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BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS

KRISTIN K. MAYES, Chairman
GARY PIERCE
PAUL NEWMAN
SANDRA D. KENNEDY
BOB STUMP

IN THE MATTER OF THE APPLICATION OF THE ARIZONA ELECTRIC POWER COOPERATIVE, INC. FOR A HEARING TO DETERMINE THE FAIR VALUE OF ITS PROPERTY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RETURN THEREON AND TO APPROVE RATES DESIGNED TO DEVELOP SUCH RETURN	Docket No. E-01773A-09-0472 **REQUEST FOR CONTRACT AMENDMENT APPROVALS AND REVISED RATES REQUEST**

GALLAGHER & KENNEDY, P.A.
2575 E. CAMELBACK ROAD
PHOENIX, ARIZONA 85016-9225
(602) 530-8000

The Arizona Electric Power Cooperative, Inc. ("AEPCO") submits this Request for approval of amendments to its Wholesale Power Contracts with Duncan Valley Electric Cooperative, Inc. ("DVEC") and Graham County Electric Cooperative, Inc. ("GCEC").

In support of the Request, AEPCO states as follows:

1. AEPCO is an Arizona non-profit electric generation cooperative which supplies all or most of the power and energy needs of its five Arizona Class A member distribution cooperatives. Currently, AEPCO's Arizona all-requirements members are DVEC, GCEC and the Trico Electric Cooperative, Inc. ("TRICO"). Under the all-requirements relationship, these Class A members are obligated to purchase, and, correspondingly, AEPCO is obligated to plan for and supply, all of the power and energy needs which these distribution cooperatives require for their retail members.

2. Mohave Electric Cooperative, Inc. ("MEC") and Sulphur Springs Valley Electric Cooperative, Inc. ("SSVEC") are AEPCO's partial-requirements Class A members. Under a

partial-requirements relationship, MEC and SSVEC commit to pay for a fixed amount of capacity and may purchase the associated energy from AEPCO. They then secure from sources of their choosing any additional power requirements necessary to meet the power and energy needs of their retail members.

3. As discussed in a Joint Request being filed simultaneously with this Request, TRICO has elected to convert its AEPCO membership from all- to partial-requirements. Approval of the new TRICO Partial-Requirements Capacity and Energy Agreement, as well as amendments to the existing partial-requirements agreements between AEPCO and MEC and AEPCO and SSVEC and revised rates, are sought by that Joint Request.

4. This Request seeks Commission approval of revised rates and similar amendments to the all-requirements Wholesale Power Contracts between AEPCO and DVEC and AEPCO and GCEC. As explained in the Joint Request, the amendments reflect revenue, rate design and cost allocation understandings which have been reached recently by AEPCO and its members. They are described in AEPCO's rate and amended rate application filings made on October 1, 2009 and April 20, 2010 in this docket.

5. Attached as Exhibit A is the Ninth Amendment to the Wholesale Power Contract between AEPCO and DVEC (the "DVEC Amendment"). Attached as Exhibit B is the Seventh Amendment to the Wholesale Power Contract between AEPCO and GCEC (the "GCEC Amendment").

6. The DVEC Amendment and the GCEC Amendment have been approved by those cooperatives' Boards of Directors as stated in the letters of support signed by the Presidents of those Boards which are attached as Exhibit C. AEPCO's Board has also approved the

amendments and has instructed AEPCO's management to secure necessary regulatory consents to their implementation.

7. In that regard, the DVEC Amendment and the GCEC Amendment are also subject to the review and approval of the Rural Utilities Service ("RUS"). AEPCO is in the process of making the required filings to secure RUS approval of the amendments.

8. Attached as Exhibit D is a Summary of Revised Proposed Rates (right-hand column) which AEPCO requests be approved for TRICO, DVEC and GCEC in this docket. These requested rates result in an estimated 1.1% decrease in revenues from DVEC, a 1% decrease from GCEC and a 5.1% decrease from TRICO as compared to AEPCO's adjusted test year revenues. As shown on Exhibit D, the Revised Proposed Rates requested for MEC and SSVEC are unaffected by TRICO's conversion. AEPCO shortly will file an Exhibit GLG-4, sponsored by Mr. Goble, which will state the revised requested PPFAC bases.

WHEREFORE, having stated its Request, AEPCO requests that the Commission enter its Order approving:

1. The DVEC Amendment, attached as Exhibit A;

2. The GCEC Amendment, attached as Exhibit B; and

3. The rates set forth in the Revised Proposed Rates column of Exhibit D for TRICO, DVEC, GCEC, MEC and SSVEC.

RESPECTFULLY SUBMITTED this 2nd day of June, 2010.

GALLAGHER & KENNEDY, P.A.

By [signature]
Michael M. Grant
2575 East Camelback Road
Phoenix, Arizona 85016-9225
Attorneys for Arizona Electric Power Cooperative, Inc.

Original and 13 copies filed this 2nd day of June, 2010, with:

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Phoenix, Arizona 85007

Copies of the foregoing delivered this 2nd day of June, 2010, to:

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Copies of the foregoing mailed this 2nd day of June, 2010, to:

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EXHIBIT A

NINTH AMENDMENT TO WHOLESALE POWER CONTRACT

This Ninth Amendment to Wholesale Power Contract (Amendment) is entered into this 11 day of May, 2010, by and between Duncan Valley Electric Cooperative, Inc., a non-profit corporation organized and existing under the laws of the State of Arizona/California (Member) and Arizona Electric Power Cooperative, Inc., a non-profit cooperative corporation organized and existing under the generation and transmission electric cooperative laws of the State of Arizona ("AEPCO" or "Generating Cooperative"). Member and AEPCO are also hereinafter referred to individually as "Party" or collectively as "Parties."

WHEREAS, the Parties have entered into that certain Wholesale Power Contract dated February 15, 1962, as amended and supplemented on March 15, 1971, November 1, 1974, November 3, 1982, February 2, 1984, September 4, 1986, November 15, 2001, and May 5, 2003 (Wholesale Power Contract), such that Member pursuant to the Wholesale Power Contract is an "AEPCO All Requirements Member," as that term is defined in the Amended and Restated Appendix A dated May 11, 2010 attached hereto and referred to herein as the "2010 Definition Appendix";

WHEREAS, the Parties intend to modify as among themselves the manner in which rates and charges for electrical service to Member are formulated and designed in order to effect resolution of certain Rate Allocation Issues and Rate Design Issues, which have developed among AEPCO and the AEPCO Class A Members, as all such capitalized terms are defined in the 2010 Definition Appendix, pursuant to the Rate Settlement Agreement dated May 14, 2010 (Rate Settlement Agreement);

WHEREAS, the Parties recognize the benefit in entering into this Amendment in order to settle the Rate Allocation Issues and Rate Design Issues by providing for a fair, equitable and repeatable allocation of costs and revenues at issue between the Partial Requirements Members (PRM) and the All Requirements Members (ARM) based on principles of cost causation;

WHEREAS, the Parties intend that this Amendment to the Wholesale Power Contract shall be an integral component of the Rate Settlement Agreement;

WHEREAS, AEPCO filed on October 1, 2009, an application with the Arizona Corporation Commission (ACC) in ACC Docket No. E-01773A-09-0472 to modify its rates and charges (AEPCO 2009 Rate Application);

WHEREAS, this Amendment is intended to be entered into contemporaneously with certain other substantially identical amendments to individual wholesale power contracts between AEPCO and each of the other AEPCO ARMs;

WHEREAS, it is in the best interest of Member and its members to enter into this Amendment to effect the changes in AEPCO's rate formulation and services provision herein contemplated, thereby partially implementing the Rate Settlement Agreement; and

WHEREAS, the Parties wish to amend the Wholesale Power Contract, as set forth in this Amendment;

NOW, THEREFORE, in consideration of the premises set forth above and for good and valuable consideration, the receipt and sufficiency of which the Parties hereby acknowledge, the Parties hereto, intending to be legally bound, mutually agree as follows:

Section 1. Amendment to Part I Section 4 (a) of the Wholesale Power Contract.

Part I, Section 4 (a) is hereby amended by adding to it concluding sentences, as follows:

"For purposes of specifying and calculating rates and charges pursuant to this Rate Schedule A, Member and other Members receiving all requirements electric service from the Generating Cooperative are individually referred to as an "ARM" and collectively referred to as "Collective ARM" or "CARM." When specified in Rate Schedule A, Member's All Requirements Member's Demand Ratio Share (ARM DRS) of certain CARM rates and charges shall be equal to the quotient of Member's 12 month rolling average demand divided by CARM's 12 month rolling average demand. Also, Member's Energy Cost Ratio Share (ARM ECR) for purposes of Rate Schedule A shall be the percentage share for each billing period of Member in the CARM S&G PPA Energy Charge, CARM Supplemental Purchase Cost, CARM Base Energy Cost, and CARM Total Other Energy Cost, determined in such billing period as the ratio expressed in percent of Member's Member Billing Energy to CARM Billing Energy."

Section 2. Amendment to Part I, Section 4 (b) of the Wholesale Power Contract.

Part I, Section 4(b) is hereby amended by replacing the term, "rate or rates" wherever it may appear therein with the term, "rate and charge" or "rates and charges," as appropriate.

Section 3. Addition of New Section 13 to Part I of the Wholesale Power Contract.

Part I is hereby amended by adding the new Section 13, which is set forth in its entirety as Attachment 1, attached hereto.

Section 4. 2010 Definition Appendix.

Attached hereto are definitions for terms not defined herein, applicable to this Amendment and other related agreements as the Amended and Restated Appendix A dated May 11 2010.

Section 5. Amendment to Rate Schedule A and all revisions thereto adopted by the Generating Cooperative, attached to the Wholesale Power Contract.

Rate Schedule A attached to the Wholesale Power Contract and all revisions thereto adopted by the Generating Cooperative shall be amended in their entirety and replaced with the Rate Schedule A, dated May 11, 2010, attached hereto as Attachment 2.

Section 6. The Rural Utilities Service and the Arizona Corporation Commission.

This Ninth Amendment shall become effective on the first day of the month following the latter of 1) the date of its approval by the Rural Utilities Service (RUS), 2) the date of approval by the ACC or 3) the effective date of a non-appealable decision in AEPCO's 2009 Rate Application, or its replacement.

Section 7. Miscellaneous.

(a) Extent of Amendment. Except as expressly herein set forth, all of the terms and conditions of the Wholesale Power Contract are hereby ratified and confirmed and shall remain in full force and effect.

(b) Counterparts. This Amendment may be executed in any number of counterparts, and all of which when taken together shall constitute one and the same instrument. The Parties hereto may execute this Amendment by signing any such counterpart.

(c) Binding Effect. This Amendment shall be binding upon the Parties and their respective successors and assigns.

(d) References to Rural Electrification Administration. Any references in the Wholesale Power Contract to the Rural Electrification Administration shall be replaced with the title of its successor agency, the RUS.

IN WITNESS WHEREOF, the undersigned have duly executed this Ninth Amendment to the Wholesale Power Contract, effective as of the date set forth below.

ARIZONA ELECTRIC POWER COOPERATIVE, INC.

By: ______________________

Name: Gary G. Grim

Title: Senior Vice President and Chief Operating Officer

Date: 5/11/10

-and-

ANZA ELECTRIC COOPERATIVE, INC.

By:______________________________

Name:____________________________

Title:_____________________________

Date:_____________________________

-or-

DUNCAN VALLEY ELECTRIC COOPERATIVE, INC.

By: Johnnie Frie

Name: Johnnie Frie

Title: Board President

Date: May 10, 2010

-or-

GRAHAM COUNTY ELECTRIC COOPERATIVE, INC.

By:______________________________

Name:____________________________

Title:_____________________________

Date:_____________________________

APPENDIX A

AMENDED AND RESTATED: DEFINITIONS
DATED May 11, 2010

1. These Definitions shall have the respective meanings set forth herein for use in the following agreements and their exhibits and schedules (unless the context in which the term is used in a particular agreement clearly requires otherwise):

    1. MEC Partial Requirements Capacity and Energy Agreement;
    2. SSVEC Partial Requirements Capacity and Energy Agreement;
    3. TRICO Partial Requirements Capacity and Energy Agreement;
    4. Resource Integration Agreement;
    5. SSVEC Transmission Agreement;
    6. MEC Transmission Agreement;
    7. TRICO Transmission Agreement;
    8. Network Service Agreement;
    9. Member Agreement between AEPCO, SWTC, Sierra and ANZA, DVEC, GCEC, MEC, SSVEC and TRICO.

2. These Definitions shall not be amended or modified without advance notice, review and approval by all parties to any of the agreements listed above, and RUS (as hereinafter defined), which remain executory, and after providing to all parties in advance a listing of any such agreements in which a proposed amended or modified defined term is contained.

3. The following shall be used in interpreting these Definitions and the agreements listed above:

    3.1 Unless otherwise required by the context in which any term appears:

    (a) Capitalized terms used in any agreement listed above shall have the meanings specified in this Appendix A or, if used solely within an Agreement, as set forth in such agreement.

    (b) The singular shall include the plural and the masculine shall include the feminine and neuter.

    (c) References to "Articles," "Sections," "Schedules," "Appendices" or "Exhibits" shall be to articles, sections, schedules, appendices, or exhibits of the agreement(s) specified, and references to paragraphs shall be to separate paragraphs of the section or subsection in which the reference occurs.

    (d) The words "herein," "hereof", "hereinbelow" and "hereunder" shall refer to an agreement, specified as a whole and not to any particular section or subsection of such agreement; the words "include," "includes" or "including" shall mean "including, but not limited to"; and the words "best effort(s)" shall mean a level of effort which, in the exercise of reasonable judgment in the light of facts known at the time a decision is made, can be expected to accomplish the desired result at a reasonable cost, consistent with Prudent Utility Practice (as hereinafter defined).

(e) Except where the context otherwise indicates, the term "day" shall mean a calendar day, and whenever an event is to be performed by a particular date, or a period ends on a particular date, and the date in question falls on a weekend, a legal holiday in the State of Arizona, or a day when the relevant cooperative is not open for business, the event shall be performed, or the period shall end, on the next succeeding business day.

(f) All accounting terms not specifically defined herein or by specified Accounting Requirements (as hereinafter defined) shall be construed in accordance with Generally Accepted Accounting Principles in the United States of America, consistently applied.

3.2 All references herein to the term "cooperative" shall be to AEPCO, TRANSCO, CSP or a Member (as hereinafter defined) cooperative as appropriate from the context in an agreement.

3.3 All references to a particular entity shall include such entity's successor and permitted assigns.

3.4 All references herein to any agreement, including its schedules, exhibits and appendices, shall be to such agreement as amended, supplemented or modified.

3.5 All references herein to any Law (as hereinafter defined) shall be to such Law as amended, supplemented, modified or replaced.

3.6 The titles of the articles and sections of the agreements have been inserted as a matter of convenience of reference only and shall not control or affect the meaning or construction of any of the terms or provisions thereof.

3.7 The parties have agreed to the wording of the agreements, and none of the provisions thereof shall be construed against one party on the ground that any party is the author of such agreement or any part thereof.

3.8 In any defined term which begins with the word "PRM*," the word PRM* may be replaced with the name of a Partial Requirements Member. When the name of a Partial Requirements Member is substituted, the definition remains the same but is applicable only to the named Partial Requirements Member. For example, "'PRM* Transmission Service' shall mean Network Integration Transmission Service and all Ancillary Services used to deliver the AC and associated energy of PRM* to PRM* AEPCO Load." If MEC is substituted, "'MEC Transmission Service' shall mean Network Integration Transmission Service and all Ancillary Services used to deliver the AC and associated energy of MEC to MEC AEPCO Load."

"AC" shall mean Allocated Capacity.

"ACC" shall mean Arizona Corporation Commission or any State of Arizona regulatory agency succeeding to its powers and functions.

"Accounting Report" shall mean the report prepared by TRANSCO that accounts for all of the installed cost of each transmission facility constructed or acquired by TRANSCO as a part of the TTS and classifies such facility or portion thereof and apportions its installed cost as an All Requirements Resource Facility, an Existing System Facility, a Load Growth System Facility, a Power Sale Resource System Facility, a Resource Facility, or a Reliability System Facility, for the purposes of Sections 2 and 6 hereof and consistent with Accounting Requirements.

"Accounting Requirements" shall mean the requirements of any system of accounts prescribed by the RUS as long as RUS is the holder of any obligation of a cooperative; provided, however, that if a cooperative is specifically required by another Governmental Authority to employ the system of accounts prescribed by that Governmental Authority, then "Accounting Requirements" means the system of accounts prescribed by that Governmental Authority; provided, further, however, that if RUS is not a holder of any obligation or, if a holder, RUS does not prescribe a system of accounts applicable to the cooperative, and the cooperative is not specifically required by another Governmental Authority to employ that entity's system of accounts, then "Accounting Requirements" means the requirements of Generally Accepted Accounting Principles or another comprehensive basis of accounting applicable to like entities conducting business similar to that of the cooperative. Generally Accepted Accounting Principles refers to a common set of accounting standards and procedures that are either promulgated by an authoritative accounting rulemaking body or accepted as appropriate due to widespread application in the United States.

"Additional AEPCO Contract" shall mean each additional contract (set forth on Schedule 1 of the Member Agreement and Schedule 6 of the Restructuring Agreement as the case may be) which either the Member Agreement or the Restructuring Agreement requires to be executed and delivered by AEPCO.

"Additional CSP Contract" shall mean each additional contract (set forth on Schedule 1 of the Member Agreement and Schedule 6 of the Restructuring Agreement as the case may be) which either the Member Agreement or the Restructuring Agreement requires to be executed and delivered by CSP.

"Additional TRANSCO Contract" shall mean each additional contract (set forth on Schedule 1 of the Member Agreement and Schedule 6 of the Restructuring Agreement as the case may be) which either the Member Agreement or the Restructuring Agreement requires to be executed and delivered by TRANSCO.

"Administrator" shall mean the Administrator of RUS or any other federal regulatory agency or department succeeding to the Administrator's power or functions as a lender or mortgagee to a cooperative.

"AEPCO" shall mean Arizona Electric Power Cooperative, Inc., a non-profit generation and transmission cooperative corporation organized under the Laws of the State of Arizona.

"AEPCO Available Resource(s)" shall mean that portion of AEPCO Resources representing operating reserves which can be sold on an interruptible basis and surplus to AEPCO Total Load.

"AEPCO By-law Amendments" shall mean the amendments to the AEPCO By-laws relating to governance, in the form adopted by AEPCO in accordance with the terms of the AEPCO By-laws and the Laws of the State of Arizona.

"AEPCO By-laws" shall mean the By-laws adopted and amended by the Members or Board of Directors of AEPCO in accordance with the Laws of the State of Arizona.

"AEPCO Class A Member" shall mean (i) any Class A Member which purchases power and energy from AEPCO pursuant to any Existing Wholesale Power Contract or Partial Requirements Capacity and Energy Agreement and is listed in Recital B to the Partial Requirements Capacity and Energy Agreement; or (ii) is determined to be a Class A member by the terms of the AEPCO By-laws.

"AEPCO Closing Date Allocation and Attribution" shall mean the allocations and attributions to be made by AEPCO on the Closing Date, as set forth in Section 2.6 of the Member Agreement and Section 2.3 of the Restructuring Agreement.

"AEPCO Delivered Load" shall mean the aggregate of the demand requirements and the associated energy requirements of all electric loads served from AEPCO Resources (including distribution losses but not including reserves or transmission losses), and shall consist of:

1. The loads of All Requirements Members served from AEPCO Resources;
2. PRM*AEPCO Load;
3. PRM*AEPCO Sales;
4. Power Sales Loads; and
5. CSP AEPCO Load.

"AEPCO Employees" shall mean those individuals employed by AEPCO as of the Closing Date.

"AEPCO Federal Hydro Power Capacity" shall mean that amount of capacity on an hourly basis scheduled by AEPCO pursuant to Federal Hydro Power Agreements.

"AEPCO Load Forecast" shall mean a listing of the demand and associated energy requirements of AEPCO Total Load (by month for the Resource Forecast Period) to be served from AEPCO Resources

"AEPCO's Member Peak Demand" shall mean the highest thirty (30) minute integrated demand in kW experienced during the billing period of the aggregate demands of all Class A

Members purchased pursuant to the Partial Requirements Capacity and Energy Agreements and the Existing Wholesale Power Contracts.

