Arizona Corporation Commission
Distributed Generation and Interconnections Workgroup

ACCESS, METERING & DISPATCH COMMITTEE
FINAL REPORT

November 22, 1999

I. INTRODUCTION

A. Objectives

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

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

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

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

   d. Identify technical requirements associated with these functions.

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

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

B. Participants

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

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

C. Definitions and Abbreviations

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

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

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

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

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

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

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

D. Approach and Report Organization

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

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

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

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

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

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

A. Overview

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

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

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

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

DG Applications and Issues

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

B. Application 1: DG is Separate from Grid

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

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

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

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

   b. No additional metering requirements for this scenario.

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

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

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

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

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

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

   b. Same issues as under "Separate" case.

   c. Switching requirements

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

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

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

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

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

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

3. Scheduling, Information, Metering

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

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

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

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

E. Application 4: Size of DG

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

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

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

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

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

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

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

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

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

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

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

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

F. Potential Remedies for UDC Distribution Planning and Operations

1. General Concerns

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

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

   c. One of the DG Providers felt strongly that DG should not impose a substantial threat to distribution system planning in the near term and was generally concerned that new rules imposed by the ACC regarding such planning could adversely ~~is~~ impact the implementation of DG in Arizona. They felt that the restructuring of the electric industry and changes in

technology and safety requirements all affect distribution system planning. Although distribution system planning~~,~~ by the distribution UDC~~,~~ could be impacted by significant penetration of DG units on the specific UDC's system, this is not expected to occur in the near term. Distribution system planning should not be adversely affected by the addition of a relatively small number of small DG units dispersed throughout the distribution system. The addition of DG to the mix of factors that distribution system planners must be cognizant of, should not be used as a basis to erect barriers to deployment of DG and customer choice and should not be construed as a basis to impose higher costs on DG owners/operators.

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

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

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

2. Rules of Thumb

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

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

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

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

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

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

4. UDC Potential Planning Remedies

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

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

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

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

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

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

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

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

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

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

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

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

e. Contingency planning (load transfers)

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

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

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

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

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

- How is the protection scheme effected?

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

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

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

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

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

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

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

III. TARIFF AND POLICY ISSUES

A. Backup Service for DG

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

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

B. Tariffs for Standby, Maintenance, and Supplemental Power

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

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

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

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

2. DG Owners Choosing Direct Access – APS & TEP

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

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

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

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

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

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

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

h. Some DG providers believe that a partial requirements, direct access tariff may not be necessary. The existing direct access tariffs could be used and any UDC distribution company revenue deficiency associated with the installation of DG could be recovered through the existing direct access rate structure. However, according to the UDCs, this implies that any revenue shortfalls will need to be recovered from other customers after

rates are adjusted in a subsequent rate case. To ensure proper revenue recovery, the existing rate design will need to be modified to recover distribution system costs through customer charges, contract demand charges, and/or ratcheted demand charges instead of the current commodity based kWh charges.

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

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

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

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

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

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

C. Selling Excess Power from DG to UDCs

1. General Obligations and Options

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

   b. UDCs suggested that under the current ACC competition rules and the APS and TEP settlement agreements, the UDC will eventually be required to purchase generation for its standard offer customer through a competitive bidding process. To obligate a UDC to

purchase surplus power from a DG would be detrimental to a competitive market and could increase costs to other Standard Offer customers.

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

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

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

2. UDC Tariffs

a. Buy-back Tariffs for QFs

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

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

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

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

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

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

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

c. Firm Vs. Non-firm Power

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

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

D. Selling Excess DG in the Open Market

1. General Obligations and Options

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

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

2. FERC Requirements

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

b. DG sales to an ESP (UDC Viewpoint)

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

D. UDC Recovery of Distribution Costs

1. UDC Concerns

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

b. The DG owner will not have as many hours of use compared with a full requirements customer. Because the UDC's ~~distribution company's~~ current recovery of fixed costs is

largely through commodity charges ~~are commodity based~~, this causes a reduction in the revenues to be collected by the ~~distribution~~ UDC without an equivalent reduction in costs. This distribution UDC revenue reduction also reduces the fixed cost contribution to distribution plant (which is unrecovered).

