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AZ CORP COMMISSION
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Commissioner

IN THE MATTER OF THE COMPETITION IN THE PROVISION OF ELECTRIC SERVICES THROUGHOUT THE STATE OF ARIZONA.	DOCKET NO. RE-00000C-94-0165 **NOTICE OF FILING**

Staff of the Arizona Corporation Commission hereby files its Staff Report detailing the issues covered and the consensus reached in the Workshops held on June 28th, July 1st, July 12th, July 13th and July 16th, 1999.

RESPECTFULLY SUBMITTED this 2nd day of August, 1999.

By: Paul A. Bullis
Paul A. Bullis
Christopher C. Kempley
Janet Wagner
Janice Alward

Original and ten copies of the foregoing filed this 2nd day of August, 1999 with:

Docket Control
Arizona Corporation Commission
1200 West Washington Street
Phoenix, Arizona 85007

Arizona Corporation Commission
DOCKETED
AUG 02 1999
DOCKETED BY

A copy of the foregoing was mailed the 3rd day of August, 1999 to:

All parties on the service list for Docket No. RE-00000C-94-0165

By: Mary Ippolito

MEMORANDUM

TO: Docket Control

FROM: Ray T. Williamson
Acting Director
Utilities Division

DATE: July 30, 1999

RE: STAFF REPORT ON WORKSHOPS ON ADDITIONAL ISSUES RELATED TO RETAIL ELECTRIC COMPETITION RULES (DOCKET NO. RE-00000C-94-0165)

Attached is the Staff Report on additional issues related to Retail Electric Competition Rules.

RTW:RAF:JDS:lhh

Originators: Ray T. Williamson, Ron A. Franquero and Jerry D. Smith

Attachment: Original and Eleven Copies

STAFF REPORT
UTILITIES DIVISION
ARIZONA CORPORATION COMMISSION

WORKSHOPS ON ADDITIONAL ISSUES RELATED TO RETAIL ELECTRIC COMPETITION RULES

DOCKET NO. RE-00000C-94-0165

AUGUST 2, 1999

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STAFF ACKNOWLEDGMENT

The Staff Report was prepared by Ray T. Williamson. Minutes of the Distributed Generation and Interconnection Workshop were prepared by Jerry D. Smith. Minutes of the workshops on Metering and Billing issues were prepared by Ron A. Franquero.

Ray T. Williamson
Acting Director

Ron A. Franquero
Electrical Engineer

Jerry D. Smith, P.E.
Electrical Engineer

H:/MYDOCS/WORKSHOP

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Metering, Load Profiling, and Billing and Collection Workshops 2

ATTACHMENTS

Distributed Generation and Interconnection Workshop 1

Metering, Load Profiling, and Billing Workshops 2

Background

By Procedural Order dated April 21, 1999, the parties in this docket were ordered to submit to the Attorney General's Office (AG) and the Residential Utility Consumer Office (RUCO) on or before April 28, 1999, a list of remaining issues to be resolved in this docket, a recommended methodology to resolve such issues, and the priority order of resolution.

On May 3, 1999, the AG and RUCO jointly filed with the Commission their Summary of Remaining Issues in Electric Industry Restructuring-Initial Filing, and on May 4, 1999, their Amended Filing of Summary of Remaining Issues in Electric Industry Restructuring.

Pursuant to the April 21, 1999, Procedural Order, a Procedural Conference was held on May 6, 1999, to discuss remaining issues to be resolved in this docket. At the Procedural Conference, concern was expressed for the need for uniformity of procedures and protocols utilized by the Utility Distribution Companies (UDCs) in the details of the implementation of competition.

Parties were ordered to submit to Staff requests for workshops by May 13, 1999.

Staff Action on Workshops

On May 13, 1999, a number of parties filed comments and suggestions in response to the Procedural Order. Staff reviewed those responses and divided them into two categories. First, there were responses that mentioned "technical issues" as requested by the Chief Hearing Officer. Second, there were responses that mentioned certain "policy issues" in the rules.

Staff determined that "policy issues" would not be addressed in the workshops. Since "policy issues" were not what was contemplated by the Chief Hearing Officer as appropriate for a workshop format, Staff recommended that they be handled in the formal rule amendment process.

On May 27, 1999, Staff identified two sets of technical issues that need to be addressed prior to the start of retail electric competition: metering issues and load profiling issues. Metering and load profiling issues have been addressed, since 1997, by the Metering Committee of the Unbundled Services and Standard Offer Working Group. Staff believed that this was the appropriate group to hold the workshops. Therefore, Staff scheduled the following workshops:

Metering Issues Workshop	July 1, 1999
Load Profiling Workshop	July 12, 1999

In addition to the two technical workshops listed above, Staff identified a need to commence a more long-term working group process to discuss technical issues that need to be addressed prior to full competition in 2001, but do not need to be resolved prior to the commencement of competition in 1999. Staff, therefore, scheduled an initial workshop to address "Interconnection and Distributed Generation issues."

Interconnection and Distributed Generation Workshop June 28, 1999

Follow-up Workshops

In addition to the three workshops originally scheduled for June 28, July 1 and July 12, follow-up workshops were held on July 13 (on Direct Access Service Requests) and on July 16 (Metering: EDI formats).

Distributed Generation and Interconnection Workshop

This workshop was designed to be the starting point for a new Distributed Generation and Interconnection Working Group that will meet over the next six to nine months. Staff anticipates that the work of this group may result in recommendation for the addition of a new section of the Retail Electric Competition Rules in the year 2000 that will need to be in place for the start of full competition in 2001. Therefore, the report included in Attachment 1 includes the issues discussed, but does not reach consensus on any issues at this time.

Metering, Load Profiling, and Billing and Collection Workshops

The minutes and details of issues discussed at these workshops and included in Attachment No. 2.

Consensus has been reached on the following issues:

- Initially, each respective transmission provider will develop load profiles for its system.
- Ultimately, an independent entity will monitor and maintain a statewide load profiling database.
- EDI 867 Version 4010 implementation guideline submitted by the EDI Technical Subgroup was approved unanimously.
- Formation of a statewide forum for planning, development and implementation of EDI document exchange formats.

- The Universal Metering Identifier (UMI) was modified per participants' recommendations.

Additional work is required concerning the following issues:

- Developing statewide load profiling segment sets. Funding of this activity has not been resolved.

- Revisions are proposed to the November 18, 1998 DSAR Handbook.

- Development of a validation procedure for DSARs to avoid excessive rejections due incomplete or incorrect data.

- Development of standard implementation formats for EDI 810, 814, 650, 820, 824, and 997.

The Billing and Collections Subcommittee will meet in late August to continue efforts to address unresolved issues listed above.

ATTACHMENT 1

Includes:

- Workshop Memorandum
- Open Meeting, June 28, 1999
  - Workshop Notes
  - List of Attendees
- Group Breakout Session Issues

Memorandum

Date: August 2, 1999
To: Ray T. Williamson, Acting Director, Utilities Division
From: Jerry D. Smith, Utility Consultant - Electrical
Subject: Summary of Distributed Generation and Interconnections Workshop

Attached are the minutes, notes, and list of issues raised and discussed at the June 28, 1999 workshop on Distributed Generation and Interconnections. The workshop initiated a six to nine month process designed to develop a consensus concerning future rulemaking requirements that accommodate distributed generation and interconnection applications in an environment of retail electric competition. A workgroup is currently being formed to continue the process. The next meeting is expected to occur in late August.

~~~

JDS
Attachments
CC: Steve Olea
~~~

Special Open Meeting Minutes

Date: June 28, 1999 **Time:** 9:30 A.M.

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

Purpose: The Arizona Corporation Commission (ACC) Utilities Division sponsored a workshop to consider advancements in Distributed Generation technology and requirements for interconnecting to the electric utility grid from a retail competition paradigm in Arizona.

Attendance: No quorum of Commissioners; Commission staff members; Maricopa County Air Quality staff members; staff from the cities of Phoenix, Scottsdale, Tempe, and Tucson; individuals representing Arizona Independent Scheduling Administrator (AISA), Residential Utility Consumers Office (RUCO), Arizona Utility Investors Association (AUIA), and Distributed Power Coalition of America (DPCA); representatives of ESPs / Utilities - APS, APS Energy Services, NEV, TEP, SSVEC, SRP, and SW Gas; and representatives of the following firms - Allied Signal, Brown & Bain, BVA Engineers, Cummins Southwest, Diversified Technical Services, ESI, ETA Engineers, Engine World, On Site Sycom Energy Corp, Phoenician Resort, RW Beck, Sierra Southwest, Snell & Wilmer, and TRW Vehicle Safety Systems; and the following private citizens - Larry Holly, Dimitros LaLaudaus, Tim McDonald, Scott McLellan, Douglas Nelson, Gerald Paulos, and Sean Seitz.

Workshop Overview: The workshop began by establishing a "state of the art" point of reference regarding DG and technical requirements for interconnecting with the electric utilities systems. Secondly, the workshop considered how DG might function within a restructured electric utility industry offering open access for retail energy transactions in Arizona. These first two workshop objectives were achieved by discussions of two diverse groups of panelists. Finally, the identification of concerns that may warrant regulatory consideration was accomplished by using a group breakout exercise. Notes of these workshop activities are provided as an Attachment.

Action Plan: Critical issues emerging from the workshop will be packaged and assigned to a Distributed Generation & Interconnections (DGI) Working Group. Formation of the DGI Working Group will be accomplished by individuals notifying Jerry Smith of the ACC Utilities Division (602-542-7271 or JSMITH@CC.STATE.AZ.US) of their interest in participating. Attendance is open to anyone who desires to participate but working group membership will be limited to one or two individuals per organization. As issues become more clearly defined they may be assigned to subcommittees for resolution. A report of recommendations will be assembled for ACC consideration by year-end, 1999.

Meeting Adjourned at 4:20 PM

Recorded By: Jerry D. Smith, P.E., Utilities Division, Arizona Corporation Commission

Workshop Notes

Date: June 28, 1999 **Time:** 9:30 A.M.

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

Attendees: List provided as an attachment

Purpose: The Arizona Corporation Commission (ACC) Utilities Division sponsored a workshop to consider advancements in Distributed Generation technology and requirements for interconnecting to the electric utility grid from a retail competition paradigm in Arizona.

Background: Ray Williamson, acting ACC Utilities Division Director, opened the meeting by giving some background concerning electric rule making for retail competition in Arizona. The fact that the proposed rules are silent regarding Distributed Generation (DG) prompted the ACC to host the June 28th workshop. It is generally felt that specific consideration of DG does not present sufficient cause to delay electric competition further in Arizona. Rather, the workshop is considered to be a forum for starting a process to consider the topic of DG.

Keynote Address: Sarah McKinley, Executive Director of Distributed Power Coalition of America, provided an informative national overview of state and federal initiatives impacting electric utility restructuring for retail competition, applications of DG, and associated interconnection standards. Some of the initiatives have been under development and consideration for some time while others have just recently been proposed. Nevertheless, a broad range of work has proceeded on the national front and in numerous other states that will serve as excellent references as the State of Arizona considers its future accommodation of DG technology.

Panel A (Local Experiences): was comprised of panelists representing three view points: the DG provider community, utility distribution companies, and consumers with actual distributed generation projects. This panel considered the current status of DG technology, three actual DG projects in Arizona and the overall DG operational experience of the Arizona utilities.

The commercial and industrial segments of the retail consumer market are currently the primary target for application of natural gas DG technology. Customers with thermal needs are good candidates for co-generation. Applications of solar and photovoltaic DG technologies are more prevalent in residential settings. Mass production of micro-turbines and fuel cell technology is likely to reshape the focus of the DG industry in the near future. Significant hours of operation are needed in which to spread the capital cost of DG technology. Provisions for fuel delivery systems and associated cost must also be taken into consideration. Fair rates are needed for standby and emergency power.

The Phoenician Resort co-generation project, the Bonita Nursery emergency and peak shaving generators north of Willcox, and Bob's Auto Spa in Tucson were represented on the panel. These DG projects indicated excellent operational interface experiences with the respective local utility. They highlighted operational concerns regarding fluctuating and escalating fuel prices and power quality issues such as the presence of third harmonics. An experienced and trained operator and maintenance crew is vital to successful operation of these projects.

The utilities reported a wide array of DG applications including wind generators; fuel cells, small hydro units on canals; a landfill plant; and numerous solar, photovoltaic, and diesel/gas fueled units. Safety remains a key concern coupled with concerns regarding transfer switches used to connect the units whether on or off the grid. While development of national interconnection standards are needed and will be helpful there will always be a need to consider site specific issues. Proper pricing mechanisms for interconnecting DG in the restructured utility industry still need attention. Utilities reported that in some cases the DG operator has leaned on the utility for expertise in operating their units. Based upon DG projects constructed and no longer operational, utilities are concerned about the uncertainty and long term viability of DG projects when planning delivery system improvements. There may also be a need to correlate DG uses and local must-run generation requirements for scheduled retail transactions.

Panel B (Retail Competition): was comprised of panelists representing three views: the jurisdictional and regulatory community, retail market advocates, and restructured utility organizations. This panel considered standards and jurisdictional requirements affecting siting and interconnecting DG to the utility; the framework of retail electric competition in Arizona; and consumer issues unique to DG applications.

The ACC rules require filing of an application with the State Power Plant and Line Siting Committee when siting generation units of 100 MW or greater in Arizona. Existing DG installations have been addressed by local jurisdictions on a case by case basis. It was suggested that complete DG systems be certified so local jurisdictions can expedite permitting. Who should certify such systems was not resolved. Industry standards for interconnection of DG are under development by IEEE, ANSI and several states. Some of these standards will not be completed until 2001.

Retail competition in Arizona is being managed via use of an Arizona Independent Scheduling Administrator (AISA) as an interim step to implementation of an Independent System Operator (ISO). These organizations are required by proposed ACC rules and by a recent FERC Notice of Proposed Rulemaking (NOPR) for Regional Transmission Organizations (RTO). Scheduling Coordinators are used to submit balanced schedules of customer loads and associated Electric Service Provider resources to respective Control Area Operators/Transmission Providers. These schedules are submitted in 1 MW increments on an hourly basis.

Rates applicable to DG selling to the grid are a concern. It was also suggested DG should be differentiated from Demand Side Management since it actually supplies the grid in

some cases. The correlation of DG and system ancillary services or generating reserve requirements was also stated as a concern.

The future looks quite different from the past. ESP's will eventually be able to dispatch specific customers' lights, HVAC, residential appliances, etc. This implies decisions will be made using real time information at the customer level instead of at the control area operator level. Inclusion of DG technologies in this new dispatch arena creates what some have called "virtual utilities." Hourly metering will become a necessity for such systems.

Breakout Groups: Attendees were split into two breakout groups to explore issues and concerns in more detail. One group addressed issues related to implementation of DG units and the other group addressed interconnection with the utility grid. A summary of the issues documented by this process is provided as an attachment.

Meeting Adjourned at 4:20 PM

Recorded By: Jerry D. Smith, P.E., Utilities Division, Arizona Corporation Commission

Attachments: List of Attendees
Group Breakout Session Issues

ACC DGI Workshop

List of Attendees

DON ADAMS
TEP

ROBERT ARPIAO
MARICOPA COUNTY AIR QUALITY

PHILLIP ASBURY
SSVEC

PREM BAHL
RUCCO

ROBERT BALTES
BVA

JAMES BARRY
TEP

BOB BAXTER
BVA ENGINEERS

STEVE BISCHOFF
APS

JANA BRANDT
SRP

ROBERT BROWN
SIERRA SOUTHWEST

MIKE BURKE
NEV TECHNOLOGIES

MIKE BUSQUAERT
PHOENICIAN RESORT

PHIL CEA
APS

CHUCK CULLOM
SW WIND POWER

GREG CZAPLEWSKI
CUMMINS SOUTHWEST

KEITH DAVIDSON
ON SITE SYCOM ENERGY CORP

LEE DEBAILLE
MARICOPA COUNTY

CHUCK DECORSE
TEP

WILLIAM DELONG
SOUTHWEST GAS

RANDY DESPAIN
CITY OF PHOENIX

DAVID T. DRUMMOND
NEV

REBECCA EICKLEY
CITY OF SCOTTSDALE

CHARLES EMERSON
TRICO

DANIEL FITCHITT
CITY OF TEMPE

RON FRANQUERO
ACC

TOM FRIDDLE
APS

LANE GARRETT
ETA ENGINEERING INC

DENNIS GERLACH
SRP

B T GERNET
APS

ED GESEKING
SOUTHWEST GAS

ELENA GORELLE
MARICOPA COUNTY

JEFF GULDNER
SNELL&WILMER

TOM HANSEN
TEP

BOB HESS
SALT RIVER PROJECT

LARRY HOLLY

MIKE HOUSLEY
APS ENERGY SERVICES

ACC DGI Workshop

List of Attendees

VINNIE HUNT
CITY OF TUCSON

JEFF JACOBSON
SOUTHWEST GAS

BARBARA KEENE
ACC

BARBARA KLEMSTINE
APS

DIMITROS LALAUDAUS

RICK LARUBETH
APS

SCOTT McCULLOUGH
MARICOPA COUNTY PLANNING DIV

TIM McDONALD

SARAH MCKINLEY
DISTR. POWER COALITION OF AMERICA

SCOTT McLELLAN

MATT MEDVRA
ESI

W W MEEK
AUIA

PATTI MORRIS
TEP

BILL MURPHY
CITY OF PHOENIX

DOUGLAS NELSON

DAVE NIZHOLE
TRW VEHICLE SAFETY SYSTEMS

BRIAN O'DONNELL
SOUTHWEST GAS

DAN PARMLER SR
DIVERSIFIED TECHNICAL SVCS

MICHAEL PATTEN
BROWN & BAIN

GERALD PAULOS

MATT PUFFER
ENGINE WORLD

RANDY SABLE
SOUTHWEST GAS

EDWARD SALGIAN
BVA

STEVE SCHMOLLINGER
TEP

RICK SCHUMM
SRP

MIKE SCWINDENHAMMER
SSVEC

SEAN SEITZ

MARK SKOWRONSKI
ALLIED SIGNAL

JERRY SMITH
APS

JERRY SMITH
ACC

BOB SMITH
APS

PAUL TAYLOR
RW BECK

DAVID TOWNLEY
NEV TECHNOLOGIES LLC

LAUREL WHISLER
AZ INDEP. SCHEDULING ADMIN ASSOC

RAY WILLIAMSON
ACC

ACC DGI Workshop

Group Breakout Session Issues

Safety

1. Ensure Protection of Workers / Customers
2. Safe Practices for Connection / Isolation of Distributed Generation to / from System
3. Training and Certification / Licensing Process for Workers
4. Standardized Safety Requirements Conforming to NEC / OSHA, etc.
5. Zero Tolerance on Unsafe Conditions
6. Distinguish Safety Requirements for Large vs. Small Customer Applications

Siting

1. Size Thresholds for Which Siting Is a Public Issue
2. Tracking / Mapping of Distributed Generation for UDC Capacity Planning
3. Who Pays for Underutilized Distribution Facilities Resulting From Distributed Generation Siting

Certification / Permitting

1. Certification of Distributed Generation System Package
2. Who has Jurisdiction Over
   - Tariffs, Cost Shifting
   - Grid Access
   - Reliability

ACC DGI Workshop

Group Breakout Session Issues

Distributed Generation Fuel Requirements

1. Is a Fuel Preference Policy Needed (Gas, Solar, Wind, H_2, etc.)
2. Is a Fuel Pressure Standard Needed for Distributed Generation
3. Who Pays For Fuel Delivery Infrastructure
4. Delivery of H_2 as By Product of Fuel Cell Application

Location and Types of Distributed Generation Connections

1. Consider Standards for Inverter vs. Synchronous Connections
2. Should Standards Distinguish Between Transmission, Distribution, and Customer's Service System Connections
3. Can a Location Match be Achieved for Mutual Benefit of Customer and UDC
4. Application Process Standardized and Streamlined
5. Must be an Electric Service Provider to Re-Sale?

Points of & Types of Interconnection

1. UDC's Total Control a Concern - Jurisdiction of All Utilities (Including SRP) for Interconnections
2. Standardize Equipment for Monitoring and Verification of Interconnection
3. Site Specific Considerations vs. Interconnection Standards
4. Parallel vs. Islanded Operations of Distributed Generators
5. Is There a Distributed Generator Size Limit for Particular Interconnections

ACC DGI Workshop

Group Breakout Session Issues

Power Quality

1. Distributed Generation Compliance with WSCC / NERC / IEEE and Industry Standards
2. Power Factor, Harmonics, Voltage Flicker, Frequency and Voltage Control Concerns
3. Bilateral Power Quality Impacts of Distributed Generators, Utilities and Other Customers
4. How to Monitor and Enforce

Operational Interdependence

1. How will Distributed Generator Customers Contribute to Ancillary Service Requirements
2. Interface Equipment Must Provide Bilateral (Mutual) Protection / Voltage Control
3. System Dispatch / Control for Mutual System Benefit
4. Management of / Response to Disturbances
5. More Complex Operational Requirements When Many Distributed Generators Co-exist
6. Customers Reliance on Utility for Operational and Engineering Expertise

System Dynamics

1. Automatic Voltage Regulation / Power System Stabilizer / Unit Testing Requirements
2. Distributed Generator Load Following Capability
3. Real-time Pricing Affect on System Dispatch and Operation
4. Automation via Supervisory Control And Data Acquisition

ACC DGI Workshop

Group Breakout Session Issues

Operational Controls

1. Who Should Control Distributed Generator - Customer vs. Control Area Operator
2. Should Manual or Automatic Controls Be Used
3. Customer Issue: Controls Need To Follow Load To Maximize Investment
4. If Control Area Operator Dispatches Unit - Standards for Control & Telemetry Equipment Interface
   - Voltage Control
   - Power System Stabilizer
   - Governor Response (Frequency)
   - Dynamic Signal if Regulating or Load Following
5. If Utility Benefits From Dispatch of Units - How is Customer Compensated

Telemetry

1. Telemetry Required For Parallel Operation (Sell Back)
2. Distributed Generator Telemetry to Send Real Time Data to Control Area Operator
3. Transfer Tripping Distributed Generator for Disturbance on Distribution System
4. Who Owns the Information / with Whom is Information Shared
5. Who Pays the Cost for Telemetry
6. Is Net Metering Allowed

ACC DGI Workshop

Group Breakout Session Issues

Protection Requirements

1. Uniform Standards or Utility Specific
2. Balance Economics / Safety
3. How Much Control Should Utility Have In Defining Requirement
4. Dependent Upon Unit Size and Location in System
5. Define by Type of Unit and Type of Utility Interconnection

Other Issues / Concerns

1. Environmental
2. Customer Education
3. Who has Jurisdiction - ACC vs. FERC, ISO, Local, etc.
4. Scheduling Requirement
5. Pricing - Rates / Incentives
   - Utility Tariffs - Backup, Stand-By, Supplemental, Emergency, Buy-Back
   - Cost -Shifting - Who Pays Cost of Departing Customer
   - Should Distributed Generation be Allowed to Bypass Wires Charges
   - Monetary Compensation for Grid Benefits of Distributed Generation
   - Providing Opportunity / Encouragement for Smaller Distributed Generation (i.e. Residential)
   - Should ACC Provide Incentives for some Distributed Generation, if Cost Increases for Others, But Overall Cost is Reduced

ATTACHMENT 2

Includes:

- Workshop Memorandum
- Open Meeting, July 1, 1999
- Open Meeting, July 12, 1999
- Open Meeting, July 13, 1999
- Open Meeting, July 16, 1999

Memorandum

Date: August 2, 1999
To: Ray T. Williamson, Acting Director, Utilities Division RTW
From: Steve M. Olea, Chief Engineer SMO
Subject: Recent Unbundled Services and Standard Offer Work Group Workshops / Meetings

Several Unbundled Services and Standard Offer Work Group workshops and meetings have recently occurred. On July 1, 1999 the Metering Subcommittee held a workshop followed by a subsequent meeting on July 16, 1999. The Load Profiling Subcommittee held a workshop on July 12, 1999. The Billing and Collections Subcommittee met on July 13, 1999. Minutes of each of these meeting are attached.

Consensus has been reached on the following issues:

- Initially, each respective transmission provider will develop load profiles for its system.
- Ultimately, an independent entity will monitor and maintain a statewide load profiling database.
- EDI 867 Version 4010 implementation guideline submitted by the EDI Technical Subgroup was approved unanimously.
- Formation of a statewide forum for planning, development and implementation of EDI document exchange formats.
- The Universal Metering Identifier (UMI) was modified per participants' recommendations.

Additional work is required concerning the following issues:

- Developing statewide load profiling segment sets. Funding of this activity has not been resolved.
- Revisions are proposed to the November 18, 1998 DSAR Handbook.
- Development of a validation procedure for DSARs to avoid excessive rejections due incomplete or incorrect data.
- Development of standard implementation formats for EDI 810, 814, 650, 820, 824, and 997.

The Billing and Collections Subcommittee will meet in late August to continue efforts to address unresolved issues listed above.