"AEPCO Minimum Base Capacity" shall mean the capacity from Available Base Capacity that must be operated from time to time to maintain system reliability or for other reasons, reflecting AEPCO's determination as to the schedule of energy from the Federal Hydro Power Agreements and AEPCO Minimum Coal Capacity.

"AEPCO Minimum Coal Capacity" shall mean the minimum output for safe and reliable operation of Apache Units 2 and 3.

"AEPCO Mortgage" shall mean the Consolidated Mortgage and Security Agreement, dated as of June 14, 1989, by and among AEPCO, as mortgagor, and the Government acting through the Administrator of the RUS, and CFC, as mortgagees, as amended and consolidated, or restated from time to time, which secures the obligations thereunder and creates a lien on substantially all of the real and tangible personal property of AEPCO in favor of such mortgagees, additional substitute mortgagees and other secured parties.

"AEPCO Notes" shall mean written instruments or notes which evidence the obligation of AEPCO for loans that in whole or in part financed the construction of AEPCO's generation and transmission facilities, the payment of which is guaranteed by the Government pursuant to the REAct, and those written instruments or notes of AEPCO outstanding on the Effective Date (with respect to the MEC Partial Requirements Capacity and Energy Agreement), the Agreement Date (with respect to the SSVEC Partial Requirements Capacity and Energy Agreement), or the Approval Date (with respect to the TRICO Partial Requirements Capacity and Energy Agreement) payable to the Government evidencing loans made by the Government, acting by and through the Administrator of RUS, pursuant to the REAct, or evidencing reimbursement obligations of AEPCO to the Government with respect to the Government's guarantee of the payment of certain notes payable to the order of FFB and all amendments, supplements, extensions, and replacements to, of, or for, such notes, and loans made by, or securities issued to, or obligations undertaken to, others, including the Financial Entities. AEPCO Notes in the future will also include written instruments, which may evidence additional or new loans or advances that AEPCO may obtain to finance the construction or purchase of new facilities, Future Resources or the modification of Existing Resources, as applicable.

"AEPCO Resource" shall mean a Resource owned or purchased from others by AEPCO.

"AEPCO Retained Personnel" shall mean AEPCO management and other personnel designated as such by the chief executive officer of AEPCO.

"AEPCO's Revenue Requirement" shall mean the total revenues, from any source whatsoever, necessary to enable AEPCO, utilizing a twelve (12) month test period to: (i) meet all its anticipated fixed, variable, fuel, and all other costs, obligations and expenses and payments (including all payments on account of Indebtedness of AEPCO); (ii) establish and maintain reasonable financial reserves; and, (iii) include appropriate levels of margins and working capital to satisfy, at a minimum, applicable prescribed annual coverage ratios or any other financial covenants or tests imposed by the Financial Entities, as may exist from time to time, determined in accordance with Accounting Requirements.

"AEPCO's Revenue Requirement from AEPCO's Class A Members" shall mean that portion of AEPCO's Revenue Requirement less revenues anticipated by AEPCO from all other sources than the AEPCO Class A Members.

"AEPCO's Revenue Requirement From Partial Requirements Members" shall mean that portion of AEPCO's Revenue Requirement from AEPCO Class A Members allocated to Partial Requirements Members in accordance with Section 5 of the Partial Requirements Capacity and Energy Agreements and Section 3 of Rate Schedules A.

"AEPCO Scheduling Portal" shall mean an Internet web site maintained by AEPCO and accessible by all Class A Members for the purpose of AEPCO posting ongoing information relating to the availability and minimum must run requirements for AEPCO Resources.

"AEPCO Secured Obligations" shall mean the AEPCO Notes, loans made by, or securities issued to, or debt obligations entitled to the lien created by the AEPCO Mortgage.

"AEPCO Total Load" shall mean the aggregate of the demand requirements and the associated energy requirements of: (i) AEPCO Delivered Load plus, (ii) losses related thereto from the transmission of power and energy, plus, (iii) applicable only to the demand requirement computation: the greater of (a) applicable installed capacity margin, or (b) operating reserve requirements.

"Agreement Date" shall mean the first day of the month following the date upon which the SSVEC Partial Requirements Capacity and Energy Agreement, the SSVEC Transmission Agreement and the Resource Integration Agreement, as amended to include SSVEC, shall have been executed and delivered by the necessary parties and approved by the RUS and, if required, by the ACC and FERC.

"All Requirements Member" shall mean any Class A Member of AEPCO that is currently a party to any Wholesale Power Contract with AEPCO which provides for the purchase from AEPCO of all such Member's requirements of electric power, which as of the Effective Date consisted of ANZA, DVEC, GCEC, SSVEC AND TRICO, which as of the Agreement Date consisted of ANZA, DVEC, GCEC and TRICO, and which as of the Approval Date shall consist of ANZA, DVEC and GCEC.

"All Requirements Resource Facility" shall mean any System Facility, or portion hereof, or Direct Assignment Facility that is required to interconnect with and to deliver to the TTS the capacity and energy of any Resource Modification or Future resource in which MEC and SSVEC have no ACP.

"Allocated Capacity" or "AC" shall mean the amount of capacity of AEPCO Resources from which a Partial Requirements Member is entitled to schedule energy in any month as set forth in its Partial Requirements Capacity and Energy Agreement. The AC for each month for the term of such agreement is set forth in Appendix B to Exhibit A-5 to Rate Schedule A of such agreement.

"Allocated Capacity Percentage" or "ACP" of a Class A Member shall mean the percentage allocation with respect to an AEPCO Resource, for which, if it is a Partial Requirements Member, such Member is responsible, including the allocation of electric capacity, cost responsibility and revenues, as set forth in its Partial Requirements Capacity and Energy Agreement. Appendix A to Exhibit A-5 to Rate Schedule A sets forth the ACP for each Class A Member with respect to Existing Resources and the S&G PPA.

"Ancillary Services" shall mean the ancillary services required by FERC to be made available with transmission service in accordance with the FERC pro-forma open access transmission tariff, including; but not limited to scheduling, system control and dispatch service; reactive supply and voltage control from generation sources service; regulation and frequency response service; energy imbalance service; operations reserve-spinning reserve service, and; operating reserve - supplemental reserve service, all as such terms are further defined by FERC in Order No. 888 and 889 and identified in transmission tariffs and service agreements of TRANSCO.

"Annual Planning Report" shall mean the annual written report and analysis given to AEPCO of a Class A Member's short, intermediate and long-range forecast of load and such other planning data required by the Resource Integration Agreement.

"Annual Transmission Requirements Report" shall have the meaning set forth in Section 5 of Schedule B hereto (Transmission Planning Policies).

"ANZA" shall mean Anza Electric Cooperative, Inc., a non-profit electric cooperative corporation organized and existing under the Laws of the State of California.

"Applicable Additional Contract" shall mean each additional contract as set forth on Schedule 1 of the Member Agreement and Schedule 6 of the Restructuring Agreement, which either the Restructuring Agreement or the Member Agreement requires to be executed by each party to the Agreements.

"Approval Date" shall mean the first day of the month, no earlier than December 1, 2010, following the latter of 1) the date upon which the TRICO Transmission Agreement and the TRICO PRC&EA shall have been approved by the RUS, 2) the date upon which the TRICO PRC&EA shall have been approved by the ACC or 3) the effective date of a non-appealable decision in AEPCO's 2009 Rate Application, or its replacement.

"ARM Energy Cost Responsibility Share or ARM ECR" shall mean the percentage share for each billing period of an individual All Requirements Member in CARM S&G PPA Energy Charge, CARM Supplemental Purchase Cost, CARM Base Energy Cost, and CARM Total Other Energy Cost, determined in such billing period as the ratio expressed in percent of each All Requirements Member's Member Billing Energy to CARM Billing Energy.

"Assignment for Security" shall mean an assignment, transfer, mortgage or pledge of a party's interest in an Agreement made as security for any obligation secured by any indenture, mortgage, deed, deed of trust, security instrument, or similar lien on its system assets, without limitation on the right of the secured party to further assign such Agreement.

"Authorized Representative" shall mean a representative designated by a party pursuant to the terms of an Agreement and authorized to act for such party in certain matters as set forth in the relevant terms of such Agreement.

"Available Base Capacity" shall mean the energy from Base Resources, including Base Economy Purchases, available for dispatch in a Future Scheduling Hour, less losses in delivery to Class A Members, and excluding (i) any coal-fired capacity that is not available due to forced outage or scheduled maintenance outage or temporary deration, (ii) capacities of Power Sales Resources, and (iii) allocations for losses in delivery of such Power Sales Resources; and for each Billing Unit Entity, shall mean that Billing Unit Entity's ACP share of such Available Base Capacity.

"Available Other Capacity" shall mean the amount of capacity that is available for dispatch as determined by AEPCO for any Future Scheduling Hour equal to the sum of (i) the aggregate of the capacities of Other Resources, which shall be as set forth in Appendix B to Exhibit A-5 of Rate Schedule A to each Partial Requirements Capacity and Energy Agreement, as may be amended, plus (ii) the capacity of any concurrent Replacement Purchases for Base Resources, less (iii) capacity set aside for Reserves and allocations for losses in delivery; and for each Billing Unit Entity, shall mean that Billing Unit Entity's ACP share of such Available Other Capacity.

"Available Resource(s)" shall mean the Pooled Resource(s) surplus to Pooled Load available for sale or dispatch as Merchant Sales.

"Available S&G PPA Capacity" shall mean S&G PPA Capacity, less an allocation for losses for delivery, that is available for dispatch by AEPCO for any Future Scheduling Hour; and for each Billing Unit Entity having an ACP in S&G PPA, shall mean that Billing Unit Entity's ACP share of such Available S&G PPA Capacity.

"Available Supplemental Capacity" shall mean Supplemental Capacity, less an allocation for losses for delivery, that is available for dispatch by AEPCO for any Future Scheduling Hour; and for each Billing Unit Entity having an interest in a Supplemental Purchase, shall mean that Billing Unit Entity's percentage share of such Available Supplemental Capacity.

"Available Transmission Resources" shall mean the transmission facilities and contract rights of the Parties (as set forth in Schedule E attached) required for the delivery of Pooled Resources to Pooled Loads.

"Base Adjustor Per Unit Cost" shall mean, for a billing period for each Billing Unit Entity, the Base Fuel Adjustor Cost divided by the Base Billing Energy for the same Billing Unit Entity for the same billing period.

"Base Average Energy Rate" shall mean, for a billing period for each Billing Unit Entity, the rate obtained by dividing the Billing Unit Entity's Base Energy Cost of the billing period by Billing Unit Entity's Base Billing Energy for the same period.

"Base Billing Energy" shall mean, for a Billing Unit Entity, the energy from its Available Base Capacity assigned and allocated in each hour pursuant to the Billing Unit Program to its Base Schedule or load, accumulated for a billing period.

"Base Capacity" shall mean for Base Resources the sum of (i) the capacity from Federal Hydro Power Agreements as adjusted to reflect seasonal and Peak Hours vs. Off-Peak Hours variations; plus (ii) 350 MW of capacity of AEPCO's coal-fired units.

"Base Economy Purchase" shall mean a purchase of energy by AEPCO from a third party, including wheeling charges recorded in RUS Uniform System of Accounts 565 Transmission of Electricity by Others or its successor for delivery of the purchase to an SWTC Point of Receipt, if any, which is made at a lower average energy rate over the purchase period than that associated with energy available from Base Resources during such period, and which AEPCO chooses to make in lieu of dispatching energy available from such Base Resources.

"Base Economy Purchase Cost" shall mean, for all hours of a billing period, the purchase energy cost incurred by AEPCO for all Base Economy Purchases made in such billing period, including wheeling costs incurred in delivery from the source of such purchase to an SWTC Point of Receipt, if any.

"Base Economy Sales" shall mean, for a billing period, the energy from Post-Transfer Excess Base Capacity assigned in each hour to each Billing Unit Entity pursuant to the Billing Unit Program as Third Party Economy Sales.

"Base Economy Sales Cost" shall mean, for each Billing Unit Entity for a billing period, the product of Base Economy Sales multiplied by the Coal Energy Rate.

"Base Economy Sales Credit" shall mean, for each Billing Unit Entity, the product of the Economy Sales Price, for each of Daytime Hours and Nighttime Hours of a billing period, multiplied by the Billing Unit Entity's Base Economy Sales for Daytime Hours and for Nighttime Hours, respectively, of the same billing period.

"Base Energy Cost" shall mean, for a billing period for each Billing Unit Entity, the sum of Remaining Base Energy Cost plus Base Transfer Sales Credits, Base Transfer Energy Cost, Base Economy Sales Credit and Base Economy Sales Cost for the same Billing Unit Entity.

"Base Energy Mismatch" shall mean, for a billing period, the accumulated net difference in energy obtained from subtracting (i) the energy from Available Base Capacity assigned and allocated in the billing period in accordance with the Billing Unit Program, from (ii) the energy actually produced from Available Base Capacity during that billing period.

"Base Energy Mismatch Charge" shall mean, for a billing period, the product of (i) any positive value of Base Energy Mismatch for the billing period, multiplied by (ii) the Coal Energy Rate for the billing period.

"Base Energy Mismatch Credit" shall mean, for a billing period, the product of (i) the absolute value of any negative value of Base Energy Mismatch for the billing period, multiplied by (ii) the Coal Energy Rate for the billing period.

"Base Energy Rate" shall mean, for each Billing Unit Entity, the rate applicable to that Billing Unit Entity's use of energy from Available Base Capacity as set forth in Exhibit A-1 to Rate Schedule A.

"Base FPPCA" shall mean Fuel and Purchase Power Cost Adjustor determined for a FPPCA Period for the Base Resources for each Billing Unit Entity.

"Base Fuel Adjustor Cost" shall mean, for a billing period for each Billing Unit Entity, the sum of the Base Energy Cost, Hydro Demand Charge, Base Transmission Wheeling Cost and Power Sales Resource Demand Revenues for the same Billing Unit Entity for the same billing period.

"Base Fuel Bank" shall mean, for a billing period for each Billing Unit Entity, the accumulation of Base Over or Under Collections.

"Base Incremental Unit Cost" shall mean, for a billing period for each Billing Unit Entity, the difference obtained by subtracting (i) the sum of (a) Base Power Cost Adjustor Base, plus (b) Base Power Cost Adjustor Rate, from (ii) Member Base Adjustor Per Unit Cost, for such Billing Unit Entity for such period.

"Base Over or Under Collection" shall mean, for a billing period for each Billing Unit Entity, the product of (i) Base Incremental Unit Cost multiplied by (ii) Base Billing Energy, for such Billing Unit Entity for such period.

"Base Power Cost Adjustor Base" shall mean the Power Cost Adjustor Base for Base Resources as set forth in the Tariff.

"Base Power Cost Adjustor Rate" shall mean the Power Cost Adjustor Rate for Base Resources as set forth in the Tariff.

"Base Resources" shall mean the Federal Hydro Power Agreements and two coal-fired steam Generating Resources that are Existing Resources located at the Apache Generating Station, in which each Class A Member has an ACP.

"Base Schedule" shall mean, for each Member*, its Pre-Schedules and Real-Time Schedules provided to AEPCO by such Member* or its Scheduling Agent pertaining to Member*'s use of its Available Base Capacity, as such Pre-Schedules and Real-Time Schedules are determined consistent with Schedule B to the Partial Requirements Capacity and Energy Agreements.

"Base Transfer" shall mean, for a Billing Unit Entity, energy from the Billing Unit Entity's Excess Base Capacity that has been assigned and allocated to the load or Other Schedule of other Billing Unit Entities in an hour pursuant to the Billing Unit Program, accumulated for a billing period separately for Daytime Hours and Nighttime Hours.

“Base Transfer Billing Energy” shall mean, for a Billing Unit Entity, energy from the Excess Base Capacity of other Billing Unit Entities that has been assigned and allocated to the Billing Unit Entity in an hour pursuant to the Billing Unit Program, accumulated for a billing period separately for Daytime Hours and Nighttime Hours.

“Base Transfer Energy Cost” shall mean, for each Billing Unit Entity for a billing period, Coal Energy Rate multiplied by Base Transfer.

“Base Transfer Purchase Cost” shall mean, for each Billing Unit Entity that has been assigned Base Transfer Billing Energy, for each of separately accumulated Daytime Hours and Nighttime Hours of a billing period, the product of its Base Transfer Billing Energy, multiplied by the Economy Purchase Rate of Daytime Hours or Nighttime Hours, as applicable.

“Base Transfer Sales Credit” shall mean, for each Billing Unit Entity, for each of separately accumulated Daytime Hours and Nighttime Hours of a billing period, the product of (i) the Economy Purchase Rate of Daytime Hours or Nighttime Hours, as applicable, multiplied by (ii) its Base Transfer Energy of Daytime Hours or Nighttime Hours, as applicable.

“Base Transmission Wheeling Cost” shall mean, for each Billing Unit Entity for a billing period, the product of (i) the costs recorded in RUS Uniform System of Accounts 565 Transmission of Electricity by Others or its successor, and allocated to Base Resources, for the same billing period, multiplied by (ii) the Billing Unit Entity’s ACP in Existing Resources.

“Billing Energy” shall mean the energy of each billing period determined pursuant to the Billing Unit Program to have served the entirety of the Schedule of each Member*, or the entirety of the load of CARM or the entirety of the Directed Sales and load of a Member* CA in such billing period, consisting of the sum of the Billing Unit Entity’s Base Billing Energy, S&G PPA Billing Energy, Other Billing Energy, Base Transfer Billing Energy, Supplemental Billing Energy, and S&G And Supplemental Transfer Billing Energy.

“Billing Unit Entity” shall mean any of CARM, a Member* or a Member* CA.

“Billing Unit Program” shall mean the software program and subroutines that are used by AEPCO’s Power Trading and Scheduling Department for the purpose of determining monthly each Billing Unit Entity’s Billing Energy from Base Resources, Other Resources, S&G PPA and Supplemental Purchase by hourly allocation and assignment of energy from Available Base Capacity, Available Other Capacity, Available S&G PPA Capacity and Available Supplemental Capacity to each of (i) the loads of the CARM; (ii) the Directed Sales and load of a Member* CA; (iii) the Schedules; (iv) Base Transfers; (v) S&G And Supplemental Transfers; and (vi) Third Party Economy Sales.

“Bonds” shall mean the CFC Guaranteed Solid Waste Disposal Revenue Bonds (Series 1994Adw) and the CFC Guaranteed Pollution Control Revenue Refunding Bonds (Series 1997C).

"CARM or Collective ARM" shall mean all of the All Requirements Members.

"CARM ACP" shall mean the sum of the ACPs in Existing Resources applicable to each All Requirements Member of AEPCO as set forth in Appendix A to Exhibit A-5 to the Rate Schedule A of the ARM Wholesale Power Contracts.

"CFC" shall mean the National Rural Utilities Cooperative Finance Corporation, a corporation organized under the Laws of the District of Columbia, or similar successor agency.

"Class A Member" shall mean any entity which is or becomes such a Member of AEPCO, TRANSCO or CSP under the relevant cooperative's By-laws.

"Closing" shall mean the execution and delivery of any and all documents and the tendering, transferring or delivering of all payments required to be made or otherwise necessary or desirable to consummate the transactions contemplated by the Restructuring Agreement and the Member Agreement, including such actions and documents described in the Closing Memorandum as specified in Section 8.1 of both the Restructuring Agreement and the Member Agreement, following satisfaction or waiver, if any, of the conditions for Closing therein.

"Closing Date" shall mean the date on which the Closing occurs.

"Closing Memorandum" shall mean the memorandum agreed to by the parties to the Member Agreement prior to the Pre-Closing which sets forth the consents, assignments, transfers, delivery of other approvals, documents, legal opinions, payments and transaction documents to be furnished by the parties, other conditions for Closing, and events and actions required to effect the Closing

"Coal Energy Cost" shall mean, for a billing period, the accumulated costs of coal and natural gas expensed during that billing period, related to the operation and dispatch during that billing period of two coal-fired steam Generating Resources that are Existing Resources located at the Apache Generating Station, as recorded in RUS Uniform System of Accounts 501 or its successor for that billing period.

