Stranded Distribution Costs

This Commission should not be distracted by the specious and insupportable allusions to "stranded distribution" costs. First, customers who self generate will need back-up services to maintain operations normally supplied power from its own generation. Thus, appropriate distribution costs will be recovered through these rates. (It should be noted that the Group's reports actually REQUIRE that a customer purchase back-up services. DPCA strongly opposes such a requirement. If a customer doesn't need to back up its generation, it should not have to pay for service it doesn't need.)

The only way a utility can face stranded distribution costs is if the cost of back up services, if desired, exceed the cost to the generator of providing his own back-up by installing multiple units of capacity in excess of his load. This suggests that the capital and operating costs of distributed generation is less than the cost to the utility of providing these services from existing distribution facilities. We submit that this is an unlikely scenario in Arizona.

The Need for Flexibility in Determining Utility Status

As we move into a new era it is important for regulators to consider greater flexibility in its treatment of consumers and their desire to solve energy problems. The imposition of utility status will have a chilling effect on consumers striving to create energy efficiencies at a local level.

One example is Delaware, which included in its electric restructuring legislation a provision to allow onsite generators to sell electricity to five contiguous neighbors without triggering utility status. This provision will make it possible for industrial companies to install onsite generation and provide electricity to other nearby companies, thereby resulting in energy efficiencies that could not be achieved through separate units at each site. Delaware officials have concluded that imposing utility status in this case is not warranted. The DPCA agrees.

In California, irrigation districts have installed generating units at several locations to meet their electric needs, and have been threatened with utility status. Another example would be a corporation with a series of franchised stores within a utility service territory wishing to install one or more generating units to serve the needs of the separate corporate facilities and wheeling the power (under a distribution rate tariff) to the individual sites.

DPCA would ask that state regulators and legislators consider waiving utility status in these cases, particularly in light of the fact that all of these examples are based on commercial contracts between private parties and lack any legal "obligation to serve."

The Need for Information Dissemination

The SC&P Committee proposed that an independent nonprofit entity like the Distributed Energy Association of Arizona (DEAA) distribute prepackaged information on the process required to install DG. It would be beneficial to have a broad-based stakeholder organization facilitate this process. DEAA is an educational organization comprised of representatives from governmental agencies, electric and gas utilities, equipment manufacturers, distributors and installers, engineering and architectural firms, contractors, energy service providers, etc. Sarah McKinley, the Executive Director of the Distributed Power Coalition of America (DPCA) has identified DEAA as a model for other states to consider in promoting the benefits of DG and to assist with the dissemination of information on the various technical issues. As a result, Hawaii is considering establishing an industry membership organization like DEAA.

Conclusion

The DPCA applauds the efforts of state regulatory agencies to forge new policies that will fit the technological realities of today. Because the ACC is at the forefront of this movement, it has few examples to look toward as examples to emulate. However, to the extent that work is being accomplished in other states, the DPCA would urge the Arizona Commission to consider the work of other states as possible templates. Our organization believes that the interconnection requirements moving forward in Texas are the best example at this time.

The consumers of Arizona will benefit from this proceeding, which will allow them to realize cost savings, increased reliability, and environmental benefits.

Submitted, December 22, 1999

By

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From: "Skowronski, Mark J" <Mark.Skowronski@AlliedSignal.com>
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Date: 12/22/99 1:38pm
Subject: Honeywell Comments on AZ Workshop Proposals

Attached please find Honeywell's comments and recommendations on the Arizona Workshop Proposals for Distributed Generation. Should you have any questions regarding this matter, please feel free to e-mail or phone me at 310.512.4178.

Honeywell greatly appreciates the opportunity to participate in these proceedings.

Regards

Arizona Corporation Commission

ACC Docket No. E-00000A-99-0431:
General Investigation of Distributed Generation and Interconnection

Comments of

Honeywell Power Systems, Inc.

December 22, 1999

Introduction

Honeywell Power Systems, Inc. (Honeywell; formerly AlliedSignal Power Systems, Inc.) appreciates this opportunity to comment on matters relating to the safe and reliable interconnection of distributed generation in Arizona. Distributed generation (DG) can reduce costs and enhance reliability for customers. DG can also reduce costs and enhance reliability for the electric system, and increase the competitiveness of the retail electric market in Arizona by providing customers with additional choices.

Honeywell appreciates the complexity of the matters before the Arizona Corporation Commission (ACC or Commission). Honeywell would like to commend the Commission, its staff, and the members of the Distributed Generation and Interconnection Workgroup (DGI Workgroup) for the progress that has been made on interconnection standards, siting and certification issues, access and tariff issues, and related policy matters. The DGI Workgroup has met frequently to develop three reports. These reports were reviewed in preparation of Honeywell's comments:

- *Arizona State Draft Interconnection Requirements for Distributed Generation (Revision 3)*. Interconnection Standards Committee, Nov. 30, 1999 (IS Report).

- *Siting, Certification, and Permitting Committee Report.* Siting, Certification, and Permitting Committee, Nov. 22, 1999 (SCP Report).

- *Access, Metering, and Dispatch Committee Final Report.* Access, Metering, and Dispatch Committee, Nov. 22, 1999 (AMD Report).

Honeywell wishes to work in good faith with all stakeholders to help ensure that the parties are fairly treated.

General Comments

Honeywell offers the following general comments on distributed generation and interconnection:

- Technical standards for safe and reliable interconnection, a standard agreement, a standard application form, and standard review procedures and timelines are necessary to create a business environment for DG. Standards, coupled with mass production of small generating units, can reduce transactions costs and eliminate the need for case-by-case analysis of DG.

- Interconnection to the grid is of paramount importance to the DG industry. Without fair and equitable treatment, a standardized interconnection agreement, and pre-certification of identical units, the concept of DG will not come to fruition. Honeywell realizes that the utility distribution company (UDC) will have the responsibility for safety and reliability of the grid; however, regulators should ensure non-discriminatory open access to the distribution network.

- DG comes in small increments and the impact of any one small generating unit on the grid will be minimal. The behavior of numerous small DG systems can be determined through statistical means in much the same manner that utilities have determined the impact of numerous small loads. Therefore, detailed measurement of each DG system is not necessary.

- The UDC maintains certain obligations to its customers during this transition period and beyond; however, these obligations should not allow the UDC to provide privileged service to any class of customer, nor should it allow the UDC to restrict the development of a competitive market. Honeywell is concerned that unequal treatment of customers and unfair treatment of DG and other competitive options may result in insurmountable barriers to full customer choice.

- Honeywell supports the development of regulations that will require the UDC to act in a competitively-neutral manner. The association of the UDC with affiliated interests that own generation will make it difficult for the UDC to act fairly, thus giving cause for continued regulation of the UDC through an appropriate code of conduct.