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SMO/js
Attachments
CC: Ron Franquero
~~~

Arizona Corporation Commission

OPEN MEETINGS

DATE: July 1, 1999

TIME: 9:30 a.m.

PLACE: Arizona Corporation Commission, 1200 West Washington St., Hearing Rooms 1 and 2, Phoenix, Arizona 85007

ATTENDANCE: No Quorum of Commissioners, Members of Commission Staff, Members of Unbundled Services Metering Subcommittee, which includes representatives from APS, TEP, Citizens, AEPCO, Trico Electric Cooperative, Navopache Electric Cooperative, Sulphur Springs Valley Electric Cooperative, Graham County Electric Cooperative, Salt River Project, NTUA, City of Scottsdale, City of Tucson , New Energy Ventures, New West Energy, CSC Energy Services, Sierra Southwest Cooperative, KR Saline & Associates, Schlumberger, Phaser Advanced Metering Services, Cellnet, and Utility.com.

TOPIC: Unbundled Services and Standard Offer Working Group - Metering Committee Meeting

MATTERS DISCUSSED:

Ron Franquero of Commission Staff presented a workshop (Attachment #1) on the current metering issues.

The next meeting is scheduled for July 16, 1999. (The next meeting of the Billing and Collections Committee is July 13, 1999.)

The meeting adjourned at 11:00 a.m.

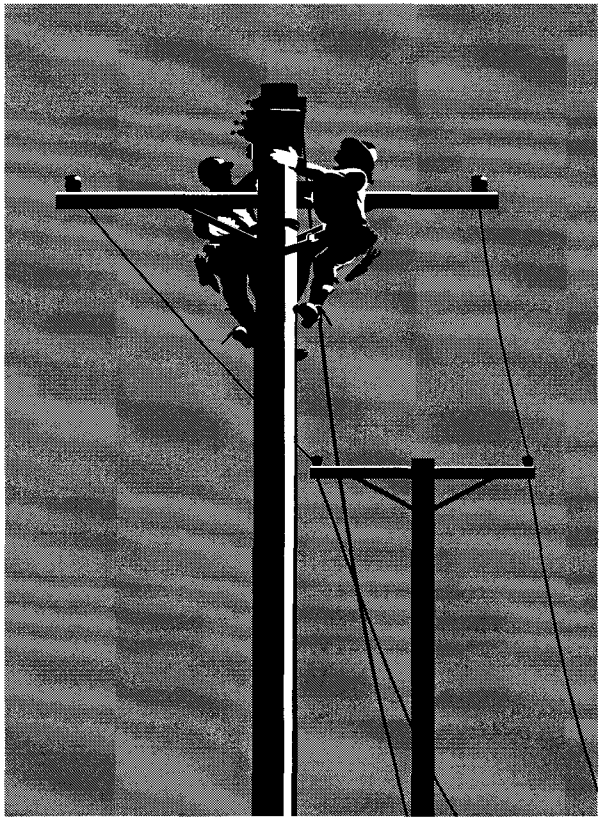
Ron Franquero, Utilities Consultant, July 7, 1999

This document has been created using Adobe Acrobat formatting. Click here for a free copy of the reader you will need to view it.

Attachment #1

UNBUNDLED SERVICES AND STANDARD OFFER WORKING GROUP

METERING ISSUES WORKSHOP



ARIZONA CORPORATION COMMISSION
HEARING ROOMS 1 AND 2

JULY 1, 1999

METERING ISSUES WORKSHOP

AGENDA

- INTRODUCTION ON FORMATION OF METERING COMMITTEE
- SUMMARY OF MEETING DATES AND 11/3/97 REPORT
- DISCUSSION OF METERING RULES IN R14-2-1612(K) 1-15
- DISCUSSION OF THE METERING RULES THAT MUST BE APPROVED BY THE DIRECTOR, UTILITIES DIVISION
- STATUS OF CC&NS FOR MSPS AND MRSPS
- QUESTIONS AND ANSWERS

UNBUNDLED SERVICES AND STANDARD OFFER WORKING GROUP

WAS CREATED BY RULE R14-2-1606(I) WHICH WAS APPROVED ON DECEMBER 26, 1996

WITHIN 90 DAYS OF THE ADOPTION OF THIS ARTICLE, THE COMMISSION STAFF SHALL COMMENCE A SERIES OF WORKSHOPS TO EXPLORE ISSUES IN THE PROVISION OF UNBUNDLED SERVICE AND STANDARD OFFER SERVICE.

1. **PARTIES TO BE INVITED TO PARTICIPATE IN THE WORKSHOPS SHALL INCLUDE UTILITIES, CONSUMERS, ORGANIZATIONS PROMOTING ENERGY EFFICIENCY, AND OTHER ELECTRIC SERVICE PROVIDERS.**

2. **AMONG THE ISSUES TO BE REVIEWED IN THE WORKSHOPS ARE: METERING REQUIREMENTS; METERING PROTOCOLS; DESIGNATION OF APPROPRIATE TEST YEARS; THE NATURE OF ADJUSTMENTS TO TEST YEAR DATA; DE-AVERAGING OF RATES; SERVICE CHARACTERISTICS SUCH AS VOLTAGE LEVELS; REVENUE UNCERTAINTY; LINE EXTENSION POLICIES; AND THE NEED FOR PERFORMANCE BONDS.**

3. **A REPORT SHALL BE SUBMITTED TO THE COMMISSION BY THE STAFF ON THE ACTIVITIES AND RECOMMENDATIONS OF THE PARTICIPANTS IN THE WORKSHOPS NOT LATER THAN 60 DAYS PRIOR TO THE DATE INDICATED IN R14-2-1602. THE COMMISSION SHALL CONSIDER ANY RECOMMENDATIONS REGARDING UNBUNDLED SERVICE AND STANDARD OFFER SERVICE TARIFFS.**

UNBUNDLED SERVICES AND STANDARD OFFER WORKING GROUP METERING SUBCOMMITTEE

SCOPE

- All issues relative to metering and meter reading which are required to be resolved in order to implement the Commission's Rules on Electric Competition.

OBJECTIVES

- To identify, discuss, and resolve metering and meter reading issues for the purpose of making recommendations to the Commission for incorporation in appropriate rule making.

UNBUNDLED SERVICES AND STANDARD OFFER WORKING GROUP METERING SUBCOMMITTEE

MEETING DATES

5/28/97	1/21/98	6/2/99
7/1/97	2/24/98	6/18/99
7/30/97	3/20/98	
8/21/97	4/22/98	
9/11/97	5/18/98	
9/26/97	6/8/98	
	6/29/98	

REPORT TO THE
ARIZONA CORPORATION COMMISSION

IN THE MATTER OF THE COMPETITION
IN THE PROVISION OF ELECTRIC SERVICE
THROUGHOUT THE STATE OF ARIZONA
DOCKET NO. E-00000-94-0165

SUBMITTED BY

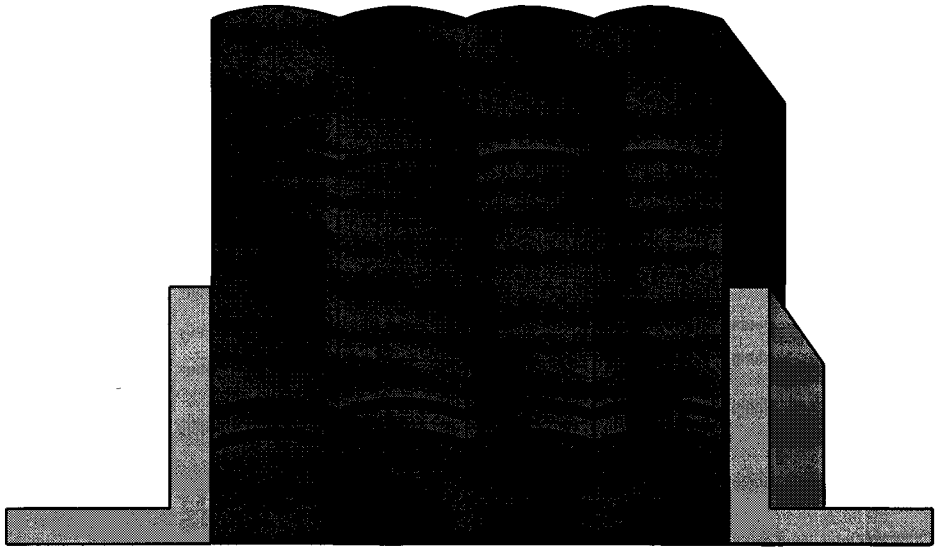
THE UNBUNDLED SERVICES AND

STANDARD OFFER WORKING GROUP

NOVEMBER 3, 1997

ELECTRIC COMPETITION METERING RULES

R14-2-1612(K) ADDITIONAL PROVISIONS FOR METERING AND METER READING SERVICES



R14-2-1612. SERVICE QUALITY, CONSUMER PROTECTION, SAFETY, AND BILLING REQUIREMENTS

K. ADDITIONAL PROVISIONS FOR METERING AND METER READING SERVICES

1. AN ELECTRIC SERVICE PROVIDER WHO PROVIDES METERING OR METER READING SERVICES PERTAINING TO A PARTICULAR CONSUMER SHALL PROVIDE ACCESS USING ELECTRONIC DATA INTERCHANGE (EDI) FORMATS TO METER READING DATA TO OTHER ELECTRIC SERVICE PROVIDERS SERVING THAT SAME CONSUMER WHEN AUTHORIZED BY THE CONSUMER.
2. ANY PERSON OR ENTITY RELYING ON METERING INFORMATION PROVIDED BY ANOTHER ELECTRIC SERVICE PROVIDER MAY REQUEST A METER TEST ACCORDING TO THE TARIFF ON FILE AND APPROVED BY THE COMMISSION. HOWEVER, IF THE METER IS FOUND TO BE IN ERROR BY MORE THAN 3%, NO METER TESTING FEE WILL BE CHARGED.
3. EACH COMPETITIVE CUSTOMER SHALL BE ASSIGNED A UNIVERSAL NODE IDENTIFIER FOR EACH SERVICE DELIVERY POINT BY THE AFFECTED UTILITY OR THE UTILITY DISTRIBUTION COMPANY WHOSE DISTRIBUTION SYSTEM SERVES THE CUSTOMER.

K. ADDITIONAL PROVISIONS FOR METERING AND METER READING SERVICES

4. UNLESS THE COMMISSION GRANTS A SPECIFIC WAIVER, ALL COMPETITIVE METERED AND BILLING DATA SHALL BE TRANSLATED INTO CONSISTENT, STATEWIDE EDI FORMATS BASED ON STANDARDS APPROVED BY THE UTILITY INDUSTRY GROUP (UIG) THAT CAN BE USED BY THE AFFECTED UTILITY OR THE UTILITY DISTRIBUTION COMPANY AND THE ELECTRIC SERVICE PROVIDER.
5. UNLESS THE COMMISSION GRANTS A SPECIFIC WAIVER, AN EDI FORMAT SHALL BE USED FOR ALL DATA EXCHANGE TRANSACTIONS FROM THE METER READING SERVICE PROVIDER TO THE ELECTRIC SERVICE PROVIDER, UTILITY DISTRIBUTION COMPANY, AND SCHEDULE COORDINATOR. THIS DATA WILL BE TRANSFERRED VIA THE INTERNET USING A SECURE SOCKETS LAYER OR OTHER SECURE ELECTRONIC MEDIA.
6. MINIMUM METERING REQUIREMENTS FOR COMPETITIVE CUSTOMERS OVER 20 KW, OR 100,000 KWH ANNUALLY, SHOULD CONSIST OF HOURLY CONSUMPTION MEASUREMENT METERS OR METER SYSTEMS. PREDICTABLE LOADS WILL BE PERMITTED TO USE LOAD PROFILES TO SATISFY THE REQUIREMENTS FOR HOURLY CONSUMPTION DATA. THE AFFECTED UTILITY OR ELECTRIC SERVICE PROVIDER WILL MAKE THE DETERMINATION IF A LOAD IS PREDICTABLE.

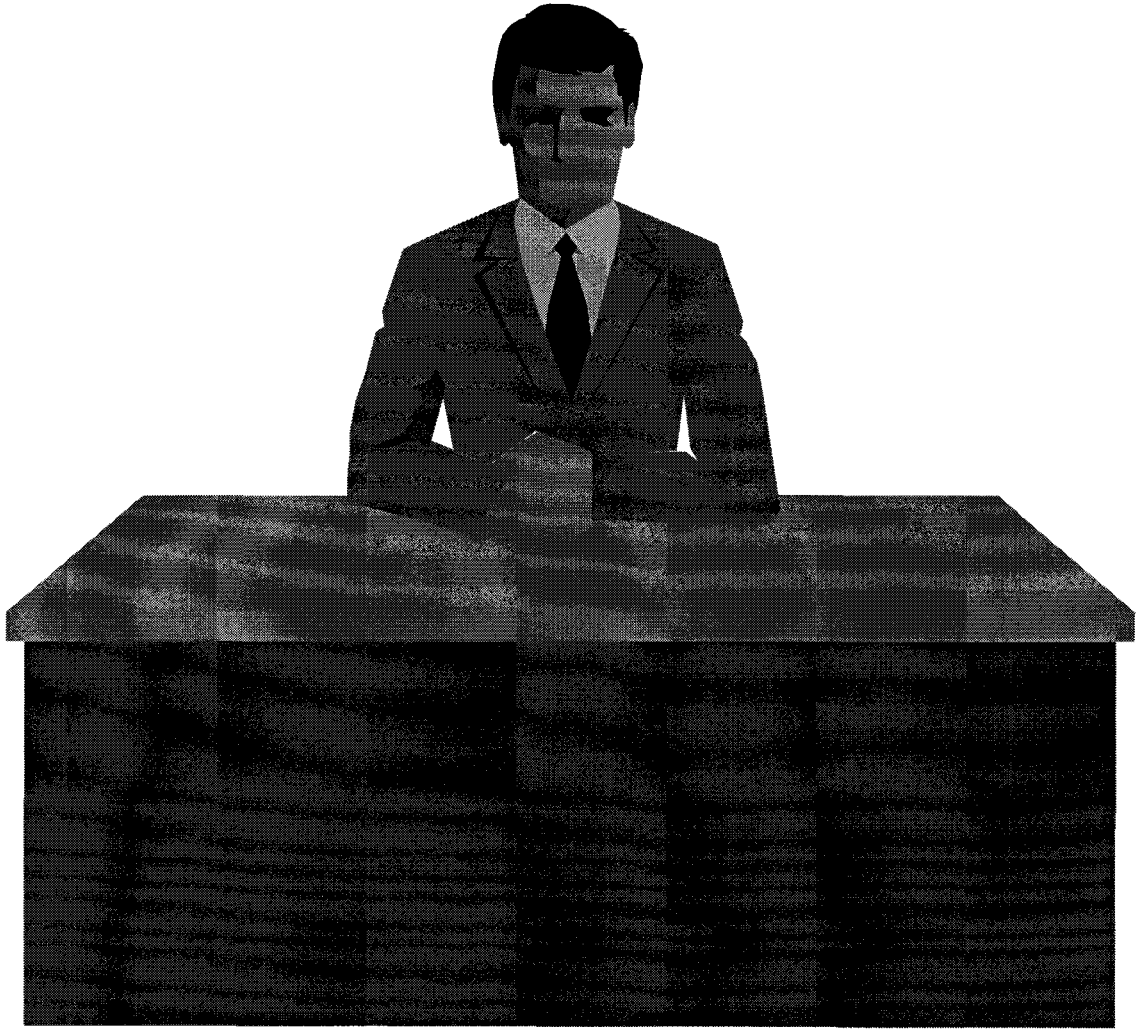
K. ADDITIONAL PROVISIONS FOR METERING AND METER READING SERVICES

7. COMPETITIVE CUSTOMERS WITH HOURLY LOADS OF 20 KW (OR 100,000 KWH ANNUALLY) OR LESS, WILL BE PERMITTED TO USE LOAD PROFILING TO SATISFY THE REQUIREMENTS FOR HOURLY CONSUMPTION DATA, HOWEVER, THEY MAY CHOOSE OTHER METERING OPTIONS OFFERED BY THEIR ELECTRIC SERVICE PROVIDER CONSISTENT WITH THE COMMISSION RULES ON METERING.
8. METERING EQUIPMENT OWNERSHIP WILL BE LIMITED TO THE AFFECTED UTILITY, UTILITY DISTRIBUTION COMPANY, AND THE ELECTRIC SERVICE PROVIDER OR THEIR REPRESENTATIVE, OR THE CUSTOMER, WHO MUST OBTAIN THE METERING EQUIPMENT THROUGH THE AFFECTED UTILITY, UTILITY DISTRIBUTION COMPANY OR AN ELECTRIC SERVICE PROVIDER.
9. MAINTENANCE AND SERVICING OF THE METERING EQUIPMENT WILL BE LIMITED TO THE AFFECTED UTILITY, UTILITY DISTRIBUTION COMPANY AND THE ELECTRIC SERVICE PROVIDER OR THEIR REPRESENTATIVE.
10. DISTRIBUTION PRIMARY VOLTAGE CURRENT TRANSFORMERS AND POTENTIAL TRANSFORMERS MAY BE OWNED ONLY BY THE AFFECTED UTILITY, UTILITY DISTRIBUTION COMPANY OR THE ELECTRIC SERVICE PROVIDER OR THEIR REPRESENTATIVE.

K. ADDITIONAL PROVISIONS FOR METERING AND METER READING SERVICES

11. TRANSMISSION PRIMARY VOLTAGE CURRENT TRANSFORMERS AND POTENTIAL TRANSFORMERS MAY BE OWNED BY THE AFFECTED UTILITY OR UTILITY DISTRIBUTION COMPANY ONLY.
12. NORTH AMERICAN ELECTRIC RELIABILITY COUNCIL RECOGNIZED HOLIDAYS WILL BE USED IN CALCULATING "WORKING DAYS" FOR METER DATA TIMELINESS REQUIREMENTS.
13. BY MAY 1, 1999, THE DIRECTOR, UTILITIES DIVISION, SHALL APPROVE OPERATING PROCEDURES TO BE USED BY THE UTILITY DISTRIBUTION COMPANIES AND THE METER SERVICE PROVIDERS FOR PERFORMING WORK ON PRIMARY METERED CUSTOMERS.
14. BY MAY 1, 1999, THE DIRECTOR, UTILITIES DIVISION, SHALL APPROVE OPERATING PROCEDURES TO BE USED BY THE METER READING SERVICE PROVIDER FOR VALIDATING, EDITING, AND ESTIMATING METERING DATA.
15. BY MAY 1, 1999, THE DIRECTOR, UTILITIES DIVISION, SHALL APPROVE PERFORMANCE METERING SPECIFICATIONS AND STANDARDS TO BE USED BY ALL ENTITIES PERFORMING METERING.

METERING RULES THAT MUST BE APPROVED BY THE DIRECTOR, UTILITIES DIVISION



R14-2-1612 (K) 13.

By May 1, 1999, the Director, Utilities Division, shall approve operating procedures to be used by the Utility Distribution Companies and the Meter Service Providers for performing work on primary metered customers.

Definition: PRIMARY METERING IS DEFINED AS METERING INSTALLED ON SERVICE VOLTAGES ABOVE 600 VOLTS.

A. MSPs CAN PERFORM PRIMARY METERING FROM 600 V TO 25 kV

1. MSP MUST COMPLY WITH THE ARIZONA OVERHEAD POWER LINE SAFETY LAW (ARS 40-360.41,45) FOR PRIMARY WORK ONLY AND CAN ASK UDC FOR A WAIVER TO THIS LAW.

2. ALL HOOKUPS TO THE PRIMARY SIDE SHALL BE DONE BY THE UDCs.

3. THE UDC SHALL PERFORM ALL SWITCHING OPERATIONS ON THE PRIMARY SIDE

B. UDCs WILL PERFORM PRIMARY METERING ABOVE 25 kV

1. UDC CAN CONTRACT WITH A THIRD PARTY TO PERFORM THIS WORK.

2. IF MSPs ARE CONTRACTED BY THE UDCs, MSP MUST FOLLOW UDC'S OPERATIONAL PROCEDURES.

3. MSP SHOULD NOT PERFORM WORK ON INSTRUMENT TRANSFORMERS FOR VOLTAGES OVER 25 kV.

4. THE UDC SHALL PERFORM ALL SWITCHING OPERATIONS ON THE PRIMARY SIDE.

C. TERMS AND CONDITIONS FOR MSPs DOING PRIMARY METERING WORK

1. MUST BE PERFORMED BY A CLASS 3 METERMAN ONLY.
2. MSP MUST CONFORM WITH ACC STANDARDS AND UDC GUIDELINES.
3. MSP MUST COORDINATE ALL WORK DIRECTLY WITH UDC.
4. UDC WILL DEVELOP AND ADMINISTER SWITCHING ORDERS
5. UDC WILL PERFORM ALL SWITCHING ON THE PRIMARY SIDE.

D. OTHER CONDITIONS FOR MSPs DOING PRIMARY METERING WORK

1. MSPs MUST FOLLOW AMERICAN PUBLIC POWER ASSOCIATION (APPA) SAFETY MANUAL.

2. UDC MAY CHARGE MSP FOR PROVIDING ASSISTANCE FOR PRIMARY METERING SYSTEMS.

3. FOR ANY DAMAGE TO OR MALFUNCTION OF MSP's PRIMARY METERING SYSTEM, UDC WILL ISOLATE EQUIPMENT FROM DISTRIBUTION SYSTEM BY CUTTING THE JUMPERS BETWEEN METERING EQUIPMENT AND THE DISTRIBUTION SYSTEM.

R14-2-1612 (K) 14.

By May 1, 1999, the Director, Utilities Division, shall approve operating procedures to be used by the Meter Reading Service Provider for Validating, Editing, and Estimating metering data.

1. **REQUIRED DATA VALIDATION TESTS**

   A. **THE FOLLOWING TESTS ARE REQUIRED FOR kWh AND kVARh (IF USED IN BILLING) INTERVAL DATA VALIDATION:**

   TIME CHECK OF METER READING DEVICE/SYSTEM
   TIME CHECK OF METER
   PULSE OVERFLOW CHECK
   SUM CHECK
   SPIKE CHECK (INTERVAL ONLY)
   HIGH/LOW CHECK: THIS TEST MUST BE BASED ON AVAILABLE HISTORICAL DATA ADJUSTED FOR LOCAL USAGE PATTERNS. MRSP MUST PROVIDE THE UDC WITH THE ALGORITHM THEY INTEND TO USE FOR THIS CHECK.
   TEST MODE CHECK
   METER IDENTIFICATION CHECK

B. THE FOLLOWING TESTS ARE REQUIRED FOR MONTHLY CONSUMPTION DATA VALIDATION:

HIGH/LOW USAGE CHECK

HIGH/LOW DEMAND CHECK (APPLIES TO DEMAND READINGS ONLY)

TIME-OF-USE CHECK (APPLIES TO TOU DATA ONLY)

ZERO CONSUMPTION FOR ACTIVE METERS:

THIS TEST MUST BE BASED ON AVAILABLE HISTORICAL DATA ADJUSTED FOR LOCAL USAGE PATTERNS. MRSP MUST PROVIDE THE UDC WITH THE ALGORITHM THEY INTEND TO USE FOR THIS CHECK.

USAGE FOR INACTIVE METERS (THIS ONLY APPLIES TO MANUAL METER READING METHODS)

DIAL DECIMAL QUANTITY (THIS ONLY APPLIES TO DEMAND METERS USED FOR DEMAND RATE ACCOUNTS)

EXTERNAL METER IDENTIFICATION

2. DATA ESTIMATION

DATA ESTIMATION IS REQUIRED <u>WHEN AN ACTUAL READ IS NOT AVAILABLE</u>. THE FOLLOWING DATA ESTIMATION RULES ARE REQUIRED:

<u>ESTIMATION FOR MONTHLY DATA:</u> USE HISTORICAL DATA FOR SAME CUSTOMER: USE CLASS PROFILE DATA IF HISTORICAL DATA FOR SAME CUSTOMER IS UNAVAILABLE

<u>ESTIMATION FOR INTERVAL DATA WHEN LESS THAN 2 HOURS OF DATA IS MISSING:</u> USE STRAIGHT-LINE INTERPOLATION

<u>ESTIMATION FOR INTERVAL DATA WHEN MORE THAN 2 HOURS OF DATA IS MISSING:</u> USE HISTORICAL DATA FOR THE SAME CUSTOMER; USE CLASS PROFILE DATA IF HISTORICAL DATA FOR THE SAME CUSTOMER IS UNAVAILABLE.

3. EXCEPTION REPORTING

MRSP MUST SUBMIT A PLAN FOR REPORTING ABNORMAL METERING CONDITIONS CONSISTENT WITH CC&N REQUIREMENT.

R14-2-1612 (K) 15.

By May 1, 1999, the Director, Utilities Division, shall approve performance metering specifications and standards to be used by all entities performing metering.

1. METERING STANDARDS (WHERE APPLICABLE)

ANSI C12.1	CODE FOR ELECTRICITY METERING
ANSI C12.6	MARKETING & ARRANGEMENT OF TERMINALS FOR PHASE SHIFTING DEVICES USED IN METERING
ANSI C12.7	WATT-HOUR METER SOCKET
ANSI C12.10	ELECTROMECHANICAL WATT-HOUR METERS
ANSI C12.13	ELECTRONIC TOU REGISTERS FOR ELECTRICITY METERS
ANSI C12.18	TYPE 2 OPTICAL PORT
ANSI C12.20	0.2% & 0.5% ACCURACY CLASS METERS
ANSI C37.90	SURGE WITHSTAND TEST
ANSI 57.13	INSTRUMENT TRANSFORMERS
ANSI Z1.4	SAMPLING PROCEDURES AND TABLES FOR INSPECTION
ANSI Z1.9	SAMPLING PROCEDURES AND TABLES FOR INSPECTION

R14-2-1612 (K) 15.

By May 1, 1999, the Director, Utilities Division, shall approve performance metering specifications and standards to be used by all entities performing metering.

2. **EEI ELECTRICITY METERING HANDBOOK**

3. **ELECTRIC UTILITIES SERVICE EQUIPMENT REQUIREMENTS COMMITTEE (EUSERC) STANDARDS THAT ARE UTILIZED BY UDC'S**

4. **NATIONAL ELECTRIC SAFETY CODE (NESC)**

5. **NATIONAL ELECTRIC CODE (NEC) & LOCAL REQUIREMENTS**

ARIZONA UNIVERSAL NODE IDENTIFIER

A UNIVERSAL IDENTIFIER IS AN IMPORTANT ELEMENT OF A COMPETITIVE ELECTRIC MARKET. IT ENABLES ACCURATE TRACKING OF ENERGY TRANSACTIONS, MINIMIZES TRANSACTION COSTS, REDUCES SYSTEM DEVELOPMENT COSTS, AND ACHIEVES OTHER ESSENTIAL BENEFITS.

THE POINT OF DELIVERY (POD) IS THE LAST POINT OF THE UDC'S DISTRIBUTION NETWORK AND TO WHICH ENERGY IS DELIVERED BY THE UDC.

THE POD IDENTIFIER (POD ID) IS A UNIQUE, PERMANENT NUMBER ASSIGNED TO EACH POD PARTICIPATING IN DIRECT ACCESS AND USED FOR DATA EXCHANGES AND SERVICE POINT TRACKING.

1. **UNIQUE**
2. **PERMANENT**
3. **USE --- REQUIRED BY R14-2-1612(K)3**
4. **ASSIGNING ENTITY---THE UDCS**
5. **ASSIGNMENT PROCESS --- A POD ID WILL BE ASSIGNED TO EACH POD AS THE DASR IS PROCESSED.**
6. **BASE FORMAT--- THE POD ID WILL HAVE A MINIMUM OF 5 ALPHANUMERIC DIGITS, WHICH IS THE DOE GEOGRAPHIC IDENTIFIER, AFTER THIS ID, THE UDC MAY PLACE ANYTHING IN COLUMNS 6 THROUGH 34.**

ARIZONA UNIVERSAL NODE IDENTIFIER

7. GEOGRAPHIC CODE --- A FIVE-DIGIT PREFIX CORRESPONDING TO THE DOE's DESIGNATOR FOR THE UTILITY DISTRIBUTION COMPANY AT THE TIME OF POD ID ASSIGNMENT.

8. LISTS --- THE UDCs SHOULD MAINTAIN MASTER LISTS OF ALL EXISTING POD ID NUMBERS ON THEIR DISTRIBUTION SYSTEMS AND PROVIDE TO ESPs A LIST OF POD ID NUMBERS FOR THAT ESP UPON THE ESP's REQUEST.

9. LINKS --- THE UDC'S DATABASE OF POD IDS SHOULD CONTAIN FOR EACH POD ID, THE FOLLOWING INFORMATION:

   1 - THE POD ID NUMBER
   2 - THE UDC'S IDENTITY
   3 - THE PHYSICAL LOCATION OF THE POD IN THE UDC'S OWN FORMAT
   4 - THE IDENTITY OF THE ESP RESPONSIBLE FOR SERVING ENERGY, BILLING, AND OR METERING FOR THAT POD

10. TRANSLATION --- THE ABOVE-DEFINED POD ID CAN BE IMPLEMENTED BY THE UDCs VIA A TRANSLATION TABLE BETWEEN THEIR EXISTING NUMBERING SYSTEMS AND THE POD ID.

ARIZONA UNIVERSAL NODE IDENTIFIER

DOE GEOGRAPHIC CODE NUMBERS

AJO	00176
AEPCO	00796
APS	00803
CITIZENS	03597
DVEC	05438
GCEC	XXXX
MEC	21538
MORENCI	12919
SRP	16572
SSVEC	XXXX
TEP	24211
TRICO	19189

UNIVERSAL METER IDENTIFIER (UMI)

WHOEVER PURCHASES THE METER WILL ASSIGN THE UMI. THIS ID WAS PROPOSED BY AEP AND IS FULLY ANSI C12.10 COMPLIANT. THE UMI FORMAT IS AS FOLLOWS (17 CHARACTER

AABYYYYYYYYYZZZZZ

WHERE

AA	**IS THE METER TEST CODE**
B	**IS AN IDENTIFIER FOR THE METER MANUFACTURER**
YYYYYYYYY	**IS THE METER MANUFACTURER'S SERIAL NUMBER**
ZZZZZ	**IS USER SPECIFIED**

THE UMI WILL BE INCLUDED AS PART OF METERING SPECIFICATIONS IN R14-2-1612(K)15.

THE UMI IS NOT REQUIRED FOR STANDARD OFFER CUSTOMERS OR FOR THE LOA PROFILED COMPETITIVE CUSTOMERS WHERE THE UDC IS THE MSP AND THE MRSP.

THIS ID IS NOT REQUIRED TO BE IMPLEMENTED UNTIL JANUARY 1, 2001; HOWEVER, THOSE SYSTEMS THAT HAVE ALREADY IMPLEMENTED THE UMI MAY BEGIN USING IT IMMEDIATELY.

STATUS OF MSP AND MRSP CC&N's

UNBUNDLED SERVICES AND STANDARD OFFER WORKING GROUP METERING SUBCOMMITTEE

STATUS OF MSP CC&N's

MSP	HEARING DATE	STATUS
PHASER ADVANCED METERING SERVICES	FEB 24, 1999	CC&N APPROVED ON 5/13/99
KWH METERING, L.L.C.	MARCH 25, 1999	CC&N APPROVED ON 5/13/99
FIRST POINT SERVICES, INC.	MAY 20, 1999	CC&N APPROVED ON 6/28/99
SCHLUMBERGER RESOURCES MANAGEMENT SERVICES, INC.	JUNE 24, 1999	WAITING FOR ORDER

UNBUNDLED SERVICES AND STANDARD OFFER WORKING GROUP METERING SUBCOMMITTEE

STATUS OF MRSP CC&N's

MRSP	HEARING DATE	STATUS
STAR DATA SERVICES, L.L.C.	APRIL 7, 1999	CC&N APPROVED ON 6/28/99
FIRST POINT SERVICES, INC.	MAY 20, 1999	CC&N APPROVED ON 6/28/99
SCHLUMBERGER RESOURCES MANAGEMENT SERVICES, INC.	JUNE 24, 1999	WAITING FOR ORDER
CELLNET	(HAS NOT FILED YET)	WAITING FOR FILING

Arizona Corporation Commission

OPEN MEETINGS

DATE: July 12, 1999

TIME: 9:30 a.m.

PLACE: Arizona Corporation Commission, 1200 West Washington St., Hearing Rooms 1 and 2, Phoenix, Arizona 85007

ATTENDANCE: No Quorum of Commissioners, Members of Commission Staff, Members of Unbundled Services Metering Subcommittee, which includes representatives from APS, TEP, Citizens, AEPCO, Trico Electric Cooperative, Navopache Electric Cooperative, Sulphur Springs Valley Electric Cooperative, Salt River Project, City of Scottsdale, City of Tucson, City of Tempe, Maricopa County, Commonwealth Energy, New West Energy, Sierra Southwest Cooperative, KR Saline & Associates, Schlumberger, RMI, Cellnet, and Utility.com.

TOPIC: Unbundled Services and Standard Offer Working Group - Metering Committee Meeting

MATTERS DISCUSSED:

Members of the Load Profiling subgroup presented a workshop (Attachment #1) on the use of Load Profiling in Arizona.

The next meeting is scheduled for July 16, 1999.

The meeting adjourned at 11:15 a.m.

Ron Franquero, Utilities Consultant, July 15, 1999

Attachment 1

Load Profiling Subgroup Report

7/12/99

Background

- Load Profiling identified as issue in 1997 Work Groups
- Sub-Group formed January 1998
- Consist of representatives for the Transmission Providers, Merchant and Customers.
- Recommendation presented August 1998

What is Load Profiling?

- Load profiling is a process that takes the retail customers cumulative kilowatt-hour (kWh) for the billing cycle and allocates it to each hour in the cycle based on a load curve developed from a statically valid sample set that is representative of the retail customer's load.

The Allocation Process

- The representative sample set's ratio for each hour is determining, by dividing each of its hourly loads by its total usage for the billing cycle.

- The ratio for each hour is then multiplied by the retail customer's total kWh usage for the billing cycle to obtain each hourly load for that customer.

Metering Rules R14-2-1612(K) 6

- **6.** Minimum metering requirements for competitive customers over 20 kW, or 100,000 kWh annually, should consist of hourly consumption measurement meters or meter systems. Predictable loads will be permitted to use load profiles to satisfy the requirements for hourly consumption data. The affected utility or electric service provider will make the determination if a load is predictable.

Metering Rules R14-2-1612(K) 7

- 7. Competitive customers with hourly loads of 20 kW (or 100,000 kWh annually) or less, will be permitted to use load profiling to satisfy the requirements for hourly consumption data, however, they may choose other metering options offered by their electric service provider consistent with the commission rules on metering.

Why Load Profile?

- Need customer hourly loads
- Economics

Ultimate Features

- A common load profiling methodology
  - Clarity
  - Simplicity
  - Consistency
- A state wide common segment set database
  - Economical
  - Ease of use
- Dynamic Segment Set
  - accurate
  - equitable
- Data base to be monitored and maintained by an independent entity
  - Impartiality

Initial Features

- Each transmission provider develops Load Profiles for its system
- Most Load Profiles will be developed from static data

Issues

- Defining Segment sets for state
- Who pays for the profiling

APS Load Profiling

- Sample Set
  - Static
  - High Country & Low Country Residential
  - Adjusted using system load profiles to reflect the profiled days' load pattern
- Apply sample set profile to residential customer's energy usage for the billing cycle

AEPCO Load Profiling

- Sample Set
  - Static developed from 1992-1994 data
  - Residential only for each member system
  - Consist of four (4) loads shapes
    - Average Week day
    - average weekend/holiday
    - weighted combined weekday & weekend/holiday
    - peak day
- Profiles to be adjusted for weather and distribution loss factors
  - Member systems may adjust to either static or dynamic weather

Load Profiling at SRP

- Available to Residential & Commercial Customers using less than 100,000 kwh annually
- One series of Residential profiles
- One series of Commercial profiles

Load Profiling at SRP

- Multiplier Method - blend of averaged Historical and Dynamic day specific data
- Historical portion - mathematical relationship between Class Loadshape and the Control Area Loadshape
- Dynamic portion - Actual Control Area Loadcurve for the profiled day

Load Profiling at SRP

- Multiplier Method yields a unique loadshape template for each day of the year.
- Advantages
  - Accurate
  - Accounts for actual weather conditions on the profiled day
  - Produces the loadshape template the next day
  - Easy to program
  - Fast and relatively inexpensive to implement

Load Profiling - TEP

Load Profiling - Data Collection

- Step 2
  - Metering Equipment and Data Collection System Have been installed

...Residential Meters have been installed.

...We are in process of Identifying Predictable Loads.

...Class profiles have been created.

Load Profiling - Data Collection

- Step 2
  - Install Interval Metering Equipment and Data Collection System

...Meters Programmed to Automatically Call In To MV-90 System Daily Between 1:00am & 5:00am.

...MV-90 System Set Up To Automatically Validate, Then Transfer Data To MV-STAR System.

...MV-90 Can Be Configured To Generate Estimated Data If Metering Device Fails To Call In.

Load Profiling -
Generate Base Profiles

- Step 3
  - Create Fixed Source And Fixed Target Groups Within MV-STAR
  - Associate Sample Interval Meters to Source Groups
  - Associate Consumption Meters Requiring Load Profiling to Target Group
  - Generate and Store Base Profiles On a Daily Basis Using MV-STAR's Load Profiling Module
  - Electronically Transmit Base Profiles to Settlement's Group FTP Server For market Participant's Use

Load Profiling - Generate Profiles for Individual Service Points

- Step 4
  - On a Daily Basis Populate MV-STAR Consumption Read Table From CIP*PL*US Island Table Using Oracle/DB2 Gateway
  - Use Consumption Read Information In Combination With Base Load Profiles to Generate Individual Profiles for Each Service Point
    - ...Calculate kWh for Base Profile Over Billing Time Period
    - ...Divide Billing kWh by Calculated Base kWh To Calculate
    - ...Adjustment Ratio
    - ...Apply Adjustment Ratio To Base Profile Over Billing Period and Store Results As Estimated Load Profile for Given Service Point

Load Profiling - Monitor Sample For Possible Bias Due To Using Existing Sampling Methodologies

- Step 5
  - Operational Plan Is To Directly Draw Random Sample From Customers Entering Direct Access Market
  - Sample Sizes Will be Determined by Studying Hourly CV's and Determining Acceptable Level of Accuracy for Market Settlements
  - Existing kWh Groupings for Stratification Will be Used Until Data Is Available to Re-Stratify Based on Market Conditions and Offerings

SPECIAL OPEN MEETING MINUTES{private }

DATE: July 13, 1999

TIME: 9:30 a.m.

PLACE: Arizona Corporation Commission
Conference Room #202
1200 W. Washington
Phoenix, Arizona 85007

ATTENDANCE:

No Quorum of Commissioners
Members of Commission Staff
Members of Unbundled Services Billing and Collections Committee which includes representatives from APS, TEP, Citizens, Trico Electric Cooperative, Navopache Electric Cooperative, Sulphur Springs Valley Electric Cooperative, Salt River Project, Enron, APS Energy Services, New West Energy, Computer Science Corp., Schlumberger, K.R. Saline & Associates, SysTrends, and CellNet.

TOPIC: **UNBUNDLED SERVICES AND STANDARD OFFER WORKING GROUP BILLING AND COLLECTIONS COMMITTEE MEETING**

MATTERS DISCUSSED:

The purpose of this meeting was to discuss the use of a common format for Direct Access Service Requests (DASR). The Billing and Collections Committee spent considerable time and effort last year developing a DASR Handbook that was finalized on Nov. 18, 1998 (Attachment # 1). Stacy Aguayo from APS then presented a handout (Attachment #2) that listed the changes that APS has made to the DASR Handbook. One of the major changes is that APS wants to add another DASR status code (#28). This code is C-Completed, which indicates that the customer has been switched to direct access. The Energy Service Providers (ESP) were agreeable to this change, but Evelyn Dryer from TEP does not want to do this since TEP designed their system for the October 26, 1998 DASR Handbook. Another APS change was to the reason code (#29) where APS wants to add a WL code which would indicate that they are waiting for a DASR to be completed. Finally, APS wanted to add code #60 which would be the UDC Direct Access rate. APS also wanted to add that the DASR is to be used only with residential load profiled customers. One of the major concerns for the ESPs is the development of a criteria for rejecting DASRs. One of the CA utilities was validating on all 59 codes, which resulted in many rejections. TEP mentioned that they were validating on UDC Customer Account number (code #8), Service Street Address (code #9), and Service Zip Code (code #12). Citizens indicated that they were validating on the UDC Customer account number and the Universal Meter ID (code#45). The original Billings and Collections committee along with the ESPs will get together to finalize the validation procedure.

The Committee then reviewed the email from Nancy Hetrick to Ron Franquero (Attachment #3) about the use of standard formats for EDI transactions 810, 814, 867 (which is done), 650, 820, 824, and 997. The 814 transaction is the same as the DASR, but Shirley Renfroe from APS mentioned that an Implementation Guide is needed for 814, similar to the one developed for 867. At the present time no format exists for transaction 650, although California and Pennsylvania are working on one. TEP has implemented transaction 820, which is the remittance between the ESP and the UDC. It appears that this transaction could be easily implemented. One of the hardest transactions to implement could be 810 since it is difficult and expensive to change existing systems. Transactions 824 (Application) and 997 (Rejections) are replies to requests. Shirley Renfroe said that 824 will be the most costly to implement, although Pennsylvania and the New England states are working on this.

ASSIGNMENTS FOR NEXT MEETING:

The original members of the Billing and Collections committee will review the revised DASR Handbook and Mikki Sampson will send revised Handbook for review prior to the next meeting.

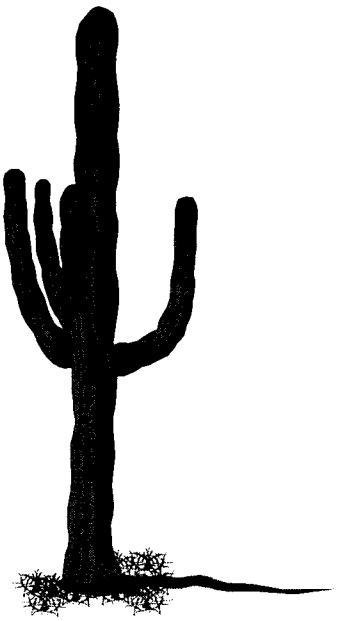
The next meeting was scheduled for August 5, 1999, although this meeting has been delayed until later in the month of August.

The meeting adjourned at 12:15 p.m.

Ron Franquero
Utilities Consultant
July 29, 1999

State of Arizona

Direct Access Service Request Handbook



11/18/98

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Background

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

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

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

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

Introduction

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

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

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

- A Letter of Authorization (LOA) will be signed by the customer and retained by the ESP as proof that the customer made a legitimate request for a new service provider
- The current service provider is responsible for submitting 12-months (or available) of customer-specific consumption history to the new service provider
- Customer always bears the burden of contacting their present service provider regarding any changes to their service agreement
- One DASR is required for each requested transaction
- The effective Direct Access (DA) switch date will occur on the customer's scheduled meter read date or the date of meter installation
- The minimum format to be used for these transactions is comma delimited value: character values are left justified; numeric values are right justified zero filled
- DASR's may initiate the meter exchange process; for specific meter exchange protocols contact the UDC
- Until January 1, 2001, load aggregation eligibility is determined within individual UDC service territories
- The Direct Access Load Aggregation Submittal (DALAS) needs to be validated by the UDC prior to the submission of DASR's for each of the services listed on the DALAS
- Self-Aggregators will perform the ESP role on their own behalf
- When a Self-Aggregator does not have a Duns number, the UDC will assign a number for the purpose of DASR/DALAS submittal
- DASR/DALAS transactions may require additional specific details refer to individual UDCs

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

Consumer Protection References

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

Request (RQ) DASR

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

ESP Responsibility:

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

UDC Responsibility:

- Determines eligibility of customer
- Responds to ESP with customer's 12-month consumption history and DASR status within 3 business days
- Upon new Request DASR acceptance, issues Termination of Service Agreement DASR to ESP of record (now prior ESP) notifying them of customer's request to switch providers
- Assigns Universal Node Identifier (UNI) if first time Direct Access customer
- Coordinates with ESP, or their designated affiliate, any meter exchange activity and/or meter reading requirements as necessary

Customer Responsibility:

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

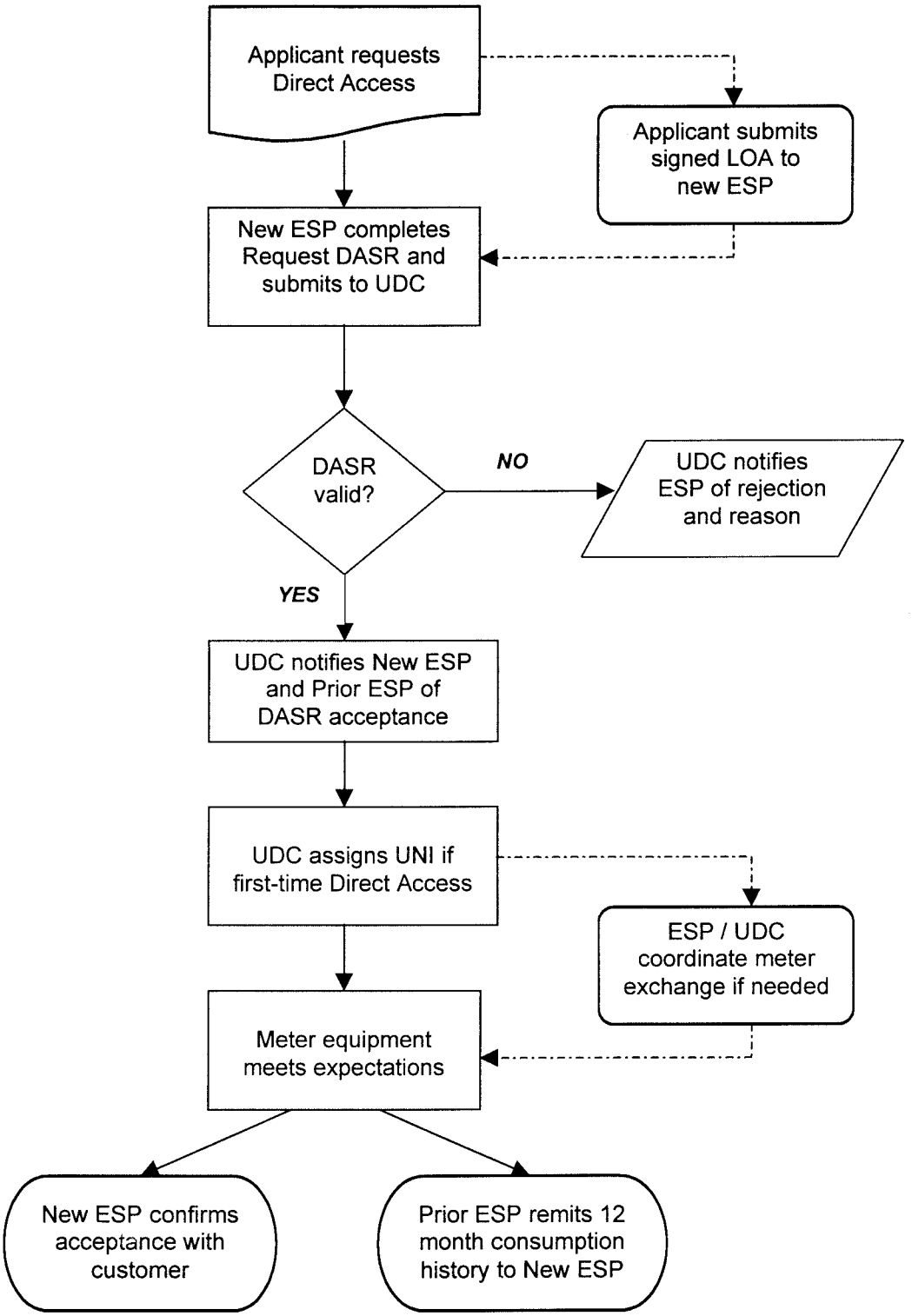
General Information:

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

In accordance with R14-2-203.D4, the following standards are also in place;

- When a meter exchange is *not* required, the switch date to Direct Access will occur on the customer's next scheduled meter read date provided that the DASR is processed [received and validated by the UDC] 15 calendar days prior to that date
- When a meter exchange is required, the switch date will occur on the meter install date
- The customer switch date may occur earlier for a fee

Request (RQ) DASR Process Flowchart



Request (RQ) DASR Submittal / Response

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

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

Cancel (CL) DASR

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

ESP Responsibility:

- Originator of DASR submits Cancel DASR to stop activation of the transaction

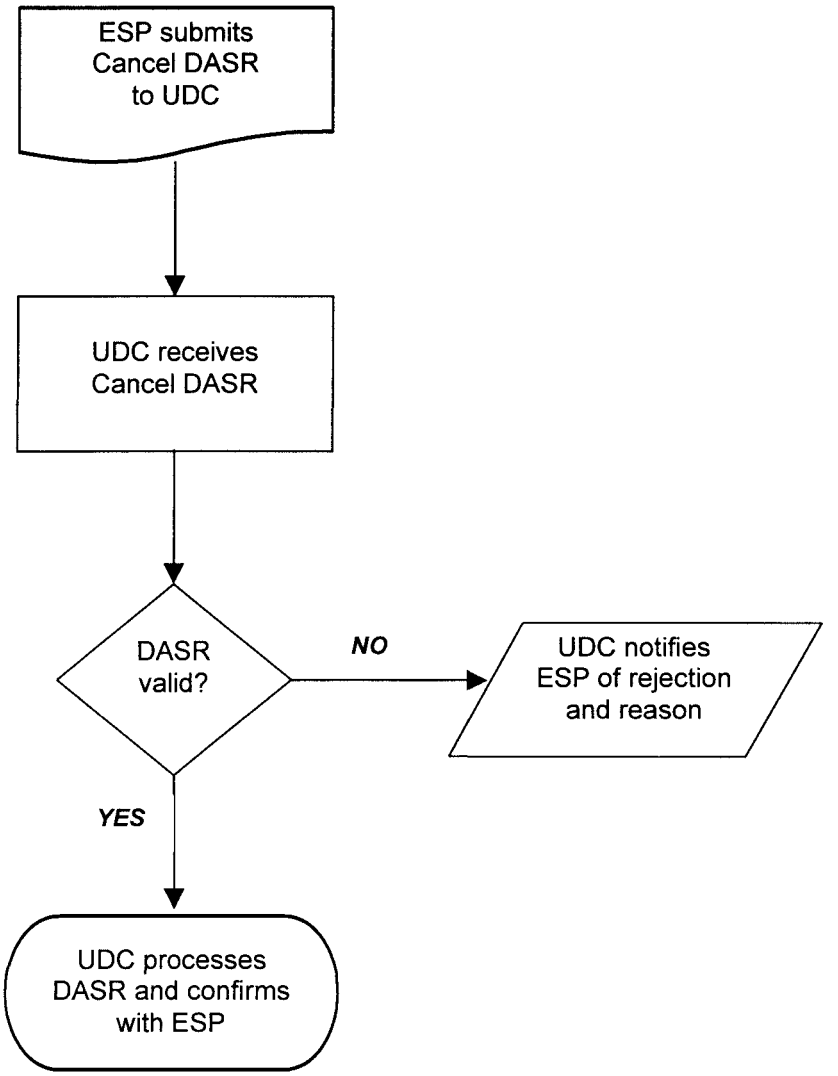
UDC Responsibility:

- Accept and respond with confirmation

Customer Responsibility:

- To promptly notify their ESP of any change of decision

Cancel (CL) DASR Process Flowchart



Cancel (CL) DASR Submittal / Response

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

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

Termination of Service Agreement (TS) DASR

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

ESP Responsibility:

- Provide minimum of 5 calendar days notice to customer of intent to terminate service agreement
- Provide 15 calendar days notice prior to the next scheduled read date, via Termination of Service Agreement DASR, to UDC regarding intent to terminate the service agreement with their customer
- When switching to a new ESP, submit customer's 12-month consumption history to new ESP; not necessary if customer is returning to a Standard Offer

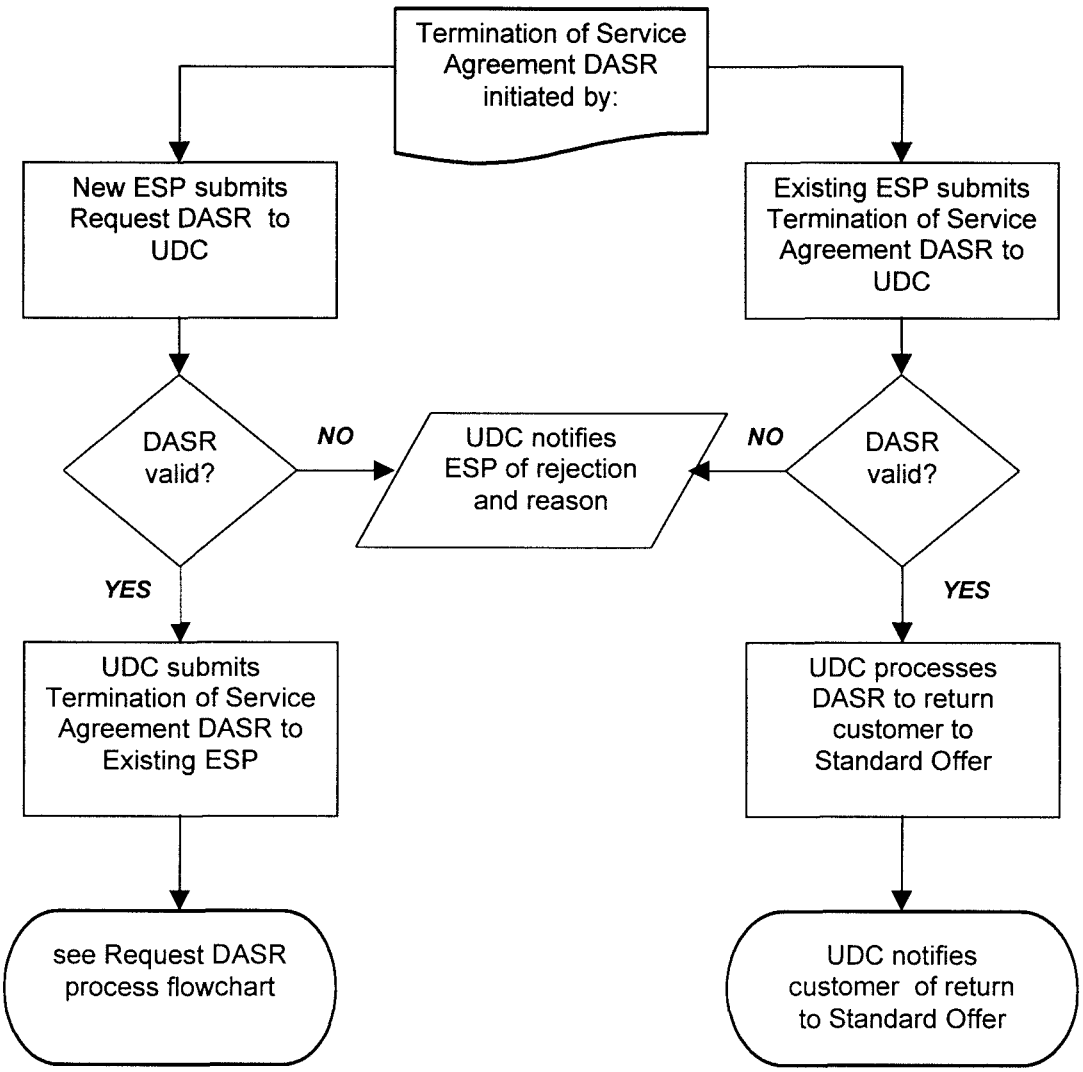
UDC Responsibility:

- When a Termination of Service Agreement DASR has been received and a new ESP has not been identified with a pending Request DASR, UDC will send notification to customer they are being returned to UDC Standard Offer
- Send Termination of Service Agreement DASR to prior ESP upon receipt of a Request DASR from a new ESP for a customer; prior ESP is not required to respond

Customer Responsibility:

- When customer is requesting termination of the service agreement, they must contact their present ESP for submittal of Termination of Service Agreement DASR or new ESP for submittal of Request DASR
- The customer will be returned to UDC Standard Offer unless another Request DASR is received within the established time frame

Termination of Service Agreement (TS) DASR Process Flowchart



Termination of Service Agreement (TS) DASR Submittal / Response

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

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

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

Physical Disconnect (PD) DASR

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

ESP Responsibility:

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

UDC Responsibility:

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

Customer Responsibility:

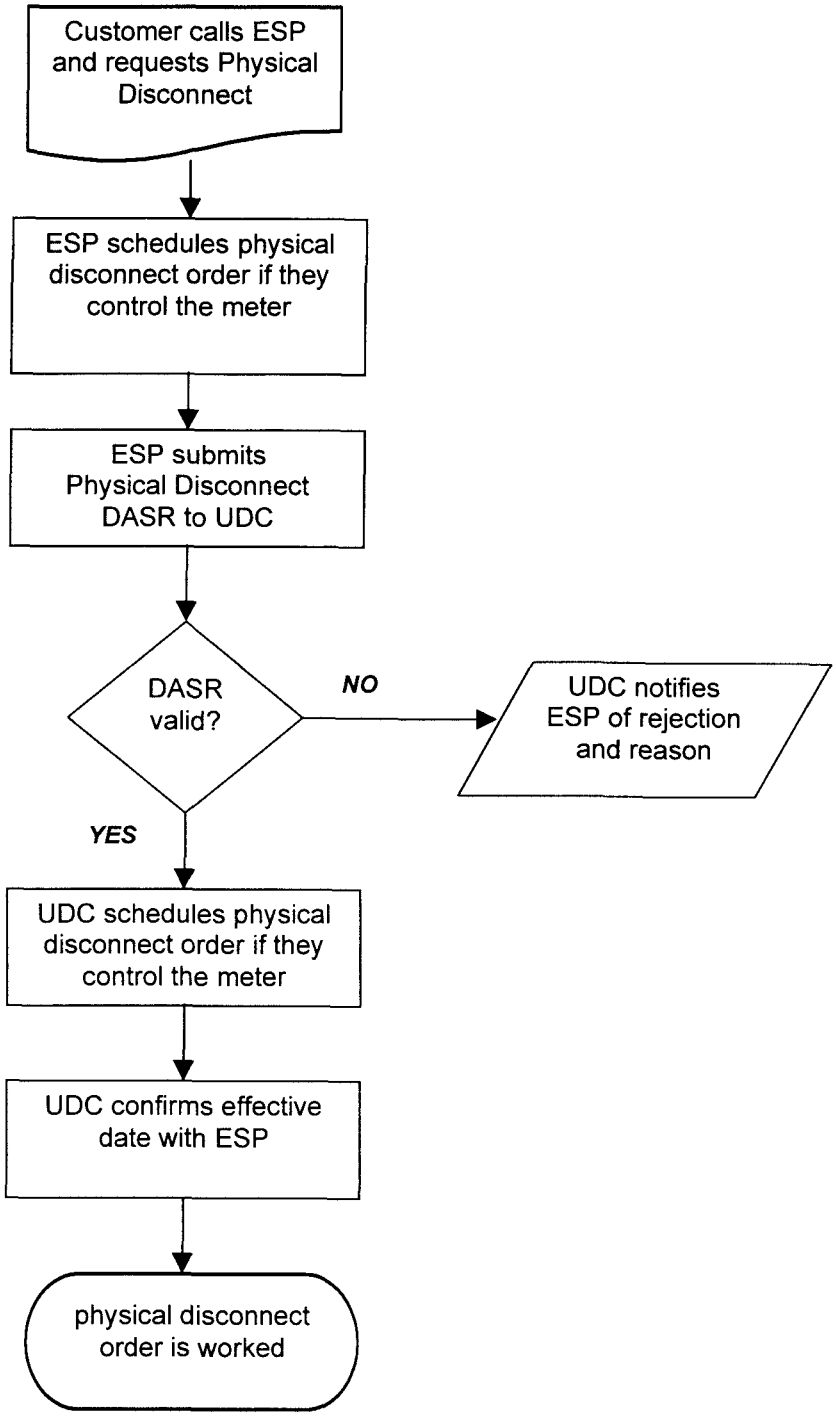
- Customer must contact their ESP directly to request physical disconnect of electric service

General Information:

In accordance with R14-2-210.I,

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

Physical Disconnect (PD) DASR Process Flowchart



Physical Disconnect (PD) DASR Submittal / Response

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

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

Update / Change (UC) DASR

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

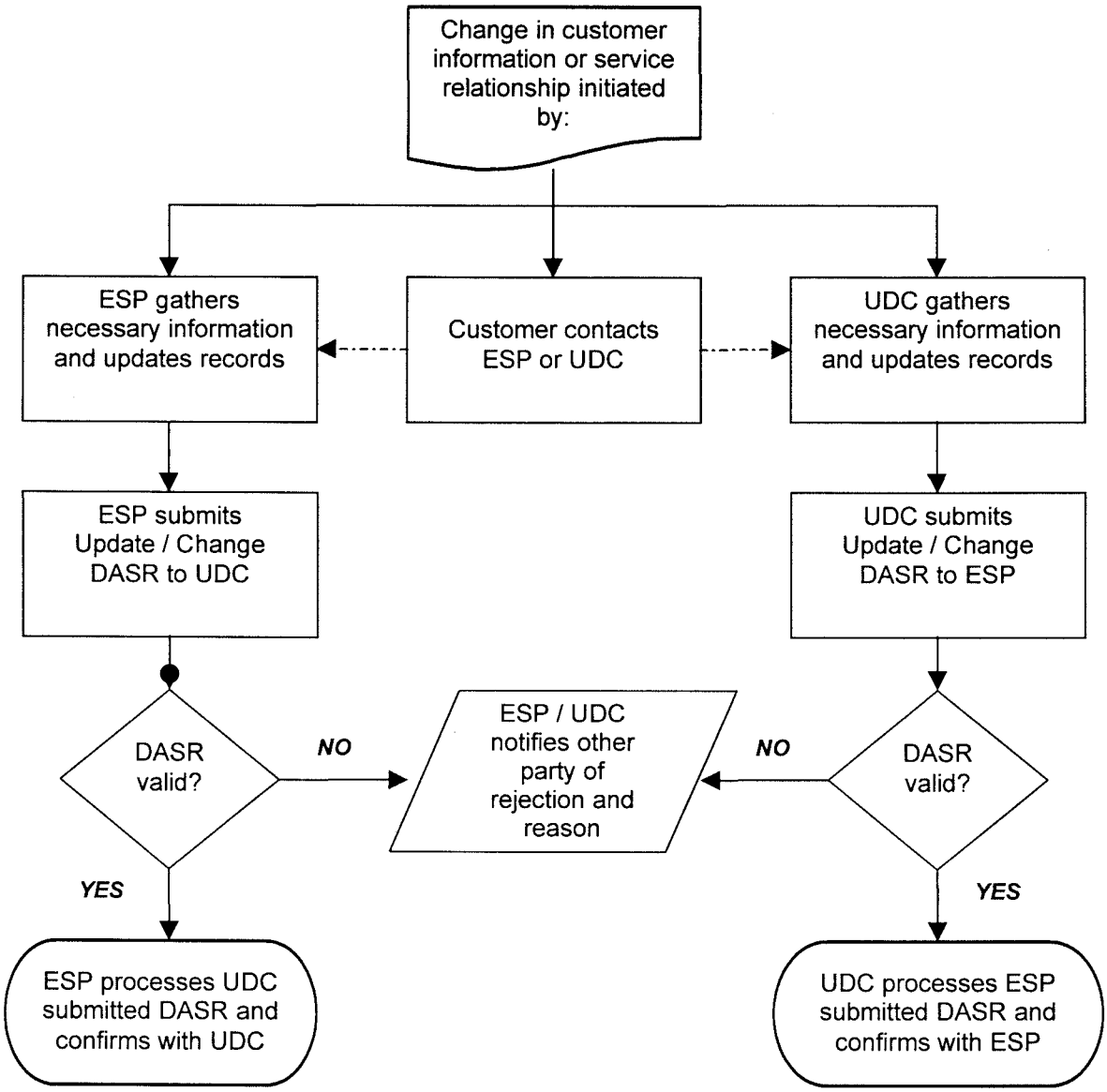
ESP Responsibility:
- To promptly notify the UDC of any change of customer information or change in service relationship for the customer

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

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

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

Update / Change (UC) DASR Process Flowchart



Update / Change (UC) DASR Submittal / Response

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

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

Direct Access Service Request (DASR)
Field Definitions

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

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

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

Field #	Name	DASR Field Definition and Format	Size maximum	Type Character or Integer
40	Forward Zip	Zip code for the customer where where future mail is to be delivered.	9	C
41	Meter #	Individual meter number at the service delivery point.	11	C
42	UDC Meter Read Cycle	Indicates the cycle in which the meter is read.	2	C
43	Universal Node ID (UNI)	Identifies a unique, permanent number assigned to the last service point of the UDC's distribution network to which energy is delivered. The ESP is responsible for the energy delivered to that service point.	34	C
44	Meter Ownership	Indicates the owner of meter. **E** ESP **U** UDC **C** Customer	1	C
45	Universal Meter ID (UMI)	Identifies a universal meter number assigned to every meter by the manufacturer.	17	C
46	MSP ID	Meter Service Provider's Duns # as recorded on the UDC agreement with the Meter Service Provider.	13	I
47	Meter Service Provider (MSP) Name	Business name of the entity providing Metering Service.	30	C
48	MRSP ID	Meter Reading Service Provider's Duns # as recorded on the UDC agreement with the Meter Reading Service Provider.	13	I
49	Meter Reading Service Provider (MRSP) Name	Business name of the entity that reads meters, performs validation, editing, and estimation on raw data to create validated meter data; translates validated data to an approved format, this posts to a Server for retrieval by billing agents; manages the Server; exchanges data with market participants; and stores meter data for problem resolution.	30	C
50	New ESP #	Duns # for the new Energy Service Provider.	13	C
51	New ESP Business Name	Business name of the Energy Service Provider as recorded on their Certificate of Convenience and Necessity Docket #.	30	C
52	New ESP Customer Account #	Customer account number assigned by the ESP.	20	C
53	New UDC Customer Account #	Customer account number assigned by the UDC where service is provided.	20	C
54	ESP Rate Code	Identifies the rate code assigned by the ESP. *required if fields 34 and 35 are selected*	25	C
55	Load Usage Profile	An estimate of a customer's hourly energy consumption based on measurements of similar customers.	5	C
56	UDC Bill Cycle	Identifies the cycle in which the UDC account is billed.	2	C
57	Original DASR Tracking #	Identifies the unique number assigned by the originator of the DASR being canceled or updated/changed.	22	C

Field #	Name	DASR Field Definition and Format	Size maximum	Type Character or Integer
58	Recipient ID	Recipient's (ESP) Duns # as recorded on the UDC agreement with the Energy Service Provider.	13	I
59	Recipient Name	Business name of the recipient (ESP) of the TS or UC DASR submitted by the UDC.	30	C

Direct Access Load Aggregation Submittal (DALAS)

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

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

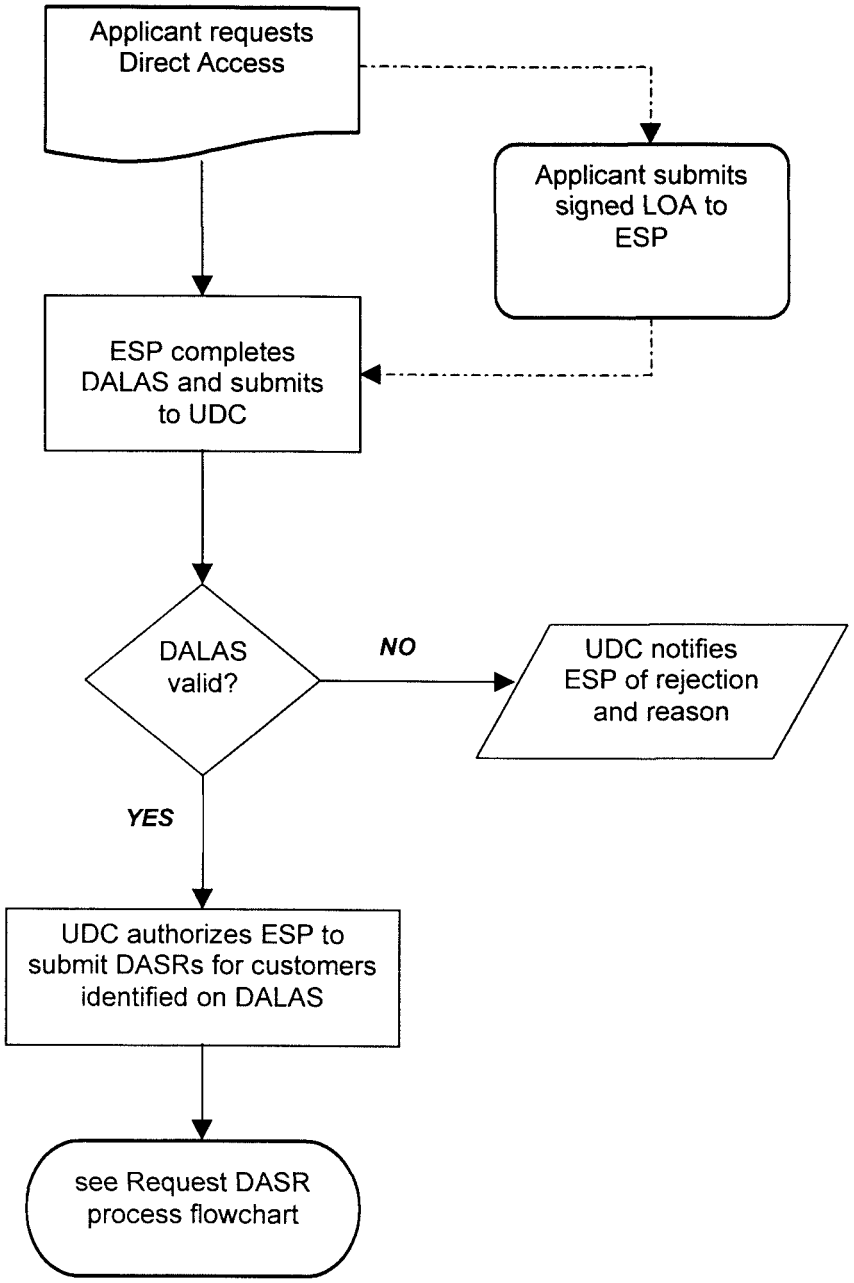
UDC Responsibility:
- Verifies identified customers are eligible and the DALAS submittal totals at least 1 MW
- Responds to ESP with status (accepted or rejected) of DALAS within 3 business days

Customer Responsibility:
- Customer makes application with ESP

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

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

DALAS Process Flowchart



State of Arizona