"Coal Energy Rate" shall mean, for a billing period, Coal Energy Cost divided by the product of Coal Energy Generated multiplied by the difference obtained by subtracting the Network Loss Factor from one (1).

"Coal Energy Generated" shall mean, for a billing period, the net energy output at the 230 kv bus of the two coal-fired steam Generating Resources that are Existing Resources located at the Apache Generating Station.

"Collected Funds" shall mean deposited funds in a banking institution that are immediately available for use without any float restrictions.

"Contract Rate of Interest" shall mean the lesser of: (i) the interest rate equal to the effective "Prime Rate" per annum as specified in the "Money Rates" section of the Wall Street Journal or, (ii) the maximum interest rate permitted by applicable Law in the State of Arizona if any is so stated.

"Cost Causation" shall mean the identification of all direct and indirect costs, revenue and billing units associated with individual Resources and services, such that costs, revenue and billing units can be accounted for and billed separately to the specific Class A Members participating in such Resource or receiving such service.

"CSP" shall mean Sierra Southwest Cooperative Services, Inc., a non-profit corporation organized under the generation and transmission cooperative corporation Laws of the State of Arizona.

"CSP Actual AEPCO Load Data" shall have the meaning set forth in Section 4 of the Resource Planning Policies.

"CSP AEPCO Load" shall mean the sum of the demand and associated energy requirements, including distribution losses, but not including reserves or transmission losses, of the Member JMP Load of each Class A Member and of those other loads for which CSP purchases capacity and energy from AEPCO as specified in separate sales agreements between AEPCO and CSP.

"CSP AEPCO Load Forecast" shall have the meaning set forth in Section 4 of the Resource Planning Policies.

"CSP Assets" shall mean all capital stock of TSEPP, personal property, authorization to make Retail Sales, intangible assets, employee benefit plans, intellectual property, software licenses, employee or consultant agreements, equipment leases and contracts, licenses, any chose in action, and other agreements related to the performance of the CSP Business identified on Schedule 2 to the Restructuring Agreement.

"CSP Business" shall mean (i) the business of power sales and retail sales; (ii) the provision of personnel and consulting services to AEPCO, TRANSCO, and others pursuant to contract; and, (iii) the ownership and use of the CSP Assets, including responsibility for CSP Liabilities.

"CSP JMP Load" shall mean the demand and energy requirements, including distribution losses but not including reserves or transmission losses, of those loads within a Member's Distribution Service Area served using capacity and energy provided by CSP from CSP Resources pursuant to a Joint Marketing Agreement between a Class A Member and CSP.

"CSP Liabilities" shall mean (i) the CSP liabilities identified on Schedule 2 to the Restructuring Agreement, as such obligations exist as of the Closing Date; and (ii) such other obligations relating to the performance of the CSP Business as CSP, AEPCO and TRANSCO may agree upon from time to time in other agreements; and (iii) any liabilities which CSP assumes in accordance with its By-laws.

"CSP Member" shall mean AEPCO, TRANSCO and the Class A Members of AEPCO on the Closing Date and any Person, which has become and retains membership in CSP in accordance with the CSP By-laws.

"CSP Resource" shall mean a Resource owned or purchased by CSP from third parties.

"Daytime Hours" shall mean the 16 hours of each day beginning Hour Ending 0700 through Hour Ending 2200 Pacific Prevailing Time, including Sundays and Holidays.

"Debt Service Coverage Ratio" or "DSC" shall mean the financial ratio determined, based on figures shown on RUS Form 12 for each calendar year-end as submitted in accordance with Accounting Requirements by AEPCO or TRANSCO, by: (1) adding (a) depreciation and amortization expense, (b) interest on long-term debt (increased by one-third of the amount, if any, by which long-term leases exceed two percent of total margins and equities less regulatory assets), and (c) net patronage capital or margins and (2) dividing the sum obtained by the total of interest and principal billed under long-term debt and debt service requirements.

"Deficiency Purchase" shall mean the purchase of additional capacity and energy through the First Right(s) of Refusal among AEPCO and MEC pursuant to Section 10.1.1 herein, which purchase is required to supply capacity and associated energy to meet AEPCO Total Load, if it is the Purchasing Party, or MEC Total Load if MEC is the Purchasing Party.

"Delivery Point" shall mean the interconnection between the TTS and the transmission, distribution system or load of a Class A Member at which TRANSCO is to deliver capacity or energy pursuant to the Transmission Agreement or the Network Service Agreement.

"Demand Overrun Adjustments" shall have the meaning set forth in Section 2.2 of Rate Schedule A.

"Direct Assignment Facilities" shall mean those transmission lines, substation facilities (or components thereof) and firm wheeling purchased by TRANSCO, for the sole use and benefit of a TRANSCO Member or of a particular transmission customer receiving service under the TRANSCO Tariff.

"Directed Sales" shall mean any transactions in which, at the advance direction of a Member* CA, AEPCO for such Member* CA's benefit sells to a third party at wholesale energy from such Member* CA's available AC in AEPCO Resources.

"Directed Sales Credit" shall mean the revenue realized from Directed Sales.

"Dispatch Pool Resources" shall mean Existing Resources, the S&G PPA and Supplemental Purchases.

"DVEC" shall mean Duncan Valley Electric Cooperative, Inc., an electric cooperative non-profit membership corporation organized and existing under the Laws of the State of Arizona.

"Economy Purchase(s)" shall mean a wholesale purchase of capacity and/or energy for a term not to exceed one year (including all renewal periods) entered into by AEPCO.

"Economy Purchase Cost" shall mean, separately accumulated for Daytime Hours and Nighttime Hours of a billing period, the total cost incurred by AEPCO (including transmission expenses, including losses, incurred in delivery from the source of such purchase to an SWTC Point of Receipt, if any) for Non-Base Economy Purchases and Replacement Purchases in effect in such Daytime Hours or Nighttime Hours of the billing period.

"Economy Purchase Rate shall mean, separately calculated for Daytime Hours and Nighttime Hours of a billing period, the rate obtained by dividing Economy Purchase Cost of Daytime Hours or Nighttime Hours of that billing period, by energy received from Non-Base Economy Purchases and Replacement Purchases in effect in such Daytime Hours or Nighttime Hours of that billing period.

"Economy Sale(s)" shall mean a wholesale sale by AEPCO of capacity and energy from AEPCO Available Resources made for monthly, daily or hourly periods of the next twelve months on a pre-scheduled basis.

"Economy Sales Price" shall mean for Third Party Economy Sales, for each of Daytime Hours and Nighttime Hours, the quotient obtained by dividing (i) the numerator equal to the sum of the revenue from all Third Party Economy Sales during the billing period in Daytime Hours and Nighttime Hours, respectively, reduced by any payments to SWTC or third parties for transmission used in delivery of such sales, by (ii) a denominator equal to the MWh of energy delivered as Third Party Economy Sales during such hours.

"Effective Date" shall mean either (i)_________________, or (ii) the Closing Date.

"Eligible Customer For TRANSCO " shall mean any of the following: (i) any electric utility (including AEPCO, CSP or any power marketer), Federal Power Marketing Agency, or any Person generating electric energy for sale for resale (electric energy sold or produced by any such entity may be produced in the United States, Canada or Mexico) or (ii) any Person offering retail electric service to others or taking retail service pursuant to a state requirement that TRANSCO offer unbundled transmission service or to a voluntary offer of such service by TRANSCO.

"Energy Cost Accounting Process" or "ECAP" shall mean the software program and subroutines that are used by AEPCO's Financial Services Department for the purpose of determining monthly each Billing Unit Entity's costs for energy from Base Resources, Other Resources, S&G PPA, and Supplemental Resources.

"Engineering Analysis Requirement" shall mean have the meaning set forth in Section 3.3.2 of the Partial Requirements Capacity and Energy Agreement.

“Equity” shall be defined in accordance with Accounting Requirements.

“Excess Base Capacity” shall mean, for a billing period for each Billing Unit Entity, the separately accumulated Daytime and Nighttime billing period totals of Available Base Capacity that is not assigned in an hour pursuant to the Billing Unit Program as Base Billing Energy

“Excess S&G And Supplemental Capacity” shall mean, for a billing period for each Billing Unit Entity having an ACP interest in S&G PPA and/or Supplemental Purchase, Available S&G PPA Capacity and/or Available Supplemental Capacity, that is not assigned in an hour pursuant to the Billing Unit Program as S&G and Supplemental Billing Energy.

“Exercise Date” shall mean date certain on or before which The Possible Selling Party or Parties shall provide notice to the Purchasing Party or Parties of an election pursuant to Section 10.1.1 herein to exercise The First Right of Refusal among AEPCO and MEC.

“Existing Resource(s)” shall mean the AEPCO Resource(s) as set forth and designated as Existing Resources in Appendix B to Exhibit A-5 to Rate Schedule A, consisting of Base Resource(s) and Other Resource(s).

“Existing System Facility” shall mean any System Facility that is in service or has been acquired as of the Agreement Date, and improvements thereto and replacements thereof occurring during the term of the Agreement.

“Existing Wholesale Power Contract” shall mean the Wholesale Power Contract between AEPCO and a Class A Member, and when used in the plural shall mean such contract and similar contracts between AEPCO and each of the Class A Members pursuant to which, in either case, such Class A Member purchases or purchased all its requirements of electric power from AEPCO prior to its becoming a Partial Requirements Member.

“FERC” shall mean the Federal Energy Regulatory Commission, an agency of the United States Department of Energy, or regulatory agency succeeding to the powers and functions thereof.

“Federal Hydro Power Agreement(s) shall mean the following contracts:

a) Contract No. 87-BCA-10001 for Firm Electric Service between Western Area Power Administration and Arizona Power Pooling Association, dated March 9, 1989 as it may be amended from time to time, and its successor agreement(s) (SLCA Integrated Projects Agreement); and
b) Contract No. 87-BCA-10085 Electric Service between Western Area Power Administration and Arizona Power Pooling Association, dated February 25, 1988 as it may be amended from time to time, and its successor agreement(s) (Parker-Davis Project Agreement).

"FFB" shall mean the Federal Financing Bank, an instrumentality and wholly owned corporation of the Government or any agency or department of the Government succeeding to the powers and functions thereof.

"Final Load Ratio Share of PRM*" shall mean the Load Ratio Share of PRM* in effect as of the Last Service Date.

"Financial Entities" shall mean collectively RUS, CFC, FFB, the trustees and bondholders of the Bonds and other lending institutions or issuers of debt who have made loans to or hold securities or other obligations of a cooperative.

"First Right(s) of Refusal" shall mean reciprocal one-time rights of first refusal to sell capacity and associated energy granted by the purchasing party to the selling party pursuant to Section 10.1 of the Resource Integration Agreement. Certain conditional first rights of refusal provided by CSP to AEPCO as set forth in Section 14 of the Resource Integration Agreement shall not be deemed to form a part of this defined term.

"First Right(s) of Refusal Period" shall mean the time period during which the First Right(s) of Refusal among AEPCO and MEC pursuant to Section 10.1 of the Resource Integration Agreement shall be in effect commencing on the Effective Date and ending on September 1, 2001.

"Fixed Charge" shall mean the charge computed in accordance with Section 5.2 of a Partial Requirements Capacity and Energy Agreement which recovers the share of a Partial Requirements Member of certain fixed costs and expenses of AEPCO.

"Force Majeure" shall mean the occurrence or non-occurrence of any act, event or cause beyond the control of a party to an Agreement whereby the party is unable to perform its obligation, other than the obligation to pay money, which act, event or cause by that party's exercise of due diligence could not have reasonably been expected and avoided, or which even with the exercise of due diligence, the party has not been able to overcome or avoid or cause to be avoided. Such act, event or cause shall include, but not be limited to: acts of God; failure or threat of immediate failure of facilities; explosions, flood, drought, earthquake, storm, fire, pestilence, lightning and other natural catastrophes; epidemic; war; riot; civil disturbance or disobedience, strike, or labor disturbance, disputes or unrest of whatever nature; civil disputes or unrest of whatever nature; labor, material or fuel shortage; sabotage; vandalism; restraint by court order or public authority; a failure or threat of failure of any generating or transmission facility, which is likely to cause an outage of electric service to customers served from that party's system (including transmission curtailments by a transmission provider) or to cause such party to experience a rapid decline in system voltage or frequency; and, action or non action by or inability to obtain the necessary authorizations or approvals from any Governmental Authority (but not including the ACC or RUS), provided however, that no act, event or cause that is the result of the lack of necessary financial resources shall constitute an event of "Force Majeure," nor shall an act, event or cause that is the result of the negligence of the party claiming Force Majeure constitute an event of "Force Majeure."

"Form 12A Balance Sheet" shall mean RUS Form 12a, Section B, Balance Sheet.

"FPPCA" shall mean Fuel and Purchase Power Cost Adjustor determined for the applicable AEPCO Resources.

"FPPCA Period" shall mean the period of months over which AEPCO is to record S&G PPA Energy Charge, Supplemental Purchase Cost, Base Energy Cost and Other Energy Cost for billing or credit to the Class A Members pursuant to the Tariff.

"Future Resource" shall mean (i) any new AEPCO Generating Resource, or (ii) any AEPCO Power Purchase Resource with a term of greater than one (1) year; either of which Resource would require the assignment of a new ACP to each Class A Member participating in such Resource and an amendment, or a new Exhibit to Rate Schedule A.

"Future Scheduling Hour" shall mean a clock hour beginning more than sixty (60) minutes after the current hour.

"Gas Energy Cost" shall mean, for a billing period, the accumulated costs of natural gas expensed during that billing period, related to the operation and dispatch during that billing period of the gas-fired Generating Resources that are Existing Resources located at the Apache Generating Station, as recorded in RUS Uniform System of Accounts 547 or its successor for that billing period.

"Gas Energy Generated" shall mean, for a billing period, the net energy output at the applicable bus of the gas-fired Generating Resources that are Existing Resources located at the Apache Generating Station.

"Gas Energy Rate" shall mean, for a billing period, Gas Energy Cost divided by the product of Gas Energy Generated.

"GCEC" shall mean Graham County Electric Cooperative, Inc., an electric cooperative non-profit membership corporation organized and existing under the Laws of the State of Arizona

"Generally Accepted Auditing Standards" shall mean a common set of auditing standards and procedures that have been developed over time by several auditing boards, the most current set of standards and procedures of which is the Auditing Standards Board.

"Generating Resource" shall mean an interest in any existing, additional, modified or repowered generating facility or unit, which may be owned (jointly or individually), leased or otherwise acquired by AEPCO, provided that in connection with any lease of an Existing Resource, such leasehold interest shall not be deemed to be a Future Resource for purposes of the Partial Requirements Capacity and Energy Agreement.

"Generation Business" shall mean with respect to AEPCO: (i) the business of generation of electricity; (ii) operation of the Resource Pool; and, (iii) the use, ownership, rights, obligations and duties associated with the generation assets including its agreements for Power Purchase Resources, Power Sales Resources, Economy Purchases and Economy

Sales including, but not limited to, the Existing Wholesale Power Contracts and the Partial Requirements Capacity and Energy Agreement.

"Government" shall mean the federal government of the United States of America.

"Governmental Authority" shall mean any local, state, regional, federal, or national administrative, legal, judicial, or executive governmental agency, commission, department, or other governmental entity having jurisdiction over AEPCO, TRANSCO, CSP, their respective Members, or any of their activities.

"Hydro Demand Charge" shall mean, for a billing period, demand charges associated with Federal Hydro Power Agreements as recorded in RUS Uniform System of Accounts 555 or its successor for the billing period.

"Hydro Energy Charge" shall mean, for a billing period, energy charges associated with Federal Hydro Power Agreements as recorded in RUS Uniform System of Accounts 555 or its successor for the billing period.

"Indebtedness" shall mean:

(1) debt incurred or assumed by a cooperative for borrowed money, or debt incurred for the reimbursement of money advanced under any credit support agreements if in either case categorized as debt according to Accounting Requirements;

(2) lease obligations, if categorized as debt according to Accounting Requirements;

(3) debt incurred or obligations assumed for facilities or power purchases included in a Member's ACP;

(4) debt incurred or obligations issued to finance the amount of a pre-payment; or

(5) debt for any Person (other than debt otherwise treated as Indebtedness hereunder) described in clauses (1), (2), (3) or (4) above which are guaranteed (whether by payment or collection) by the cooperative, provided that none of the following shall constitute Indebtedness:

   (A) guarantees of performance or payment by, or any obligations of, any Person under contracts to pay for fuel for the system; and

   (B) guarantees of performance by any Person for other than payment of debt incurred or assumed for borrowed money, or any obligation if categorized as debt according to Accounting Requirements, including, without limitation, all debt (other than indebtedness otherwise treated as Indebtedness hereunder) for borrowed money or the acquisition, construction or improvement of property or capitalized lease obligations guaranteed directly or indirectly, in any manner by a cooperative, or in effect guaranteed, directly or indirectly, by such cooperative through an agreement, contingent or otherwise, to assume any such indebtedness or to advance or supply funds for the payment or purchase of any such indebtedness or to purchase property or services primarily for the purpose of enabling the debtor or seller to make payment of such indebtedness, or to assure the owner of the indebtedness against loss, because of such indebtedness or to supply funds to or in any other manner invest in the debtor (including any agreement to pay for property or services irrespective of whether or not such property is delivered or such services are rendered) or otherwise.

"Interest Expense" shall mean an amount constituting interest on long-term Indebtedness (less any interest during construction and allowance for funds used during construction including an interest rate swap collar, floor forward or other hedging agreement, arrangement or security, however denominated) and other interest expense computed in accordance with Accounting Requirements.

"Intra-Day Schedule" shall mean a Real-Time Schedule.

"Joint Marketing Agreement" shall mean an agreement by and between CSP and a Class A Member pertaining to joint competitive retail electric marketing and sales activities, in accordance with applicable Law, within such Member's Distribution Service Area.

"Joint Marketing Plan" shall mean a plan designed by and entered into between CSP and a Class A Member concerning Retail Sales, the form of which is set forth in Exhibit B to the Joint Marketing Agreement.

"Last Service Date" shall mean the last date on which TRANSCO provides service to PRM* pursuant to Section 2 of a PRM* Transmission Agreement, unless otherwise extended by mutual agreement of the Parties as set forth in writing.

"Law" shall mean any applicable treaty, statute, code, constitutional provision, ordinance, rule, regulation, order, judgment, decree, decision, injunction, process or any similar form of legally binding decision or directive issued by any Governmental Authority including permits and regulatory approvals and any applicable common law.

"Legal Requirement" shall mean any obligation of AEPCO or TRANSCO required by Law.

"Load Forecast" shall mean he projections of monthly coincident peak kilowatt and total monthly kilowatt-hour loads of a party to an Agreement.

"Load Growth System Facility" shall mean any System Facility or portion thereof that is not an All Requirements Resource Facility or a Resource Facility and is constructed or acquired by TRANSCO to deliver the power and energy of any Future Resource or Resource Modification to All Requirements Members for serving the portion of total load of All Requirements Members that is in excess of the sum of the collective AC of All Requirements Members in Existing Resources with all Power Sales Resources reduced to zero.

"Load Pool" shall mean those Pooled Loads served from Pooled Resources.

"Load Ratio Share" shall have the meaning set forth in the TRANSCO Tariff.

"Load Ratio Share of PRM*" shall mean the ratio, expressed as a decimal, that results from dividing: (i) the demand of PRM* AEPCO Load at the time of the TRANSCO system Peak, by (ii) the sum of: (a) the actual total of the demands of all firm loads of all TRANSCO customers at the time of the TRANSCO system peak, including PRM* plus (b) the reserved transmission capacity of all TRANSCO customers receiving firm point to point transmission service under the TRANSCO Tariff, less (c) the actual demands at the time of the TRANSCO system peak of the loads of TRANSCO's customers receiving firm point to point transmission service under the TRANSCO Tariff. Such ratio shall be calculated on a rolling twelve month basis.

"Long Term" shall mean with respect to a forecast deficiency of AEPCO Resources with respect to AEPCO Total Load, a time period extending beyond the subsequent five calendar years.