- Honeywell in concerned that the system benefits of DG will not be adequately quantified and that this value will not be compensated. While there is a willingness of the UDC to account for and charge DG customers for any additional system costs, there is little willingness to account and pay for system benefits, such as improved power quality, dispatchable generating capacity, and other ancillary services. While the value of DG may be easily recognized by the end use customer, system benefits from DG may not be acknowledged by the UDC.

- Honeywell appreciates that growth in the application of DG may affect the profitability of the UDC under traditional regulatory approaches. An appropriate regulatory response is to alter the regulations such that the UDC has an incentive to operate as efficiently as possible. One approach is "revenue cap regulation" where the amount of revenue is capped. Under this approach, the UDC operates as efficiently as possible under the revenue cap, rather than attempting to maximize electricity sales to maximize UDC profits.

- A system of distributed resource credits should be investigated. Geographically "deaveraged" credits could share the benefits of installing distributed resources in high distribution cost areas without the adverse consequences of deaveraged customer prices. Distributed resource development zones could give developers information about where distributed resources are most desirable. This information could be coupled with location-based incentive payments -- such as standby charge waivers -- to encourage investment in distributed resources in these areas.

- Honeywell supports the development of open access distribution tariffs that mirror the Federal Energy Regulatory Commission's (FERC) open access transmission tariffs. The unbundling of distribution service tariffs will provide customers with more energy service and distribution service options.

In addition to providing these general comments and the specific comments below, Honeywell has provided two background papers that may be of interest to the Commission. The first paper discusses general barriers to DG. This paper will help the Commission understand Honeywell's general concerns regarding the regulation of utility market power. The second paper focuses on ancillary services provided by DG, and the need to provide incentives to DG customers. The papers are attached to these comments:

- Attachment No. 1. *White Paper: Comments on Economic Burdens and Obstacles Facing Distributed Generation*, Mark Skowronski, Honeywell Power Systems, 1999.

- Attachment No. 2. *Proposed Methodologies for Evaluating Grid Benefits of Distributed Generation*, Mark Skowronski, Honeywell Power Systems, 1999.

Comments on the Committee Reports

Honeywell offers the following specific comments on the three committee reports. An effort has been made to reference specific paragraphs.

Interconnection Standards Report (IS Report)

Honeywell believes the IS Report represents progress toward the goal of fair interconnection standards. Honeywell encourages the Commission to provide leadership with respect to the outstanding issues, including the issues that were not resolved by the committee.

1. Large power plant standards (Section 2, first paragraph). Honeywell supports the concept of protecting the public, protecting utility employees, and ensuring grid reliability. However, DG should not be held to the same standard as large central plants because DG cannot have the same impact on the grid. It is not appropriate to require DG to comply with all regional[1] rules and procedures. Applying these standards to a 100-kW DG system is unnecessary. There is no way, in any failure mode, that a small DG facility could impose significant harm or deterioration on the grid. Standards must be set and complied with, however, these standards must be consistent with the potential negative impact of a small, quality-controlled, mass-produced product. Different standards are appropriate for large, custom-designed, central plants.

2. Minimum standards (Section 2, third paragraph). The concept of a "notwithstanding clause" is inappropriate. A "standard" that is merely a minimum for public safety, and that allows the "industry" (presumably the utilities) to subsequently and unilaterally impose other criteria and requirements, will not work. This approach renders the whole concept of a "standard interconnection" ineffective. DG manufacturers require the certainty of standards to develop and bring viable products to the marketplace. All requirements must be specified in the standards, and deviations (which may be necessary from time to time) must be preapproved by the regulatory authority.

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[1] Regional organizations that impose standards include the Western Systems Coordinating Council (WSCC), the Arizona Independent System Administrator (AZ-ISA), the Desert Star Independent System Operator (Desert STAR ISO), the National Electric Reliability Council (NERC) and the Regional Transmission Organization (RTO).

3. Utility Grade Definition (Section 3, paragraph 3.19). The whole concept of "utility grade" products is antiquated. (The airlines made a comparable argument when they were deregulated stating that "planes would fall out of the sky" if their standards were not followed.) This term served a purpose in a monopoly environment, but it is inconsistent with the competitive environment. Once the technical standards are determined, competitors will develop new means of ensuring safety and reliability.

4. Non-PURPA facilities (Section 4, first paragraph). There are no laws prohibiting non-qualifying facilities (QF) from operating in parallel with the grid. The Public Utilities Regulatory Policies Act (PURPA) affords QF's the right to connect to the UDC; however, it does not state that only a QF can connect. The Commission should focus on what is necessary to enhance customer choice in Arizona, instead of focusing on special privileges that exist under federal law. All generating facilities, whether qualifying facilities or not, should receive the same treatment with respect to interconnection.

5. Non-radial lines (Sections 2 and 4). DG systems should be allowed on non-radial lines on an interim basis with appropriate, cautious restrictions. One approach that will allow the UDC to gain experience with non-radial DG applications is to restrict the amount of DG connected to a non-radial feeder. The Commission should explore any approach that insures that the impact on the distribution system is minimal. If the caution expressed in the IS Report is merely a step toward further negotiations, then the parties should continue to develop and resolve this issue. For guidance, the parties may review the Public Utility Commission of Texas Substantive Rule 25.211(h), relating to network interconnection of distributed generation.

6. Parallel Systems and Backfeeding (Section 5, paragraph 5.2). DG systems that are designed to prevent backfeed should not be classified as "utility interactive mode." These DG systems have one or more of the following attributes: (1) generation follows the house load being served; (2) installation of a reverse power

relay precludes backfeed to the grid; or (3) maximum load of the DG never exceeds the minimum load of the customer being served. Separate and streamlined procedures must be recognized for small DG systems (Class I & II) that do not backfeed to the grid. The grid essentially sees nothing more than a load reduction at the DG customer site. Except for certain grid enhancement (such as voltage support), a UDC would not be able to electrically distinguish that there is generation on the customer's premises under normal load situations. For abnormal situations, it is the purpose of standards to protect the public and UDC employees, and ensure grid integrity.

7. Blanket Approval and Type Testing (Section 5, paragraph 5.2) and Testing and Start-Up Requirements (Section 10). The rejection of the "blanket approval" concept by the UDC is inappropriate. A "type testing" or certification procedure can rely on standard interconnection requirements developed by nationally-recognized agencies, professional associations, and testing agencies (including ANSI, IEEE, and UL)[2]. The purpose of type testing is to ensure the grid's integrity, safety, and reliability. National criteria expedite the concept of pre-certification or type testing and eliminate the need for individual testing and verification of Class I & II applications. All DG units having the same operating, safety, interconnection equipment, and performance parameters should be allowed to connect to the grid as "pre-certified" units unless the UDC shows "cause" why such interconnection would be detrimental to the safety and reliability of the grid.