Direct Access Load Aggregation Submittal (DALAS)

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

ESP Name _____ Date & Time Sent _____

ESP Duns # _____ Date & Time Received _____

UDC ID _____ ESP / UDC Contract # _____

DA Load Aggregation Submittal ID _____

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

APS' DASR Changes

#	Name	APS	ACC DASR Handbook
1	DASR Tracking #		
2	ESP Business Name		
3	Date & Time Sent		
4	Date & Time Received		
5	Transaction Type		
6	ESP Customer Account #		
7	Customer UDC Account Name	Field Size = 30	Field Size = 42
8	UDC Customer Account #		
9	Service Street Address		
10	Service City		
11	Service State		
12	Service Zip		
13	Mail Address		
14	Mail City		
15	Mail State		
16	Mail Zip		
17	Contact Phone #		
18	UDC ID		
19	UDC Business Name		
20	Quarter Eligible		
21	ESP Medical Code		
22	UDC Medical Code		
23	Scheduling Coordinator Duns #		
24	Scheduling Coordinator Name		
25	Congestion Zone		
26	UDC Customer Eligibility		
27	DA Load Aggregation Submittal ID		
28	DASR Status	Added **C- Completed** as a status.	
29	Reason Code	Added **WL – Wait** List as a pending code for Phase-In only	
30	ESP Comments		
31	UDC Comments		

#	Name	APS	ACC DASR Handbook
32	Requested Change Date		
33	Effective Change Date		
34	Billing Options		
35	Bill Calculation		
36	Disconnect Requested By	Field Size = 30	Field Size = 42
37	Forward Mail Address		
38	Forward City		
39	Forward State		
40	Forward Zip		
41	Meter #	Field Size = 6	Field Size = 11
42	UDC Meter Read Cycle		
43	Universal Node ID (UNI)		
44	Meter Ownership		
45	Universal Meter ID (UMI)	**Definition:** Identifies a number assigned by the ESP or UDC to specify physical characteristic of the meter	**Definition:** Identifies a universal meter number assigned to every meter by the manufacturer
46	MSP ID		
47	Meter Service Provider (MSP) Name		
48	MRSP ID		
49	Meter Reading Service Provider (MRSP) Name		
50	New ESP #		
51	New ESP Business Name		
52	New ESP Customer Account #		
53	New UDC Customer Account #		
54	ESP Rate Code		
55	Load Usage Profile		
56	UDC Bill Cycle		
57	Original DASR Tracking #	Field Size = 22	Field Size = 20 (Should be the same size as Field 1)
58	Recipient ID		
59	Recipient Name		
60	UDC DA Rate	APS Added	

Request (RQ) DASR Submittal / Response

This table demonstrates the **R**equired and **O**ptional fields necessary to complete this DASR transaction type.

Field	Submittal – Field Description	Req'd	ACC
1	DASR Tracking #	R	
2	ESP Business Name	R	
3	Date & Time Sent	R	
5	Transaction Type	R	
6	ESP Customer Account #	R	
7	Customer UDC Account Name	R	
8	UDC Customer Account #	R	
9	Service Street Address	R	
10	Service City	R	
11	Service State	R	
12	Service Zip	R	
13	Mail Address	R	
14	Mail City	R	
15	Mail State	R	
16	Mail Zip	R	
17	Contact Phone #	R	
18	UDC ID	R	
21	ESP Medical Code	O	
23	Scheduling Coordinator Duns #	R	
24	Scheduling Coordinator Name	R	
26	UDC Customer Eligibility	R	
27	DA Load Aggregation Submittal ID	O	
30	ESP Comments	O	
32	Requested Change Date	R	
34	Billing Options	R	
35	Billing Calculation	O	
41	Meter #	R	
43	Universal Node ID (UNI)	O	
44	Meter Ownership	R	
45	Universal Meter ID (UMI)	O	
46	MSP ID	O	**R**
47	Meter Service Provider Name	O	**R**
48	MRSP ID	R	
49	Meter Reading Service Provider Name	R	
54	ESP Rate Code	O	

Field	Response – Field Description	Req'd	ACC
1	DASR Tracking #	R	
3	Date & Time Sent	R	
6	ESP Customer Account #	R	
18	UDC ID	R	
20	Quarter Eligible	O	
22	UDC Medical Code	R	
25	Congestion Zone	R	
26	UDC Customer Eligibility	O	
28	DASR Status	R	
29	Reason Code	O	
31	UDC Comments	O	
33	Effective Change Date	R	
42	UDC Meter Read Cycle	R	
43	Universal Node ID (UNI)	R	
45	Universal Meter ID (UMI)	O	
55	Load Profile	O	
56	UDC Bill Cycle	O	
58	Recipient ID	R	**None**
59	Recipient Name	R	**None**
60	UDC DA Rate	R	**None**

Cancel (CL) DASR Submittal / Response

This table demonstrates the **R**equired and **O**ptional fields necessary to complete this DASR transaction type.

Field	Submittal – Field Description	Req'd	ACC	Field	Response – Field Description	Req'd	ACC
1	DASR Tracking #	R		1	DASR Tracking #	R	
2	ESP Business Name	R		5	Transaction Type	R	
3	Date & Time Sent	R		6	ESP Customer Account #	R	
5	Transaction Type	R		18	UDC ID	R	
6	ESP Customer Account #	R		28	DASR Status	R	
7	Customer UDC Account Name	R		29	Reason Code	R	
8	UDC Customer Account #	R		31	UDC Comments	O	
9	Service Street Address	R		33	Effective Date	O	
10	Service City	R		58	Recipient ID	R	**None**
11	Service State	R		59	Recipient Name	R	**None**
12	Service Zip	R					
18	UDC ID	R					
30	ESP Comments	O					
41	Meter #	R					
57	Original DASR Tracking #	R					

Termination of Service Agreement (TS) DASR Submittal / Response

This table demonstrates the **R**equired and **O**ptional fields necessary to complete this DASR transaction type.

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

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

Physical Disconnect (PD) DASR Submittal / Response

This table demonstrates the **R**equired and **O**ptional fields necessary to complete this DASR transaction type.

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

Field	Response – Field Description	Req'd	ACC
1	DASR Tracking #	R	
3	Date & Time Sent	R	
6	ESP Customer Account #	R	
18	UDC ID	R	
28	DASR Status	R	
29	Reason Code	O	
31	UDC Comments	O	
33	Effective Change Date	R	
58	Recipient ID	R	**Non**
59	Recipient Name	R	**Non**

Update / Change (UC) DASR Submittal / Response

This table demonstrates the **R**equired and **O**ptional fields necessary to complete this DASR transaction type.

Field	Submittal – Field Description	Req'd	ACC
1	DASR Tracking #	R	
2	ESP Business Name	R	
3	Date & Time Sent	R	
5	Transaction Type	R	
6	ESP Customer Account #	R	
7	Customer UDC Account Name	R	
8	UDC Customer Account #	R	
9	Service Street Address	R	
10	Service City	R	
11	Service State	R	
12	Service Zip	R	
13	Mail Address	O	
14	Mail City	O	
15	Mail State	O	
16	Mail Zip	O	
18	UDC ID	R	
21	ESP Medical Code	O	
23	Scheduling Coordinator Duns #	O	
24	Scheduling Coordinator Name	O	
30	ESP Comments	O	
31	UDC Comments	O	
32	Requested Change Date	R	
34	Billing Options	O	
35	Bill Calculation	O	
41	Meter #	O	
42	UDC Meter Read Cycle	O	
43	Universal Node ID (UNI)	R	
44	Meter Ownership	O	
45	Universal Meter ID (UMI)	O	
46	MSP ID	O	
47	Meter Service Provider Name	O	
48	MRSP ID	O	
49	Meter Reading Service Provider Name	O	
52	New ESP Customer Account #	O	
53	New UDC Customer Account #	O	
54	ESP Rate Code	O	
56	UDC Bill Cycle	O	
57	Original DASR Tracking #	O	
58	Recipient ID	O	
59	Recipient Name	O	
60	UDC DA Rate	O	**None**

Field	Response – Field Description	Req'd	ACC
1	DASR Tracking #	R	
3	Date & Time Sent	R	
6	ESP Customer Account #	R	
28	DASR Status	R	
29	Reason Code	R	
31	UDC Comments	O	
33	Effective Change Date	R	
58	Recipient ID	R	**None**
59	Recipient Name	R	**None**

From: "Nancy Hetrick" <Nancy_Hetrick@enron.com>{private }
To: CC.UTIL(RAF)
Date: July 2, 1999 (Friday) 7:31am
Subject: Common, Statewide EDI Formats

I concur 100% with all of the comments that you have been receiving from others regarding the critical need for common, statewide EDI standards in Arizona. Enron has struggled along with the many other California market participants to implement and maintain separate and unique processes and protocols for each of the three California UDCs. This has proven to be very costly and inefficient for all ESPs. Ultimately, though the real pain has been reaped upon our customers in the form of late and inaccurate bills, hassles with switching from the UDC to a supplier, etc.

This is exactly what we would like to see avoided in Arizona. I know that the Commissioners watched what happened in California and took the appropriate steps to order EDI in Arizona with the intent that there would be common transactions within the state. But this is not what has happened. Unknown to the Commissioners is the fact that EDI can be interpreted and implemented in a vast variety of formats and this is exactly what has happened. This factor has a huge impact on ESPs by drastically increasing the cost to enter the Arizona market. Suppliers will be required to develop and map transactions three different ways to just accommodate APS, TEP and SRP. This has a major cost impact to the Suppliers and ultimately results in higher energy costs to Arizona customers.

Lastly, standardization for 814, 810, 867, 650, 820, 824, and 997 EDI transactions are all equally important and necessary. EDI is a communication tool and can be utilized to bridge the gap between different CIS systems. Using system constraints, etc., to rationalize the use of a propietary format just to get data in their own format rather than responding to the market needs, places an anti-competitive burden on the market.

CC: CC.UTIL(RTW),CC.SMTP("Brian_McFaden@orcom.com")

SPECIAL OPEN MEETING MINUTES{private }

DATE: July 16, 1999

TIME: 9:30 a.m.

PLACE: Arizona Department of Revenue
9th Floor Training Room
1600 W. Monroe
Phoenix, Arizona 85007

ATTENDANCE:

No Quorum of Commissioners
Members of Commission Staff
Members of Unbundled Services Metering Subcommittee
which includes representatives from APS, TEP, Citizens, Trico Electric Cooperative, Navopache Electric Cooperative, Sulphur Springs Valley Electric Cooperative, Salt River Project, New West Energy, New Energy Ventures Southwest, Phaser Advanced Metering Systems, Computer Science Corp., and K. R. Saline & Associates.

TOPIC: **UNBUNDLED SERVICES AND STANDARD OFFER WORKING GROUP METERING COMMITTEE MEETING**

MATTERS DISCUSSED:

The purpose of this meeting was to review the final version of EDI 867 Version 4010's implementation guide developed by the EDI Technical Subgroup. Joe Webster from APS, the chairman of the subgroup, distributed the final version of the implementation guide (Attachment #1) and included some examples (Attachment #2) for using the guide. After much discussion, a vote was taken on approval of the final version. The final version passed by a vote of 10-0 and a list of those voting is shown in Attachment #3.

The Committee then reviewed the use of a Universal Metering Identifier (UMI). The UMI had been previously sent out for review on June 22, 1999 and the discussion at the meeting was based on this revised version. It was agreed that whoever **initially** purchases the meter will assign the UMI. APS wanted the option to assign their own number to the **YY** field and this was agreed to by everyone. Also, the **ZZ** field was changed to be the DOE ID number for UDCs and an ACC assigned number for Providers. The final version of the UMI is included as Attachment # 4.

Finally, Rene Castillo and Patrick Bouquet of SRP presented a report they had prepared called the "EDI Discussion Document" (Attachment #5). This report included findings of current practices of other utilities regarding development of EDI standards and practices. The discussion led to the use of State-Level forums for discussing EDI. These forums are being used in California, Pennsylvania, and Massachusetts. The oversight for these forums is provided by the state PUC and PUC attendance is regular, but, technical discussions are driven by UDCs, and

generally hosted by the UDCs on a rotating basis. As previously mentioned, Arizona is working on developing statewide EDI formats and this mechanism will help the state achieve this goal.

ASSIGNMENTS FOR NEXT MEETING:

There are no future meetings scheduled for the Metering Committee.

The meeting adjourned at 12:15 p.m.

Ron Franquero
Utilities Consultant
July 30, 1999

Arizona Implementation Guidelines for ANSI ASC X12 EDI Ver/Rel 004010

867 - Meter Data Exchange

VERSION: 1.0.4 Proposed final

Modified: July 14, 1999

Notes: proposed final Document

Revision notes (version 1.0.3 => version 1.0.4):

- **Clarified PDT ref02 MT example text for metering intervals to start on top of hour.**
- **Fixed example 03 historical demand, changed REF MT from K101567 to K101551 to be consistent with text.**

867 Product Transfer and Resale Report

Functional Group=PT

This draft Standard for Trial Use contains the format and establishes the data contents of the Product Transfer and Resale Report Transaction Set (867) for use within the context of an Electronic Data Interchange (EDI) environment. The transaction set can be used to: (1) report information about product that has been transferred from one location to another; (2) report sales of product from one or more locations to an end customer; or (3) report sales of a product from one or more locations to an end customer, and demand beyond actual sales (lost orders). Report may be issued by either buyer or seller.

This document describes the implementation to be used for the Arizona electric meter read data transfer.

Notes:

2/010 Each use of the PTD loop will represent one meter register

Heading:

Pos	Id	Segment Name	Req	Max Use	Repeat	Notes	Usage
010	ST	Transaction Set Header	M	1			Must use
020	BPT	Beginning Segment for Product Transfer and Resale	M	1			Must use
LOOP ID - N1					5		
090	N1	Name	O	3			Must use
130	REF	Reference Identification	O	2			Must use

Detail:

Pos	Id	Segment Name	Req	Max Use	Repeat	Notes	Usage
LOOP ID - PTD					>1		
010	PTD	Product Transfer and Resale Detail	M	1		N2/010	Must use
030	REF	Reference Identification	O	10			Used
LOOP ID - QTY					>1		
150	QTY	Quantity	O	1			Must use
230	MEA	Measurements	O	1			Used
260	REF	Reference Identification	O	2			Used
280	DTM	Date/Time Reference	O	2			Used

Summary:

Pos	Id	Segment Name	Req	Max Use	Repeat	Notes	Usage
040	SE	Transaction Set Trailer	M	1			Must use

ST Transaction Set Header

Pos: 010	Max: 1
Heading - Mandatory	
Loop: N/A	Elements: 2

To indicate the start of a transaction set and to assign a control number

Semantics:

1. The transaction set identifier (ST01) used by the translation routines of the interchange partners to select the appropriate transaction set definition (e.g., 810 selects the Invoice Transaction Set).

Element Summary:

Ref	Id	Element Name	Req	Type	Min/Max	Usage
ST01	143	**Transaction Set Identifier Code** **Description:** Code uniquely identifying a Transaction Set Code Name 867 Product Transfer and Resale Report	M	ID	3/3	Must use
ST02	329	**Transaction Set Control Number** **Description:** Identifying control number that must be unique within the transaction set functional group assigned by the originator for a transaction set.	M	AN	4/9	Must use

BPT Beginning Segment for Product Transfer and Resale

Pos: 020	Max: 1
Heading - Mandatory	
Loop: N/A	Elements: 5

To indicate the beginning of the Product Transfer and Resale Report Transaction Set and transmit identifying data

Syntax:

Semantics:

1. BPT02 identifies the transfer/resale number.
2. BPT03 identifies the transfer/resale date.
3. BPT09 is used when it is necessary to reference a requesting document.

Element Summary:

Ref	Id	Element Name	Req	Type	Min/Max	Usage
BPT01	**353**	**Transaction Set Purpose Code** **Description:** Code identifying purpose of transaction set	**M**	**ID**	**2/2**	**Must use**
		Code **Name** 00 Original **Description:** Conveys original readings for the account being reported. Use for both Inbound and Outbound transactions 07 Duplicate **Description:** Indicates that this is a retransmission of previously furnished information. Use for both Inbound and Outbound transactions 22 Information Copy **Description:** Indicates that meter data is for information only and not to be used for billing purposes 52 Response to Historical Inquiry **Description:** Response to a request for historical meter reading. Used for Outbound only CO Corrected **Description:** Indicates that the readings previously reported for the account are being corrected. Use for both Inbound and Outbound transactions				
BPT02	**127**	**Reference Identification** **Description:** Reference information as defined for a particular Transaction Set or as specified by the Reference Identification Qualifier. It is a unique transaction identification number assigned by the originator of this transaction.	**O**	**AN**	**1/30**	**Used**
BPT03	**373**	**Date** **Description:** Date expressed as CCYYMMDD. Transaction Creation Date	**M**	**DT**	**8/8**	**Must Use**
BPT04	**755**	**Report Type Code**	**O**	**ID**	**2/2**	**Used**

Ref	Id	Element Name	Req	Type	Min/Max	Usage
		Description: Code indicating the title or contents of a document, report or supporting item **Code** **Name** C1 Cost Data Summary **Description:** Interval readings DD Monthly reads **Description:** Usage				
BPT09	**127**	**Reference Identification** **Description:** Reference information as defined for a particular Transaction Set or as specified by the Reference Identification Qualifier. **User Note 1:** When BPT01 = 52 , this element may contain the DASR number which initiated this request.	**O**	**AN**	**1/30**	**Used**

N1 Name

Pos: 090	Max: 1
Heading - Optional	
Loop: N1	Elements: 5

To identify a party by type of organization, name, and code

Syntax:

R0203 -- At least one of N102 or N103 is required.
P0304 -- If either N103 or N104 are present, then the others are required.

Comments:

1. This segment, used alone, provides the most efficient method of providing organizational identification. To obtain this efficiency the "ID Code" (N104) must provide a key to the table maintained by the transaction processing party.
2. At least two N1 segments will be used in Arizona. One identifying the originator of the transaction, the other identifying the receiver of the transaction.

Element Summary:

Ref	Id	Element Name	Req	Type	Min/Max	Usage
N101	98	**Entity Identifier Code** **Description:** Code identifying an organizational entity, a physical location, property or an individual		ID	2/3	Must Use
		Code **Name** 55 Service Manager **Description:** Used to identify the party that manages meter data on behalf of another. Meter Reading Service Provider (MRSP) 8S Consumer Service Provider (CSP) **Description:** Utility (UDC) SJ Service Provider **Description:** Energy Service Provider (ESP)				
N102	93	**Name** **Description:** Free-form name, this name if used is only for clarity of the transaction. Not used in processing, not verified consistent with N104.	C	AN	1/60	Used
N103	66	**Identification Code Qualifier** **Description:** Code designating the system/method of code structure used for Identification Code (67)	C	ID	1/2	Used
		Code **Name** 1 D-U-N-S Number, Dun & Bradstreet **Description:** 9 digit Duns number required by all **AZ** Utilities except SRP. 91 Assigned by Seller or Seller's Agent **Description:** An identifier assigned by the Utility this option is only supported by SRP at this time.				

Ref	Id	Element Name	Req	Type	Min/Max	Usage
N104	**67**	**Identification Code** **Description:** Code identifying a party or other code	**C**	**AN**	**2/80**	**Used**
N106	**98**	**Entity Identifier Code** **Description:** Code identifying an organizational entity, a physical location, property or an individual	**O**	**ID**	**2/3**	**Must Use**

Code	Name
40	Receiver **Description:** Entity to accept transmission
41	Submitter **Description:** Entity transmitting transaction set

REF Reference Identification

Pos: 130	Max: 12
Heading - Optional	
Loop: N1	Elements: 3

To specify identifying information

Syntax:

Semantics:

1.

Comments:

1. The Service Delivery site is identified in this segment. Multiple meters may be associated with one delivery site.
2. Only one REF01 code is required.

Element Summary:

Ref	Id	Element Name	Req	Type	Min/Max	Usage
REF01	**128**	**Reference Identification Qualifier** **Description:** Code qualifying the Reference Identification **Code** **Name** 11 Account Number **Description:** Energy Service Provider-assigned account Number for the end use customer. **Required by SRP on both inbound and outbound transactions.** LU Location Number **Description:** Identification Number for the point where service is delivered to the customer - Universal Node ID (UNI). If more than one delivery point at a site, this will be the first UNI at that site. **Required by all UDCs except SRP on both inbound and outbound transactions.**		**ID**	**2/3**	**Must Use**
REF02	**127**	**Reference Identification** **Description:** Reference information as defined for a particular Transaction Set or as specified by the Reference Identification Qualifier	**C**	**AN**	**1/30**	**Must Use**

PTD Product Transfer and Resale Detail

Pos: 010	Max: 1
Detail - Mandatory	
Loop: PTD	Elements: 3

To indicate the start of detail information relating to the transfer/resale of a product and provide identifying data. Each PTD represents one meter register

Syntax:

P0405 -- If either PTD04 or PTD05 is present, then the other is required.

Comments:

Each PTD loop will represent a meter register, whether demand, monthly, or detailed interval data.

Element Summary:

Ref	Id	Element Name	Req	Type	Min/Max	Usage
PTD01	**521**	**Product Transfer Type Code** **Description:** Code identifying the type of product transfer **Code** **Name** PM Physical Meter Information **Description:** Individual meter installation.	**M**	**ID**	**2/2**	**Must Use**
PTD04	**128**	**Reference Identification Qualifier** **Description:** Code qualifying the Reference Identification **Code** **Name** OZ Product Number	**C**	**ID**	**2/3**	**Used**
PTD05	**127**	**Reference Identification** **Description:** Reference information as defined for a particular Transaction Set or as specified by the Reference Identification Qualifier **Code** **Name** EL Electric Service	**C**	**AN**	**1/30**	**Used**

REF Reference Identification

Pos: 030	Max: 20
Detail - Optional	
Loop: PTD	Elements: 3

To specify identifying information

Syntax:

Semantics:

1.

Comments:

1. At least three REF records are required for every PTD loop: LU, MT, and MG if metered service - LU, MT, and SC if un-metered service.

Element Summary:

Ref	Id	Element Name	Req	Type	Min/Max	Usage
REF01	128	**Reference Identification Qualifier** **Description:** Code qualifying the Reference Identification	M	ID	2/3	Must Use

Code	Name
6W	Sequence Number **Description:** Optional channel number. Only used when there is more than one channel on a meter measuring the same quantity (e.g. two KWh channels). Only supported by SRP at this time.
IX	Item Number **Description:** Optional Number of dials. Only supported by SRP at this time.
LU	Location Number (UNI) **Description:** *Required* Specific UNI, defines the point of delivery.
MG	Meter Number one of either the MG or SC ref record is required.
MT	Meter Ticket Number **Description:** Required. Meter Type. Used to identify the type of consumption measured by this meter and register. Defines the interval between measurements. See REF02 for examples.
NH	Rate Card Number **Description:** Utility Rate class or tariff. Optional field initially only supported by SRP.
SC	Shipper Car Order Number **Description:** Unmetered Service Indicator. See REF02 for valid value. Only supplied if usage is for an unmetered service. Not initially supported by APS.

Ref	Id	Element Name	Req	Type	Min/Max	Usage
		SU Special Processing Code **Description:** Life support equipment verification. See REF02 for valid values. Optional field only supported by SRP.				
REF02	**127**	**Reference Identification** **Description:** Reference information as defined for a particular Transaction Set or as specified by the Reference Identification Qualifier **User Note 1:** When REF01 is SU, valid values for REF02 are: Y - Life Support Required N - Life Support Not Required I - Investigating whether Life Support is Required **User Note 2:** When REF01 is SC, valid value for REF02 is: U- Unmetered **User Note 3:** When REF01 is MT, the meter type is expressed as a seven character field. The first two characters are the type of consumption, expressed as: K1 – Kilowatt Demand K2 – Kilovolt Amperes Reactive Demand K3 - Kilovolt Amperes Reactive Hour KH – Kilowatt Hour The next three-characters are the metering interval, expressed as: Nnn = number of minutes: , from 001 to 999 in factors or multiples of 60 Initially in Arizona only 60 minutes and 15 minutes are supported. The interval must start at the top of the hour for 60 minute intervals and on the quarter hour for 15 minute intervals. For transaction files with 15 min intervals the first interval should start at the top of an hour and the last interval should stop at the top of an hour. DAY = daily * MON = monthly (any period data defined by a start date and end date). ANN = annual * BIA = bi-annual * BIM = bi-monthly * QTR = quarterly * (* Coordinate with receiver prior to using codes other than 060, 015, or MON as not all frequencies are supported by all trading partners.) The last two characters are the register type, expressed as: (Coordinate with receiver prior to using any of the following codes as not all codes are supported by all trading partners).	**C**	**AN**	**1/30**	**Must Use**

Ref	Id	Element Name	Req	Type	Min/Max	Usage
		41 = Off Peak 42 = On Peak (For TEP Documents – Peak-1) 45 = Summer On Peak 49 = Winter On Peak 51 = Total 63 = Peak-2 66 = Shoulder 67 = Non Time –Related Demand 73 = Summer Off Peak 75 = Winter Off Peak 96 = Interval (* used when BPT04 = C1) Examples: KHMON51: Kilowatt hours used during the month. KHMON42: Kilowatt hours used during peak hours during the month. K106042: Highest kilowatt demand hour which occurred during Peak period hours during the usage period. K101551: Highest kilowatt demand 15min. which occurred during the usage period. KH06096: Hourly intervals data. K101567 Highest demand 15 min in which its time stamp in the QTY loop identifies the time that this 15 minute demand took place				
REF03	**352**	**Description** **Description:** A free form description to clarify the related data elements and their content. Optional: SRP may provide reference to a related Meter Number in this field. May be used on SRP outbound messages for information only.	**C**	**AN**	**1/80**	**Used**

QTY Quantity

Pos: 150	Max: 1
Detail - Optional	
Loop: QTY	Elements: 3

To specify quantity information

Syntax:

Semantics:

1.

Element Summary:

Ref	Id	Element Name	Req	Type	Min/Max	Usage
QTY01	673	**Quantity Qualifier** **Description:** Code specifying the type of quantity	M	ID	2/2	Must Use
		Code **Name** 87 Quantity Received from end use customer. **Description:** Received from the customer in a co-generation environment. QD Quantity Delivered to end use customer.				
QTY02	380	**Quantity** **Description:** Numeric value of quantity	C	R	1/15	Must Use
QTY03	C001	**Composite Unit of Measure** **Description:** To identify a composite unit of measure.	O	Comp		Used
	355	**Unit or Basis for Measurement Code** **Description:** Code specifying the units in which a value is being expressed, or manner in which a measurement has been taken	M	ID	2/2	Must Use
		Code **Name** K1 Kilowatt Demand (KW) **Description:** Real power, or the rate at which real energy is delivered to the load, averaged over a predetermined interval of time (normally 60 min or 15 min). KW is the product of the volts supplied to the circuit and the in-phase component of the resultant current, divided by 1000. Real power is the work-producing part of apparent power. K2 Kilovolt Amperes Reactive Demand (KVAR) **Description:** Reactive power, or the rate at which reactive energy (kVARh) is delivered to the load, averaged over a predetermined interval of time. It is measured at a given instant or averaged over any designated period of time. KVAR is the product of the volts supplied to the load and the quadrature component of the resultant current, divided by 1000. Reactive power is the portion of apparent power that does no work. K3 Kilovolt Amperes Reactive Hour (KVARH)				

Ref	Id	Element Name	Req	Type	Min/Max	Usage
		Description: The total reactive energy delivered to the load, the product of reactive power (kVAR) and the length of time (hours). Reactive energy is energy that cannot perform any work.				
	KH	Kilowatt Hour (KWH) **Description:** The total real energy delivered to the load, the accumulation of the product of real power (KW) and time in hours. Real energy is energy that can perform actual work.				

MEA Measurements

Pos: 230	Max: 40
Detail - Optional	
Loop: QTY	Elements: 7

To specify physical measurements or counts, including dimensions, tolerances, variances, and weights(See Figures Appendix for example of use of C001)

Syntax:

R03050608 -- At least one of MEA03, MEA05, MEA06 is required.
C0504 -- If MEA05 is present, then MEA04 is required
C0604 -- If MEA06 is present, then MEA04 is required
L07030506 -- If MEA07 is present, then at least one of MEA03, MEA05 or MEA06 is required.

Semantics:

1. MEA04 defines the unit of measure for MEA03, MEA05, and MEA06.

Comments:

1. On the MEA record, the beginning and ending read are always provided for all KH and K3 type measurements, except interval reads (96) and unmetered usage (ref SC = U)
2. On the MEA record, the demand read is provided for all K1 and K2 type measurements, except unmetered usage.
3. On the MEA record, when interval reads are being provided (96) the interval pulse count may be provided in MEA06.

Element Summary:

Ref	Id	Element Name	Req	Type	Min/Max	Usage
MEA01	**737**	**Measurement Reference ID Code** **Description:** *Defines the quality of the meter read defined in MEA05 & MEA06.*	**O**	**ID**	**2/2**	**Used**

Code	Name
	The following four codes are required for monthly usage reads to qualify fields five and six. Not used for interval reads.
AA	Meter reading-beginning actual/ending actual
AE	Meter reading-beginning actual/ending estimated
EA	Meter reading-beginning estimated/ending actual
EE	Meter reading-beginning estimated/ending estimated
BO	Meter Reading as Billed **Description:** Used for unmetered accounts. Used when billing charges are based on contractual agreements or pre-established usage and not on actual usage.

MEA02	**738**	**Measurement Qualifier** **Description:** Code identifying a specific product or process characteristic to which a measurement applies	**O**	**ID**	**1/3**	**Used**

Code	Name

Ref	Id	Element Name	Req	Type	Min/Max	Usage
		MU Multiplier **Required for non -interval usage.** PJ Pulse Width **Description:** Pulse multiplier				
MEA03	**739**	**Measurement Value** **Description:** The value of the measurement and only used if MEA02=MU **User Note 1:** Represents the meter constant when MEA02 = "MU". When no multiplier is present, use a value of "1". The difference of the meter reads in MEA05 & MEA06 times this multiplier should be equal to the value in QTY02. (accounting for roll over). When MEA02 = PJ, the value in MEA06 times this multiplier should equal the interval value in QTY02	**C**	**R**	**1/20**	**Used**
MEA04	**C001**	**Composite Unit of Measure** **Description:** To identify a composite unit of measure	**C**	**Comp**		**Used**
	355	**Unit or Basis for Measurement Code** **Description:** Code specifying the units in which a value is being expressed, or manner in which a measurement has been taken. This should be the same as that found on the QTY record. **Code** **Name** K1 Kilowatt Demand (KW) **Description:** Real power, or the rate at which real energy is delivered to the load, averaged over a predetermined interval of time. KW is the product of the volts supplied to the circuit and the in-phase component of the resultant current, divided by 1000. Real power is the work-producing part of apparent power. K2 Kilovolt Amperes Reactive Demand (KVAR) **Description:** Reactive power, or the rate at which reactive energy (kVARh) is delivered to the load, averaged over a predetermined interval of time. It is measured at a given instant or averaged over any designated period of time. KVAR is the product of the volts supplied to the load and the quadrature component of the resultant current, divided by 1000. Reactive power is the portion of apparent power that does no work. K3 Kilovolt Amperes Reactive Hour (KVARH) **Description:** The total reactive energy delivered to the load, the product of reactive power (kVAR) and the length of time (hours). Reactive energy is energy that cannot perform any work. KH Kilowatt Hour (KWH) **Description:** The total real energy delivered to the load, the product of real power (KW) and length of time (hours). Real energy is energy that can perform actual work.	**M**	**ID**	**2/2**	**Must Use**
MEA05	**740**	**Range Minimum** **Description:** The value specifying the beginning meter read. **Required for monthly usage. Not used for demand values or interval reads.**	**C**	**R**	**1/20**	**Used**
MEA06	**741**	**Range Maximum**	**C**	**R**	**1/20**	**Used**

Ref	Id	Element Name	Req	Type	Min/Max	Usage
		Description: The value specifying the ending reading or single reading (e.g., demand) or optionally the number of pulses for interval data. **Required for monthly usage and demand values. Optional for interval reads.**				
MEA07	**935**	**Measurement Significance Code**	**O**	**ID**	**2/2**	**Used**
		Description: Code used to benchmark, qualify or further define usage conveyed in QTY02.				

Code	Name
22	Actual -normal usage passed validation (included non-metered)
46	Estimated - usage not derived from actual meter reads.
83	Good Verified – value appears anomalous but has been verified.
88	Adjusted

REF Reference Identification

Pos: 260	Max: >1
Detail - Optional	
Loop: QTY	Elements: 3

To specify identifying information

Syntax:

1. REF02 R0203 -- At least one of REF02 or REF03 is required.

Semantics:

1. REF04 contains data relating to the value cited in REF02.

Notes:

1. This segment is required when the MEA07 = 46 (estimated), based on ACC rules. Not required for meters in SRP territory.

Element Summary:

Ref	Id	Element Name	Req	Type	Min/Max	Usage
REF01	**128**	**Reference Identification Qualifier** **Description:** Code qualifying the Reference Identification - Estimate Reason Code	**M**	**ID**	**2/3**	**Must Use**
		Code **Name** ESN Estimate Sequence Number				
REF02	**127**	**Reference Identification** **Description:** Reference information as defined for a particular Transaction Set or as specified by the Reference Identification Qualifier	**C**	**AN**	**1/30**	**Used**

Code **Name**

EA1 = Extreme Weather - Flood
EA2 = Extreme Weather - Snow
EA3 = Extreme Weather - Storm
EA4 = Extreme Weather
EA5 = Labor Disagreement
EA6 = Emergency
EB0 = Self read not received from customer
EC1 = No Access - Bad Animal
EC2 = No Access - Gate Locked
EC3 = No Access - Trim Foliage
EC4 = No Access - No Answer at Premises
EC5 = No Access - Meter Blocked
EC6 = No Access - Irrigation

Ref	Id	Element Name	Req	Type	Min/Max	Usage
		EC7 = No Access - Business Not Open				
		EC8 = No Access				
		ED1 = Customer Meter Equipment Failure				
		ED2 = Customer Meter Removed				
		ED3 = Customer Meter Changed				
		ED4 = Customer Dirty Meter Glass				
		EE0 = Read Not Received From Meter Reading Agent				
		EE1 = Other				
		EV1 = Meter Was Misread				
		EV2 = Zero Consumption - Check Failure				
		EV3 = High/Low Check Failure				
		EV4 = Meter in Test (Interval Estimate Only)				
		EV5 = Demand Not Reset				
		EV6 = Energy Diversion - Read Estimated				
		MA1 = Power Failure in Interval				
		MA2 = Meter Tamper				
		MS1 = Dead Meter				
		MS2 = Kit Faulted Service				
		MS3 = Kit Source Service				
		MS4 = Flatted in UDC				
		MS5 = Exposed Wiring				
		MS6 = Low Service Wire				
		MS7 = Meter Destroyed				
		MS8 = Broken Glass				
		MS9 = Service Wires in Trees				
		MS10 = Curled Dial				
		MS11 = Demand Won't Reset to Zero				
		MS12 = Wrong Meter Number				
		MS13 = Wrong Address				
		MS14 = Battery Failure				
		MS15 = Pot Light				
		MD1 = Wrong Color Seal				
		MD2 = Inverted Meter				
		MD3 = Meter Not Sealed				
		MD4 = Ring Damaged				
		MD5 = Jumpers Bypassed				
		MD6 = Diversion				
		MD7 = No Panel Seal				
		MD8 = Hole in Cover				
		MD9 = Disc Jammed				
		MD10 = Stolen Meter Installed				

Ref	Id	Element Name	Req	Type	Min/Max	Usage
		GT = Go to REF03 for Description				
REF03	**352**	**Description** **Description:** A free-form description to clarify the related data elements and their content.	**C**	**AN**	**1/80**	**Used**

DTM Date/Time Reference

Pos: 280	Max: 10
Detail - Optional	
Loop: QTY	Elements: 3

To specify pertinent dates and times

Syntax:

P0506 -- If either DTM05 or DTM06 is present, then the other is required.

Element Summary:

Ref	Id	Element Name	Req	Type	Min/Max	Usage
DTM01	374	**Date/Time Qualifier** **Description:** Code specifying type of date or time, or both date and time **Code** **Name** 150 Service Period Start 151 Service Period End	M	ID	3/3	Must Use
DTM02	373	**Date (not used at this time)** **Description:** Date expressed as CCYYMMDD	O	DT	8/8	Used
DTM03	337	**Time (not used at this time)** **Description:** Time expressed in 24-hour clock time as follows: HHMM, or HHMMSS, or HHMMSSD, HHMMSSDD where H= Hours (00-23), M = Minutes (00-59), S = Integer seconds (00-59), and DD = Decimal seconds: decimal seconds are expressed as follows: D= tenths (0-9) and DD = hundredths (00-99)	O	TM	4/8	Used
DTM04	623	**Time Code** **Description:** Code identifying the time. No change for Daylight Savings Time. **Code** **Name** MS Mountain Standard Time	O	ID	2/2	Must Use
DTM05	1250	**Date Time Period Format Qualifier** **Description:** Code indicating the date format, time format, or date and time format **Code** **Name** D8 Date Expressed in Format CCYYMMDD When D8 is used the time is assumed to default to 0000. DT Date and Time Expressed in Format CCYYMMDDHHMM	C	ID	2/3	Must Use
DTM06	1251	**Date Time Period** **Description:** Expression of a date, a time, or range of dates, times or dates and times.	C	AN	1/35	Used

SE Transaction Set Trailer

Pos: 040	Max: 1
Summary - Mandatory	
Loop: N/A	Elements: 2

To indicate the end of the transaction set and provide the count of the transmitted segments (including the beginning (ST) and ending (SE) segments)

Comments:

1. SE is the last segment of each transaction set.

Element Summary:

Ref	Id	Element Name	Req	Type	Min/Max	Usage
SE01	96	**Number of Included Segments** **Description:** Total number of segments included in a transaction set including ST and SE segments	M	N0	1/10	Must Use
SE02	329	**Transaction Set Control Number** **Description:** Identifying control number that must be unique within the transaction set functional group assigned by the originator for a transaction set	M	AN	4/9	Must Use

======= 1

THIS EXAMPLE CONTAINS MONTHLY KW AND COMMERCIAL (15 MIN) DEMAND VALUES USING THE AZ COMMON FORMAT, VERSION 1.
SENT BY MRSP AND REC BY A UDC.