"Long Term Debt" shall have the meaning given in accordance with Accounting Requirements.

"MEC" shall mean Mohave Electric Cooperative, Inc., an electric cooperative non-profit membership corporation organized and existing under the Laws of the State of Arizona.

"Member" shall mean a member of AEPCO, a CSP Member or a TRANSCO Member, as applicable.

"Member Actual AEPCO Load Data" shall have the meaning set forth in Section 3 of the Resource Planning Policies.

"Member AEPCO Load Forecast" shall have the meaning set forth in Section 3 of the Resource Planning Policies.

"Member Agreement" shall mean the Member Agreement as executed and delivered by and among the Class A Members, AEPCO, TRANSCO and CSP, dated July 2, 2001.

"Member Billing Demand" shall mean as to Member, the demand of Member in kW integrated over the thirty (30) minute period occurring coincident in time with the AEPCO's Member Peak Demand purchased by Member from AEPCO pursuant to a PRM* Partial Requirements Capacity and Energy Agreement, which consists of the demands of PRM* AEPCO Load and PRM* AEPCO Sales.

"Member Billing Energy" shall mean the energy in kWh received by PRM* from AEPCO during the billing period pursuant to a PRM* Partial Requirements Capacity and Energy Agreement which consists of the energy requirements of PRM* AEPCO Load and PRM* AEPCO Sales.

"Member JMP Load" shall mean the demand and energy requirements, including distribution losses but not including reserves or transmission losses of loads located within a Member's Distribution Service Area served using capacity and energy provided by CSP as a result of a Joint Marketing Agreement between CSP and a Class A Member, for which CSP purchases capacity and energy from AEPCO.

“Member Transaction” shall mean (i) the consolidation or merger by the Partial Requirements Member with any other Person; (ii) the reorganization or change of the form of the Partial Requirements Member’s business organization from an electric cooperative non-profit membership-owned corporation; or, (iii) the sale, transfer, lease, or other disposal of all or substantially all the Partial Requirements Member’s assets to any Person (or any effort or agreement therefor), whether accomplished in a single transaction or contemplated through a series of transactions as set forth in Section 12 of the Partial Requirements Capacity and Energy Agreement and the Transmission Agreement.

“Member*” shall mean a PRM whose load is not assigned to the SWTC metered subsystem of the Western Area Lower Colorado Balancing Authority in the Desert Southwest Region.

“Member* CA” shall mean a PRM whose load is assigned to the SWTC metered subsystem of the Western Area Lower Colorado Balancing Authority in the Desert Southwest Region.

“Member’s Distribution Service Area” shall mean the geographical electric service territory of a Class A Member as certificated by the ACC, the California Public Utility Commission or the New Mexico Public Utility Commission, as applicable, to supply distribution service as well as all other territory so served by such Class A Member pursuant to applicable Law, or any inter-utility border agreement.

“Merchant Purchase(s)” shall mean a wholesale purchase of capacity and/or energy (pursuant to Section 11 herein) for periods occurring in the next twelve months and for a duration not to exceed twelve consecutive months (including all renewal periods) arranged for and entered into by AEPCO as operator of Pooled Resources to: (i) minimize the cost of energy production from Pooled Resources, and (ii) displace energy from Pooled Resources of higher Pool Price.

“Merchant Sale(s)” shall mean a wholesale sale of capacity and/or energy (pursuant to Section 11 herein) from Surplus Resources for periods occurring in the next twelve months and for a duration not to exceed twelve consecutive months (including all renewal periods) arranged for and entered into by AEPCO as operator of Pooled Resources to use Surplus Resources for the economic benefit of the Pool Resource Owners.

“Minimum Other Capacity” shall mean the capacity from Available Other Capacity that must be operated from time to time to maintain system reliability or for other reasons as described in Section 4.2 of Schedule B to the Partial Requirements Capacity and Energy Agreements.

“Minor Resource Modification” shall mean an addition, improvement, repair or modification to an AEPCO Generating Resource or the modification or extension of an AEPCO Power Purchase Resource for five years or less, undertaken by AEPCO in its sole discretion, which will not: (i) increase of greater than ten percent the capacity of the AEPCO Resource being modified; (ii) result in an increase of greater than five percent in AEPCO’s Revenue Requirement From AEPCO’s Class A Members upon the operation of such addition, improvement, repair and modification or extension, as the case may be; or, (iii) extend the term of any Existing Wholesale Power Contract or Partial Requirements Capacity and Energy Agreement.

“Must-Pool Load(s)” shall mean those loads of AEPCO, CSP and MEC which Section 3 herein requires be served from the Resource Pool.

“Must-Pool Resources” shall mean AEPCO Resources and those Resources of CSP and the Partial Requirements Member, which are required to be included in the Resource Pool.

“Native Load” shall mean (i) for AEPCO, the electric load of wholesale power customers of AEPCO on whose behalf AEPCO, by Law, tariff or contract, has undertaken an obligation to construct, or otherwise obtain, reliably operate and provide AEPCO Resources (including Purchase Power Resources of AEPCO) to meet the electric requirements of such customers and shall include, but not be limited to, AEPCO Delivered Load, (ii) for TRANSCO, “Native Load” shall mean the electric loads of the TTS customers on whose behalf TRANSCO, by Law, tariff or contract (including as TTS successor to AEPCO) has undertaken an obligation to construct and operate the TTS and shall include, but not be limited to, AEPCO Delivered Load, and (iii) for a Member, “Native Load” shall mean the electric load of the customers of a Member to whom such Member sells power and/or energy and on whose behalf the Member, by Law, tariff, or contract, has undertaken an obligation to construct, or otherwise obtain, and reliably operate the Member’s system to meet the power supply requirements of such customers.

“Near Term” shall mean” shall mean with respect to a forecast deficiency of AEPCO Resources with respect to AEPCO Total Load, a time period not to exceed the subsequent two calendar years.

“NERC” shall mean the North American Electric Reliability Council, or entity or agency succeeding to its powers and functions.

“Net Utility Plant” shall mean total utility plant less accumulated depreciation as computed consistent with Accounting Requirements.

“Network Integration Transmission Service” shall described in Part III of the TRANSCO Tariff.

“Network Loads” shall have the meaning set forth in Section 1 of the TRANSCO Tariff. The Delivery Points of the Network Loads of Member served pursuant to this Agreement are set forth in Schedule C hereto.

“Network Loss Factor” shall mean the adjustment factor for transmission losses assigned for network service under the Southwest Transmission Cooperative, Inc. Open Access Transmission Tariff as in effect from time to time.

“Network Resources” shall have the meaning set forth in Section 1 of the TRANSCO Tariff.

“Network Service Agreement” shall mean the Network Service Agreement by and between TRANSCO, AEPCO and the All Requirements Members, substantially in the form attached as Exhibit B-1 to the Member Agreement.

"Nighttime Hours" shall mean the eight (8) hours beginning Hour Ending 2300 of one day continuing through Hour Ending 0600 of the following day, Pacific Prevailing Time.

"Non-Base Economy Purchase" shall mean any purchase of energy by AEPCO from a third party that is not a Base Economy Purchase which is made at a lower average energy rate over the purchase period than that which would be associated with energy dispatched from Available Other Capacity or Available S&G PPA Capacity during such period, and which is made in lieu of dispatching energy from such capacity.

"Non-Generation Assets" shall mean as determined in accordance with Accounting Requirements, all assets of AEPCO of every kind, description, and location which shall be acquired by TRANSCO from AEPCO, as of the Closing Date, which are set forth in Schedule 1 to the Restructuring Agreement.

"Non-Pool Loads" shall mean those loads of a Partial Requirements Member or CSP or applicable portions of such loads which are not included in Pooled Loads.

"Non-Pool Resource" shall mean any Resource obtained by a Partial Requirements Member or CSP and which is not included in the Resource Pool.

"O&M" shall mean the general accounting term used to describe activities and expenses involved with the use, operation, maintenance and repair of a cooperative's plant and facilities including expenses associated with activities intended to prevent or remedy an impending or actual breakdown of those facilities. The term O&M does not include the enlargement or improvement of the property owned or leased and operated by a cooperative nor does it include the replacement of retirement units.

"O&M Charge" shall mean the charge computed in accordance with 5.3 of a Partial Requirements Capacity and Energy Agreement which recovers the share of a Partial Requirements Member of certain fixed costs and expenses of AEPCO.

"Off-Peak Hours" shall mean those hours defined by the Western Systems Coordinating Council to represent off-peak load periods, which for each day consist of the eight hours of the hour ending at 2300 through hour ending at 0600, Mountain Standard Time, and the remaining hours of each Sunday and of each of six holidays (New Years Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas Day).

"Operating Committee" shall mean the standing committee(s) established in the Partial Requirements Capacity and Energy Agreement and assigned by the parties thereto to deal on a prompt and orderly basis with certain technical and operating issues that may arise in connection with system development or operations.

"Operating Reserve Purchases" shall mean any purchases of operating reserve capacity to avoid curtailing any energy from any more economical AEPCO Resource that would otherwise be required to provide such operating reserve capacity.

"Optional Pool Resources" shall mean those Resources which a party may commit to the Resource Pool.

"Order No. 888" shall mean that certain FERC order Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities, Order No. 888, 61 Fed. Reg. 21,540 (1996), FERC Stats. & Regs. para. 31,036 (1996), order on reh'g, Order No. 888-A, 62 Fed. Reg. 12,274 (1997), FERC Stats. & Regs. para. 31,048 (1997), order on reh'g, Order No. 888-B, 81 FERC para. 61,248 (1997), order on reh'g, Order No. 888-C, 82 FERC para. 61,046 (1998).

"Order No. 889" shall mean that certain FERC order Open Access Same-Time Information System and Standards of Conduct, Order No. 889, 61 Fed. Reg. 21,737 (1996), FERC Stats. & Regs. para. 31,035 (1996), order on reh'g, Order No. 889-A, 62 Fed. Reg. 12,484 (1997), FERC Stats. & Regs. para. 31,049 (1997), order on reh'g, Order No. 889-B, 81 FERC 61,253 (1997).

"Other Adjustor Per Unit Cost" shall mean, for a billing period for each Billing Unit Entity, the Other Fuel Adjustor Cost divided by the Total Other Billing Energy for the same Billing Unit Entity for the same billing period.

"Other Average Energy Rate" shall mean, for a billing period for a Billing Unit Entity, the rate obtained by dividing its Total Other Energy Cost of the billing period by its Other Billing Energy for the same period.

"Other Billing Energy" shall mean, for a Billing Unit Entity, the energy from Available Other Capacity assigned and allocated in each hour pursuant to the Billing Unit Program to its Other Schedule or load, accumulated for a billing period.

"Other Economy Sales" shall mean, for a billing period, the energy from dispatched Other Capacity and from Post-Transfer S&G And Supplemental Capacity assigned in each hour to each Billing Unit Entity pursuant to the Billing Unit Program as Third Party Economy Sales.

"Other Economy Sales Credit" shall mean, for each Billing Unit Entity, the product of the Other Economy Energy Sales Revenue of Daytime Hours and Nighttime Hours, as applicable, multiplied by the ratio of (i) for each of separately accumulated Daytime Hours and Nighttime Hours of the billing period, the Post-Transfer S&G And Supplemental Capacity energy in the case of a Billing Unit Entity with an ACP in such capacity, the Other Schedule in the case of a Member*, and in the case of CARM or a Member* CA, its load's use of Available Other Capacity, to (ii) the total of such Post-Transfer S&G And Supplemental Capacity, such Other Schedules and such uses of Available Other Capacity by all Billing Unit Entities for the same time periods.

"Other Economy Sales Revenue" shall mean the difference obtained by subtracting the Base Economy Sales Credit from the revenue of all Third Party Economy Sales during a billing period.

"Other Energy Cost" shall mean, for a billing period for each Billing Unit Entity, the costs of purchased energy and natural gas fuel and oil fuel expensed during that billing period, related to the operation and dispatch of Available Other Capacity during that billing period, as recorded in Accounts described in Section 4.0 of Exhibit A-2 to Rate Schedule A and reported to RUS by AEPCO for that billing period, including purchased energy expenses, wheeling charges and costs of any transmission losses related to Other Economy Purchases and Replacement Purchases for Base Resources and Other Resources as incurred during that billing period.

"Other Energy Mismatch" shall mean, for a billing period, the accumulated net difference in energy obtained from subtracting (i) the total energy from Available Other Capacity, Available Supplemental Capacity, and Available S&G PPA Capacity assigned and allocated in the billing period in accordance with the Billing Unit Program, from (ii) the energy actually produced from Available Other Capacity, Available Supplemental Capacity, and Available S&G PPA Capacity during that billing period.

"Other Energy Mismatch Credit" shall mean, for a billing period, the product of: (i) the absolute value of any negative value of Other Energy Mismatch for the billing period, multiplied by (ii) the Gas Energy Rate for the billing period.

"Other Energy Mismatch Charge" shall mean, for a billing period, the product of: (i) any positive value of Other Energy Mismatch for the billing period, multiplied by (ii) the Gas Energy Rate for the billing period.

"Other Energy Rate" shall mean, for each Billing Unit Entity, the rate applicable to that Billing Unit Entity's use of energy from Available Other Capacity as set forth in Exhibit A-1 to Rate Schedule A.

"Other FPPCA" shall mean, Fuel and Purchase Power Cost Adjustor determined for a FPPCA Period for Other Resources, Supplemental Purchase as made for each Billing Unit Entity, and S&G PPA for each Billing Unit Entity having an ACP interest in S&G PPA.

"Other Fuel Adjustor Cost" shall mean, for a billing period for each Billing Unit Entity, the sum of the Total Other Energy Cost, Other Transmission Wheeling Cost, plus, for those Billing Unit Entities with interests in S&G PPA Capacity or Supplemental Capacity, Supplemental Demand Charge, Supplemental Wheeling Cost, S&G PPA Purchase Demand Charge and S&G PPA Wheeling Cost.

"Other Fuel Bank" shall mean, for a billing period for each Billing Unit Entity, the accumulation of Other Over or Under Collections.

"Other Incremental Unit Cost" shall mean, for a billing period for each Billing Unit Entity, the difference obtained by subtracting (i) the sum of (a) Other Power Cost Adjustor Base plus (b) Other Power Cost Adjustor Rate from (ii) Other Adjustor Per Unit Cost, for such Billing Unit Entity for such period.

"Other Over or Under Collection" shall mean, for a billing period for each Billing Unit Entity, the product of (i) Other Incremental Unit Cost, multiplied by (ii) Total Other Billing Energy, for such Billing Unit Entity for such period.

"Other Power Cost Adjustor Base" shall mean the Power Cost Adjustor Base for Other Resources as set forth in the Tariff.

"Other Power Cost Adjustor Rate" shall mean the Power Cost Adjustor Rate for Other Resources as set forth in the Tariff.

"Other Resources" shall mean all gas-fired combustion turbine and gas-fired steam Generating Resources that are Existing Resources located at Apache Generating Station, in which each Class A Member has an ACP, which include GT-1, Steam 1, GT-2, GT-3 and GT-4.

"Other Schedule" shall mean, for each Member*, its Pre-Schedules and Real-Time Schedules provided to AEPCO by Member*'s Scheduling Agent pertaining to such Member*'s use of its Available Other Capacity and, separately identified, of its Available S&G PPA Capacity, if any, as such Pre-Schedules and Real-Time Schedules are determined consistent with Schedule B to its Partial Requirements Capacity and Energy Agreement.

"Other Transmission Wheeling Cost" shall mean, for each Billing Unit Entity for a billing period, the product of (i) the costs recorded in RUS Uniform System of Accounts 565 Transmission of Electricity by Others or its successor, and allocated to Other Resources, for the same billing period, multiplied by (ii) the Billing Unit Entity's ACP in Existing Resources.

"Partial Requirements Member" shall mean MEC, SSVEC, TRICO or any other Class A Member of AEPCO that executes and delivers a Partial Requirements Capacity and Energy Agreement.

"Peak Hours" shall mean all hours of each day which are not Off-Peak Hours.

"Performance Default" shall meant the default by either party to a Partial Requirements Capacity and Energy Agreement, a Transmission Agreement, a Network Service Agreement, or a Joint Marketing Agreement, whereby, as provided by the terms of each such Agreement, such party fails to comply, after any notice of such failure and opportunity to cure, with any of the respective terms, conditions, obligations or covenants of such Agreement.

"Person" shall mean an individual, partnership, association, limited liability company, corporation, membership corporation, business trust, joint stock company, trust, cooperative, unincorporated organization, joint venture, or other entity.

"PGR Purchase Agreement" shall mean the Power Purchase Agreement between Panda Gila River, L.P., and AEPCO, dated April 15, 2003, as amended.

"Planning Contract Member" shall mean a Partial Requirements Member which has contracted separately from the Partial Requirements Capacity and Energy Agreement to obtain Planning Services from AEPCO.

"Planning Services" shall mean bulk power supply planning and Future Resource procurement services.

"Pool Price" shall mean the price, in mills/kWh, established for a Pooled Resource pursuant to Appendix A-2 of the Resource Pooling Policies.

"Pool Resource Owner" shall mean a Party that has committed Resources to the Resource Pool pursuant to Section 4 herein.

"Pooled Loads" shall mean the aggregate total electric load and sales of the parties that are to be served by Pooled Resources, including distribution losses and not including reserves or transmission losses.

"Pooled Resources" shall mean those Resources which have been committed to the Resource Pool.

"Possible Selling Party" shall have the meaning set forth in Section 10.1 of the Resource Integration Agreement.

"Post-Base Load" shall mean, for CARM or a Member* CA, the load of such Billing Unit Entity that remains after assignment of such Billing Unit Entity's Post-S&G And Supplemental Load to that Billing Unit Entity's Available Base Capacity.

"Post-Base Other Schedule" shall mean, for a Member*, the portion of the Total Schedule of such Member* that remains after assignment of such Member*'s Base Schedule to that Member*'s Available Base Capacity.

"Post-Base Transfer Load" shall mean, for CARM or a Member* CA, any load of such Billing Unit Entity that remains after assignment of such Billing Unit Entity's Post-S&G And Supplemental Transfer Load to Base Transfers of other Billing Unit Entities.

"Post-Base Transfer Other Schedule" shall mean, for Member*, any Post-S&G And Supplemental Other Schedule that remains after assignment of such Member*'s Post S&G And Supplemental Transfer Other Schedule to Base Transfers from other Billing Unit Entities.

"Post-Sales Base Capacity" shall mean, for each Billing Unit Entity, any Post Transfer Base Capacity that remains after its allocation to Base Economy Sales.

"Post-S&G And Supplemental Load" shall mean, for CARM or a Member* CA, the load of such Billing Unit Entity that remains after assignment of such Billing Unit Entity's load to that Billing Unit Entity's allocated share of S&G PPA Capacity and Supplemental Capacity.

"Post-S&G And Supplemental Transfer Load" shall mean, for CARM or a Member* CA, the load of such Billing Unit Entity that remains after assignment of S&G And Supplemental Transfers from another Billing Unit Entity to that Billing Unit Entity's Post-Base Load.

"Post-S&G And Supplemental Transfer Other Schedule" shall mean, for Member*, the Post-Base Other Schedule that remains after allocation of S&G And Supplemental Transfers from CARM or a Member* CA.

"Post-Transfer Base Capacity" shall mean, for a Billing Unit Entity, each hour's Excess Base Capacity remaining after energy from its Excess Base Capacity has been assigned as Base Transfers.

"Post-Transfer Load" shall mean, for CARM or a Member* CA, the load of such Billing Unit Entity that remains after assignment of such Billing Unit Entity's Post-Base Load to that Billing Unit Entity's allocated share of S&G And Supplemental Transfers and of Base Transfers from other Billing Unit Entities.

"Post-Transfer Other Schedule" shall mean, for a Member*, the Total Schedule of such Member* that remains after assignment of such Member*'s allocated share of S&G And Supplemental Transfers from other Billing Unit Entities to its Post-Base Other Schedule, and then assignment of such Member*s allocated share of Base Transfers from other Billing Unit Entities to that Member*'s Post-S&G And Supplemental Transfer Other Schedule.