8. Studies (Section 6, first paragraph). No studies are necessary to interconnect DG in the following instances: (1) the DG does not constitute a significant portion of the short circuit duty of the feeder (the amount can be discussed); and (2) there is no feedback to the grid. Most DG systems that serve only a portion of the feeder requirements pose no more potential harm to the grid than an equivalent-sized electric motor.

[2] American National Standards Institute (ANSI), Institute of Electrical and Electronics Engineers, Inc. (IEEE), and Underwriters Laboratories Inc. (UL).

9. Cost allocation for studies and utility upgrades (Section 6, first paragraph). The cost of additional facilities installed on the utility system may be the responsibility of the DG developer or may be a cost that should be averaged into regulated distribution service rates. For example, studies required due to special circumstances such as the configuration of the distribution system (e.g., DG located at the end of the feeder), should be paid by all customers in distribution service rates. Honeywell is particularly concerned that the UDC would account for and charge DG customers for any additional system costs, but not be willing to account and pay for system benefits. These benefits include improved power quality, dispatchable DG generating capacity, and other ancillary services. Direct assignment of incremental costs to the party that caused the costs makes sense if that policy is consistently and comprehensively applied to payments to DG projects that reduce system costs.

10. Insurance (Section 6.1). The IS Report states that insurance may be required. Insurance requirements should be defined to provide certainty to the DG developer.

11. Electric Supply/Purchase Agreement (Section 6, paragraph 6.3). Honeywell does not agree with the requirements stated in this section because it appears that the UDC is mandating the level of service that a customer must receive. If the customer chooses not to sell back (feedback) to the grid, or elects not to have standby service, then no agreement is necessary. The UDC should not tie one product or service with another.

12. Meter Installation (Section 6, paragraph 6.6 and Section 8, paragraph 8.1.5). For those instances where there is no feedback, the customer is entitled to determine whether a meter is necessary.

13. Power quality (Section 8.4). The requirements are too vague and unenforceable. Honeywell recommends that a reference to the IEEE 519 standard, as this is a nationally-recognized standard on which all can (or should) agree.

14. General Protection Requirements (Section 8, paragraph 8.7.1.4). While the differentiation is made between a microprocessor-based protection package and traditional discrete relays, there is no mention made of using a different set of qualifying criteria for testing. These are two different kinds of protection schemes and the tests for a discrete relay operation may not necessarily be practical with a microprocessor-based unit. This is not to say that the microprocessor is deficient in any particular test requirement, only that different implementation methods may have to be used for true and accurate testing.

15. General Protection Requirements (Section 8, paragraph 8.7.1.6). The grounding requirements for a DG located on site is no more than an equivalent sized induction motor. (Rarely is there a utility requirement for grounding when kWh sales result.) In addition, a static inverter usually has fault current limits that are $^1/_3$ or ¼ of a traditional generator or motor. This requirement is unnecessary.

16. General Protection Requirements (Section 8, paragraph 8.7.1.7). The utility should make no rules regarding how the customer protects his/her own equipment unless there is an impact to the grid.

17. Generator Class Protection Requirements (Section 8, paragraph 8.7.2.2.4). Any requirements imposed by the utility on a pre-certified non-feedback unit must have demonstrated "cause" by the utility. Any investigation to determine "cause" must be paid for by the utility. The UDC must not be allowed to arbitrarily assess DG on a case-by-case basis when it is not needed for small, non-feedback, pre-certified DG units. If the Commission determines that there is a justified cause, then any modifications required to modify the grid should be paid by the DG customer.

18. Application and Equipment Information Form (Appendix A and Supplemental Information). Nearly all of these requirements and needs can be satisfied by applying the pre-certified unit concept. It would be redundant for a customer to submit additional information if the DG unit is already pre-certified.

19. Load Characteristics and Relay Settings (Exhibits 1 and 2). The concept of standardization is to have a common set of parameters. DG manufacturers can comply with uniform national standards. Different requirements for each utility defeat the purpose of standardization. There is simply no point to having a "standard" if each utility imposes its own conditions.

20. Application Process (Exhibit 3). Given the serious concerns that Honeywell has concerning the interconnection standards, the application process should be rethought. In particular, the concept of streamlining, fair allocation of risks, the need to perform only needed studies, and the use of the pre-certified concept should be taken into account. Honeywell suggests a separate meeting with the stakeholders to re-work the application process.

21. Time limits (Exhibit 3, Step 9). This matter is discussed below in the SCP Report comments.

Siting, Certification, and Permitting Report (SCP Report)

The SCP Report opens with a recognition that "There is currently no written set of statewide requirements" for siting, certification, and permitting, and "Each Utility Distribution Company (UDC) has individual requirements dating back to the Public Utilities Regulatory Policies Act (PURPA)" (Executive Summary). The development of written statewide requirements and the elimination of UDC discretion are essential to the development of an appropriate business climate.

22. Standard process. Honeywell agrees with the recommendation that a statewide standard application process be developed (SCP Report Recommendation 1). While the ACC does not have the jurisdiction to address all siting, permitting, and personnel issues, the Commission can take the lead to educate local governmental entities so that their processes are simplified and standardized. Further, the Commission can take the lead to prepare a list and flow chart that outlines the agencies involved in the permitting and approval of each DG project (SCP Report Recommendation 2).

23. Time limits. Interconnection should proceed smoothly and rapidly once the technical standards are established. If a unique situation arises, and the UDC believes the DG system will compromise the grid, the UDC should obtain a Commission order to address the problem. In instances where studies are required, the scope, timing, and cost of any study should be set forth in a matrix. The matrix must include all requirements, and no UDC should be allowed to unilaterally develop new requirements. The study time must not be left to UDC discretion, and a promise to "handle the process expeditiously" (SCP Report Section 4) is not acceptable.

<u>Access, Metering, and Dispatch Report (AMD Report)</u>

The AMD Report addresses a variety of issues that are critical to the establishment of a competitive retail market. Honeywell recommends that the Commission take time to fully develop the tariffs and policies that will support full customer choice. The AMD Report addresses the impact of DG on the grid, the potential remedies to these impacts, and the tariff and policy issues.

Operation and UDC Planning Issues

Honeywell is concerned that distribution operations and planning activities may provide the UDC with opportunities to establish barriers to DG. Honeywell advocates a "plug and play" approach that will eliminate the need for case-by-case analysis of DG installations.

24. Impact of DG (Section II.B.2.d). Honeywell finds that the AMD Report unfairly singles out DG as the cause of supposed grid impacts. The operation of DG is similar to demand-side management, where customer load is reduced through load control. The sudden arrival of a cold front on a warm day, or the loss of a customer through an industrial plant closure creates similar impacts on the grid. The UDC has been managing similar impacts since the creation of distribution systems.

25. Potential Distribution Impacts (Section II.C.2). Just as the DG customer might "lean" on the grid, the grid might "lean" on the DG customer if the grid experiences problems. The UDC should attempt to determine how best to maintain service using all available resources.