```
ISA*00*          *00*          *01*123456789      *01*006901995      *990702*1442*U*00401*000000014*0*P*:
GS*PT*123456789*006901995*19990702*1442*14*X*004010
ST*867*0001                                   /* UNIQUE CONTROL NUMBER WITHIN THE TRANSACTION SET.
BPT*00*444EXAMPLE 04*19990702*DD              /* ORGINAL * REF NUMBER * TRANSACTION DATE * MONTHLY READ
N1*8S*APS*1*006901999**40                     /* ID'S UDC * TEXT NAME OF UDC * DUNS # *APS DUNS NUMBER ** RECEVIER
N1*SJ*ACME ESP*1*007048413                    /* ID'S ESP * TEXT NAME OF ESP * DUNS # *ACME DUNS NUMBER
N1*55*NO SWEAT METER READING*1*123456789**41 /* ID'S MRSP* TEXT NAME OF MRSP* DUNS # *NO SWEAT METER READING DUNS NUMBER **SENDER
REF*LU*0080315839428800001                    /* FIRST UNI AT SITE, OPTIONAL SRP-OTHERS REQUIRED, 11 - 34 CHAR, INBOUND/OUTBOUND
REF*11*0T5689643                              /* ESP ACCOUNT NUMBER, SRP REQUIRED-OTHERS OPTIONAL, INBOUND/OUTBOUND
PTD*PM***OZ*EL                                /* PTD LOOP
REF*LU*0080315839428800001                    /* REQUIRED UNI FOR METERED POINT OF DELIVERY 11 - 34 CHARACTERS
REF*MG*X123456                                /* REQUIRED METER NUMBER REFERENCE 6 - 17 CHARACTERS.
REF*MT*KHMON51                                /* REQUIRED METER TICKET, KH = METER TYPE, MON = MONTHLY METER INTERVAL, 51 = TOTAL REGISTER TYPE
QTY*QD*1331.2*KH                              /* QTY LOOP
MEA*AA*MU*5.2*KH*4267*4523*22                 /* AA DEFINES QUALITY OF METER READ BEGINNING AND ENDING VALUES * MEASUREMENT QUALIFIER * MULTIPLIER
                                                 VALUE * MEASUREMENT CODE * BEGINNING READ * ENDING READ * 22 DEFINES QUALITY OF USAGE IN QTY SEGMENT
DTM*150***MS*DT*199906011204                  /* DEFINES START TIME
DTM*151***MS*DT*199907021023                  /* DEFINES STOP TIME
PTD*PM***OZ*EL                                /* PTD LOOP
REF*LU*0080315839419400001                    /* REQUIRED UNI FOR METERED POINT OF DELIVERY 11 - 34 CHARACTERS
REF*MG*X123456                                /* REQUIRED METER NUMBER REFERENCE 6 - 17 CHARACTERS
REF*MT*K101567                                /* REQUIRED METER TICKET, K1 = METER TYPE, 015 = METER INTERVAL, 67 = NON TIME RELATED DEMAND
QTY*QD*1219.8*K1                              /* QTY LOOP
MEA*AA*MU*3.8*K1**321*22                      /* AA DEFINES QUALITY OF METER READ BEGINNING AND ENDING VALUES * MEASUREMENT QUALIFIER * MULTIPLIER
                                                 VALUE * MEASUREMENT CODE ** ENDING READ * 22 DEFINES QUALITY OF DEMAND IN QTY SEGMENT
DTM*150***MS*DT*199906111215                  /* DEFINES START TIME OF PEAK DEMAND PERIOD
DTM*151***MS*DT*199906111230                  /* DEFINES STOP TIME OF PEAK DEMAND PERIOD
SE*24*0001
GE*1*14
IEA*1*000000014
```

======== 2