"Post-Transfer S&G And Supplemental Capacity" shall mean, for CARM or Member* CA having an ACP in S&G PPA and/or an interest in Supplemental Purchase, each hour's Excess S&G And Supplemental Capacity remaining after energy from its Excess S&G And Supplemental Capacity has been assigned as an S&G And Supplemental Transfer, accumulated for a billing period separately for Daytime Hours and Nighttime Hours.

"Power Factor" shall mean the cosine of the phase angle between the voltage and the current. Power Factor can be lagging or leading indicating whether the current is lagging or leading the applied voltage.

"Power Factor Adjustment" shall have the meaning set forth in Section 2.2 of Rate Schedule A.

"Power Purchase Resource" shall mean capacity and energy or energy purchased by a party under a contract with a term greater than one year, including any such capacity and energy or energy purchased or acquired pursuant to (i) the Public Utility Regulatory Policies Act of 1978, as it may be amended from time to time, or (ii) the Environmental Portfolio Standard set forth in A.A.C. R14-2-1618, as it may be amended from time to time, as adopted by the Arizona Corporation Commission.

"Power Sale(s)" shall mean a wholesale sale of capacity or energy for a term of one year or more. Power Sales do not include Retail Sales.

"Power Sales Load" shall mean the demand and energy requirements of the load associated with Power Sales Resource(s).

“Power Sales Resource” shall mean a sale of capacity and energy from Existing Resources made by AEPCO with a contract term greater than one year (other than sales to Class A Members pursuant to a Wholesale Power Contract and the Partial Requirements Capacity and Energy Agreement) including sales to Class B and Class C Members of AEPCO.

“Power Sales Resource Demand Revenues” shall mean, for a billing period for each Billing Unit Entity, the product of (i) the demand-related revenue received pursuant to Power Sales Resource contracts as recorded in RUS Uniform System of Account 447 Sales for Resale, or its successor, for that billing period, multiplied by (ii) the Billing Unit Entity’s ACP in Existing Resources.

“Power Sales Resource Energy Revenue” shall mean, for a billing period, the energy-related revenue received pursuant to Power Sales Resource contracts as recorded in RUS Uniform System of Account 447 Sales for Resale or its successor, for that billing period

“Power Sales Resource System Facility” shall mean any System Facility or portion thereof that is required to enable delivery of capacity and energy to Class A Members from expired Power Sales Resources which existed as of the Effective Date.

“Pre-Closing” shall mean the execution and delivery of all documents that are a condition to Closing, as further described in the Closing Memorandum.

“Pre-Schedule” shall mean a Schedule submitted by a Scheduling Agent to AEPCO for the use of Resources for the following Scheduling Day as defined by WECC.

“Pre-Schedule Day” shall mean the day on which a Pre-Schedule must be submitted for the next Scheduling Day.

“PRM” shall mean a Partial Requirements Member.

“PRM*” shall mean a term in definitions which may be replaced with the name of a PRM so that the definition would apply only to the specified PRM (see Section 3.8 above).

“PRM* AEPCO Load” shall mean the demand and energy requirements, including distribution losses but not including reserves or transmission losses, of loads located within the Member’s Distribution Service Area (or served from line extensions therefrom) for which PRM* purchases capacity and energy pursuant to the PRM* Partial Requirements Capacity and Energy Agreement, but shall not include PRM* Wheeling Load. Such demand and energy requirements are included within PRM* Metered kW and PRM* Metered kWh. The demand component of PRM* AEPCO Load numerically consists of the coincident aggregate, at a specific time, of: (i) PRM* Metered kW; less (ii) kW of PRM* Wheeling Load; less (iii) kW of Member JMP Load of PRM*; less (iv) kW of CSP JMP Load of PRM*; (v) less Kw of PRM* Internal Load. The energy component of PRM* AEPCO Load numerically consists of the aggregate during a specific time interval of: (i) PRM* Metered kWh; less (ii) kWh of PRM* Wheeling Load; less (iii) kWh of Member JMP Load of PRM*; less (iv) kWh of CSP JMP Load of PRM*; less, (v) kWh of PRM* Internal Load.

"PRM* AEPCO Sales" shall mean the demand and associated energy requirements, including any distribution losses and not including reserves or transmission losses, of those sales of PRM* to wholesale buyers or to end use loads which are external to Member's Distribution Service Area of PRM* for which PRM* purchases capacity and energy pursuant to the PRM* Partial Requirements Capacity and Energy Agreement. The demand and energy requirements of PRM* AEPCO Sales shall be metered (or determined) as agreed between PRM* and TRANSCO, on the basis of actual capacity and energy supplied at the applicable points of delivery.

"PRM* External Load" shall mean the demand and energy requirements, including distribution losses but not including reserves or transmission losses, of loads located external to the Member's Distribution Service Area of PRM* (and not served from line extensions therefrom) for which PRM* sells capacity and energy from PRM* Resources. The demand and energy requirements of PRM* External Load are not included in PRM* Metered kW and Member* Metered kWh, respectively.

"PRM* Internal Load" shall mean the demand and energy requirements, including distribution losses but not including reserves or transmission losses, of loads located within the Member's Distribution Service Area of PRM* (or served from line extensions therefrom) for which Member* sells capacity and energy from PRM* Resources. The demand and energy requirements of PRM* Internal Load are included in PRM* Metered kW and PRM* Metered kWh, respectively.

"PRM* Metered kW" shall have the meaning set forth in Section 1 of the PRM* Partial Requirements Capacity and Energy Agreement.

"PRM* Metered kWh " shall have the meaning set forth in Section 1 of the PRM* Partial Requirements Capacity and Energy Agreement.

"PRM* Partial Requirements Capacity and Energy Agreement" shall mean the Partial Requirements Capacity and Energy Agreement, by and between AEPCO and PRM*.
"PRM* Resource(s)" shall mean a Resource of a Partial Requirements Member of AEPCO; PRM* Resource does not include the capacity and energy purchased from AEPCO under the PRM* Partial Requirements Capacity and Energy Agreement, or purchased by AEPCO under separate contract.

"PRM* Transmission Agreement" shall mean the Transmission Agreement by and between TRANSCO and PRM* for the purposes of PRM* Transmission Service.

"PRM* Transmission Service" shall mean Network Integration Transmission Service and all Ancillary Services used to deliver the AC and associated energy of PRM* to PRM* AEPCO Load.

"PRM* Wheeling Load" shall mean the demand and energy requirements, including distribution losses but not including reserves or transmission losses, of loads located within Member's Distribution Service Area of PRM* (or served from line extensions therefrom), which are supplied by capacity and energy from third parties (and not from Member Resources or the AC of PRM*) and for which PRM* provides delivery services over its distribution system. The demand and energy requirements of PRM* Wheeling Load are included within PR* Metered kW and PRM* Metered kWh, respectively.

"Project Approval" shall mean the approval required by Section 3.4.5 of the Partial Requirements Capacity and Energy Agreement for a Resource Modification.

"Proposal and Analysis" shall have the meaning set forth in Section 3.4.3 of the Partial Requirements Capacity and Energy Agreement.

"Prudent Utility Practice" shall mean any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts that, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety, and expedition. Prudent Utility Practice is not intended to be limited to the optimum practice, method, or act, to the exclusion of all others, but rather to include a spectrum of possible practices, methods, or acts generally acceptable in the region that could be expected to accomplish the desired result at a reasonable cost consistent with reliability, safety and expedition in light of the circumstances.

"Purchasing Party" shall have the meaning set forth in Section 10.1 of the Resource Integration Agreement.

"Rate Schedule A" shall mean the Schedule A to the Partial Requirements Capacity and Energy Agreements or to an Existing Wholesale Power Contract.

"REAct" shall mean the Rural Electrification Act of 1936.

"Real-Time Schedule" shall mean any Schedule submitted by a Scheduling Agent to AEPCO that changes a previously submitted Tag or that requires a new Tag to be created for a Future Scheduling Hour of the current operating day.

"Receipt Point" shall mean the interconnection between the TTS and the transmission, sub-transmission, generating resource or distribution facilities at which TRANSCO is to accept capacity or energy from AEPCO Resources for delivery pursuant to the Transmission Agreement or Network Service Agreement, and from which TRANSCO provides transmission service to the Delivery Point.

"Reliability System Facilities" shall mean System Facilities and/or improvements that are constructed and installed or acquired by TRANSCO to enhance or maintain the reliability of the TTS as required by the transmission system performance criteria of the NERC, as applied within the WECC, consistent with Prudent Utility Practice.

"Remaining Base Energy Cost" shall mean, for a billing period, the total of Remaining Coal Energy Cost, Hydro Energy Charge, Base Economy Purchase Cost and Power Sales Resource Energy Revenue, for the same billing period as allocated to each Billing Unit Entity based on the ratio of (i) the Billing Unit Entity's Base Billing Energy for that billing period to (ii) the total of all Billing Unit Entities' Base Billing Energy for the same billing period.

"Remaining Coal Energy Cost" shall mean, for a billing period, Coal Energy Cost for the billing period less the sum of Base Transfer Sales Credits and Base Economy Sales Credits for all Billing Unit Entities for the same billing period.

"Remaining Equity Investment of TRANSCO" shall mean that portion of the installed cost of a System Facility or Direct Assignment Facility financed by an equity contribution of TRANSCO (with interest accrued thereon) which remains undepreciated on the Last Service Date (or the date of closing of a transaction between the parties involving the disposition of a Direct Assignment Facility).

"Remaining Indebtedness of TRANSCO" shall mean the principal balance remaining unamortized as of the Last Service Date (or the Date of Closing of a transaction between the Parties involving the disposition of a Direct Assignment Facility) of that portion of the installed cost of a System Facility or Direct Assignment Facility financed by TRANSCO debt, with interest accrued thereon, which remains unamortized on the Last Service Date or termination or exercise of an option to purchase the Direct Assignment Facilities serving SSVEC (plus any actual prepayment penalties incurred from the prepayment of such debt).

"Replacement Purchase" shall mean any purchase of energy made to replace energy that is not available from any AEPCO Resource due to forced outage, scheduled outage or deration of such AEPCO Resource.

"Required Modification" shall have the meaning set forth in Section 3.3.2 of the Partial Requirements Capacity and Energy Agreement.
"Resource" shall mean either a Generating Resource or Power Purchase Resource.

"Resource Acquisition" shall mean the performance of analyses of Resource needs or Resource sales proposals, the recommendation of a Power Purchase Resource or Generating Resource, and the negotiation of and acquisition for AEPCO of a Resource.

"Resource Deficiency" shall mean a deficiency in AEPCO Resources available to serve Class A Members and Power Sales Loads.

"Resource Facility" shall mean any System Facility, or portion thereof, or Direct Assignment Facility required to interconnect with and to deliver to the TTS the capacity and energy of any Resource Modification or Future Resource in which SSVEC has all ACP.

"Resource Forecast Period" shall mean the period beginning January 1 of the next calendar year (following the year in which the forecast is prepared) and ending upon the earlier of:(a)the twentieth anniversary thereafter or (b) the last service date of a Class A Member's Wholesale Power Contract, as set forth in the Resource Planning Policies.

"Resource Integration Agreement" shall mean the multi-party agreement by and between CSP, TRANSCO, AEPCO and MEC and dated July 2, 2001, as amended to include SSVEC and TRICO as parties.

"Resource Modification" shall mean any addition, improvement, repair or modification to a Generating Resource or the modification or extension of the term of an existing Power Purchase Resource made by AEPCO which would: (i) increase the capacity of the AEPCO Resource by more than ten percent; or (ii) result in an increase of more than five percent in AEPCO's Revenue Requirement upon the operation of such addition, improvement, repair and modification, or extension, as the case may be, or (iii) require an extension of the term of an Existing Wholesale Power Contract or Partial Requirements Capacity and Energy Agreement. A Resource Modification shall not be construed to include a Minor Resource Modification.

"Resource Operation Policies" shall mean the resource operation policies set forth in Schedule B to the Resource Integration Agreement and Exhibit B2 to Schedule B of the Partial Requirements Capacity and Energy Agreement.

"Resource Planning" shall mean the process used to identify a deficiency in the amount of existing Resources needed to reliably meet anticipated load requirements (including reserves). Resource Planning includes a review of alternative Resources and the selection of the preferred Resources to be constructed or acquired to meet the deficiency.

"Resource Planning Policies" shall mean the resource planning policies set forth in resource planning and acquisition documents.

"Resource Pool" shall mean the capacity and energy pool which integrates the electric capacity and associated energy of AEPCO Resources with Resources owned or contracted for by the Partial Requirements Members and CSP, which the Partial Requirements Member or CSP is required to include or has designated for inclusion in such pool.

"Resource Pool Operation" shall mean that load and resource integration service provided by AEPCO.

"Resource Pooling Policies" shall mean the resource pooling policies set forth in Schedule A of the Resource Integration Agreement.

"Resource Pre-Schedule" shall mean a schedule of energy needed from the Resources of the Resource Pool to meet the aggregate of the Pooled Loads made on a least energy cost and a day-ahead basis.

"Restructuring Agreement" shall mean the Restructuring Agreement as executed and delivered by and among AEPCO, TRANSCO and CSP, dated the 11th day of October 2000.

"Retail Sales" shall mean sales arranged or made by CSP in the competitive retail electric market, including sales at retail from Surplus AEPCO Resources. Retail Sales do not include Power Sales.

"Revenue Shortfall" shall mean the failure of a cooperative to receive sufficient revenue to cover its revenue requirement.

"Rights of Way" shall mean the various rights of way and easements held by TRANSCO from time to time.

"RUS" shall mean the Rural Utilities Service, as successor-in-interest to the Rural Electrification Administration, which is an agency of the United States Department of Agriculture, or any agency of the Government succeeding to its powers and functions

"S&G And Supplemental Sales Credit" shall mean, for a billing period for each Billing Unit Entity with an ACP in S&G PPA or an interest in Supplemental Purchase, the product of the Economy Purchase Rate multiplied by S&G And Supplemental Transfer, for such Billing Unit Entity for such billing period.

"S&G And Supplemental Transfer" shall mean, for a Billing Unit Entity with an ACP in S&G PPA and/or an interest in Supplemental Purchase, energy from its Excess S&G And Supplemental Capacity that has been assigned and allocated to another Billing Unit Entity in an hour pursuant to the Billing Unit Program, accumulated for a billing period separately for Daytime Hours and Nighttime Hours.

"S&G And Supplemental Transfer Billing Energy" shall mean, for a Billing Unit Entity, energy from the Excess S&G And Supplemental Capacity of another Billing Unit Entity with an ACP in S&G PPA and/or an interest in Supplemental Purchase that has been assigned and allocated to the Billing Unit Entity in an hour pursuant to the Billing Unit Program as a S&G And Supplemental Transfer from the other Billing Unit Entity, accumulated for a billing period.

"S&G And Supplemental Transfer Purchase Cost" shall mean, for a billing period for each Billing Unit Entity that is assigned an S&G And Supplemental Transfer pursuant to the Billing Unit Program, the product of the Economy Purchase Rate multiplied by S&G And Supplemental Transfer Billing Energy, for such Billing Unit Entity for such billing period.

"S&G PPA" shall mean either or both of the following purchase power agreements: (i) the Confirmation Agreement dated August 17, 2004, between AEPCO and South Point Energy Center, LLC (South Point), by which AEPCO purchases between 25 MW and 55 MW of electric capacity and associated energy in Daylight Hours of May through October of each year from 2008 through 2014; and (ii) the Confirmation Agreement dated August 19, 2004, between AEPCO and Griffith Energy, LLC, as currently assigned pursuant to Assignment and Consent Agreement dated March 14, 2008, by which AEPCO purchases 25 MW of electric capacity and associated energy in WECC Peak Hours of May through October of each year from 2008 through 2014.

"S&G PPA Billing Energy" shall mean, for a billing period for a Billing Unit Entity with an ACP in S&G PPA, the energy from its Available S&G PPA Capacity assigned and allocated in each hour pursuant to the Billing Unit Program to its load and its S&G PPA Transfers, accumulated for a billing period.

"S&G PPA Capacity" shall mean capacity from S&G PPA.

"S&G PPA Demand Charge" shall mean, for a billing period for each Billing Unit Entity with an ACP in S&G PPA, the product of (i) the total cost incurred by AEPCO for capacity from S&G PPA during the billing period multiplied by (ii) the Billing Unit Entity's ACP in S&G PPA.

"S&G PPA Energy Charge" shall mean, for a billing period for each Billing Unit Entity with an ACP in S&G PPA, the product of (i) the total cost incurred by AEPCO for all energy from S&G PPA during the billing period multiplied by (ii) the Billing Unit Entity's ACP in S&G PPA.

"S&G PPA Schedule" shall mean, for a Member* with an ACP in S&G PPA, its Pre-Schedules and Real-Time Schedules provided to AEPCO by its Scheduling Agent pertaining to its use of its Available S&G PPA Capacity.

"S&G PPA Wheeling Cost" shall mean, for a billing period for each Billing Unit Entity with an ACP in S&G PPA, the product of (i) the cost incurred by AEPCO for wheeling energy from S&G PPA during the billing period multiplied by (ii) the Billing Unit Entity's ACP in S&G PPA.

"Schedule" shall mean for each Member*, any of its Base Schedule, its Other Schedule, and, if applicable, its S&G PPA Schedule.

"Scheduled Day" shall mean the Scheduling Day, as defined by WECC, for which a Pre-Schedule has been submitted.

"Scheduling Agent" shall mean the entity designated by a Member* to provide Pre-Schedules and Real-Time Schedules to AEPCO for such Member*'s hourly use of its AC in AEPCO Resources.

"Scheduling Party" shall mean the owner of an Optional Pool Resource that qualifies to be a Pooled Resource but is not included in the Resource Pool and which is separately scheduled by such owner.

"SEC" shall mean the Securities and Exchange Commission, or any agency of the Government succeeding to its powers and functions.

"Separation of Functions and Standards of Conduct" shall mean the Separation of Functions and Standards of Conduct referenced in Section 15 of the Resource Integration Agreement and set forth as Schedule F attached thereto.

"Service Agreement" shall mean the agreement entered into by a transmission customer or network customer and TRANSCO for transmission service or network service under Part II or Part III respectively, of the TRANSCO Tariff.

"Service Agreement(s) for Firm and Non-Firm Transmission and Ancillary Services" shall mean any Service Agreement by and between TRANSCO and AEPCO for transmission service pursuant to Part II of the TRANSCO tariff, substantially in the form of agreement attached to the TRANSCO Tariff.

"Short Term" shall mean with respect to a forecast deficiency of AEPCO Resources with respect to AEPCO Total Load, a time period greater than the subsequent two calendar years but lasting less than five calendar years.

"Southwest" shall mean TRANSCO.

"SSVEC" shall mean Sulphur Springs Valley Electric Cooperative, Inc., an electric cooperative non-profit membership corporation organized and existing under the Laws of the State of Arizona.

"Staffing Agreement" shall mean each of the individual staffing agreements whereby CSP shall furnish personnel services to TRANSCO or AEPCO, respectively.

"Standards of Conduct" shall mean the Separation of Functions and Standards of Conduct as set forth as Schedule F to the Resource Integration Agreement.

"Stranded Costs" shall mean any actual charge or cost (including any transmission or distribution surcharges, fee, competition transition charge, wires charge, adjustment, rate, system benefit charge, regulatory charge, regulatory asset surcharge, exit fee or any other mechanism or systematic recovery program approved for use for the recovery of stranded investments) that are permitted by the ACC pursuant to the ACC Electric Competition Rules, A.A.C. R14-2-1601, et seq. or successor rule, or otherwise assessed or levied in order to recover the expenses and liabilities associated with stranded investments including without limitation, regulatory assets, or costs associated with the introduction of competition in the retail sales of electric energy and capacity.

"Supplemental Billing Energy" shall mean, for a billing period for a Billing Unit Entity with an interest in Supplemental Purchase, the energy from its Available Supplemental Capacity assigned and allocated in each hour pursuant to the Billing Unit Program to its load and its Supplemental Transfers, accumulated for a billing period.

"Supplemental Capacity" shall mean capacity from Supplemental Purchase.

"Supplemental Demand Charge" shall mean, for a billing period for each Billing Unit Entity with an interest in Supplemental Purchase, the product of (i) the total cost incurred by AEPCO for capacity from Supplemental Purchase during the billing period multiplied by (ii) the Billing Unit Entity's ACP in Supplemental Purchase.