26. UDC Potential Planning Remedies (Section II.F.4). The required studies need to be set forth in a matrix so that DG developers will have certainty with respect to the scope and timing of all studies. Honeywell is concerned with the references to "permitting," and seeks clarification with regard to which entities will have the authority to permit or certify the DG units.

27. Voltage Profiles (Section II.F.4.c.3). If a DG customer is required to buy power factor correction from the UDC, then the UDC should be required to buy power factor correction from the DG customer if it is being provided.

Tariff and Policy Considerations

Honeywell believes that alternative approaches to the regulation of the UDC will provide appropriate incentives for the efficient operation of the grid.

28. Partial Requirements Direct Access (Section III.B.2.d) and UDC Recovery of Distribution Costs (Section III.D (sic)). Honeywell does not agree with the UDC position that there is a concern with the recovery of T&D costs from the DG customers. While it is true that current rate design largely relies on volumetric charges, it is not true that the traditional approach to regulation and rate design is efficient or effective. Honeywell recommends that the Commission explore alternative approaches that will provide incentives to the UDC to reduce costs. Because fixed cost recovery is at risk with respect to the total volume of sales, traditional regulation has provided incentives to increase the volume of electricity sales. A per-customer revenue cap (PCRC) approach is one alternative method of regulation that is worth consideration. A PCRC, coupled with an annual reconciliation, eliminates fixed cost recovery risk completely, but allows

continued use of volumetric retail T&D rates. A PCRC also removes much of the incentive to erect market barriers to DG.

29. Selling Excess Power (Section III.C.1). Honeywell concurs that the market is not sufficiently developed to ensure "effective competition" and that regulatory oversight is warranted to ensure that the market is not functioning at the discretion of the UDC.

30. Tariff and Policy Issues (Section III). Honeywell supports the development of open access distribution tariffs that mirror FERC open access transmission tariffs. There is a need to develop and enforce an open information system in order to make open access workable.

31. UDC Recovery of Distribution Costs (Section III.D (sic)). The UDC should not be allowed to provide privileged service to any class of customer. Honeywell is concerned that unequal treatment of customers and unfair treatment of DG will present insurmountable barriers to customer choice. Tariffs that allow the UDC to match any alternative energy pricing to the customer should be carefully analyzed. The "contribution to the utility margin" concept greatly restricts the right of the customer to choose, and unilaterally benefits the utility. Since the utility is already protected through stranded cost recovery, it is unfair to afford the utility additional authority and pricing flexibility. The ACC should ensure that distribution cost recovery and generation cost recovery are treated separately. The Commission should ensure that no predatory pricing exists, either by design or accident, as a result of the utility tariff structure.

Conclusion

Honeywell appreciates the opportunity to submit these comments and would be willing to participate in the development of standards and regulatory mechanisms that encourage full and fair retail competition.

Attachment No. 1

White Paper

Comments on Economic Burdens and Obstacles Facing Distributed Generation

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Introduction

From the early 1900's until the early 1970's, the regulated electric utility compact with the regulatory agency has been hugely successful, ensuring a real or constant dollar cost reduction in the price of the product (kilowatt-hours) every year except one (1943). This compact is the "quid pro quo" agreement between the utility and the regulatory agency that allows the utility to operate a monopolistic franchise to sell electricity, and, in exchange, the regulated utility was obligated to serve all who asked to be served, to price their product according to cost (*not* according to market) and to be allowed an opportunity to earn a fair return on invested capital.

Around 1970, however, the real dollar cost of electricity started to rise and the first chapter of the free market and entrepreneurial generation of electricity was created with the passage of the Public Utility Regulatory Policies Act (PURPA) in 1978. This act allowed competition to help ensure lower generation costs. But while PURPA established a market only for generation, the current restructuring is establishing a market for the consumer and also integrates the exchange between the seller and buyer. This integration is the primary purpose of restructuring and must allow the consumer free and unfettered choice; ultimately, the concept of "doing it yourself" with on-site generation represents the final choice by the consumer in a free and open market.

During the transitional period of the electric industry restructuring, regulated utility companies are being exposed to a more competitive market and, in many cases, being divested of the generation aspect of their business. Confounding the transitional period is the introduction of a disruptive technology, distributed generation, which, while not necessarily directly associated with the restructuring effort, is nevertheless dependent upon the utilities accepting competition, and allowing free and open access to the grid.

As deregulation continues in the electric industry, the Competitive Transition Charge (CTC) and Exit Fees have been the focal point of many discussions, as they exact specific and retroactive charges against owner/operators of distributed generation products. In addition, unfair and/or unjustified Standby Charges, Contract Complexity and Interconnection Requirements may also result in obstacles and burdens imposing significant economic penalties against distributed generation. Finally, little or no acknowledgement is attributed to distributed generation's benefits to the UDC and the ratepayer/consumer.

The purpose of these generalized statements is to offer arguments and positions that are fair to all parties, and to identify certain inconsistencies and unreasonable utility practices that, either through deliberate obstinacy or unintended actions, may result in significant economic and contractual penalties that precludes the use of distributed generation.

Relationship Among the Parties

Honeywell, as well as a multitude of other companies, wish to enter the distributed generation market. While the manufacturers feel that each of their products will be superior to the utilities' product (and, of course, superior to each other), we, the industry understands that, ultimately, it is the consumer who will determine the worth of our products. However, in this peculiar and unconventional market, to deliver the greatest value to customer and grid, we must pass their product through the control of our biggest competitor...the utilities, in order to access our customers. It is very difficult to do business on a "level playing field" when you must pass your product through the competition.

Imagine yourself as the CEO of Pepsico and you wish to sell Pepsi to the customers of Coke. Only in this market, you must not only ask permission of Coke to sell your drink, but also must accept the terms and conditions dictated by Coke upon which you will make your sale. And, of course, every time you are successful at making a sale, Coca Cola will lose money (or, as in our case, the CTC and the contribution to utility margins). This analogy is not altogether inaccurate or untrue when related to the concept of distributed competition. Although the utilities are a regulated monopoly under the supervision and surveillance of the ACC, the contractual terms and conditions, technical requirements and tariff interpretation and/or manipulations dictated by the utilities to the owner/user of distributed generation pose enormous opportunity by the utility to self-deal.

Unfortunately, under the present rate structure and monopoly rules, the concept of distributed competition puts the utilities in a position of potentially losing revenue and, for the near interim, a loss of CTC collection. Accordingly, the utilities will do what any privately owned companies do...protect their revenue stream within all legal means. Given the unique nature of control the utilities have over any distributed competition, i.e. all competitors must access their customers through the utility, the utilities can only be expected to provide nuances of barriers under the guise of grid protection, uneconomic bypass, safety and reliability. The intent of the utilities may be noble and represent an honest attempt to "protect" their customer. But that is the point...under deregulation, the utilities are not automatically entitled to the customer. The regulator should provide market alternatives to the consumer,...if you deny the consumer alternatives, you are denying the consumer choice! And if you deny choice then what is the purpose of deregulation?