```
*  THIS EXAMPLE CONTAINS ONE MONTHS WORTH OF INTERVAL DATA (60 minute) USING THE AZ COMMON FORMAT, VERSION 1.
SENT BY MRSP AND REC BY A UDC

ISA*00*          *00*          *01*123456789      *01*006901995      *990702*1442*U*00401*000000017*0*P*:
GS*PT*123456789*006901995*19990702*1442*17*X*004010
ST*867*0001                                   /* UNIQUE CONTROL NUMBER WITHIN THE TRANSACTION SET.
BPT*00*45167865432345667*19990702*C1          /* ORGINAL * REF NUMBER * TRANSACTION DATE * INTERVAL DATA
N1*8S*APS*1*006901995**40                     /* ID'S UDC * TEXT NAME OF UDC * DUNS # APS DUNS NUMBER **RECEVIER
N1*SJ*ACME ESP*1*007048413                    /* ID'S ESP * TEXT NAME OF ESP * DUNS # *ACME DUNS NUMBER
N1*55*NO SWEAT METER READING*1*123456789**41 /* ID'S MRSP* TEXT NAME OF MRSP* DUNS # *AMR DUNS NUMBER **SENDER
REF*LU*0080315839419400001                    /* FIRST UNI AT SITE REQUIRED BOTH INBOUND/OUTBOUND, 11 - 34 CHARACTERS
REF*11*0T56789643                             /* ESP ACCOUNT NUMBER, SRP REQUIRED-OTHERS OPTIONAL, INBOUND/OUTBOUND
PTD*PM***OZ*EL                                /* PTD LOOP
REF*LU*0080315839419400001                    /* REQUIRED UNI FOR THE METERED POINT OF DELIVERY 11 TO 34 CHARACTERS
REF*MG*C89030                                 /* REQUIRED METER NUMBER REFERENCE 6 TO 17 CHARACTERS.
REF*MT*KH06096                                /* REQUIRED METER TICKET, KH = METER TYPE, 060 = METERING INTERVAL
                                                 96 = INTERVAL REGISTER TYPE
QTY*QD*10.4*KH                                /* FIRST QTY LOOP
MEA**MU*1*KH***22                             /* DEFINES INITIAL DEFAULT QUALITY
DTM*150***MS*DT*199904010000                  /* DEFINES FIRST INTERVAL START TIME
DTM*151***MS*DT*199904010100                  /* DEFINES FIRST INTERVAL STOP TIME
QTY*QD*42.2*KH                                /* SECOND INTERVAL USES DEFAULT QUALITY CODE AND TIME INTERVAL IS
                                                 INFERRED FROM PREVIOUS DTM SEGMENTS
QTY*QD*41.8*KH
QTY*QD*46.1*KH
QTY*QD*42.6*KH
QTY*QD*41.6*KH
QTY*QD*43.6*KH
QTY*QD*43.2*KH
QTY*QD*44.7*KH
QTY*QD*41.5*KH
QTY*QD*42.8*KH
QTY*QD*42.7*KH
QTY*QD*41.3*KH
QTY*QD*41.6*KH
MEA**MU*1*KH***46                              /* VALUE ON ABOVE QTY WAS ESTIMATED
REF*ESN*ED1                                    /* ESTIMATED DUE TO CUSTOMER METER FAILURE
QTY*QD*43.2*KH                                 /* FOLLOWING QTY INTERVALS ALL ARE ESTIMATED DUE TO METER FAILURE
QTY*QD*44.9*KH
QTY*QD*44.6*KH
QTY*QD*43.7*KH
QTY*QD*42.5*KH
QTY*QD*45.1*KH
QTY*QD*45*KH
QTY*QD*42.7*KH
QTY*QD*42.7*KH
QTY*QD*44.5*KH
QTY*QD*41*KH
QTY*QD*42.6*KH
QTY*QD*44*KH
```