"Supplemental Energy Charge" shall mean, for a billing period for each Billing Unit Entity with an interest in Supplemental Purchase, the product of (i) the total cost incurred by AEPCO for all energy from Supplemental Purchase during the billing period multiplied by (ii) the Billing Unit Entity's ACP in the Supplemental Purchase

"Supplemental Energy Intrachange" shall have the meaning set forth in Section 6 of the Resource Pooling Policies.

"Supplemental Purchase" shall mean, in a billing period, any purchase of firm energy made by AEPCO for a period of less than a year to serve load of CARM or a Member* CA Planning Contract Member in excess of CARM's or such Planning Contract Member's ACP shares of capacity of S&G PPA and Existing Resources.

"Supplemental Purchase Cost" shall mean, for a billing period, the total cost incurred by AEPCO (including transmission expenses, including losses, incurred in delivery from the source of such purchase to an SWTC Point of Receipt, if any) for all Supplemental Purchases during the billing period.

"Supplemental Wheeling Cost" shall mean, for a billing period for each Billing Unit Entity with an interest in Supplemental Purchase, the product of (i) the cost incurred by AEPCO for wheeling energy from Supplemental Purchase during the billing period multiplied by (ii) the Billing Unit Entity's ACP in Supplemental Purchase.

"Surplus AEPCO Resource(s)" shall mean AEPCO Resources available and not necessary or used to serve AEPCO Total Load.

"Surplus Resource" shall mean a Pooled Resource(s) that is surplus to Pooled Load and its operating reserves as determined by a Pool Resource Owner in accordance with Prudent Utility Practice.

"System Facilities" shall mean the transmission lines, substation facilities or components thereof and firm wheeling purchased by TRANSCO, which do not constitute Direct Assignment Facilities and are used to deliver capacity and energy to the Members and other transmission customers of TRANSCO.

"Tag" shall mean the collection of information in the electronic form of request and subsequent response as part of the process implemented by the North American Electric Reliability Corporation for electronically communicating a request for, securing approval of, and recording an energy transaction via the Internet.

"Tariff" shall mean at any time, the currently effective form setting forth the various AEPCO rates and charges applicable to each Billing Unit Entity as approved by the ACC.

"Third Party Economy Sale" shall mean, for each of Daytime Hours and Nighttime Hours, any transactions in which AEPCO sells at wholesale energy from available AEPCO Resources to a third party, which transaction is not a Power Sales Resource, and which is recorded and reported by AEPCO as an economy sale to RUS Uniform System of Accounts Number 447.

"Times Interest Earned Ratio" or "TIER" " shall mean the financial ratio determined based on figures shown on Form 12 Balance Sheet for each calendar year-end as submitted in accordance with Accounting Requirements by AEPCO or TRANSCO, by: (1) adding (a) net patronage capital or margins and (b) Interest Expense on long-term Indebtedness, and (2) dividing the sum obtained by Interest Expense on long-term Indebtedness.

"Total Assets" shall mean an amount constituting the total assets of a Class A Member determined in accordance with Accounting Requirements.

"Total Other Billing Energy" shall mean, for a billing period for each Billing Unit Entity, the sum of S&G And Supplemental Transfer Billing Energy, S&G PPA Billing Energy, Supplemental Billing Energy, Other Billing Energy and Base Transfer Billing Energy for such Billing Unit Entity for such billing period.

"Total Other Energy Cost" shall mean, for a billing period for each Billing Unit Entity, the sum of Other Energy Cost, S&G PPA Energy Charge, Supplemental Purchase Cost, S&G And Supplemental Transfer Purchase Cost, S&G And Supplemental Sales Credit, Directed Sales Credit, Base Transfer Purchase Cost, and Other Economy Sales Credit.

"Total Schedule" shall mean for each Member*, its Base Schedule, plus its Other Schedule, plus, if applicable, its S&G PPA Schedule.

"TRANSCO", which is also known as "Southwest", shall mean Southwest Transmission Cooperative, Inc., a non-profit corporation organized under the Laws of the State of Arizona.

"TRANSCO Assumed AEPCO Debt" shall mean that portion of AEPCO's Indebtedness that TRANSCO assumes pursuant to the TRANSCO CFC Note (if required), the TRANSCO FFB Note(s), the TRANSCO RUS Note(s) and the TRANSCO Assumption and Indemnity Agreements, in each case, in accordance with applicable Law.

"TRANSCO Assumption and Indemnity Agreements" shall mean collectively the Assumption and Indemnity Agreements between TRANSCO and AEPCO and the trustees of certain financial instruments, the forms of which are set forth in Appendix A to the Restructuring Agreement pursuant to which TRANSCO will agree to assume the obligation to pay that portion of AEPCO's debt secured under the AEPCO Mortgage that AEPCO and TRANSCO have agreed will be assumed as part of the payment of the purchase price for such assets and liabilities.

"TRANSCO By-laws" shall mean the By-laws, in the form adopted by the TRANSCO Board of Directors or the TRANSCO Members, as appropriate.

"TRANSCO Employees" shall mean all persons employed by TRANSCO, including TRANSCO Management and systems operations personnel designated by the chief executive officer of TRANSCO, but shall not include persons employed by CSP or any other contractor.

"TRANSCO FFB Note(s)" shall mean the note(s) in the form required by FFB pursuant to which TRANSCO will assume and replace AEPCO as an obligor with respect to that portion of AEPCO's Indebtedness to the FFB outstanding as of the Effective Date that each of

AEPCO and TRANSCO have agreed will be assumed as part of the payment of the purchase price for such assets and liabilities.

"TRANSCO Member" or "Southwest Member" shall mean any of the Class A Members of TRANSCO, and others, including AEPCO and CSP, that become members of TRANSCO in accordance with the TRANSCO By-laws.

"TRANSCO Mortgage" shall mean the Mortgage and Security Agreement, dated as of the Effective Date, made by and among TRANSCO, RUS and CFC which secures the TRANSCO Secured Obligations.

"TRANSCO Notes" shall mean written instruments or notes which evidence the obligation of TRANSCO for its assumption of a portion of the AEPCO Indebtedness (the TRANSCO Assumed AEPCO Debt) to purchase the Transmission Business as evidenced and effected by delivery of the TRANSCO FFB Note(s) and the TRANSCO RUS Note(s), payable to or guaranteed by the Government, acting through the RUS, and by its assumption of the repayment obligations of a portion of the loans made by, or securities issued to, or obligations undertaken to the Financial Entities, and which in the future will also include written instruments which may evidence additional or new loans or advances TRANSCO may obtain to finance the construction or purchase of new facilities for the TTS or the modification of existing TTS facilities, as applicable.

"TRANSCO RUS Note" shall mean the simple allocation of the AEPCO Note owed to RUS.

"TRANSCO Secured Obligations" shall mean collectively, the TRANSCO Notes, certain of the loans made by others to TRANSCO, or securities issued to others by TRANSCO, or debt obligations entitled to the lien created by the TRANSCO Mortgage.

"TRANSCO Tariff" or "Southwest Tariff" shall mean the open access transmission tariff under which transmission services and Ancillary Services are offered by TRANSCO.

"TRANSCO Transmission System" or "TTS" shall mean the electric transmission system of TRANSCO including all transmission lines, substations, microwave and telecommunication facilities, system control and data acquisition system, inventories, works in progress, contract rights to provide or receive transmission services, leases, interests in joint transmission projects, licenses, other related transmission agreements and all other such transmission related assets.

"Transferee" shall mean any of the following Persons: (i) the Person formed as a result of a Member Transaction by any consolidation of the Partial Requirements Member with any other Person; (ii) the survivor of any merger or reorganization of the Partial Requirements Member; (iii) or a Person that acquires or leases all or substantially all of the electric assets of the Partial Requirements Member.

"Transmission Agreement" shall mean the Transmission Agreement by and between TRANSCO and a Partial Requirements Member.

"Transmission Business" shall mean the performance of transmission services and Ancillary Services, and the ownership and use of any rights, obligations, duties, approvals and licenses to the Non-Generation Assets, including the Transmission Resources, and shall include responsibility for the Non-Generation Liabilities.

"Transmission Forecast" shall mean with respect to any Person, such Person's forecast, on an annual basis, of its transmission requirements from TRANSCO.

"Transmission Forecast Period" shall mean the period beginning January 1 of the next calendar year (following the year in which the forecast is prepared) and ending at least the tenth anniversary thereafter.

"Transmission Planning" shall mean the process by which the performance of an electric transmission system is evaluated with respect to specified load-serving capability in accordance with Prudent Utility Practice and by which future modifications, improvements and additions to such electric transmission system are determined by TRANSCO.

"Transmission Requirements Study" shall have the meaning set forth in Section 4 of the Network Service Agreement.

"TRICO" shall mean Trico Electric Cooperative, Inc., an electric cooperative non-profit corporation organized and existing under the Laws of the State of Arizona.

"TRS Work Plan" shall have the meaning set forth in Section 4 of the Network Service Agreement.

"TSEPP" shall mean TSE Promotional Products, Inc., an Arizona corporation.

"TTS" shall mean TRANSCO Transmission System.

"WECC" shall mean Western Electricity Coordinating Council, a regional division of NERC, and successor to WSCC.

"Wholesale Power Contract" shall mean a contract, including its amendments and modifications, including the Existing Wholesale Power Contract and the Partial Requirements Capacity and Energy Agreement, between AEPCO and a Class A Member of AEPCO, for the wholesale sale by AEPCO of electric power or electric power and transmission services to such Class A Member.

"Withdrawal Agreement" shall mean the form of withdrawal agreement attached to the Member Agreement as Exhibit D.

"WSCC" shall mean Western System Coordinating Council, a regional division of NERC.

ATTACHMENT 1 to Ninth Amendment to Wholesale Power Contract

Section 13. Operations Review Committee.

13.1 The Class A Members of Generating Cooperative (Class A Members), including Member, shall have an opportunity to make recommendations to the Operations and Construction Committee (OCC) and the Finance and Audit Committee (FAC) of the Board of Directors of Generating Cooperative (AEPCO) and to the AEPCO Board as described below on any matters that relate to the service and cost of the service provided by AEPCO to Member through the representative of each (Representative) on a committee herein designated as the Operations Review Committee (Committee).

13.2 The Committee shall consist of one authorized Representative from each Class A Member and a Representative designated by AEPCO, who shall serve as Chairperson of the Committee. Each Class A Member shall designate as its Representative an employee of such Class A Member with experience in the areas in which the Committee will function and AEPCO shall designate the Chairperson, who shall be an AEPCO employee.

13.3 Each Class A Member shall evidence the appointment of its Representative by written notice to the other Class A Members and AEPCO, and by similar notice, any Class A Member or AEPCO may change its Representative on the Committee at any time. The list of Committee Representatives will be updated by the Chairperson and distributed to each of the Class A Members with appropriate contact information as necessary to keep the list current as to representation on the Committee.

13.4 Each Class A Member shall be entitled to one vote through its Representative on matters that come before the Committee. In the absence of unanimous consent, the various positions of the Representatives shall be compiled, referred and communicated to the OCC and or FAC by those Representatives electing to do so.

13.5 The Committee shall meet in person or telephonically quarterly except as otherwise determined by the Committee, but in no event less frequently than annually. The Representatives shall determine the agenda of the Committee and have access to all information related to the resources used by AEPCO to provide service.

13.6 Prior to the beginning of each calendar year, and as may be required during any such calendar year, an agenda for the Committee meeting will be solicited from the Representatives and the Committee will receive, consider and review all information requested by the Committee including but not limited to the Apache Station Operations and Maintenance Budget, Capital Budget and Construction Work Plans, A & G expenses proposed by AEPCO management, load forecasts, financial forecasts, cash flow forecasts, rate filings and forecasts, and review variances, updates and amendments thereto and such other operations data as may be requested. Following consideration thereof by the Committee, the Chairperson will promptly report to either the OCC or the FAC, as appropriate, such recommendations concerning any issues considered together with alternatives raised by a Representative. The Representatives may make reports through the AEPCO Director for the Member they represent on the positions they sponsor if they differ from the Committee recommendation report to the OCC or the FAC. Such reports to the OCC and the FAC given by the Chairman and the sponsoring Director(s) shall present all alternatives considered by the Committee in addition to the recommendations of the Committee. Representatives of the Committee may assist in the presentation by their Director(s) of alternatives considered by the Committee for the Board's review in making the final Board decision.

ATTACHMENT 2 to Ninth Amendment to Wholesale Power Contract

Rate Schedule A for ARMs

All Requirements Members

RATE SCHEDULE A

Dated May 11 **, 2010**

1. INTRODUCTION:

This Rate Schedule A specifies the rates and charges and the methodology for developing and administering those rates and the charges for capacity and energy sales made by AEPCO to Member pursuant to its Existing Wholesale Power Contract (the "Agreement") to which this Rate Schedule A is attached. For purposes of specifying and calculating rates and charges pursuant to this Rate Schedule A, Member and other All Requirements Members are individually referred to as an "ARM" and collectively referred to as "Collective ARM" or "CARM." When specified, Member's All Requirements Member's Demand Ratio Share (ARM DRS) of certain CARM rates and charges shall be equal to the quotient of Member's 12 month rolling average demand divided by CARM's 12 month rolling average demand.

Exhibit A-1 to this Rate Schedule A sets forth the rates and charges which are currently in effect in accordance with the Agreement. Exhibit A-2 specifies the methodology for calculating the rates and charges, utilizing the treatment of expenses and certain revenues or credits depicted in Exhibit A-3 and the calculation of ACP and AC in Exhibit A-5. "CARM ACP" shall mean the sum of the ACPs in Existing Resources applicable to each All Requirements Member of AEPCO as set forth in Appendix A to Exhibit A-5 to this Rate Schedule A. Exhibit A-4 sets forth the methodologies for determining billing units, energy rates and energy charges using cost causation principles. Exhibit A-6 sets forth a sample of the bill to be presented to Member by AEPCO for services provided pursuant to the Agreement.

This Rate Schedule A applies to Existing Resources, the S&G PPA and Supplemental Purchases (the "Dispatch Pool Resources"). AEPCO may include the Dispatch Pool Resources in a larger pool for dispatch purposes, provided that the Billing Unit Program is maintained pursuant to Exhibit A-4 and the rights and benefits of each Class A Member are not diminished. No additional members may be added to the existing Class A Members with rights in the Dispatch Pool Resources, and changes in the membership shall be subject to applicable provisions of the Agreement.

AEPCO shall not enter into contracts for or acquire (i) any new AEPCO Generating Resource; or (ii) any AEPCO Power Purchase Resource with a term of greater than one year, unless AEPCO has first entered into a written agreement between AEPCO and all Class A Members agreeing to participate in such Resource, under which no related direct and indirect costs, charges and revenues derived from such Resource would be assigned to any non-participating Class A Members.

2. CONDITIONS OF SERVICE:

2.1 Applicability.

The rates, charges, and adjustments and the methodology for setting and adjusting such rates, charges and adjustments are set forth in this Rate Schedule A. Member shall make payment for electric service under the Agreement through the rates, charges and adjustments established by AEPCO in accordance with the Agreement and this Rate Schedule A. Member shall remain obligated at all times during the term of the Agreement, including periods in which a Force Majeure has been declared, to pay its Fixed Charge and O&M Charge as determined in accordance with this Rate Schedule A.

2.2 Power Factor Adjustment.

If the Power Factor of Member measured at the aggregated Member's Delivery Point(s) at the time of Member peak demand is outside a bandwidth of 95% leading to 95% lagging, a Power Factor Adjustment shall be separately charged to such Member. The Power Factor Adjustment shall be the product of Member's power factor adjustment (as set forth below) multiplied by the quotient of Member's ARM DRS of the CARM O&M Charge divided by the sum of CARM's 12 month rolling average demand. The power factor adjustment shall be any non-negative number determined from the following formula:

$$pfakW = ((mkW / mpf)(bpf)) - mkW$$

Where:

pfakW	=	power factor adjustment in kW; and
mkW	=	Member Metered kW, and
mpf	=	measured power factor at the time of Member peak demand, and
bpf	=	0.95.

2.3 Demand Overrun Adjustment.

If CARM's metered load in any hour exceeds its Allocated Capacity, then AEPCO shall compute a Demand Overrun Adjustment for CARM, and Member shall be charged a portion of such Demand Overrun Adjustment in proportion to Member's ARM DRS. Such Demand Overrun Adjustment shall equal the product of CARM's Fixed Charge multiplied by the demand overrun adjustment factor. The demand overrun adjustment factor shall be any non-negative number determined from the following formula:

$$doaf = ((mbdkW) / AC) - 1$$

Where:

doaf	=	demand overrun adjustment factor
mbdkW	=	Metered kW of CARM, and
AC	=	Allocated Capacity of CARM, in kW.

In addition, Member shall pay for the energy associated with the Demand Overrun Adjustment at the then-applicable Other Energy Rate.

2.4 Capacity and Energy Below AC.

If CARM is utilizing a Future Resource, Supplemental Purchase or S&G PPA in any hour to serve Native Load and CARM fails to take its required share of Minimum Base Capacity or Minimum Other Capacity, CARM shall pay a charge as set forth in this Section 2.4.

2.4.1 CARM Minimum Base Capacity Charge - In the event that CARM has replaced its use of AEPCO Resources with a Future Resource, Supplemental Purchase or S&G PPA to serve Native Load in any hour and fails to utilize energy from AEPCO sufficient to meet its share of Minimum Base Capacity, AEPCO shall charge and the CARM shall pay a charge in an amount obtained by multiplying the lesser of (i) the amount of Future Resource, Supplemental Purchase or S&G PPA used in such hour, or (ii) the amount of CARM's deficiency in its share of Minimum Base Capacity in such hour, by the Coal Energy Rate as defined in Exhibit A-4 of Rate Schedule A and as determined for the billing period. CARM shall only be subject to CARM Minimum Base Capacity Charge to the extent that Available Base Capacity dispatched for Class A Members as a whole is below Minimum Base Capacity.

2.4.2 CARM Minimum Other Capacity Charge - In the event that CARM has replaced its use of AEPCO Resources with a Future Resource, Supplemental Purchase or S&G PPA to serve Native Load in any hour and fails to utilize energy from AEPCO sufficient to meet its share of Minimum Other Capacity, AEPCO shall charge and CARM shall pay an amount obtained by multiplying the lesser of (i) the amount of Future Resource, Supplemental Purchase or S&G PPA used in such hour, or (ii) the amount of CARM's deficiency in its share of Minimum Other Capacity in such hour, by the Gas Energy Rate as defined in Exhibit A-4 of Rate Schedule A and as determined for the billing period.

2.4.3 In the event that in any hour both Sections 2.4.1 and 2.4.2 would apply, the CARM Minimum Other Capacity Charge will be determined first as set forth in Section 2.4.2 above, and the associated CARM Minimum Base Capacity Charge shall be an amount obtained by multiplying the lesser of (i) the amount of Future Resource, Supplemental Purchase or S&G PPA used in such hour less the amount of energy used as the basis for the

CARM Minimum Other Capacity Charge, or (ii) the amount of CARM's deficiency in its share of Minimum Base Capacity in such hour, by the Coal Energy Rate as defined in Exhibit A-4 of Rate Schedule A and as determined for the billing period.

2.5 Taxes and/or Assessments.

The rates and charges set forth in Exhibit A-1 to Rate Schedule A herein do not include sales taxes, transaction privilege taxes or regulatory assessments or similar governmental impositions which are, or may in the future be, levied on AEPCO by any Governmental Authority having jurisdiction and which are not included in the AEPCO Revenue Requirement used to develop the rates and charges. Therefore, bills rendered under the terms of this Rate Schedule A shall include all such federal, state and local sales taxes, transaction privilege taxes, assessments or similar governmental impositions. Such taxes and/or assessments shall be itemized and added to the bill in addition to the rates and charges for capacity and energy sales for payment by Member.