There are three stakeholders: the distributed generation owner/manufacturer; the utility; and, the consumer/ratepayer. In addition, there is one rule maker and referee...the regulatory agencies. In order to provide harmony among the stakeholders, we respectfully ask the regulator to ensure the following three items:

- fairness;
- consistency; and,
- remuneration or incentive to all.

Without these three values, the full promise and benefits of distributed will be difficult to realize.

Stranded Investment for T&D

The finances/economics of a regulated utility is generally based on a "return on the investment" premise which allows the utility an "authorized rate of return" on capital spent and a fair opportunity to earn this return. It was this concept of return on capital that led many utilities to invest in large and high capital cost power plants, e.g. nuclear and coal. Many of these plants are no longer economically viable and this "stranded investment" forms the core argument for collection of the CTC. In many instances, the argument is valid, since many types of generation, for fuel diversity and environmental considerations, were thrust upon the utilities by the regulatory agencies even though the generation technologies were known to be economically non-competitive. The non-economic penalty was essentially "ratebased", i.e. spread over all customer bills as a cost of doing business, albeit for the ratepayer's overall societal benefit. For Transmission and Distribution, however, there is different rationale.

T&D Does Not Qualify for Stranded Investment

Transmission and Distribution should not qualify as stranded investments for the following reasons:

- The argument and rationale for collection of generation stranded investment are not applicable to T&D. Indeed existing precedent precludes the argument to allow any form of CTC collection for unused portions of T&D. The utility covenant with the regulators has always required investments made by the utility on behalf on the ratepayer (and to the benefit of the shareholder) to be "used and useful". Failing this basic test, empowers the regulators to take the investment out of the ratebase at a shareholder loss. This basic test of "used and useful" has always been applied on an economic basis; there is no reason to change this precedent due to the technical obsolescence of a particular utility investment.

- Furthermore, the installation of a non sell back distributed generator (i.e. no electricity flow to grid) is merely another form of Demand Side Management (DSM). By the use of the DSM, house or on-site load reductions are accomplished which may greatly benefit many utilities' T&D systems especially on peak days. By the use of DSM and reducing demand on the system, imported power that the utility may be receiving via transmission interties can be increased without the incremental cost of transmission addition. In addition, of course, there is also the benefit of distribution deferral that can be attributed to the installation of distributed generation.

- Finally, while there is no CTC/exit fee for new site distributed generation, i.e. areas where distribution costs are reduced or avoided to serve a new location, there is also an unrecognized saving to the utility by not having to install the incremental T&D. This is because the utility is saving an unrecognized incremental T&D charge which is almost always higher than the average weighted cost of T&D. Accordingly, distributed generation for new facilities saves the ratepayer money since the fixed capital base is not increased.

The use of distributed generation is a form of Demand Side Management which lowers the incremental costs of both transmission and distribution to the utility. Accordingly, stranded investment or exit fees cannot be justified.

Standard Interconnections

Distributed generators must be allowed to connect to the utility grid if the benefits both to the customer and grid are to be realized. Owners and operators of distributed generators are concerned about false safety issues, fees, and other interconnection requirements which could provide additional barriers to DG. We recognize the legitimate safety and reliability concerns associated with interconnection, however, regulators must ensure that the interconnection standards do not become an artificial barrier to DG.

To this end, a common set of technical interconnection requirements should be accepted by all participants and sides in the deregulatory arena. In so far as practical, a national standard should be adapted when available. The IEEE currently has a subcommittee working on the development of a standard interconnection for distributed generation. The final package (dubbed Standard No. 1547) will be a consensus effort with all committee members, consisting of a wide diversity of nearly 200 interested parties, agreeing on the principles and requirements for interconnection. We at Honeywell strongly endorse this voluntary, consensus effort by the various stakeholders to come to terms on this important link to the free and open market of competition.

The alternative to no national standards is a state by state morass of 50 different standards fueled by the requirements of over 3,000 IOU's. The economic concept of distributed generations is based on "unit volume production" as opposed to "unit size". A large plant connecting at transmission or subtransmission voltage can easily absorb the cost of designing and constructing to a unique interconnection standard, but for a volumetric based industry, a common and nationally accepted interconnection standard is, literally, a "make or break" issue for distributed generation. Without a national standard, distributed generation will be relegated only for those larger markets which permit volume product based on a set standard. Honeywell strongly urges the regulator to adapt a national standard for interconnection as soon as practical.

Without a national standard, distributed generation will be relegated only to those larger markets which permit volume production based on a set regional standard.

Predatory Pricing and Tariff Fairness

The utilities are obligated by law to "price according to cost". The concept of a return on an investment in lieu of a market risk based profit is a basic tenet of the legal monopoly enjoyed by the electric utility industry. However, under deregulation, the way the utility is structured and does business will change. The remnant of the vertically integrated utility will be the distribution or "wires" company that will still have the power to establish the tariffs paid by the electricity customer. There is significant opportunity by the "wires" company to establish tariffs, and to enforce existing tariffs, in such a way as to establish a bias against distributed generation. In many instances, tariffs approved by the regulatory authorities allow the utility to match any alternative energy pricing to the electricity customer so long as the pricing structure provides a contribution to the utility margins.

This type of tariff, generally called a "generation deferral" concept results in:

- greatly restricting the right of the customer to "choose";
- unilaterally benefiting the utility; and,
- imposing an unfair and restrictive burden on the distributed generation market.

Since the utility is already protected from generation stranded costs, this type of tariff tampering is essentially an "end around run" to protect distribution facilities and is grossly unfair to the electricity customer, since, in the long term, the customer is being denied "choice". Regulatory guidelines should be established to ensure tariffs are true "according to cost" mechanisms and, in addition, prior to approval by the regulatory authorities, tariff impact studies should be mandated and include the potential effect on the distributed generation market. The goal is to ensure that no predatory pricing exists, either by design or accident, as a result of the utility tariff structure.

Regulatory Authorities should carefully evaluate the impact of new and existing tariffs to determine the impact on distributed generation and to ascertain whether predatory pricing exists.