```
QTY*QD*41.1*KH
QTY*QD*43.5*KH
QTY*QD*44.1*KH
QTY*QD*42.5*KH
QTY*QD*41.7*KH
QTY*QD*42.5*KH
QTY*QD*42.8*KH
QTY*QD*42.8*KH
QTY*QD*42.8*KH
QTY*QD*43.1*KH
QTY*QD*41.3*KH
MEA**MU*1*KH***22                    /* QUALITY RETURNS TO ACTUAL
QTY*QD*41.3*KH
QTY*QD*45.3*KH
QTY*QD*43.3*KH
QTY*QD*42.7*KH
QTY*QD*40.9*KH
QTY*QD*44.7*KH
QTY*QD*42.8*KH
QTY*QD*44.3*KH
QTY*QD*44.7*KH
QTY*QD*43.7*KH
QTY*QD*73.2*KH
MEA**MU*1*KH***83                    /* VERIFIED - VALUE IS ACTUAL BUT APPEARS ANOMALOUS
QTY*QD*44.4*KH
MEA**MU*1*KH***22                    /* QUALITY RETURNS TO ACTUAL
QTY*QD*42.4*KH
QTY*QD*43.6*KH
QTY*QD*42.9*KH
QTY*QD*42.8*KH
QTY*QD*43.5*KH
QTY*QD*45.1*KH
QTY*QD*42.2*KH
QTY*QD*41.8*KH
QTY*QD*44.1*KH
QTY*QD*41.6*KH
QTY*QD*42.6*KH
QTY*QD*42.7*KH
QTY*QD*44.6*KH
QTY*QD*42.7*KH
QTY*QD*43.3*KH
QTY*QD*42.7*KH
QTY*QD*43.4*KH
QTY*QD*43.8*KH
QTY*QD*42.3*KH
QTY*QD*41.9*KH
QTY*QD*42.5*KH
```

QTY*QD*42.1*KH
QTY*QD*43.7*KH
QTY*QD*45.7*KH
QTY*QD*42*KH
QTY*QD*44.4*KH
QTY*QD*42*KH
QTY*QD*40.6*KH
QTY*QD*42.1*KH
QTY*QD*43.6*KH
QTY*QD*42.5*KH
QTY*QD*43.9*KH
QTY*QD*44.4*KH
QTY*QD*44.6*KH
QTY*QD*44.5*KH
QTY*QD*41.6*KH
QTY*QD*40.3*KH
QTY*QD*42.9*KH
QTY*QD*43.6*KH
QTY*QD*43.6*KH
QTY*QD*42.2*KH
QTY*QD*45.6*KH
QTY*QD*44.4*KH
QTY*QD*43.9*KH
QTY*QD*42.8*KH
QTY*QD*44.5*KH
QTY*QD*42.8*KH
QTY*QD*44.7*KH
QTY*QD*42.1*KH
QTY*QD*42.8*KH
QTY*QD*44.6*KH
QTY*QD*43.7*KH
QTY*QD*43*KH
QTY*QD*42.9*KH
QTY*QD*44.4*KH
QTY*QD*45*KH
QTY*QD*42.8*KH
QTY*QD*44.3*KH
QTY*QD*42.5*KH
QTY*QD*43*KH
QTY*QD*42.7*KH
QTY*QD*43.3*KH
QTY*QD*42.7*KH
QTY*QD*43.2*KH
QTY*QD*43.6*KH
QTY*QD*41.5*KH
QTY*QD*43.7*KH
QTY*QD*43.4*KH
QTY*QD*41.8*KH
QTY*QD*44.6*KH
QTY*QD*44.4*KH
QTY*QD*41.9*KH
QTY*QD*43*KH
QTY*QD*43.7*KH
QTY*QD*42*KH
QTY*QD*44.6*KH
QTY*QD*43.2*KH
QTY*QD*44*KH
QTY*QD*42.3*KH
QTY*QD*42.2*KH
QTY*QD*41*KH
QTY*QD*44.3*KH
QTY*QD*43.5*KH
QTY*QD*42.2*KH
QTY*QD*40.9*KH
QTY*QD*41.4*KH
QTY*QD*43.8*KH
QTY*QD*43.3*KH
QTY*QD*43.4*KH

QTY*QD*42.3*KH
QTY*QD*42.1*KH
QTY*QD*43.4*KH
QTY*QD*42.3*KH
QTY*QD*44.9*KH
QTY*QD*44.2*KH
QTY*QD*42.5*KH
QTY*QD*44*KH
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*  THIS EXAMPLE CONTAINS MONTHLY HISTORICAL KWH AND DEMAND (15 MIN) VALUES USING THE AZ COMMON FORMAT, VERSION 1.
SENT BY UDC TO ESP, 8 MONTHS HISTORY

ISA*00*          *00*          *01*006901995      *01*007048413      *000202*1442*U*00401*000000016*0*P*:
GS*PT*006901995*007048413*20000202*1442*16*X*004010
ST*867*0001                                      /* Unique control number within the transaction set
BPT*52*444EXAMPLE 06*20000202*DD*****DASRTRACK# /* HIST*REF #*TRANSACTION CREATION DATE*MONTHLY READS*DASR # THAT REQUESTED HISTORICAL READS
N1*8S*APS*1*006901999**41                        /* ID'S UDC * TEXT NAME OF UDC * DUNS # *APS DUNS # ** SENDER
N1*SJ*ACME ESP*1*007048413**40                   /* ID'S ESP * TEXT NAME OF ESP * DUNS # *ACME DUNS NUMBER ** RECEIVER
REF*LU*0080315839428800001                       /* FIRST UNI AT SITE, OPTIONAL SRP-OTHERS REQUIRED, 11 TO 34 CHARACTERS, INBOUND/OUTBOUND
REF*11*0T5689643                                 /* ESP ACCOUNT NUMBER, SRP REQUIRED-OTHERS OPTIONAL, INBOUND/OUTBOUND

PTD*PM***OZ*EL                                   /* PTD LOOP - HISTORICAL MONTHLY USAGE - MONTH ONE
REF*LU*0080315839428800001                       /* REQUIRED UNI FOR THE METERED POINT OF DELIVERY 11 TO 34 CHARACTERS
REF*MG*X123456                                   /* REQUIRED METER NUMBER REFERENCE 6 TO 17 CHARACTERS.
REF*MT*KHMON51                                   /* REQUIRED METER TICKET, KH VALUES FOR MONTH, TOTAL KH USED DURING MONTH
QTY*QD*1331.2*KH                                 /* QTY LOOP
MEA*AA*MU*5.2*KH*4267*4523*22                    /* AA DEFINES THE QUALITY OF METER READ BEGINNING AND ENDING VALUES * MEASUREMENT QUALIFIER *
                                                    MULTIPLIER VALUE * MEASUREMENT CODE * BEGINNING READ * ENDING READ * 22 DEFINES QUALITY OF
                                                    USAGE IN QTY SEGMENT
DTM*150***MS*DT*199906011204                     /* SERVICE PERIOD START ***MS = MOUNTAIN STANDARD TIME * DATE/TIME
DTM*151***MS*DT*199907021023                     /* SERVICE PERIOD END ***MS = MOUNTAIN STANDARD TIME * DATE/TIME

PTD*PM***OZ*EL                                   /* PTD LOOP - HISTORICAL MONTHLY DEMAND - MONTH ONE
REF*LU*0080315839419400001                       /* REQUIRED UNI FOR THE METERED POINT OF DELIVERY 11 TO 34 CHARACTERS
REF*MG*X123456                                   /* REQUIRED METER NUMBER REFERENCE 6 TO 17 CHARACTERS.
REF*MT*K101551                                   /* REQUIRED METER TICKET, K1 VALUE, PEAK 15 MIN DURING THE MONTH
QTY*QD*1219.8*K1                                 /* QTY LOOP
MEA*AA*MU*3.8*K1**321*22                         /* AA DEFINES THE QUALITY OF METER READ ENDING VALUE * MEASUREMENT QUALIFIER * MULTIPLIER
                                                    VALUE * MEASUREMENT CODE * * ENDING READ * 22 DEFINES QUALITY OF USAGE IN QTY SEGMENT
DTM*150***MS*DT*199906011204                     /* SERVICE PERIOD START ***MS = MOUNTAIN STANDARD TIME * DATE/TIME
DTM*151***MS*DT*199907021023                     /* SERVICE PERIOD END ***MS = MOUNTAIN STANDARD TIME * DATE/TIME

PTD*PM***OZ*EL                                   /* PTD LOOP - HISTORICAL MONTHLY USAGE - MONTH TWO
REF*LU*0080315839428800001
REF*MG*X123456
REF*MT*KHMON51
QTY*QD*795.6*KH
MEA*AA*MU*5.2*KH*4523*4676*22
DTM*150***MS*DT*199907021023
DTM*151***MS*DT*199907300909

PTD*PM***OZ*EL                                   /* PTD LOOP - HISTORICAL MONTHLY DEMAND - MONTH TWO
REF*LU*0080315839419400001
REF*MG*X123456
REF*MT*K101551
QTY*QD*1569.4*K1
MEA*AA*MU*3.8*K1**413*22
DTM*150***MS*DT*199907021023
DTM*151***MS*DT*199907300909
```

```
PTD*PM***OZ*EL                          /* PTD LOOP - HISTORICAL MONTHLY USAGE - MONTH THREE
REF*LU*0080315839428800001
REF*MG*X123456
REF*MT*KHMON51
QTY*QD*1700.4*KH
MEA*AE*MU*5.2*KH*4676*5003*46           /* COULD NOT READ METER - ESTIMATED ENDING READ
REF*ESN*EA4                             /* QUALIFIER DEFINING ESTIMATED REASON CODE * EA4 IS THE ESTIMATED REASON CODE
DTM*150***MS*DT*199907300909
DTM*151***MS*DT*199908140000

PTD*PM***OZ*EL                          /* PTD LOOP - HISTORICAL MONTHLY DEMAND - MONTH THREE
REF*LU*0080315839419400001
REF*MG*X123456
REF*MT*K101551
QTY*QD*1569.4*K1
MEA*AE*MU*3.8*K1**413*46                /* COULD NOT READ METER - DEMAND ESTIMATED
REF*ESN*EA4
REF*ESN*EV5
DTM*150***MS*DT*199907300909
DTM*151***MS*DT*199908140000

PTD*PM***OZ*EL                          /* PTD LOOP - HISTORICAL MONTHLY USAGE - MONTH FOUR
REF*LU*0080315839428800001
REF*MG*X123456
REF*MT*KHMON51
QTY*QD*1201.2*KH
MEA*EA*MU*5.2*KH*5003*5234*46           /* PREVIOUS ENDING READ WAS AN ESTIMATE.
REF*ESN*EA4
DTM*150***MS*DT*199908140000
DTM*151***MS*DT*199909130645

PTD*PM***OZ*EL                          /* PTD LOOP - HISTORICAL MONTHLY DEMAND - MONTH FOUR
REF*LU*0080315839419400001
REF*MG*X123456
REF*MT*K101551
QTY*QD*1679.6*K1
MEA*AA*MU*3.8*K1**442*22
DTM*150***MS*DT*199908140000
DTM*151***MS*DT*199909130645

PTD*PM***OZ*EL                          /* PTD LOOP - HISTORICAL MONTHLY USAGE - MONTH FIVE
REF*LU*0080315839428800001
REF*MG*X123456
REF*MT*KHMON51
QTY*QD*4784*KH
MEA*AA*MU*5.2*KH*5234*6154*83           /* VERIFIED - VALUE IS ACTUAL BUT APPEARS ANOMALOUS
DTM*150***MS*DT*199909140645
DTM*151***MS*DT*199910121023

PTD*PM***OZ*EL                          /* PTD LOOP - HISTORICAL MONTHLY DEMAND - MONTH FIVE
REF*LU*0080315839419400001
REF*MG*X123456
```

```
REF*MT*K101551
QTY*QD*1143.8*K1
MEA*AA*MU*3.8*K1**301*22
DTM*150***MS*DT*199909140645
DTM*151***MS*DT*199910121023

PTD*PM***OZ*EL                          /* PTD LOOP - HISTORICAL MONTHLY USAGE - MONTH SIX
REF*LU*0080315839428800001
REF*MG*X123456
REF*MT*KHMON51
QTY*QD*3421.6*KH
MEA*AA*MU*5.2*KH*6154*6812*22
DTM*150***MS*DT*199910121023
DTM*151***MS*DT*199911124022

PTD*PM***OZ*EL                          /* PTD LOOP - HISTORICAL MONTHLY DEMAND - MONTH SIX
REF*LU*0080315839419400001
REF*MG*X123456
REF*MT*K101551
QTY*QD*334.4*K1
MEA*AA*MU*3.8*K1**88*83                 /* VERIFIED - VALUE IS ACTUAL BUT APPEARS ANOMALOUS
DTM*150***MS*DT*199910121023
DTM*151***MS*DT*199911124022

PTD*PM***OZ*EL                          /* PTD LOOP - HISTORICAL MONTHLY USAGE - MONTH SEVEN
REF*LU*0080315839428800001
REF*MG*X123456
REF*MT*KHMON51
QTY*QD*2657.2*KH
MEA*AA*MU*5.2*KH*6812*7323*22
DTM*150***MS*DT*199911124022
DTM*151***MS*DT*199912181123

PTD*PM***OZ*EL                          /* PTD LOOP - HISTORICAL MONTHLY DEMAND - MONTH SEVEN
REF*LU*0080315839419400001
REF*MG*X123456
REF*MT*K101551
QTY*QD*1311*K1
MEA*AA*MU*3.8*K1**345*22
DTM*150***MS*DT*199911124022
DTM*151***MS*DT*199912181123

PTD*PM***OZ*EL                          /* PTD LOOP - HISTORICAL MONTHLY USAGE - MONTH EIGHT
REF*LU*0080315839428800001
REF*MG*X123456
REF*MT*KHMON51
QTY*QD*1398.8*KH
MEA*AA*MU*5.2*KH*7233*7502*22
DTM*150***MS*DT*199912181123
DTM*151***MS*DT*200001150701

PTD*PM***OZ*EL                          /* PTD LOOP - HISTORICAL MONTHLY DEMAND - MONTH EIGHT
REF*LU*0080315839419400001
```

```
REF*MG*X123456
REF*MT*K101551
QTY*QD*1204.6*K1
MEA*AA*MU*3.8*K1**317*22
DTM*150***MS*DT*199912181123
DTM*151***MS*DT*200001150701
SE*139*0001
GE*1*16
IEA*1*000000016
```