2.6 Charges.

The monthly charge billed to Member in accordance with Section 5.1 of the Agreement and as provided for in applicable provisions of Section 5 of the Agreement, shall consist of the following:

1. Member's ARM DRS of CARM's Fixed Charge as such Fixed Charge is set forth in Exhibit A-1 hereof; plus,

2. Member's ARM DRS of CARM's O&M Charge as such O&M Charge is set forth in Exhibit A-1 hereof; plus,

3. Member's ARM ECR of CARM's Base Energy Charge and Base Fuel Cost Adjustor Charge, as such terms are defined in and charges are calculated pursuant to Exhibit A-4; plus

4. Member's ARM ECR of CARM's Other Energy Charge and Other Fuel Cost Adjustor Charge, as such terms are defined in and charges are calculated pursuant to Exhibit A-4; plus

5. Any Power Factor Adjustment pursuant to Section 2.2 hereof; plus,

6. Member's ARM DRS of CARM's Demand Overrun Adjustment as such Demand Overrun Adjustment is calculated pursuant to Section 2.3 hereof; plus,

7. All taxes and/or assessments pursuant to Section 2.5 hereof, if any.

2.7 Sample Bill.

A form of bill which sets forth for illustrative purposes rates, charges and adjustments to be made by AEPCO to Member pursuant to the Agreement, including this Rate Schedule A, is attached to this Rate Schedule A as Exhibit A-6 and made a part hereof. Actual billings made by AEPCO to Member pursuant to Section 5.1 of the Agreement shall be substantially in the form of, and contain the information set forth in, such sample bill.

3. RATE DEVELOPMENT:

3.1 Rate Administration.

The Board of Directors of AEPCO shall review the level of revenues generated by the rates and charges set forth in Exhibits A-1 to Rate Schedules A and revenues generated from other rates and charges to the Class A Members, together with revenues generated from all other sources, to determine their sufficiency to meet AEPCO's Revenue Requirement. In the event that the rates and charges as set forth in Exhibits A-1 to Rate Schedules A and revenues generated from other rates and charges to the Class A Members do not provide revenues sufficient, but only sufficient, to satisfy AEPCO's Revenue Requirements from Class A Members, the Board of Directors of AEPCO shall establish new rates and new charges for electric service to Member pursuant to the procedures set forth in Section 5.6 of the Agreement and otherwise comply with those provisions pertaining to rates and the charges as set forth in Section 5 of the Agreement. Such new rates and charges established in conjunction with new rates and charges for all other Class A Members shall be submitted to the RUS and shall become effective unless they have been disapproved in writing by the RUS, and Exhibits A-1 (and other Exhibits, as may be applicable) to Rate Schedules A shall be modified to reflect such new rates and charges in effect.

3.2 Development of Cost of Service and Revenue Requirement.

AEPCO rates and the charges developed under this Rate Schedule A for charging Member and rates and charges for charging the other Class A Members shall be based upon AEPCO's Revenue Requirement, and cost of service studies utilizing a twelve-month test period ending not more than six months before proposed rates and charges based on such cost of service studies and Revenue Requirement are approved by the AEPCO Board of Directors. Accounting data for such test period shall be taken from the books and records of AEPCO.

The test period data for the cost of service studies shall be adjusted to reflect known and measurable changes to expenses and billing determinants that have occurred during the test period and/or are expected to continue to occur after the test period, i.e., data shall be normalized for the test period. The cost of service studies may also be normalized for changes that are known and measurable which will occur after the test period (out of period changes).

The fixed, O&M and energy components of all Class A Members shall be developed pursuant to this Rate Schedule A.

3.3 Classification of Expenses.

The expenses and revenue credits included in the cost of service studies shall be classified as fixed, O&M, or energy as set forth in Exhibit A-2 and depicted in Exhibit A-3 hereto.

3.4 Development of Rates, Charges, and Billing Determinants.

Once the components of fixed, O&M, and energy of AEPCO's Revenue Requirement from All Class A Members are determined pursuant to Section 3.2, and all expenses are classified pursuant to Section 3.3, the rates and charges for electric service pursuant to the Agreement shall be determined in accordance with Exhibit A-2. The billing determinants for the CARM Fixed Charge and the CARM O&M Charge shall be the ACP as specified in Section 3.5 below. The billing determinants for the energy rates shall be determined pursuant to Exhibit A-4 and as set forth in Section 5.4 of Exhibit A-2.

3.5 Allocated Capacity Percentage (ACP) and Allocated Capacity (AC).

Appendix A to Exhibit A-5 sets forth the Allocated Capacity Percentages (ACP) that shall be used to develop the CARM ACP, which will be used to develop the Fixed Charge and O&M Charge for CARM. Appendix B to Exhibit A-5 to this Rate Schedule A identifies AEPCO Resources in the Dispatch Pool as well as the Allocated Capacity (AC) for CARM. In each case, Member's share of such charges shall be determined based on Member's ARM DRS.

Exhibit A-1 to Rate Schedule A

All Requirements Member
Rates and Fixed Charge
(Effective as of Agreement Date)

Fixed Charge	$_______	per month *
O&M Charge	$_______	per month *
Energy Rates: **Base Energy Rate**	$_______ of base resources used during the billing period.	per kWh *
Other Energy Rate	$_______ of other resources used during the billing period.	per kWh *
Power Cost Adjustor Rate for FPPCA: **Base Resources**	$_______	per kWh *
Other Resources	$_______	per kWh *

*Based on test year data with pro forma adjustments as approved by the ACC.

All Requirements Members
Exhibit A-2 to Rate Schedule A
Development of Rates and Fixed Charge

1.0 INTRODUCTION:

This Exhibit A-2 specifies the methodology for the development of rates and the charges applicable for AEPCO Resources in which Member has an ACP. This methodology shall be applied to AEPCO expenses and revenues described herein which are maintained under the RUS Uniform System of Accounts and classified as (a) fixed, (b) O&M, or (c) energy. All amounts described hereunder and included in such accounts shall be those amounts recorded in AEPCO's financial records for the test period used in the applicable cost of service study from which the rates and charges are to be developed. Such amounts when adjusted for appropriate credits and normalized with appropriate adjustments are the AEPCO costs and expenses which shall be used as the basis for the cost of service which determines AEPCO's Revenue Requirement which is the sum of: (i) revenues to be recovered from Member through charging the rates and charges developed pursuant to the Agreement, plus (ii) revenues to be recovered from the Partial Requirements Members through rates and charges pursuant to their Partial Requirements Capacity and Energy Agreements; plus (iii) revenues to be recovered from other All Requirements Members through rates and charges pursuant to their Existing Wholesale Power Contracts, plus (iv) AEPCO revenues from all other sources.

2.0 CLASSIFICATION OF EXPENSES AND REVENUES:

2.1 Classifications.

For purposes of this Exhibit A-2 to Rate Schedule A, classifications shall be made of the AEPCO expenses and revenues from sources other than sales to AEPCO Class A Members and maintained and identified using the RUS Uniform System of Accounts, for the purpose of identifying such expenses as either: (a) fixed (F), (b) Operations and Maintenance (O&M) (O), or(c) energy (E), as follows:

(The account numbers refer to accounts maintained under the RUS Uniform System of Accounts by AEPCO in its financial records.)

Amounts in Accounts 500 through 554, with the exception of Accounts 501 and 547, shall each be classified as Production-O (consisting of operations and maintenance expenses related to steam and other power generation).

Amounts in Accounts 501 and 547 shall be separated and classified either as: Fuel-F (consisting of O&M and gas transportation reservation charges), or as Fuel-E (consisting of remaining Accounts 501 and 547 Expenses).

Amounts in Accounts 555 shall be separated and classified as: Purchased Power-F (capacity or demand charges), Purchased Power-O (O&M related charges), or as Purchased Power-E (energy charges).

Amounts in Accounts 556 and 557 shall be classified as: Other Power Supply-O (System Control, dispatching and O&M charges).

Amounts in Account 565 shall be separated and classified as: Wheeling Expense-O (consisting of firm wheeling charges), or as Wheeling Expense-E (consisting of non-firm wheeling charges).

Amounts in Accounts 901-916, which consist of consumer accounts, customer accounts and sales expense, shall be classified as Customer-O.

Based on the respective ratios of labor expenses in (a) Steam Power Generation (Accounts 500-507 and 510-514) and Other Power Production (Accounts 546-554) and (b) Other Power Supply (Accounts 556 and 557), compared to the sum of all such labor expenses, the amounts in Accounts 920-923 and 927-932 shall each be separated and classified as either: (a) Administrative & General I-O, or as (b) Administrative & General I-E.

Based on the portions of Production Plant (Accounts 300-316) and General Plant (Accounts 389-399) respectively associated with (a) fixed, (b) O&M, and (c) energy, compared to the sum of such expenses, the amounts in Account 924 shall be respectively separated and classified as either: (a) Administrative & General II-F, (b) Administrative & General II-O, or as (c) Administrative & General II-E.

Based on the respective ratios of labor expenses in (a) Steam Power Generation (Accounts 500-507 and 510-514) and Other Power Production (Accounts 546-554), (b) Other Power Supply (Accounts 556 and 557), (c) Sales Expense (Accounts 911-916) and (d) Administrative and General (Accounts 920-923 and 927-932), compared to the sum of such labor expenses, the amounts in Accounts 925 and 926 shall each be separated and classified as either: (a) Administrative & General III-O, or as (b) Administrative & General III-E.

The revenue amounts in Accounts 447-456 shall be first aggregated into credits and classified as either: (a) Credits-F, (b) Credits-O, or (c) Credits-E.

Margins shall be classified and assigned to the fixed category.

2.2 Depiction.

The expense and revenue accounts and their classification into fixed, O&M and energy specified in this Exhibit A-2 are depicted in tabular form in Exhibit A-3.

3.0 FIXED CAPACITY AND O&M COMPONENT:

3.1 Purpose and Elements.

The purpose of this Section 3.1 and Sections 3.2 and 3.3 hereof is to set forth the methodology for the development of the rates and charges attributable to electric service under the Agreement. The fixed capacity component and the O&M component shall be used to calculate and determine the Fixed Charge as provided in Section 5.2 hereof, and the O&M Charge as provided in Section 5.3 hereof.

3.2 Fixed Capacity Component.

The fixed capacity component for CARM shall be the sum of either the amounts in the following accounts, or the portion of such amounts classified as fixed, as applicable pursuant to Section 2 hereof, to the extent attributable to the AEPCO Resources in which CARM has an ACP:

Account 403	(Depreciation & Amortization Expense),
Account 408	(Ad Valorem Taxes),
Accounts 427-428	(Interest on Long Term Debt, Interest Charged to Construction, Other Interest Expense, and Other Deductions),
Account 501	(Fuel-F only),
Account 547	(Fuel-F only),
	Account 555 (Purchased Power - F only),
Account 924	(Administrative & General II-F only),
Plus Margin	in an amount sufficient to assure AEPCO of, at a minimum, a reasonable level of working capital and maintenance of annual coverage ratios, or any other financial covenants or tests prescribed or imposed by RUS or any other applicable Financial Entities, and
Less Accts 447-456	(Credits – F) which include: (a) a portion of the revenues from Power Sales Resources, consisting of total Power Sales Resources' revenues less Power Sales Resources' energy revenues, to be credited to

CARM in an amount equal to the product of CARM ACP expressed in decimal units multiplied by the amount of such revenues; and (b) a portion as described in footnote 7 of Exhibit A-3 of any other revenues received by AEPCO for any goods or services or other such services, but excluding the sales of power in subparagraph a above; such portion to be credited to CARM in an amount equal to the product of CARM ACP expressed in decimal units multiplied by the amount of such net revenues.

3.3 O&M Component.

The CARM O&M component shall be the sum of either the amounts in the following accounts, or the portion of such amounts classified as O&M, as applicable pursuant to Section 2 hereof, to the extent attributable to the AEPCO Resources in which CARM has an ACP:

Accounts 500-554, except for Accounts 501 and 547 (Production-O only),

Account 555	(Purchased Power-O only),
Accounts 556, 557	(Other Power Supply-O only),
Account 565	(Wheeling Expense-O only),
Accounts 901-916	(Customer-O only),
Accounts 920-923	(Administrative & General I-O only),
Account 924	(Administrative & General II-O only),
Accounts 925-926	(Administrative & General III-O only),
Accounts 927-932	(Administrative & General I-O only), and
Less Accts 447-456	(Credits-O) consisting of : (a) Scheduling Revenues – the scheduling revenues resulting from providing scheduling and trading services for customers other than Class A Members of AEPCO, excluding energy-related revenues, to be credited to CARM in an amount equal to the product of the total of such revenues multiplied by the CARM ACP; and (b) a portion as described in footnote 7 of Exhibit A-3 of any other revenues received by AEPCO for any goods or services or other such services; such portion to be credited to CARM in an amount equal to the product of CARM ACP expressed in decimal units multiplied by the amount of such net revenues.

4.0 ENERGY COMPONENT:

The CARM energy component shall be the sum of either the amounts in the following accounts, or the portion of such amounts classified as energy, as applicable, pursuant to Section 2 hereof, to the extent attributable to the AEPCO Resources in which CARM has an ACP:

Accounts 501 and 547	(Fuel-E only),
Accounts 555	(Purchased Power-E only),
Account 565	(Wheeling Power-E only),
Accounts 920-923	(Administrative & General I-E only),
Account 924	(Administrative & General II-E only),
Accounts 925-926	(Administrative & General III-E only), and
Accounts 927-932	(Administrative & General I-E only),
Less Accts 447-456	(Credits-E only).

5.0 MEMBER RATES AND CHARGES:

5.1 Elements.

The rates and charges for electric service under the Agreement to Member shall consist of (a) the Fixed Charge, composed of an appropriate allocated fixed capacity component, including a margin, (b) an O&M Charge, (c) Base Energy Rate, and (d) Other Energy Rate.

5.2 Fixed Charge.

The monthly CARM Fixed Charge stated in dollars, shall equal: the quotient of (a) the product of (i) the expenses less revenue credits used to determine the current fixed capacity component in Section 3.2 of this Exhibit A-2, and shall include prior period losses (negative equity) resulting from deficiencies or shortfalls caused by failures of Class A Members to meet their portion of AEPCO's Revenue Requirement, multiplied by (ii) the CARM ACP , (b) divided by twelve (12) to convert to a monthly charge. Member's share of the monthly CARM Fixed Charge shall be determined based on Member's ARM DRS.

5.3 O&M Charge.

The CARM O&M Charge shall be equal to the quotient of (a) the product of (i) the annual test year O&M component as calculated in Section 3.3 of this Exhibit A-2, multiplied by (ii) the CARM ACP , (b) divided by twelve (12) to convert to a monthly charge. Member's Share of the monthly CARM O&M Charge shall be determined based on Member's ARM DRS.

5.4 Base Energy Rate and Other Energy Rate.

The CARM Base Energy Rate and CARM Other Energy Rate shall be established based on the methodology contained in Exhibit A-4, and shall together equal the energy component comprised of the expenses, less revenue credits as identified in Section 4.0 of this Exhibit A-2 and calculated pursuant to the methodology in Exhibit A-4, divided by the aggregate test year energy billing units (stated in kWh) developed pursuant to Exhibit A-4 in the cost of service study for the Class A Members, adjusted for known and measurable changes.

6.0 REVENUE SHORTFALLS:

Any deficiencies or shortfalls in collections of AEPCO's Revenue Requirement from Class A Members will be recovered through appropriate adjustments to: (a) the O&M Charge, or (b) the margin included in the Fixed Charge. An adjustment will be made to the O&M Charge to the extent such deficiencies or shortfalls are attributable to the collection of revenues for operations and maintenance expenses. An adjustment will be made to the margin included in the Fixed Charge for all other such deficiencies or shortfalls. Such deficiencies or shortfalls may also be recovered through a combination of appropriate adjustments to the O&M Charge or the margins.

7.0 NO ADJUSTMENT FOR TRANSMISSION LOSSES:

The billing determinants included in the cost of service study and used to develop and implement the rates and charges shall be based on Schedules or on metered data at the Delivery Points. Consequently, AEPCO's Revenue Requirement developed as a result of such cost of service study reflects the costs of generating or acquiring sufficient capacity and energy to cover transmission losses. Therefore, the rates and charges developed as set forth herein implicitly encompass recovery of the costs associated with transmission losses and there is no need for a separate adjustment for transmission losses.

All Requirements Members

Exhibit A-3 to Rate Schedule A

Classification of Expenses

Uniform System Account No.	Description	Fixed Expenses (F)	O&M Expenses (O)	Energy Expenses (E)
	Production and Other Power Supply			
	Steam Power Generation:			
	Operation:			
500	Operation Supervision & Engineering		X	
501	Fuel	X[1]		X[1]
502	Steam Expenses		X	
505	Electric Expenses		X	
506	Miscellaneous Steam Power Expenses		X	
507	Rents		X	
	Maintenance:			
510	Supervision & Engineering		X	
511	Structures		X	
512	Boiler Plant		X	
513	Electric Plant		X	
514	Miscellaneous Steam Plant		X	
	Other Power Generation:			
	Operation:			
546	Operation Supervision & Engineering		X	
547	Fuel	X[1]		X[1]
548	Generation Expenses		X	
549	Miscellaneous Other Power Generation		X	
550	Rents		X	
	Maintenance:			

[1]All fuel related costs are assigned to the energy classification, except for gas transportation reservation charges which are assigned to the fixed classification because they do not pertain to fuel commodity costs.

Uniform System Account No.	Description	Fixed Expenses (F)	O&M Expenses (O)	Energy Expenses (E)
551	Supervision & Engineering		X	
552	Structures		X	
553	Generating and Electric Equipment		X	
554	Miscellaneous Other Power Generation		X	
	Other Power Supply Expenses:			
555	Purchased Power	X[(2)]	X[(2)]	X[(2)]
556	System Control & Load Dispatching		X	
557	Other Expenses		X	
565	Wheeling Expense		X[(3)]	X[(3)]
901-905	Consumer Accounts		X	
906-910	Customer Service & Information		X	
911-916	Sales Expense		X	
	Administrative & General:			
920	Salaries		X[(4)]	X[(4)]
921	Office Supplies & Expenses		X[(4)]	X[(4)]
922	A&G Expenses Transferred Credit		X[(4)]	X[(4)]
923	Outside Services		X[(4)]	X[(4)]

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[2]Purchased power, capacity or demand charges are assigned to the fixed classification, any O&M charges to the O&M classification and energy charges and interchange expenses are assigned to the energy classification.

[3]Firm wheeling charges are assigned to the O&M classification and non-firm wheeling charges are assigned to the energy classification.

[4]Administrative and general expenses are assigned to the O&M and energy classifications based upon the distribution of production and other power supply labor expenses to the O&M and energy classifications.

Uniform System Account No.	Description	Fixed Expenses (F)	O&M Expenses (O)	Energy Expenses (E)
924	Property Insurance	X[5]	X[5]	X[5]
925	Injuries & Damages		X[6]	X[6]
926	Employee Pensions & Benefits		X[6]	X[6]
927	Franchise Requirements		X[4]	X[4]
928	Regulatory Commission Expenses		X[4]	X[4]
929	Duplicate Charges Credit		X[4]	X[4]
930	Miscellaneous General Expense		X[4]	X[4]
931	Rents		X[4]	X[4]
932	Maintenance of General Plant		X[4]	X[4]
403	Depreciation & Amortization Expense	X		
408	Ad Valorem Taxes	X		
	Interest & Other Deductions:			
427	Interest on Long Term Debt	X		
427	Interest Charged to Construction	X		
427	Other Interest Expense	X		
428	Other Deductions	X		
447-456	Operating Revenues from Other Sources – Credit	X[7]	X[7]	X[7]
	Margin Component	X		

[5]Assigned to the fixed, O&M and energy classifications based upon the distribution of production and general plant between classifications.

[6]Assigned to the O&M and energy classifications based upon the distribution of total labor expenses to the O&M and energy classifications.

[7]Excluding revenue from Power Sales Resources, revenue from sources other than AEPCO's Class A Members shall be credits to the Fixed component and to the O&M component in amounts proportionate to Fixed Revenue Requirements and O&M Revenue Requirements.

Exhibit A-4 to Rate Schedule A
Determination of Billing Units, Energy Rates and Energy Charges Using Cost Causation Principles

1. INTRODUCTION:

This Exhibit A-4 sets forth the methodology for the determination of energy billing units, energy rates and energy charges for each of AEPCO's Class A Members using cost causation allocation principles.