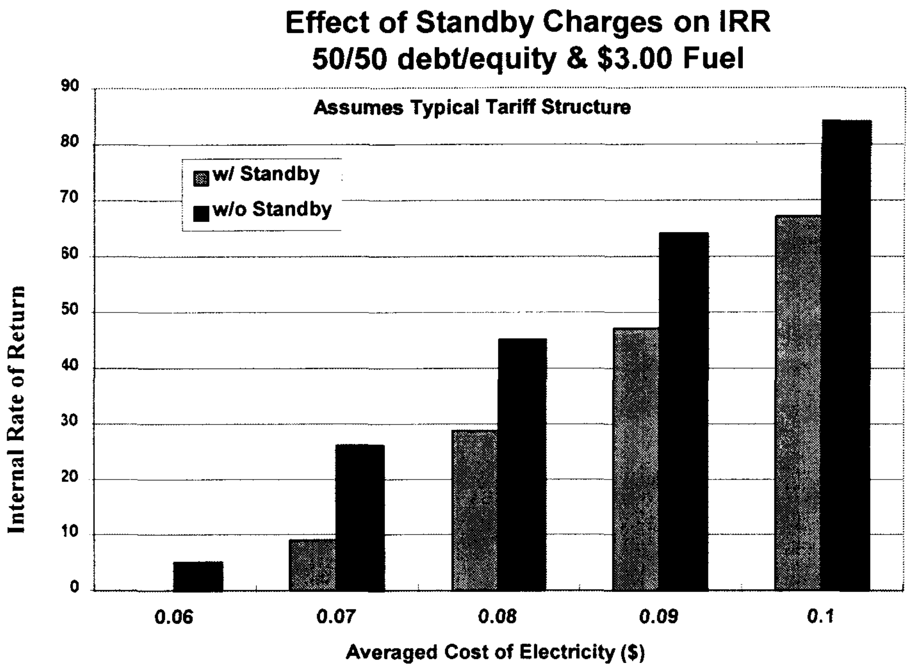
Standby Charges

Perhaps no single issue is as subjective, qualitative and potentially injurious to the economics of distributed generation as is the "standby charge". We fully recognize that the utility is providing a service to the owners of distributed generation and that fair compensation for this service is required. However, the manner of calculating this charge fairly is murky.

In the past, utilities have used the concept of a combustion turbine installation as the basis for Standby Costs to the ratepayer. This concept held that the cost of maintaining generation to provide standby capacity is the appropriate and fair cost to pass to the ratepayer requesting standby service. However, in recent years, perhaps in anticipation of restructuring, the method of calculating standby costs has shifted from standby "generation" to the cost of the "wires" needed to serve the customer.

The utility now wishes to determine the cost of standby charges based on the cost of the "wires", i.e. the transmission and distribution system to the ratepayer. While certain arguments can be made, such as basing any standby T&D costs on the book value and not replacement value, in the end, any argument that relies on accounting practices by the utilities can be construed, and will ultimately become, self-serving. There is simply no quantitative way an accurate, fair and consistent method of accounting can be developed given the complexities and inherent overlaps of the T&D infrastructure. The only "fair" method would be a rate based on the aggregated cost of T&D and then charging the customer a portion of these costs based on capacity use. But this is highly discriminatory since "first on the line" will have paid considerably less than the "last on the line" given that the incremental cost in real dollars is substantially more to connect new customers. And given these complexities of cost calculations there can be no accurate, fair and consistent method to ensure that the utility has indeed calculated a fair cost to the ratepayer for standby service.

The results of a high standby charge to an owner of distributed generator is illustrated below where an internal rates of return are shown with and without a typical Standby Tariff of $7.00/kW-month. The national average cost of electricity is about 7.5 cents/kWh; as noted on the graph, it is at this point where the impact of a heavy handed standby charge is felt the strongest and has substantial and deleterious effects on the internal rate of return (IRR) to the distributed generation user. The effect of the standby charge is diminished with a higher IRR since the fixed standby charge is reduced in proportion to higher profits.



As noted above, when the standby charges are added, the IRR is reduced to approximately 9% which would most likely be below the "hurdle rate" for the owner investor of distributed generation. The purpose of quantifying the effect of standby costs is not to present an argument to arbitrarily lower or eliminate the charge, but rather to illustrate that any excess, either by design or accident, can and will have significant and deleterious effects on the economics of distributed generation

Overall rate restructuring can also be detrimental to the IRR of on site DG owners. Manipulations of the "on, mid and off peak" energy and demand charges can significantly effect the overall return to the owner of distributed generation. Rates can be restructured such that the average cost of the bill remains the same to the customer, but if the customer self generates a portion of his bill, the savings evaporate due to the higher billing of the remaining energy and demand served by the utility. Such restructuring normally shifts the market where one application may now be uneconomical to serve but other applications become profitable. However, in this market shifting, ultimately the overall market may shrink for distributed generation as the utility structures its tariffs to protect itself and not create markets for the competition

The ACC should pay particular attention to the method of calculation of standby charges and ensure that they are fairly calculated as these charges significantly effect the economics of most distributed generator.

Barriers by Another Name

While we recognize certain obligations of the existing utility company to its customer during the deregulatory period (and beyond), these obligations should not be allowed nor construed to be a license for "privileged" service to the electricity customer. In addition, this privileged position should not be used to set up artificial barriers and obstacles that inhibit customer choice. Ultimately, market decisions to buy or purchase must be made by the consumer and not by the entity that is selling the wares, be it the utility or manufacturer. Certain nuances of rules and laws can be further exasperated by the utilities' interpretations or concerns that may be beyond normal expectations and rationale. Some of these concerns are described below:

Case by Case Analyses

The vast majority of small scale distributed generation will not involve sell back, i.e. flowback of electricity to the grid. Accordingly, as determined previously, the distributed generator, in these cases, are DSM. Furthermore, those distributed generators that use inverters (an electronic device that can convert dc or high speed ac to a standard 60 cycles) pose significantly less risk to the grid than an equivalent sized electric induction motor running, say, a refrigeration unit. In order to facilitate the installation of equipment, the distributed generation industry supports the concept of "Type Testing" where one unit is configured to meet the necessary interconnection requirements and then other similar models, which would have an UL stamp or equivalent to warrant similar performance and operation, would be allowed to connect without requiring a case by case inspection.

Contract Issues

At one utility, a 43 page commercial contract (with several long appendices) was required to connect a 37 kW distributed generator; one sentence in the contract was 98 words long! The contract took approximately $13,000 in legal and technical fees to consummate. Clearly, this cannot be sustained on an individual unit basis. A clear, concise, consistent and uniform contract must be established before there can be a mass market for distributed generation.

Utility Purchases

The ability of the utility to purchase distributed generation is clearly to the benefit of the ratepayer and consumer. Distributed generation allows the utility to best serve its customer by allowing its planners, economists and engineers an additional "solution" to the intricate problems involving distribution. The grid can be optimized for maximum performance if only all of the available options and resources are evaluated and used. Accordingly, while not a specific "barrier" to deployment per se, the disallowance of the utility to own distributed generation will retard and minimize the market keeping the production volume low and depriving the market of more cost effective technologies. Distributed generation is based on the economics of production; minimizing the market is self defeating.

available at whatever cost people are willing to pay, i.e. the "market price". These margins will most likely be in the form of "hedging" contracts provided by Power Marketers who will broker the excess generation capacity to the ISO and/or by direct customer contracts.