======== 4

```
*  THIS EXAMPLE CONTAINS MONTHLY TIME OF USE METER READS WITH DEMAND VALUES USING THE AZ COMMON FORMAT, VERSION 1.
SENT BY MRSP AND REC BY A UDC

ISA*00*          *00*          *01*123456789      *01*006901995      *990702*1442*U*00401*000000015*0*P*:
GS*PT*123456789*006901995*19990702*1442*15*X*004010

ST*867*0001                                   /* UNIQUE CONTROL NUMBER WITHIN THE TRANSACTION SET.
BPT*00*444EXAMPLE 05*19990702*DD              /* ORGINAL * REF NUMBER * TRANSACTION DATE * MONTHLY READS
N1*8S*APS*1*006901999**40                     /* ID'S UDC * TEXT NAME OF UDC * DUNS # *APS DUNS NUMBER ** RECEVIER
N1*SJ*ACME ESP*1*007048413                    /* ID'S ESP * TEXT NAME OF ESP * DUNS # *ACME DUNS NUMBER
N1*55*NO SWEAT METER READING*1*123456789**41  /* ID'S MRSP* TEXT NAME OF MRSP* DUNS # * NO SWEAT METER READING DUNS NUMBER
                                                **SENDER
REF*LU*0080315839419400001                    /* FIRST UNI AT SITE, OPTIONAL SRP-OTHERS REQUIRED, 11 TO 34 CHARACTERS, INBOUND/OUTBOUND
REF*11*0T5689643                              /* ESP ACCOUNT NUMBER, SRP REQUIRED-OTHERS OPTIONAL, INBOUND/OUTBOUND

PTD*PM***OZ*EL                                /* PTD LOOP - TOTAL MONTHLY USAGE
REF*LU*0080315839419400001                    /* REQUIRED UNI FOR THE METERED POINT OF DELIVERY 11 TO 34 CHARACTERS
REF*MG*X123456                                /* REQUIRED METER NUMBER REFERENCE 6 TO 17 CHARACTERS
REF*MT*KHMON51                                /* REQUIRED METER TICKET, KH IS METER TYPE, MON IS MONTHLY METER, 51 IS TOTAL
                                                REGISTER TYPE
QTY*QD*332.0*KH                               /* QTY LOOP
MEA*AA*MU*1*KH*34267*34599*22                 /* AA DEFINES THE QUALITY OF METER READ BEGINNING AND ENDING VALUES * MEASUREMENT
                                                QUALIFIER * MULTIPLIER VALUE * MEASUREMENT CODE * BEGINNING READ * ENDING READ * 22
                                                DEFINES QUALITY OF USAGE IN QTY SEGMENT
DTM*150***MS*DT*199906011204                  /* SERVICE PERIOD START ***MS = MOUNTAIN STANDARD TIME * DATE/TIME
DTM*151***MS*DT*199906281023                  /* SERVICE PERIOD END ***MS = MOUNTAIN STANDARD TIME * DATE/TIME

PTD*PM***OZ*EL                                /* PTD LOOP - MONTHLY ON PEAK USAGE
REF*LU*0080315839419400001                    /* FIRST UNI AT SITE, OPTIONAL SRP-OTHERS REQUIRED, 11 TO 34 CHARACTERS, INBOUND/OUTBOUND
REF*MG*X123456                                /* REQUIRED METER NUMBER REFERENCE 6 TO 17 CHARACTERS
REF*MT*KHMON42                                /* REQUIRED METER TICKET, KH IS METER TYPE, MON IS MONTHLY METER, 42 IS ON PEAK REGISTER
                                                TYPE
QTY*QD*132.0*KH                               /* QTY LOOP
MEA*AA*MU*1*KH*14467*14599*22                 /* AA DEFINES THE QUALITY OF METER READ BEGINNING AND ENDING VALUES * MEASUREMENT
                                                QUALIFIER * MULTIPLIER VALUE * MEASUREMENT CODE * BEGINNING READ * ENDING READ * 22
                                                DEFINES QUALITY OF USAGE IN QTY SEGMENT
DTM*150***MS*DT*199906011204                  /* SERVICE PERIOD START ***MS = MOUNTAIN STANDARD TIME * DATE/TIME
DTM*151***MS*DT*199906281023                  /* SERVICE PERIOD END ***MS = MOUNTAIN STANDARD TIME * DATE/TIME

PTD*PM***OZ*EL                                /* PTD LOOP - MONTHLY OFF PEAK USAGE
REF*LU*0080315839419400001                    /* FIRST UNI AT SITE, OPTIONAL SRP-OTHERS REQUIRED, 11 TO 34 CHARACTERS, INBOUND/OUTBOUND
REF*MG*X123456                                /* REQUIRED METER NUMBER REFERENCE 6 TO 17 CHARACTERS
REF*MT*KHMON41                                /* REQUIRED METER TICKET, KH IS METER TYPE, MON IS MONTHLY METER, 41 IS OFF PEAK REGISTER
                                                TYPE
QTY*QD*200.0*KH                               /* QTY LOOP
MEA*AA*MU*1*KH*54207*54407*22                 /* AA DEFINES THE QUALITY OF METER READ BEGINNING AND ENDING VALUES * MEASUREMENT
                                                QUALIFIER * MULTIPLIER VALUE * MEASUREMENT CODE * BEGINNING READ * ENDING READ * 22
                                                DEFINES QUALITY OF USAGE IN QTY SEGMENT
DTM*150***MS*DT*199906011204                  /* SERVICE PERIOD START ***MS = MOUNTAIN STANDARD TIME * DATE/TIME
DTM*151***MS*DT*199906281023                  /* SERVICE PERIOD END ***MS = MOUNTAIN STANDARD TIME * DATE/TIME
```

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PTD*PM***OZ*EL                          /* PTD LOOP - MONTHLY ON PEAK DEMAND
REF*LU*0080315839419400001              /* FIRST UNI AT SITE, OPTIONAL SRP-OTHERS REQUIRED, 11 TO 34 CHARACTERS, INBOUND/OUTBOUND
REF*MG*X123456                          /* REQUIRED METER NUMBER REFERENCE 6 TO 17 CHARACTERS
REF*MT*K106042                          /* REQUIRED METER TICKET, K1 DEMAND PEAK HOUR DURING ON PEAK TOU PERIOD
QTY*QD*32.0*K1                          /* QTY LOOP
MEA*AA*MU*2*K1**16*22                   /* AA DEFINES THE QUALITY OF METER READ ENDING VALUE * MEASUREMENT
                                           QUALIFIER * MULTIPLIER VALUE * MEASUREMENT CODE * * ENDING READ * 22
                                           DEFINES QUALITY OF USAGE IN QTY SEGMENT
DTM*150***MS*DT*199906011204            /* SERVICE PERIOD START ***MS = MOUNTAIN STANDARD TIME * DATE/TIME
DTM*151***MS*DT*199906281023            /* SERVICE PERIOD END ***MS = MOUNTAIN STANDARD TIME * DATE/TIME

PTD*PM***OZ*EL                          /* PTD LOOP - MONTHLY OFF PEAK DEMAND
REF*LU*0080315839419400001              /* FIRST UNI AT SITE, OPTIONAL SRP-OTHERS REQUIRED, 11 TO 34 CHARACTERS
REF*MG*X123456                          /* REQUIRED METER NUMBER REFERENCE 6 TO 17 CHARACTERS
REF*MT*K106041                          /* REQUIRED METER TICKET, K1 DEMAND PEAK HOUR DURING OFF PEAK TOU PERIOD
QTY*QD*12.0*K1                          /* QTY LOOP
MEA*AA*MU*2*K1**6*22                    /* AA DEFINES THE QUALITY OF METER READ ENDING VALUE * MEASUREMENT
                                           QUALIFIER * MULTIPLIER VALUE * MEASUREMENT CODE * * ENDING READ * 22
                                           DEFINES QUALITY OF USAGE IN QTY SEGMENT
DTM*150***MS*DT*199906011204            /* SERVICE PERIOD START ***MS = MOUNTAIN STANDARD TIME * DATE/TIME
DTM*151***MS*DT*199906281023            /* SERVICE PERIOD END ***MS = MOUNTAIN STANDARD TIME * DATE/TIME

SE*48*0001
GE*1*15
IEA*1*000000015
```

======= 5

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*  THIS EXAMPLE CONTAINS A METER EXCHANGE COMPLETED DURING THE BILLING CYCLE FOR MONTHLY KW AND COMMERCIAL (15 MIN) DEMAND VALUES USING THE AZ COMMON
FORMAT, VERSION 1.  SENT BY MRSP AND REC BY A UDC.

ISA*00*          *00*          *01*123456789      *01*006901995      *990702*1442*U*00401*000000018*0*P*:
GS*PT*123456789*006901995*19990702*1442*18*X*004010

ST*867*0001                                  /* UNIQUE CONTROL NUMBER WITHIN THE TRANSACTION SET.
BPT*00*444EXAMPLE 04*19990702*DD             /* ORGINAL * REF NUMBER * TRANSACTION DATE * MONTHLY READ
N1*8S*APS*1*006901999**40                    /* ID'S UDC * TEXT NAME OF UDC * USE DUNS # *APS DUNS NUMBER ** RECEVIER
N1*SJ*ACME ESP*1*007048413                   /* ID'S ESP * TEXT NAME OF ESP * USE DUNS # *ACME DUNS NUMBER
N1*55*NO SWEAT METER READING*1*123456789**41 /* ID'S MRSP* TEXT NAME OF MRSP* USE DUNS # *NO SWEAT METER READING DUNS NUMBER **SENDER
REF*LU*0080315839428800001                   /* FIRST UNI AT SITE, OPTIONAL SRP-OTHERS REQUIRED, 11 TO 34 CHAR, INBOUND/OUTBOUND
REF*11*0T5689643                             /* ESP ACCOUNT NUMBER, SRP REQUIRED-OTHERS OPTIONAL, INBOUND/OUTBOUND

PTD*PM***OZ*EL                               /* PTD LOOP - MONTHLY USAGE FOR METER NUMBER ONE
REF*LU*0080315839428800001                   /* REQUIRED UNI FOR THE METERED POINT OF DELIVERY 11 TO 34 CHARACTERS
REF*MG*X123456                               /* REQUIRED METER NUMBER REFERENCE 6 TO 17 CHARACTERS.
REF*MT*KHMON51                               /* REQUIRED METER TICKET, KH IS METER TYPE, MON IS MONTHLY METER INTERVAL, 51 IS TOTAL REGISTER TYPE
QTY*QD*291.2*KH                              /* QTY LOOP
MEA*AA*MU*5.2*KH*4267*4323*22                /* AA DEFINES THE QUALITY OF METER READ BEGINNING AND ENDING VALUES * MEASUREMENT QUALIFIER *
                                                MULTIPLIER VALUE * MEASUREMENT CODE * BEGINNING READ * ENDING READ * 22 DEFINES QUALITY OF USAGE IN
                                                QTY SEGMENT
DTM*150***MS*DT*199906011204                 /* DEFINES START TIME
DTM*151***MS*DT*199906051023                 /* DEFINES STOP TIME

PTD*PM***OZ*EL                               /* PTD LOOP - DEMAND FOR METER NUMBER ONE
REF*LU*0080315839419400001                   /* REQUIRED UNI FOR THE METERED POINT OF DELIVERY 11 TO 34 CHARACTERS
REF*MG*X123456                               /* REQUIRED METER NUMBER REFERENCE 6 TO 17 CHARACTERS
REF*MT*K101551                               /* REQUIRED METER TICKET, K1 IS METER TYPE, 015 IS METER INTERVAL, 67 IS NON TIME RELATED DEMAND
QTY*QD*1219.8*K1                             /* QTY LOOP
MEA*AA*MU*3.8*K1**321*22                     /* AA DEFINES THE QUALITY OF METER READ BEGINNING AND ENDING VALUES * MEASUREMENT QUALIFIER *
                                                MULTIPLIER VALUE * MEASUREMENT CODE ** ENDING READ * 22 DEFINES QUALITY OF DEMAND IN QTY SEGMENT
DTM*150***MS*DT*199906011204                 /* DEFINES START TIME OF PEAK DEMAND PERIOD
DTM*151***MS*DT*199906051023                 /* DEFINES STOP TIME OF PEAK DEMAND PERIOD

PTD*PM***OZ*EL                               /* PTD LOOP - MONTHLY USAGE FOR METER NUMBER TWO
REF*LU*0080315839428800001                   /* REQUIRED UNI FOR THE METERED POINT OF DELIVERY 11 TO 34 CHARACTERS
REF*MG*B235677                               /* REQUIRED METER NUMBER REFERENCE 6 TO 17 CHARACTERS.
REF*MT*KHMON51                               /* REQUIRED METER TICKET, KH IS METER TYPE, MON IS MONTHLY METER INTERVAL, 51 IS TOTAL REGISTER TYPE
QTY*QD*1279.2*KH                             /* QTY LOOP
MEA*AA*MU*5.2*KH*0*246*22                    /* AA DEFINES THE QUALITY OF METER READ BEGINNING AND ENDING VALUES * MEASUREMENT QUALIFIER *
                                                MULTIPLIER VALUE * MEASUREMENT CODE * BEGINNING READ * ENDING READ * 22 DEFINES QUALITY OF USAGE IN
                                                QTY SEGMENT
DTM*150***MS*DT*199906051030                 /* DEFINES START TIME
DTM*151***MS*DT*199907021023                 /* DEFINES STOP TIME

PTD*PM***OZ*EL                               /* PTD LOOP - DEMAND FOR METER NUMBER TWO
REF*LU*0080315839419400001                   /* REQUIRED UNI FOR THE METERED POINT OF DELIVERY 11 TO 34 CHARACTERS
REF*MG*B235677                               /* REQUIRED METER NUMBER REFERENCE 6 TO 17 CHARACTERS
REF*MT*K101551                               /* REQUIRED METER TICKET, K1 IS METER TYPE, 015 IS METER INTERVAL, 67 IS NON TIME RELATED DEMAND
```

```
QTY*QD*1208.4*K1                    /* QTY LOOP
MEA*AA*MU*3.8*K1**318*22            /* AA DEFINES THE QUALITY OF METER READ BEGINNING AND ENDING VALUES * MEASUREMENT QUALIFIER *
                                       MULTIPLIER VALUE * MEASUREMENT CODE ** ENDING READ * 22 DEFINES QUALITY OF DEMAND IN QTY SEGMENT
DTM*150***MS*DT*199906051030        /* DEFINES START TIME OF PEAK DEMAND PERIOD
DTM*151***MS*DT*199907021023        /* DEFINES STOP TIME OF PEAK DEMAND PERIOD
SE*40*0001
GE*1*18
IEA*1*000000018
```

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THIS FILE CONTAINS 15 MINUTE INTERVAL DATA USING THE AZ COMMON FORMAT, VERSION 1. SENT BY UDC AND REC BY AN ESP.

```
ISA*00*          *00*          *01*123456789      *01*006901995      *990702*1442*U*00401*000000022*0*P*:
GS*PT*123456789*006901995*19990702*1442*22*X*004010

ST~867~0001
BPT~00~6203028182R1999-01-11~19990303~C1
N1~SJ~APS ESP Test~1~006901995~~40
N1~8S~SRP~91~123456~~41
REF~11~ESP1-0012
REF~LU~1657290000000001
PTD~PM~~~OZ~EL
REF~MG~0351919
REF~MT~KH01596
REF~LU~1657290000000001
QTY~QD~43.65~KH
MEA~~MU~.09~KH~~~22
DTM~150~~~~DT~199901110000
DTM~151~~~~DT~199901110015
QTY~QD~43.92~KH
QTY~QD~43.92~KH
QTY~QD~43.92~KH
QTY~QD~43.74~KH
QTY~QD~44.01~KH
QTY~QD~44.01~KH
QTY~QD~44.1~KH
QTY~QD~44.1~KH
QTY~QD~43.56~KH
QTY~QD~43.38~KH
QTY~QD~43.65~KH
QTY~QD~43.47~KH
QTY~QD~43.65~KH
QTY~QD~43.83~KH
QTY~QD~43.83~KH
QTY~QD~53.01~KH
QTY~QD~65.25~KH
QTY~QD~65.16~KH
QTY~QD~65.43~KH
QTY~QD~65.43~KH
QTY~QD~47.34~KH
QTY~QD~43.65~KH
QTY~QD~43.65~KH
QTY~QD~43.83~KH
QTY~QD~43.2~KH
QTY~QD~43.29~KH
QTY~QD~40.5~KH
QTY~QD~38.25~KH
QTY~QD~38.61~KH
QTY~QD~36.45~KH
QTY~QD~35.73~KH
```

QTY~QD~35.55~KH
QTY~QD~35.46~KH
QTY~QD~35.37~KH
QTY~QD~35.55~KH
QTY~QD~35.55~KH
QTY~QD~35.37~KH
QTY~QD~35.64~KH
QTY~QD~35.64~KH
QTY~QD~35.55~KH
QTY~QD~35.01~KH
QTY~QD~34.2~KH
QTY~QD~34.29~KH
QTY~QD~34.29~KH
QTY~QD~37.08~KH
QTY~QD~35.82~KH
QTY~QD~35.1~KH
QTY~QD~35.19~KH
QTY~QD~34.83~KH
QTY~QD~34.92~KH
QTY~QD~35.1~KH
QTY~QD~35.19~KH
QTY~QD~35.01~KH
QTY~QD~35.19~KH
QTY~QD~35.1~KH
QTY~QD~35.19~KH
QTY~QD~34.65~KH
QTY~QD~34.11~KH
QTY~QD~34.47~KH
QTY~QD~36.63~KH
QTY~QD~38.61~KH
QTY~QD~36.36~KH
QTY~QD~34.92~KH
QTY~QD~34.92~KH
QTY~QD~34.92~KH
QTY~QD~44.19~KH
QTY~QD~56.88~KH
QTY~QD~56.97~KH
QTY~QD~56.88~KH
QTY~QD~56.79~KH
QTY~QD~42.12~KH
QTY~QD~34.65~KH
QTY~QD~34.74~KH
QTY~QD~34.56~KH
QTY~QD~34.65~KH
QTY~QD~36.36~KH
QTY~QD~35.28~KH
QTY~QD~35.28~KH
QTY~QD~35.28~KH
...ETC...
SE~6040~0001
GE~1~22
IEA~1~000000022

====== 7

HISTORICAL REQUEST FOR MONTHLY DATA USING THE AZ COMMON FORMAT, VERSION 1. SENT BY UDC AND REC BY AN ESP.

```
ISA~00~          ~00~          ~01~123456789      ~01~006901995      ~990702~1442~U~00401~000000023~0~P~:
GS~PT~123456789~006901995~19990702~1442~23~X~004010

ST~867~0001
BPT~52~~19990303~DD~~~~~1006                    /* REQUEST FOR HISTORICAL USAGE WITH REQUEST DASR NUMBER 1006
N1~SJ~APS ESP~1~006901995~~40
N1~8S~SRP~91~123456~~41
REF~11~ESP-005                                  /* ESP ACCOUNT NUMBER
REF~LU~1657200000100056                         /* UNI
PTD~PM~~~OZ~EL
REF~MG~0295146
REF~MT~KHMON51                                  /* MONTHLY KWH DATA TOTAL CONSUMPTION
REF~LU~1657200000100056                         /* UNI
REF~IX~4
QTY~QD~1610~KH
MEA~AA~MU~10~KH~7889~8050~22
DTM~150~~~~D8~19990212
DTM~151~~~~D8~19990312
QTY~QD~3630~KH
MEA~~MU~10~KH~7526~7889~22
DTM~150~~~~D8~19990111
DTM~151~~~~D8~19990212
QTY~QD~3900~KH
MEA~~MU~10~KH~7136~7526~22
DTM~150~~~~D8~19981209
DTM~151~~~~D8~19990111
QTY~QD~2130~KH
MEA~~MU~10~KH~6923~7136~22
DTM~150~~~~D8~19981109
DTM~151~~~~D8~19981209
QTY~QD~1570~KH
MEA~~MU~10~KH~6766~6923~22
DTM~150~~~~D8~19981008
DTM~151~~~~D8~19981109
QTY~QD~2130~KH
MEA~~MU~10~KH~6553~6766~22
DTM~150~~~~D8~19980908
DTM~151~~~~D8~19981008
QTY~QD~3510~KH
MEA~~MU~10~KH~6202~6553~22
DTM~150~~~~D8~19980807
DTM~151~~~~D8~19980908
QTY~QD~3010~KH
MEA~~MU~10~KH~5901~6202~22
DTM~150~~~~D8~19980710
DTM~151~~~~D8~19980807
QTY~QD~2830~KH
MEA~~MU~10~KH~5618~5901~22
```

```
DTM~150~~~~D8~19980609
DTM~151~~~~D8~19980710
QTY~QD~1980~KH
MEA~~MU~10~KH~5420~5618~22
DTM~150~~~~D8~19980507
DTM~151~~~~D8~19980609
QTY~QD~1370~KH
MEA~~MU~10~KH~5283~5420~22
DTM~150~~~~D8~19980409
DTM~151~~~~D8~19980507
QTY~QD~1210~KH
MEA~~MU~10~KH~5162~5283~22
DTM~150~~~~D8~19980311
DTM~151~~~~D8~19980409
QTY~QD~1620~KH
MEA~~MU~10~KH~5000~5162~22
DTM~150~~~~D8~19980210
DTM~151~~~~D8~19980311
SE~64~0001
GE~1~23
IEA~1~000000023
```