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

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

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

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

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

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

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

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

2. DG Provider Concerns

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

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

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

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

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

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

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

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

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

j. A distribution wheeling charge should not be assessed in conjunction with any distribution access charge. This is duplicative and requires a DG owner/operator to pay twice for the

same service. A distribution wheeling charge, if any, should only be assessed against one party to the transaction. The appropriate party could be determined by where the ESP takes title or ownership to the excess power.

E. Metering

1. General

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

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

2. Summary of Metering Options

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

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

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

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

3. UDC Recommendations

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

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

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

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

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

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

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

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

4. DG Providers Recommendations

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

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

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

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

5. Ownership of information

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

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

1. DG Provider Viewpoint

a. DG could provide avoidance of costs, as well as system benefits for the ~~distribution~~ UDC's distribution system. DG can provide many benefits to the distribution system as noted

below. Additionally, there are many examples of DG applications that will result in the distribution infrastructure being used as many hours as it was originally anticipated.

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

2. UDC Viewpoint

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

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

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

APPENDIX A

ACCESS, METERING & DISPATCH COMMITTEE

ASSIGNED QUESTIONS AND KEY TOPICS

OPERATIONS SUBCOITTEE

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

TOPICS

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

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

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

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

TARIFF AND POLICY SUBCOMMITTEE

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

TOPICS

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

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

3. PURPA issues

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

5. Jurisdiction Issues

6. Net metering

7. Coordination policy
   Dispatch, control
   CAO scheduling
   Ancillary services

8. Value to grid

9. Information ownership and access

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

APPENDIX B

ACCESS, METERING & DISPATCH COMMITTEE

Members

	Contact	Representing	Telephone
Chair --	Chuck Miessner	NewEnergy, Inc.	(520) 918-6453
	Tariff Subcommittee		
Chair --	Steve Schmollinger	Tucson Electric Power Company	(520) 884-3619
	Jeff Jacobson	Southwest Gas Corporation	(702) 876-7380
	Rob Borcich	Stewart & Stevenson Power	(505) 881-3511
	Dave Drummond	Distributed Power Coalition of America	(602) 265-4999
	Kelly Rogers	Abbott Labs	(520) 421-6269
	William Thomas	Abbott Labs	(520) 421-6517
	Chuck Miessner	New Energy, Inc.	(520) 918-6453
	Keith Van Ausdal	Arizona Public Service Company	(602) 250-2951
	David Daer	Salt River Project	(602) 236-2521
	Rebecca Eickley	City of Scottsdale	(480) 312-7606
	Scott Swanson	Arizona Public Service Company	(602) 250-2096
	Operations Subcommittee		
Chair --	Steve Bischoff	Arizona Public Service Company	(602) 371-6933
	Jerry Smith	Arizona Public Service Company	(602) 250-1135
	Prem Bahl	Residential Utility Consumers Office	(602) 279-5659
	Walter L. Goodman	International Brotherhood of Electrical Workers	(602) 275-6222
	Ron Franquero	Arizona Corporation Commission	(602) 542-7275
	Paul Taylor	R W Beck	(602) 522-1486
	Terry Linde	Agra-Simons	(602) 200-6510
	Bob Evans	Agra-Simons	(602) 200-6537
	Paul McGuire	Touchstone Energy	(520) 547-7911
	Robert Brown	Sierra Southwest	(520) 547-7915
	Dennis Gerlach	Salt River Project	(602) 236-8037
	Dan Goodrich	Salt River Project	(602) 236-6485
	Bud Wheeler	Engine World, Inc.	(702) 361-1719
	Randy Sable	Southwest Gas Corporation	(702) 364-3079
	Bill Meek	Arizona Utility Investors Association	(602) 257-9200
	Chuck Skidmore	City of Scottsdale	(480) 312-7606
	Barbara Klemstine	Arizona Public Service Company	(602) 250-2031