Proposed Method to Quantify Savings

The use of Distributed Generation, installed as emergency house "back up" or to improve reliability of the host customer, can be called upon to start whenever the system or grid is capacity short or when there is an interruption in the transmission service. The savings available to the ratepayer is the difference between the cost of running the emergency generation and the cost the utility or ESCO/marketer would have had to pay on the open market for the same capacity/energy. To simplify, a fixed rate could be established with predetermined portions going to the three stakeholders: ratepayer; Distributed Generation owner; and, utility. In this manner, reliability to the system as whole is increased and the ratepayer and utility share in the economic gain when compared to not having Distributed Generation available.

<u>Transmission Loss Reduction</u>

Wide spread use of Distributed Generation will reduce the utilities need to import power. This reduction will allow the utility to "wheel" additional contracts between the points of installed generation and the end use customers. This is particularly important when the ISO is bypassed, i.e. the end use customer has a direct contract with the power generator.

Proposed Method to Quantify Savings

The amount of Distributed Generation power/capacity produced within the utilities urban areas can easily be determined and that amount of power can then be subtracted from any incremental power that would have been wheeled from afar. Particular transmission losses need not be accounted for but rather an aggregate average of reduction in imported power. The transmission losses are the "saved" amounts of energy that benefit the stakeholders; this saved energy can be "monetized" and the savings passed to the stakeholders.

<u>Spinning and Non-Spinning Reserve Margin</u>

Under deregulation, the utility will most likely be obligated to provide power as a "last resort". This will necessitate a certain amount of reserve, both spinning and non-spinning (immediate standby) to be provided by the utility.

Proposed Method to Quantify Savings

Distributed Generation can provide a portion of these requirements by utilities contracting with the Distributed Generation owners to provide the required capacity margins. The Distributed Generation owner would pledge to provide actual capacity back to the system, or in the case of a customer installed emergency generation, the Distributed Generation owner would pledge to start up his emergency generator to serve his own "house load". The savings to the ratepayer is the difference of what this capacity would have cost on the open market vs. the cost of the using Distributed Generation at a predetermined contractual price. The utility would be paid a portion of the savings realized by the ratepayer; "bookkeeping" would be the responsibility of the ISO.

The New York ISO DSM Focus Group Report entitled "The Role Of Demand Reduction In New York's Electricity Markets" could serve as a template to determine several ways to quantify the worth of Distributed Generation when used as "Spinning or Non-Spinning Reserve" margins. While this report is obviously specific to the New York region, the methodology could be applied to other utility territories.

<u>Peak Shaving And Interruptible Loads</u>

Peak shaving is the ability to assist the utility/ISO in meeting their peak demands through the use of generation other than what would be available from the utility or ISO. Distributed Generation is particularly well suited for this use since it does not necessarily have to feed the grid to "shave" the peak. By having the customers meet their own needs at critical high capacity times also, effectively, reduces the load served by the grid and thereby reduces the overall demand. The amount of capacity/energy that is reduced or "shaved" can be easily calculated in an unregulated market. During high capacity periods, the amount of capacity/energy provided by the Distributed Generation units could be ascertained and quantified by merely using the market value of the replaced capacity/energy. Peak shaving is perhaps the most valuable and easily quantified benefit of Distributed Generation that benefits all of the stakeholders.

Proposed Method to Quantify Savings

By serving his own peak loads (and thereby reducing the amount of capacity/energy served by the grid) or by feeding capacity/energy directly into the grid, the owner of Distributed Generation provides a definitive and quantifiable benefit to the ratepayer. The cost of capacity and energy becomes acute in those situation of very low capacity factors. Theoretically, the cost of serving the last kW on a grid system becomes astronomical since this last kW may only be needed for, say, a few hours a year.

Consequently, the true market cost of this last kW is very high since little revenue is generated to pay for the indebted cost of capital. For example, if a "peaking" kilowatt is required for 25 hours per year and the installed cost of this "peaking" kilowatt is, say, $250/kW. Then the recovery of this invested capital is $10/kWh (plus the actual fuel or energy charge, which is miniscule when compared to a very large capital recovery charge). Accordingly, the actual market price of this seldom used kW is roughly $10/kWh.

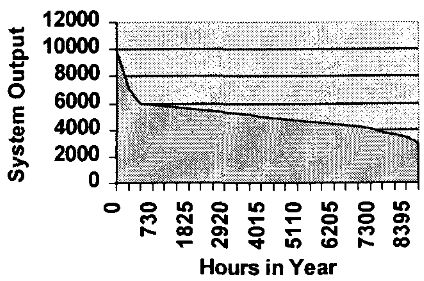
The "Load Duration Curve" chart above represents a grid system that has a 10,000 MW peak (ordinate axis); the System Output corresponds to the number of Hours per Year (abscissa axis) that the load must be served. (For example, approximately 4,000 MW's must be served for 7,300 hours per year.) It is seen that as the peak is shaved, the next to last supplied kW's are used more often in the year, and, therefor, become less expensive since these kW's are now supplied at a higher use (capacity) factor, i.e. the generation source is used more often. In other words, the <u>last</u> kW supplied to the grid may be required for only 25 hours per year, but the <u>next to last kW</u> will be required for, say, 30 hours per year, and so on. As the "capacity factor" is increased, the fixed cost component of each kWh decreases because the capital recovery factor, on a per unit basis, is reduced with higher usage. Ultimately, the concept of peak shaving reduces the overall cost of demand by lowering the average cost of generation. Accordingly, ratepayers (and all customers of demand) benefit since peak shaving reduces the averaged demand charge.

The cost saved could be calculated based on the value of the next kW available on the market, or simply a fixed charge per kW could be used when Distributed Generation is used on peak to satisfy the customer's internal loads or feeds back to the system/grid. These savings are then dispersed to the stakeholders.

<u>Transmission and Distribution Deferral</u>

Another significant and easily quantifiable benefit of Distributed Generation is the offsetting of Transmission and Distribution upgrades (T&D Deferral). The use of Distributed Generation can, in many and perhaps most cases, provide a more cost effective and less disruptive method to serve those areas where voltage sags or when T&D construction is required for a new service to a mall, school, hospital or small commercial or industrial center.

Load Duration Curve



In addition, larger Distributed Generation concepts or "aggregate" systems of smaller Distributed Generation can also offset large transmission lines that may be required to bring power to a growing area.

Proposed Method to Quantify Savings

Currently, the "wires" portion of the utility is not generally obligated to investigate Distributed Generation as a alternative to installing additional transmission and distribution lines. The regulating authorities (Public Service Commissions, Public Utility Commissions, etc.) should mandate the utilities to investigate the use of Distributed Generation as a potential option prior to any T&D upgrade. In this study, the cost differences could be ascertained and these differences would then define the savings associated with using Distributed Generation.