====== 8

THIS EXAMPLE CONTAINS MONTHLY KWH ACTUAL METER READ ONLY USING THE AZ COMMON FORMAT VERSION 1, SENT BY MRSP AND REC BY A UDC.

```
ISA*00*          *00*          *01*123456789      *01*006901995      *990702*1442*U*00401*000000011*0*P*:
GS*PT*123456789*006901995*19990702*1442*11*X*004010

ST*867*0001                                  /* Unique control number within the transaction set.
BPT*00*3337865432345667*19990702*DD          /* ORGINAL * REF NUMBER * TRANSACTION DATE * MONTHLY READ
N1*8S*APS*1*006901995**40                    /* ID'S UDC * TEXT NAME OF UDC * USE DUNS # *APS DUNS NUMBER **RECEVIER
N1*SJ*ACME ESP*1*007048413                   /* ID'S ESP * TEXT NAME OF ESP * USE DUNS # *ACME DUNS NUMBER
N1*55*NO SWEAT METER READING*1*123456789**41 /* ID'S MRSP* TEXT NAME OF MRSP* USE DUNS # *NO SWEAT METER READING DUNS NUMBER **SENDER
REF*LU*0080315839419400001                   /* FIRST UNI AT SITE, OPTIONAL SRP-OTHERS REQUIRED, 11 TO 34 CHAR, INBOUND & OUTBOUND TRANSACTIONS
REF*11*0T5689643                             /* ESP ACCOUNT NUMBER, SRP REQUIRED-OTHERS OPTIONAL, INBOUND & OUTBOUND TRANSACTIONS
PTD*PM***OZ*EL                               /* PTD LOOP
REF*LU*0080315839419400001                   /* REQUIRED UNI FOR THE METERED POINT OF DELIVERY 11 TO 34 CHARACTERS
REF*MG*AAB0345Y9092S457T                     /* REQUIRED METER NUMBER REFERENCE 6 TO 17 CHARACTERS.
REF*MT*KHMON51                               /* REQUIRED METER TICKET, KH IS METER TYPE, MON IS MONTHLY METER INTERVAL, 51 IS TOTAL REGISTER TYPE
QTY*QD*332.0*KH                              /* QTY LOOP
MEA*AA*MU*1*KH*34267*34599*22                /* AA DEFINES THE QUALITY OF METER READ BEGINNING AND ENDING VALUES * MEASUREMENT QUALIFIER * MULTIPLIER
                                                VALUE * MEASUREMENT CODE * BEGINNING READ * ENDING READ * 22 DEFINES QUALITY OF USAGE IN QTY SEGMENT
DTM*150***MS*DT*199906011204                 /* SERVICE PERIOD START ***MS IS MOUNTAIN STANDARD TIME * DATE/TIME
DTM*151***MS*DT*199906281023                 /* SERVICE PERIOD END ***MS IS MOUNTAIN STANDARD TIME * DATE/TIME
SE*16*0001                                   /* SEGMENT COUNT INCLUDES ST AND SE * MUST MATCH ST02 CONTROL NUMBER
GE*1*11
IEA*1*000000011
```

======= 8A

THIS EXAMPLE CONTAINS MONTHLY KWH ACTUAL METER READ ONLY USING THE AZ COMMON FORMAT VERSION 1, SENT BY MRSP AND REC BY A ESP.

```
ISA*00*          *00*          *01*123456789      *01*007048413      *990702*1442*U*00401*000000012*0*P*:
GS*PT*123456789*007048413*19990702*1442*12*X*004010

ST*867*0001                                  /* UNIQUE CONTROL NUMBER WITHIN THE TRANSACTION SET.
BPT*00*3337865432345667*19990702*DD          /* ORGINAL * REF NUMBER * TRANSACTION DATE * MONTHLY READ
N1*8S*APS*1*006901995                        /* ID'S UDC * TEXT NAME OF UDC * USE DUNS # * APS DUNS NUMBER
N1*SJ*ACME ESP*1*007048413**40               /* ID'S ESP * TEXT NAME OF ESP * USE DUNS # * ACME DUNS NUMBER ** RECEVIER
N1*55*NO SWEAT METER READING*1*123456789**41 /* ID'S MRSP* TEXT NAME OF MRSP* USE DUNS # * NO SWEAT METER READING DUNS NUMBER ** SENDER
REF*LU*0080315839419400001                   /* FIRST UNI AT SITE, OPTIONAL SRP-OTHERS REQUIRED, 11 TO 34 CHAR, INBOUND & OUTBOUND TRANSACTIONS
REF*11*0T5689643                             /* ESP ACCOUNT NUMBER, SRP REQUIRED-OTHERS OPTIONAL, INBOUND & OUTBOUND TRANSACTIONS
PTD*PM***OZ*EL                               /* PTD LOOP
REF*LU*0080315839419400001                   /* REQUIRED UNI FOR THE METERED POINT OF DELIVERY 11 TO 34 CHARACTERS
REF*MG*AAB0345Y9092S457T                     /* REQUIRED METER NUMBER REFERENCE 6 TO 17 CHARACTERS.
REF*MT*KHMON51                               /* REQUIRED METER TICKET, KH IS METER TYPE, MON IS MONTHLY METER INTERVAL, 51 IS TOTAL REGISTER TYPE
QTY*QD*332.0*KH                              /* QTY LOOP
MEA*AA*MU*1*KH*34267*34599*22                /* AA DEFINES THE QUALITY OF METER READ BEGINNING AND ENDING VALUES * MEASUREMENT QUALIFIER * MULTIPLIER
                                                VALUE * MEASUREMENT CODE * BEGINNING READ * ENDING READ * 22 DEFINES QUALITY OF USAGE IN QTY SEGMENT
DTM*150***MS*DT*199906011204                 /* SERVICE PERIOD START ***MS IS MOUNTAIN STANDARD TIME * DATE/TIME
DTM*151***MS*DT*199906281023                 /* SERVICE PERIOD END ***MS IS MOUNTAIN STANDARD TIME * DATE/TIME
SE*16*0001                                   /* SEGMENT COUNT INCLUDES ST AND SE * MUST MATCH ST02 CONTROL NUMBER
GE*1*12
IEA*1*000000012
```

======= 9

THIS EXAMPLE CONTAINS MONTHLY KWH ESTIMATED METER READS ONLY USING THE AZ COMMON FORMAT VERSION 1, SENT BY MRSP AND REC BY A UDC.

```
ISA*00*          *00*          *01*123456789      *01*006901995      *990702*1442*U*00401*000000013*0*P*:
GS*PT*123456789*006901995*19990702*1442*13*X*004010

ST*867*0001                                  /* Unique control number within the transaction set.
BPT*00*3337865432345667*19990702*DD          /* ORGINAL * REF NUMBER * TRANSACTION DATE * MONTHLY READ
N1*8S*APS*1*006901995**40                    /* ID'S UDC * TEXT NAME OF UDC * USE DUNS # *APS DUNS NUMBER ** RECEVIER
N1*SJ*ACME ESP*1*007048413                   /* ID'S ESP * TEXT NAME OF ESP * USE DUNS # *ACME DUNS NUMBER
N1*55*NO SWEAT METER READING*1*123456789**41 /* ID'S MRSP* TEXT NAME OF MRSP* USE DUNS # *NO SWEAT METER READING DUNS NUMBER ** SENDER
REF*LU*0080315839419400001                   /* FIRST UNI AT SITE, OPTIONAL SRP-OTHERS REQUIRED, 11 TO 34 CHAR, INBOUND & OUTBOUND TRANSACTIONS
REF*11*0T5689643                             /* ESP ACCOUNT NUMBER, SRP REQUIRED-OTHERS OPTIONAL, INBOUND & OUTBOUND TRANSACTIONS
PTD*PM***OZ*EL                               /* PTD LOOP
REF*LU*0080315839419400001                   /* REQUIRED UNI FOR THE METERED POINT OF DELIVERY 11 TO 34 CHARACTERS
REF*MG*AAB0345Y9092S457T                     /* REQUIRED METER NUMBER REFERENCE 6 TO 17 CHARACTERS.
REF*MT*KHMON51                               /* REQUIRED METER TICKET, KH IS METER TYPE, MON IS MONTHLY METER INTERVAL, 51 IS TOTAL REGISTER TYPE
QTY*QD*332.0*KH                              /* QTY LOOP
MEA*AE*MU*1*KH*34267*34599*46                /* AE DEFINES THE QUALITY OF METER READ BEGINNING AND ENDING VALUES * MEASUREMENT QUALIFIER * MULTIPLIER
                                                VALUE * MEASUREMENT CODE * BEGINNING READ * ESTIMATED ENDING READ * 46 DEFINES QUALITY OF USAGE IN
                                                QTY SEGMENT

REF*ESN*EC5                                  /* QUALIFIER DEFINING ESTIMATED REASON CODE * EC5 IS THE ESTIMATED REASON CODE

DTM*150***MS*DT*199906011204                 /* SERVICE PERIOD START ***MS IS MOUNTAIN STANDARD TIME * DATE/TIME
DTM*151***MS*DT*199906281023                 /* SERVICE PERIOD END ***MS IS MOUNTAIN STANDARD TIME * DATE/TIME
SE*17*0001                                   /* SEGMENT COUNT INCLUDES ST AND SE * MUST MATCH ST02 CONTROL NUMBER
GE*1*13
IEA*1*000000013
```

====== 10

THIS EXAMPLE CONTAINS UNMETERED MONTHLY USAGE USING THE AZ COMMON FORMAT VERSION 1, SENT BY MRSP AND REC BY A UDC.

```
ISA*00*          *00*          *01*123456789      *01*006901995      *990702*1442*U*00401*000000019*0*P*:
GS*PT*123456789*006901995*19990702*1442*19*X*004010

ST*867*0001                                  /* UNIQUE CONTROL NUMBER WITHIN THE TRANSACTION SET.
BPT*00*3337865432345667*19990702*DD          /* ORGINAL * REF NUMBER * TRANSACTION DATE * MONTHLY READ
N1*8S*APS*1*006901995**40                    /* ID'S UDC * TEXT NAME OF UDC * USE DUNS # *APS DUNS NUMBER **RECEVIER
N1*SJ*ACME ESP*1*007048413                   /* ID'S ESP * TEXT NAME OF ESP * USE DUNS # *ACME DUNS NUMBER
N1*55*NO SWEAT METER READING*1*123456789**41 /* ID'S MRSP* TEXT NAME OF MRSP* USE DUNS # *NO SWEAT METER READING DUNS NUMBER **SENDER
REF*LU*0080315839419400001                   /* FIRST UNI AT SITE, OPTIONAL SRP-OTHERS REQUIRED, 11 TO 34 CHAR, INBOUND & OUTBOUND TRANSACTIONS
REF*11*0T5689643                             /* ESP ACCOUNT NUMBER, SRP REQUIRED-OTHERS OPTIONAL, INBOUND & OUTBOUND TRANSACTIONS
PTD*PM***OZ*EL                               /* PTD LOOP
REF*LU*0080315839419400001                   /* REQUIRED UNI FOR THE UNMETERED POINT OF DELIVERY  11 TO 34 CHARACTERS
REF*MT*KWMON51                               /* UNMETERED KW VALUE FOR THE MONTH
REF*SC*U                                     /* SC = UNMETERED, REQUIRED FOR UNMETERED ACCOUNT
QTY*QD*332.0*KH                              /* QTY LOOP
MEA*BO**1*KH***22                             /* BO DESCRIBES PRE-ESTABLISHED USAGE, MEASUREMENT CODE, 22 DEFINES QUALITY OF USAGE IN QTY SEGMENT
DTM*150***MS*DT*199906011200                 /* SERVICE PERIOD START ***MS IS MOUNTAIN STANDARD TIME * DATE/TIME
DTM*151***MS*DT*199906281200                 /* SERVICE PERIOD END ***MS IS MOUNTAIN STANDARD TIME * DATE/TIME
SE*15*0001                                   /* SEGMENT COUNT INCLUDES ST AND SE * MUST MATCH ST02 CONTROL NUMBER
GE*1*19
IEA*1*000000019
```

======11

THIS EXAMPLE CONTAINS MULTIPLE METERS AT ONE SITE WITH KWH VALUES USING THE AZ COMMON FORMAT VERSION 1.

```
ISA*00*          *00*          *01*123456789      *01*006901995      *990702*1442*U*00401*000000014*0*P*:
GS*PT*123456789*006901995*19990702*1442*14*X*004010

ST*867*0001                                  /* UNIQUE CONTROL NUMBER WITHIN THE TRANSACTION SET.
BPT*00*444EXAMPLE 04*19990702*DD             /* ORGINAL * REF NUMBER * TRANSACTION DATE * MONTHLY READ
N1*8S*APS*1*006901999**40                    /* ID'S UDC * TEXT NAME OF UDC * USE DUNS # *APS DUNS NUMBER ** RECEVIER
N1*SJ*ACME ESP*1*007048413                   /* ID'S ESP * TEXT NAME OF ESP * USE DUNS # *ACME DUNS NUMBER
N1*55*NO SWEAT METER READING*1*123456789**41 /* ID'S MRSP* TEXT NAME OF MRSP* USE DUNS # *NO SWEAT METER READING DUNS NUMBER **SENDER
REF*LU*0080315839428800001                   /* FIRST UNI AT SITE, OPTIONAL SRP-OTHERS REQUIRED, 11 TO 34 CHAR, INBOUND/OUTBOUND
REF*11*0T5689643                             /* ESP ACCOUNT NUMBER, SRP REQUIRED-OTHERS OPTIONAL, INBOUND/OUTBOUND
PTD*PM***OZ*EL                               /* PTD LOOP
REF*LU*0080315839428800001                   /* REQUIRED UNI FOR THE METERED POINT OF DELIVERY 11 TO 34 CHARACTERS
REF*MG*X123456                               /* REQUIRED METER NUMBER REFERENCE 6 TO 17 CHARACTERS.
REF*MT*KHMON51                               /* REQUIRED METER TICKET, KH IS METER TYPE, MON IS MONTHLY METER INTERVAL, 51 IS TOTAL REGISTER TYPE
QTY*QD*1331.2*KH                             /* QTY LOOP
MEA*AA*MU*5.2*KH*4267*4523*22                /* AA DEFINES THE QUALITY OF METER READ BEGINNING AND ENDING VALUES * MEASUREMENT QUALIFIER * MULTIPLIER
                                                VALUE * MEASUREMENT CODE * BEGINNING READ * ENDING READ * 22 DEFINES QUALITY OF USAGE IN QTY SEGMENT
DTM*150***MS*DT*199906011204                 /* DEFINES START TIME
DTM*151***MS*DT*199907021023                 /* DEFINES STOP TIME
PTD*PM***OZ*EL                               /* PTD LOOP FOR SECOND METER
REF*LU*0080315839428800002                   /* REQUIRED UNI FOR THE METERED POINT OF DELIVERY 11 TO 34 CHARACTERS
REF*MG*X567998                               /* REQUIRED METER NUMBER REFERENCE 6 TO 17 CHARACTERS.
REF*MT*KHMON51                               /* REQUIRED METER TICKET, KH IS METER TYPE, MON IS MONTHLY METER INTERVAL, 51 IS TOTAL REGISTER TYPE
QTY*QD*978.6*KH                              /* QTY LOOP
MEA*AA*MU*4.2*KH*5267*5500*22                /* AA DEFINES THE QUALITY OF METER READ BEGINNING AND ENDING VALUES * MEASUREMENT QUALIFIER * MULTIPLIER
                                                VALUE * MEASUREMENT CODE * BEGINNING READ * ENDING READ * 22 DEFINES QUALITY OF USAGE IN QTY SEGMENT
DTM*150***MS*DT*199906011206                 /* DEFINES START TIME
DTM*151***MS*DT*199907021025                 /* DEFINES STOP TIME
PTD*PM***OZ*EL                               /* PTD LOOP FOR THIRD METER
REF*LU*0080315839428800003                   /* REQUIRED UNI FOR THE METERED POINT OF DELIVERY 11 TO 34 CHARACTERS
REF*MG*X456921                               /* REQUIRED METER NUMBER REFERENCE 6 TO 17 CHARACTERS.
REF*MT*KHMON51                               /* REQUIRED METER TICKET, KH IS METER TYPE, MON IS MONTHLY METER INTERVAL, 51 IS TOTAL REGISTER TYPE
QTY*QD*400*KH                                /* QTY LOOP
MEA*AA*MU*2*KH*400*600*22                    /* AA DEFINES THE QUALITY OF METER READ BEGINNING AND ENDING VALUES * MEASUREMENT QUALIFIER * MULTIPLIER
                                                VALUE * MEASUREMENT CODE * BEGINNING READ * ENDING READ * 22 DEFINES QUALITY OF USAGE IN QTY SEGMENT
DTM*150***MS*DT*199906011208                 /* DEFINES START TIME
DTM*151***MS*DT*199907021027                 /* DEFINES STOP TIME

SE*34*0001                                   /* SEGMENT COUNT INCLUDES ST AND SE * MUST MATCH ST02 CONTROL NUMBER
GE*1*11
IEA*1*000000011
```

ATTACHMENT # 3

VOTE ON THE USE OF A COMMON FORMAT FOR EDI 867 VERSION 4010
7/16/99

REPRESENTATIVE	COMPANY	VOTE
Stacy Aguayo	APS	Yes
Evelyn Dryer	TEP	Yes
Dennis Hughes	NEC	Yes
Barry Scott	SSVEC	Yes
Paul Taylor	Citizens	Yes
Larry Nuszloch	SRP	Yes
Janie Mollon	NWE	Yes
Marv Buck	CSC	Yes
Ward Camp	Phaser	Yes
Darrel Pichoff	KR Saline	Yes
Bob Soutner	NEV	?

UNIVERSAL METER IDENTIFIER (UMI)

WHOEVER INITIALLY PURCHASES THE METER WILL ASSIGN THE UMI. THIS ID WAS PROPOSED BY AEP AND IS FULLY ANSI C12.10 COMPLIANT. THE UMI FORMAT IS AS FOLLOWS (17 CHARACTERS):

AABYYYYYYYYYZZZZZ

WHERE

AA	**IS THE METER TEST CODE**
B	**IS AN IDENTIFIER FOR THE METER MANUFACTURER**
YYYYYYYYY	**IS THE METER MANUFACTURER'S SERIAL NUMBER OR A UTILITY'S-ASSIGNED NUMBER**
ZZZZZ	**IS DOE'S ID NUMBER FOR UDCs AND ACC ASSIGNED NUMBER FOR PROVIDERS**

THE UMI WILL BE INCLUDED AS PART OF METERING SPECIFICATIONS IN R14-2-1612 (K) 15.

THE UMI IS NOT REQUIRED FOR STANDARD OFFER CUSTOMERS OR FOR THE LOAD-PROFILED COMPETITIVE CUSTOMERS WHERE THE UDC IS THE MSP AND THE MRSP.

THIS ID IS NOT REQUIRED TO BE IMPLEMENTED UNTIL JANUARY 1, 2001; HOWEVER, THOSE SYSTEMS THAT HAVE ALREADY IMPLEMENTED THE UMI MAY BEGIN USING IT IMMEDIATELY.

EDI Discussion Document

Title: Change Control in the Deregulated Market

Findings of current practices of other utilities regarding development of EDI standards and practices.

Authors: Renee Castillo & Patrick Bouquet

SRP

Created on 07/30/99 06:54

Objective

The purpose of this document is to provide information sufficient to facilitate meaningful discussion re: developing a practice/policy to support a change control process that will be inclusive of EDI trading partners. Reasons for this research are:

1. Prevent downtime between when EDI development efforts are ready and when EDI trading partners are ready.
2. Gather intelligence regarding the external business environment (as it pertains to EDI documents and processes) and incorporate that knowledge into the systems design and development process.
3. Foster competition in Arizona's electricity deregulation business environment.

Research Methodology

Utilities and state regulators in the states of California, Pennsylvania and Massachusetts were approached and interviewed as to the practices within those states pertaining to change control and EDI. Three basic questions were covered:

1. What methods of communication are being used?
2. Which work (and why)?
3. Which do not work (and why)?

Results and Discussion

Utility Distribution Companies (UDCs) have been the primary drivers of EDI development in their respective deregulated environments. Initially, UDCs made use of two communications vehicles for discussions about EDI implementation:

1. E-Mail based List Serves, and,
2. UDC hosted ESP forums (informational and networking meetings).

As markets have moved toward state (and regional) EDI standards, an additional communication vehicle was incorporated into UDCs' modus operandi for discussing EDI plans and development. These are:

3. State level forums (informational, EDI working session and networking meetings).

E-Mail-Based List Serves

- Used in all states, though, not uniformly implemented. California has UDC-specific list serves. Pennsylvania has state-specific list serves. Massachusetts has both.
- UDC-specific list serves are used to disseminate information to ESPs that are operating in the UDC service area.
- State-specific list serves are used to disseminate information about state-level EDI development and schedules.

Comments re: e-mail based list serves:

1. In California, there are UDC specific list-serves to disseminate announcements re: forthcoming EDI changes (and, in my experience, to disseminate info about changes that already occurred but were not announced until the damage had been done). The audience for these list-serves, in California, are the people at the ESP's who are the main point of contact for UDC-ESP communications. Typically, what these contact people do with the notes is to re-distribute the notes to a wide range of folks internal to the ESP because there is often content that they have no comprehension of. Unfortunately, what happens with this model is that there are things that fall through the cracks because there is no one person that is responsible to see that all that is contained in the note is acted upon. However, from a UDC standpoint, the information was provided, and thus, there is no question re: the UDC being a responsible and informative citizen in the deregulated environment.
2. In California, each UDC maintains its own website with its own set of EDI implementation guidelines. There is some movement toward a state standard, but, such is not the case at this time.
3. In Pennsylvania, the list serve that serves the aforementioned monthly EDI meetings, serves also to keep all market participants informed of schedules, deadlines, plans, etc.. The PA list serves are open to all market participants, and, are considered the main vehicle for tracking and introducing change to EDI documents.

UDC-Hosted ESP Forums

- Used in California and Massachusetts.
- Used to disseminate information to ESPs that are operating in the UDC service area.

Comments re: UDC hosted ESP forums

1. California has UDC specific ESP "training and information sessions". A UDC (PG&E, for example) will have quarterly meetings to which all ESPs are invited and the ESP coordinators present information that includes, but is not limited to, discussion of EDI. These meetings will be held at the UDC offices, or, a hotel ballroom. For EDI specifically, plans and schedules are discussed, as well as, problems (solicited from the ESPs or problems that the UDC has uncovered) are discussed. ESP coordinators use these meetings to discuss issues one-on-one (during breaks, etc.) with their constituent ESPs, as well.
2. In Pennsylvania, there are no UDC hosted/UDC specific ESP training/information sessions. It is all managed on the state level.

State-Level Forums

- Used in California, Pennsylvania and Massachusetts. Pennsylvania uses this as their only communications medium for the discussion of EDI. California and Massachusetts use this to augment their UDC-based communications. Pennsylvania and Massachusetts (and eventually, California) use this to publish EDI information, including certification information.
- Used to involve any or all market participants in planning, development and scheduling of EDI related implementations.
- Used by individual market participants (i.e., UDCs and ESPs) to inform all other market participants of needs, changes and schedules.
- Oversight is provided by PUC's and PUC attendance is regular, but, technical discussions are driven by UDCs, and generally hosted by the UDCs on a rotating basis.

Comments re: state-level forums:

1. California state level EDI development/planning meetings are usually document specific. These meetings are generally hosted by UDCs, but, they are not necessarily UDC run, though, participation from other types of market entities (i.e. ESPs, MDMAs, etc.) is quite modest. The purpose of these meetings is to develop guidelines for the use of EDI in the state. California UDCs have struggled with the issue of creating uniform EDI implementation guides, and, these

are the forums where this is being accomplished. UDCs and other entities will introduce needs for changes, or, represent their internal operations in these meetings in such a manner as to affect the guidelines that are produced (much as we have been doing with the 867 guides here in Arizona).

2. In California, there are also the State level Rule 22 meetings, where EDI is discussed only distantly, but, dates are set that impact the implementation schedules for EDI.
3. In California, each UDC maintains its own website with its own set of EDI implementation guidelines. There is some movement toward a state standard, but, such is not the case at this time.
4. In Pennsylvania, the market participates in a state hosted (though meetings often occur at UDC offices) forum for the development of EDI standards and guidelines. There is a greater willingness, on the part of all market participants, to evolve business processes in such a manner as to enable the creation of a single set of EDI guidelines that have a minimum of variations by UDC. The EDI guidelines for the State of Pennsylvania are maintained at one website, with variations (i.e., the use of ESP account number) noted on the single set of guidelines.
5. In Pennsylvania, there are monthly working group meetings where all market participants meet to discuss their individual needs in light of the current EDI guides (or, in order to develop new EDI documents).
6. In Pennsylvania, the list serve that serves the aforementioned monthly EDI meetings, serves also to keep all market participants informed of schedules, deadlines, plans, etc.. The PA list serves are open to all market participants, and, are considered the main vehicle for tracking and introducing change to EDI documents.
7. Pennsylvania is developing a new website that will serve the needs of all UDCs as an information repository/distribution center in the state of PA, as well as other states in the region that intend to follow the PA model for implementing EDI and energy competition. Those additional states are, New Jersey, Delaware, Maryland and Virginia. New York may participate as well, but, will likely maintain a separate set of EDI guides (once developed).
8. Massachusetts has an approach similar to Pennsylvania, but, what the ESP discovers is that each UDC is secretly harboring their own implementation guides that are discovered only when testing has begun. (It's true!)

Additional Comments

1. Nobody has produced a white paper on the subject.
2. All considered it in their interest to keep the ESPs fully informed (i.e., schedules, plans, development) and seek to include others at the earliest possible opportunity.
3. No system is without its critics.

Recommendations

1. Statewide forum for the planning, development and implementation of EDI document exchange guidelines.
2. Hosting of forums will be shared on a rotating basis.
3. Notes and minutes will be shared amongst meeting participants and others, if requested, and, easily accessible to all market and meeting participants.