<u>VAR Support and Power Quality</u>

An important service currently provided by, and sometimes charged for, is the amount of reactive power (VAR's) that the utility produces in order to keep the system stable. Many Distributed Generation technologies, such as the microturbine and fuel cells can provide VAR's to help maintain system competency. VAR's charges are normally added to a specific utility bill when the customer loads have excessive VAR needs.

Proposed Method to Quantify Savings

The value of service for VAR generation has, in essence, already been calculated by the utilities. The value is merely the added facility charges the utility would charge the customer due to excessive VAR requirements. The utilities should be required to allow the customer to serve his own VAR needs by taking the additional monies that the utility would charge and giving it to the customer to allow him to meet his own needs. The VAR surcharge paid by the utility to the customer could help offset the cost of installing Distributed Generation which would then provide added benefits to the system.

<u>Cogeneration Capability</u>

The installation of small thermal powered Distributed Generation on the customer's site allows for cogeneration of energy streams that a traditional, central station plant cannot provide. This is an innate benefit of Distributed Generation. Normally, cogeneration uses the waste heat from electric generation to provide hot water or steam or direct thermal energy to meet the customer needs.

Proposed Method to Quantify Savings

While there is macro societal benefits to cogeneration, the actual benefits are difficult to quantify. It is in *everyone's advantage, however, to use fossil fuels as prudently as possible; not only for conservation of natural resources but also to reduce global warming gas emissions as well. There is proposed legislation on the federal level that offers quantifiable values for reduction in CO_2 and this may be one way to asses a benefit to cogeneration. Another way is to have the local jurisdiction set the value of emission reductions, although this method would be highly regional at this time and really does not address the true benefits of cogeneration. Some sort of fixed allowance should be reached on a consensus basis among the stakeholders and a flat incentive fee paid for installing cogeneration. Alternately, this incentive could be in the form of expanding discounts on the gas rates. Assuming no additional infrastructure is required to deliver additional gas, rates should be based on the incremental cost of the commodity and not be based on fixed tariffs otherwise "windfall" profits will result..*

Improvement in Utility Load

The use of Distributed Generation improves the utility generation load factor. This allows the utility more revenue on a fixed asset base and ultimately will lower the overall demand charges paid by the ratepayer.

Proposed Method to Quantify Savings

The concept to share in the savings due to an improvement in the utility rate base is analogous to the argument presented above in "Peak Shaving". As the utilities/ISO load factor is improved there will be savings generated to the ratepayer. Normally, this would be reflected in lower tariffs on the "wires" and lower capacity/energy generation costs from the ISO/Utility. If these benefits are derived from Distributed Generation, then the savings should be passed to the stakeholders.

Fuel Diversity

From time to time, the regulatory agencies will require the utility to install certain kinds of generation to ensure a diversified fuel mix. Fuel diversity allows for increased generation reliability in case of a specific fuel type interruption. Generally, when a power plant is built with a specific fuel specified, there is an economic penalty associated with the type of fuel used.

Proposed Method to Quantify Savings

It is not known how this concern will be addressed in the deregulated market, however, in order to entice independent power producers to use different fuel mix, some incentive would have to be provided. Whatever mechanism is used, the incentive should also be extended to all Distributed Generation units.

Emission Reductions

Emissions reduction resulting from Distributed Generation are highly specific to regions and depend on the generation "mix" of each utility and the type of Distributed Generation considered. The national average for CO_2 production (greenhouse gas), is about 1.5 pounds of CO2 per kWh generated; there are many Distributed Generation technologies that are significantly below this figure and, in some instances, are zero, e.g. photovoltaics. The national NOX emission figure has been improving significantly over recent years given the new technology and the increased efficiency of modern combined cycle plants, however, in many, if not most cases, Distributed Generation technologies can reduce NOX and fine particulate emissions when compared to the grid. This can be particularly important in view of the new National Ambient Air Quality Standards (NAAQS).

Proposed Method to Quantify Savings

In Southern California, there is an existing exchange market for NOX and greenhouse gases could, in the future, also be traded. Given the growing global concern about greenhouse gases and the Kyoto Accord, future markets in trading these gases are very likely with a "give and take" open market between nations. As an example, CO2 reduction is expected to be in the cost range of $30 to $200 per ton; precise numbers are unavailable but will be defined in the expected future market. Distributed Generation that can be shown to lower the incremental CO_2, or other emissions, should be eligible for this market based offset.

Evaluation of Qualitative Factors

Qualitative Factors can be summarized as follows:

Reduced Energy "Congestion"
Less Societal Disruption
Faster Response Time
Black Start Capability
System Operation Benefits

There will always be benefits that cannot be quantifiably valued. Reducing "Energy Congestion" on the grid will ultimately benefit the utilities since more of their T&D assets will be freed up to allow a greater amount power (and greater revenue) by "wheeling". There will be less "Societal Disruption since there will less intrusion caused by T&D construction in the nations open spaces and less disruption in the urban areas such as street tear-up. The Electric Power Research Institute (EPRI) estimates that up to 40% of all new generation will be Distributed Generation by the year 2006. This amount of penetration into the existing infrastructure will allow better flexibility and "Faster Response Time" to meet the load in both normal and transient conditions. Distributed Generation will allow for "Black Start Capability" of the system and provide a multitude of "System Operation Benefits", many of which will not even become apparent until the customer exercises his final choice to "do it himself" and installs onsite generation. While these benefits cannot be quantified, they should not be ignored either. Rather, due consideration should be made relative to the overall needs of the ratepayer, customer and society, and an impartial evaluation made to determine the solutions to these needs that Distributed Generation can provide.

Summary and Conclusion

There are many quantifiable benefits other than the direct benefit of lowering the cost of electric service to the customer. This "White Paper" proposes methodologies to allow these ancillary savings to be paid to all three stakeholder:

- Ratepayer
- Distributed Generation Owner
- Utility

Ultimately, many of the savings defined come from the ratepayer, i.e. the savings are based on the differences between the options that the utility chooses. If the Distributed Generation option is the least cost option, then there should be a sharing among the stakeholders. In other words, the savings are derived from what the "aggregate" ratepayer pays with Distributed Generation and what the "aggregate" ratepayer would have paid if a traditional "wires" option had been used. Other revenue may be surcharges based on the ISO bidding process. The surcharge would be calculated from the savings resulting from Distributed Generation.

The concept of sharing ratepayer benefits is not a new as Performance Based Ratemaking (PBR) is already an accepted practice which allows the utility to share in the savings with the ratepayer based on better management and performance. Other savings identified in this "white paper" come from the market itself.

There is an obvious "link" between the utility and distributed generation and the utility/ISO should be rewarded as a stakeholder and share in those savings that benefit the ratepayer.