2. DEFINITIONS:

The following terms are used in this Exhibit and its Appendices.

"ARM Energy Cost Responsibility Share" or "ARM ECR" shall mean the percentage share for each billing period of an individual All Requirements Member in CARM S&G PPA Energy Charge, CARM Supplemental Purchase Cost, CARM Base Energy Cost, and CARM Total Other Energy Cost, determined in such billing period as the ratio expressed in percent of each All Requirements Member's Member Billing Energy to CARM Billing Energy.

"Available Base Capacity" shall mean the energy from Base Resources, including Base Economy Purchases, available for dispatch in a Future Scheduling Hour, less losses in delivery to Class A Members, and excluding (i) any coal-fired capacity that is not available due to forced outage or scheduled maintenance outage or temporary deration, (ii) capacities of Power Sales Resources, and (iii) allocations for losses in delivery of such Power Sales Resources; and for each Billing Unit Entity, shall mean that Billing Unit Entity's ACP share of such Available Base Capacity.

"Available Other Capacity" shall mean the amount of capacity that is available for dispatch as determined by AEPCO for any Future Scheduling Hour equal to the sum of (i) the aggregate of the capacities of Other Resources, which shall be as set forth in Appendix B to Exhibit A-5 of Rate Schedule A to each Partial Requirements Capacity and Energy Agreement, as may be amended, plus (ii) the capacity of any concurrent Replacement Purchases for Base Resources, less (iii) capacity set aside for Reserves and allocations for losses in delivery; and for each Billing Unit Entity, shall mean that Billing Unit Entity's ACP share of such Available Other Capacity.

"Available S&G PPA Capacity" shall mean S&G PPA Capacity, less an allocation for losses for delivery, that is available for dispatch by AEPCO for any Future Scheduling Hour; and for each Billing Unit Entity having an ACP in S&G PPA, shall mean that Billing Unit Entity's ACP share of such Available S&G PPA Capacity.

"Available Supplemental Capacity" shall mean Supplemental Capacity, less an allocation for losses for delivery, that is available for dispatch by AEPCO for any Future

Scheduling Hour; and for each Billing Unit Entity having a percentage interest in a Supplemental Purchase, shall mean that Billing Unit Entity's percentage share of such Available Supplemental Capacity.

"Base Adjustor Per Unit Cost" shall mean, for a billing period for each Billing Unit Entity, the Base Fuel Adjustor Cost divided by the Base Billing Energy for the same Billing Unit Entity for the same billing period.

"Base Average Energy Rate" shall mean, for a billing period for each Billing Unit Entity, the rate obtained by dividing the Billing Unit Entity's Base Energy Cost of the billing period by Billing Unit Entity's Base Billing Energy for the same period.

"Base Billing Energy" shall mean, for a Billing Unit Entity, the energy from its Available Base Capacity assigned and allocated in each hour pursuant to the Billing Unit Program to its Base Schedule or load, accumulated for a billing period.

"Base Capacity" shall mean for Base Resources the sum of (i) the capacity from Federal Hydro Power Agreements as adjusted to reflect seasonal and Peak Hours vs. Off-Peak Hours variations; plus (ii) 350 MW of capacity of AEPCO's coal-fired units.

"Base Economy Purchase" shall mean a purchase of energy by AEPCO from a third party, including wheeling charges recorded in RUS Uniform System of Accounts 565 Transmission of Electricity by Others or its successor for delivery of the purchase to an SWTC Point of Receipt, if any, which is made at a lower average energy rate over the purchase period than that associated with energy available from Base Resources during such period, and which AEPCO chooses to make in lieu of dispatching energy available from such Base Resources.

"Base Economy Purchase Cost" shall mean, for all hours of a billing period, the purchase energy cost incurred by AEPCO for all Base Economy Purchases made in such billing period, including wheeling costs incurred in delivery from the source of such purchase to an SWTC Point of Receipt, if any.

"Base Economy Sales" shall mean, for a billing period, the energy from Post-Transfer Excess Base Capacity assigned in each hour to each Billing Unit Entity pursuant to the Billing Unit Program as Third Party Economy Sales.

"Base Economy Sales Cost" shall mean, for each Billing Unit Entity for a billing period, the product of Base Economy Sales multiplied by the Coal Energy Rate.

"Base Economy Sales Credit" shall mean, for each Billing Unit Entity, the product of the Economy Sales Price, for each of Daytime Hours and Nighttime Hours of a billing period, multiplied by the Billing Unit Entity's Base Economy Sales for Daytime Hours and for Nighttime Hours, respectively, of the same billing period.

"Base Energy Cost" shall mean, for a billing period for each Billing Unit Entity, the sum of Remaining Base Energy Cost plus Base Transfer Sales Credits, Base Transfer Energy Cost, Base Economy Sales Credit and Base Economy Sales Cost for the same Billing Unit Entity.

"Base Energy Mismatch" shall mean, for a billing period, the accumulated net difference in energy obtained from subtracting (i) the energy from Available Base Capacity assigned and allocated in the billing period in accordance with the Billing Unit Program, from (ii) the energy actually produced from Available Base Capacity during that billing period.

"Base Energy Mismatch Charge" shall mean, for a billing period, the product of (i) any positive value of Base Energy Mismatch for the billing period, multiplied by (ii) the Coal Energy Rate for the billing period.

"Base Energy Mismatch Credit" shall mean, for a billing period, the product of (i) the absolute value of any negative value of Base Energy Mismatch for the billing period, multiplied by (ii) the Coal Energy Rate for the billing period.

"Base Energy Rate" shall mean, for each Billing Unit Entity, the rate applicable to that Billing Unit Entity's use of energy from Available Base Capacity as set forth in Exhibit A-1 to Rate Schedule A.

"Base FPPCA" shall mean Fuel and Purchase Power Cost Adjustor determined for a FPPCA Period for the Base Resources for each Billing Unit Entity.

"Base Fuel Adjustor Cost" shall mean for a billing period for each Billing Unit Entity, the sum of the Base Energy Cost, Hydro Demand Charge, Base Transmission Wheeling Cost and Power Sales Resource Demand Revenues for the same Billing Unit Entity for the same billing period.

"Base Fuel Bank" shall mean, for a billing period for each Billing Unit Entity, the accumulation of Base Over or Under Collections.

"Base Incremental Unit Cost" shall mean, for a billing period for each Billing Unit Entity, the difference obtained by subtracting (i) the sum of (a) Base Power Cost Adjustor Base, plus (b) Base Power Cost Adjustor Rate, from (ii) Member Base Adjustor Per Unit Cost, for such Billing Unit Entity for such period.

"Base Over or Under Collection" shall mean, for a billing period for each Billing Unit Entity, the product of (i) Base Incremental Unit Cost multiplied by (ii) Base Billing Energy, for such Billing Unit Entity for such period.

"Base Power Cost Adjustor Base" shall mean the Power Cost Adjustor Base for Base Resources as set forth in the Tariff.

"Base Power Cost Adjustor Rate" shall mean the Power Cost Adjustor Rate for Base Resources as set forth in the Tariff.

"Base Resources" shall mean the Federal Hydro Power Agreements and two coal-fired steam Generating Resources that are Existing Resources located at the Apache Generating Station, in which each Class A Member has an ACP.

"Base Schedule" shall mean, for each Member*, its Pre-Schedules and Real-Time Schedules provided to AEPCO by such Member* or its Scheduling Agent pertaining to Member*'s use of its Available Base Capacity, as such Pre-Schedules and Real-Time Schedules are determined consistent with Schedule B to the Partial Requirements Capacity and Energy Agreements.

"Base Transfer" shall mean, for a Billing Unit Entity, energy from the Billing Unit Entity's Excess Base Capacity that has been assigned and allocated to the load or Other Schedule of other Billing Unit Entities in an hour pursuant to the Billing Unit Program, accumulated for a billing period separately for Daytime Hours and Nighttime Hours.

"Base Transfer Billing Energy" shall mean, for a Billing Unit Entity, energy from the Excess Base Capacity of other Billing Unit Entities that has been assigned and allocated to the Billing Unit Entity in an hour pursuant to the Billing Unit Program, accumulated for a billing period separately for Daytime Hours and Nighttime Hours.

"Base Transfer Energy Cost" shall mean, for each Billing Unit Entity for a billing period, Coal Energy Rate multiplied by Base Transfer.

"Base Transfer Purchase Cost" shall mean, for each Billing Unit Entity that has been assigned Base Transfer Billing Energy, for each of separately accumulated Daytime Hours and Nighttime Hours of a billing period, the product of its Base Transfer Billing Energy, multiplied by the Economy Purchase Rate of Daytime Hours or Nighttime Hours, as applicable.

"Base Transfer Sales Credit" shall mean, for each Billing Unit Entity, for each of separately accumulated Daytime Hours and Nighttime Hours of a billing period, the product of (i) the Economy Purchase Rate of Daytime Hours or Nighttime Hours, as applicable, multiplied by (ii) its Base Transfer of Daytime Hours or Nighttime Hours, as applicable.

"Base Transmission Wheeling Cost" shall mean, for each Billing Unit Entity for a billing period, the product of (i) the costs recorded in RUS Uniform System of Accounts 565 Transmission of Electricity by Others or its successor, and allocated to Base Resources, for the same billing period, multiplied by (ii) the Billing Unit Entity's ACP in Existing Resources.

"Billing Energy" shall mean the energy of each billing period determined pursuant to the Billing Unit Program to have served the entirety of the Schedule of each Member*, or the entirety of the load of CARM or the entirety of the Directed Sales and load of a Member* CA in such billing period, consisting of the sum of the Billing Unit Entity's Base Billing Energy, S&G PPA Billing Energy, Other Billing Energy, Base Transfer Billing Energy, Supplemental Billing Energy, and S&G And Supplemental Transfer Billing Energy.

"Billing Unit Entity" shall mean any of CARM, a Member* or a Member* CA.

"Billing Unit Program" shall mean the software program and subroutines that are used by AEPCO's Power Trading and Scheduling Department for the purpose of determining monthly each Billing Unit Entity's Billing Energy from Base Resources, Other Resources, S&G PPA and Supplemental Purchase by hourly allocation and assignment of energy from Available Base Capacity, Available Other Capacity, Available S&G PPA Capacity and Available Supplemental Capacity to each of (i) the loads of the CARM; (ii) the Directed Sales and load of a Member* CA; (iii) the Schedules; (iv) Base Transfers; (v) S&G And Supplemental Transfers; and (vi) Third Party Economy Sales.

"CARM" or "Collective ARM" shall mean all of the All Requirements Members.

"CARM ACP" shall mean the sum of the ACPs in Existing Resources and in S&G PPA, as applicable to each All Requirements Member as set forth in Appendix A to Exhibit A-5 to Rate Schedule A to the ARM Wholesale Power Contracts.

"Coal Energy Cost" shall mean, for a billing period, the accumulated costs of coal and natural gas expensed during that billing period, related to the operation and dispatch during that billing period of two coal-fired steam Generating Resources that are Existing Resources located at the Apache Generating Station, as recorded in RUS Uniform System of Accounts 501 or its successor for that billing period.

"Coal Energy Rate" shall mean, for a billing period, Coal Energy Cost divided by the product of Coal Energy Generated multiplied by the difference obtained by subtracting the Network Loss Factor from one (1).

"Coal Energy Generated" shall mean, for a billing period, the net energy output at the 230 kv bus of the two coal-fired steam Generating Resources that are Existing Resources located at the Apache Generating Station.

"Daytime Hours" shall mean the 16 hours of each day beginning Hour Ending 0700 through Hour Ending 2200 Pacific Prevailing Time, including Sundays and Holidays.

"Directed Sales" shall mean any transactions in which, at the advance direction of a Member* CA, AEPCO for such Member* CA's benefit sells to a third party at wholesale energy from such Member* CA's available AC in AEPCO Resources.
"Directed Sales Credit" shall mean the revenue realized from Directed Sales.

"Dispatch Pool Resources" shall mean Existing Resources, the S&G PPA and Supplemental Purchases.

"Economy Purchase Cost" shall mean, separately accumulated for Daytime Hours and Nighttime Hours of a billing period, the total cost incurred by AEPCO (including transmission expenses, including losses, incurred in delivery from the source of such purchase to an SWTC Point of Receipt, if any) for Non-Base Economy Purchases and Replacement Purchases in effect in such Daytime Hours or Nighttime Hours of the billing period.

"Economy Purchase Rate" shall mean, separately calculated for Daytime Hours and Nighttime Hours of a billing period, the rate obtained by dividing Economy Purchase Cost of Daytime Hours or Nighttime Hours of that billing period, by energy received from Non-Base Economy Purchases and Replacement Purchases in effect in such Daytime Hours or Nighttime Hours of that billing period.

"Economy Sales Price" shall mean, for Third Party Economy Sales, for each of Daytime Hours and Nighttime Hours, the quotient obtained by dividing (i) the numerator equal to the sum of the revenue from all Third Party Economy Sales during the billing period in Daytime Hours and Nighttime Hours, respectively, reduced by any payments to SWTC or third parties for transmission used in delivery of such sales, by (ii) a denominator equal to the MWh of energy delivered as Third Party Economy Sales during such hours.

"Energy Cost Accounting Process" or "ECAP" shall mean the software program and subroutines that are used by AEPCO's Financial Services Department for the purpose of determining monthly each Billing Unit Entity's costs for energy from Base Resources, Other Resources, S&G PPA, and Supplemental Resources.

"Excess Base Capacity" shall mean, for a billing period for each Billing Unit Entity, the separately accumulated Daytime and Nighttime billing period totals of Available Base Capacity that is not assigned in an hour pursuant to the Billing Unit Program as Base Billing Energy.

"Excess S&G And Supplemental Capacity" shall mean, for a billing period for each Billing Unit Entity having an ACP interest in S&G PPA and/or Supplemental Purchase, Available S&G PPA Capacity and/or Available Supplemental Capacity, that is not assigned in an hour pursuant to the Billing Unit Program as S&G PPA Billing Energy and Supplemental Billing Energy.

"Federal Hydro Power Agreement(s)" shall mean the following contracts:

a) Contract No. 87-BCA-10001 for Firm Electric Service between Western Area Power Administration and Arizona Power Pooling Association, dated March 9, 1989 as it may be amended from time to time, and its successor agreement(s) (SLCA Integrated Projects Agreement); and

b) Contract No. 87-BCA-10085 Electric Service between Western Area Power Administration and Arizona Power Pooling Association, dated February 25, 1988 as it may be amended from time to time, and its successor agreement(s) (Parker-Davis Project Agreement).

"FPPCA" shall mean Fuel and Purchase Power Cost Adjustor determined for the applicable AEPCO Resources.

"FPPCA Period" shall mean the period of months over which AEPCO is to record S&G PPA Energy Charge, Supplemental Purchase Cost, Base Energy Cost and Other Energy Cost for billing or credit to the Class A Members pursuant to the Tariff.

"Future Scheduling Hour" shall mean a clock hour beginning more than sixty (60) minutes after the current hour.

"Gas Energy Cost" shall mean, for a billing period, the accumulated costs of natural gas expensed during that billing period, related to the operation and dispatch during that billing period of the gas-fired Generating Resources that are Existing Resources located at the Apache Generating Station, as recorded in RUS Uniform System of Accounts 547 or its successor for that billing period.

"Gas Energy Generated" shall mean, for a billing period, the net energy output at the applicable bus of the gas-fired Generating Resources that are Existing Resources located at the Apache Generating Station.

"Gas Energy Rate" shall mean, for a billing period, Gas Energy Cost divided by the product of Gas Energy Generated.

"Hydro Demand Charge" shall mean, for a billing period, demand charges associated with Federal Hydro Power Agreements as recorded in RUS Uniform System of Accounts 555 or its successor for the billing period.

"Hydro Energy Charge" shall mean, for a billing period, energy charges associated with Federal Hydro Power Agreements as recorded in RUS Uniform System of Accounts 555 or its successor for the billing period.

"Member*" shall mean a PRM whose load is not assigned to the SWTC metered subsystem of the Western Area Lower Colorado Balancing Authority in the Desert Southwest Region.

"Member* CA" shall mean a PRM whose load is assigned to the SWTC metered subsystem of the Western Area Lower Colorado Balancing Authority in the Desert Southwest Region.

"Minimum Other Capacity" shall mean the capacity from Available Other Capacity that must be operated from time to time to maintain system reliability or for other reasons as described in Section 4.2 of Schedule B to the Partial Requirements Capacity and Energy Agreements.

"Network Loss Factor" shall mean the adjustment factor for transmission losses assigned for network service under the Southwest Transmission Cooperative, Inc. Open Access Transmission Tariff as in effect from time to time.

"Nighttime Hours" shall mean the eight (8) hours beginning Hour Ending 2300 of one day continuing through Hour Ending 0600 of the following day, Pacific Prevailing Time.

"Non-Base Economy Purchase" shall mean any purchase of energy by AEPCO from a third party that is not a Base Economy Purchase which is made at a lower average energy rate over the purchase period than that which would be associated with energy dispatched from Available Other Capacity or Available S&G PPA Capacity during such period, and which is made in lieu of dispatching energy from such capacity.

"Operating Reserve Purchases" shall mean any purchases of operating reserve capacity to avoid curtailing any energy from any more economical AEPCO Resource that would otherwise be required to provide such operating reserve capacity.

"Other Adjustor Per Unit Cost" shall mean, for a billing period for each Billing Unit Entity, the Other Fuel Adjustor Cost divided by the Total Other Billing Energy for the same Billing Unit Entity for the same billing period.

"Other Average Energy Rate" shall mean, for a billing period for a Billing Unit Entity, the rate obtained by dividing its Total Other Energy Cost of the billing period by its Other Billing Energy for the same period.

"Other Billing Energy" shall mean, for a Billing Unit Entity, the energy from Available Other Capacity assigned and allocated in each hour pursuant to the Billing Unit Program to its Other Schedule or load, accumulated for a billing period.

"Other Economy Sales" shall mean, for a billing period, the energy from dispatched Other Capacity and from Post-Transfer S&G And Supplemental Capacity assigned in each hour to each Billing Unit Entity pursuant to the Billing Unit Program as Third Party Economy Sales.

"Other Economy Sales Credit" shall mean, for each Billing Unit Entity, the product of the Other Economy Energy Sales Revenue of Daytime Hours and Nighttime Hours, as applicable, multiplied by the ratio of (i) for each of separately accumulated Daytime Hours and Nighttime Hours of the billing period, the Post-Transfer S&G And Supplemental Capacity energy in the case of a Billing Unit Entity with an ACP in such capacity, the Other Schedule in the case of a Member*, and in the case of CARM or a Member* CA, its load's use of Available Other Capacity, to (ii) the total of such Post-Transfer S&G And Supplemental Capacity, such Other Schedules and such uses of Available Other Capacity by all Billing Unit Entities for the same time periods.

"Other Economy Sales Revenue" shall mean the difference obtained by subtracting the Base Economy Sales Credit from the revenue of all Third Party Economy Sales during a billing period.

"Other Energy Cost" shall mean, for a billing period for each Billing Unit Entity, the costs of purchased energy and natural gas fuel and oil fuel expensed during that billing period, related to the operation and dispatch of Available Other Capacity during that billing period, as recorded in Accounts described in Section 4.0 of Exhibit A-2 to Rate Schedule A and reported to RUS by AEPCO for that billing period, including purchased energy expenses, wheeling charges and costs of any transmission losses related to Other Economy Purchases and Replacement Purchases for Base Resources and Other Resources as incurred during that billing period.

"Other Energy Mismatch" shall mean, for a billing period, the accumulated net difference in energy obtained from subtracting (i) the total energy from Available Other Capacity, Available Supplemental Capacity, and Available S&G PPA Capacity assigned and allocated in the billing period in accordance with the Billing Unit Program, from (ii) the energy actually produced from Available Other Capacity, Available Supplemental Capacity, and Available S&G PPA Capacity during that billing period.

"Other Energy Mismatch Credit" shall mean, for a billing period, the product of: (i) the absolute value of any negative value of Other Energy Mismatch for the billing period, multiplied by (ii) the Gas Energy Rate for the billing period.

"Other Energy Mismatch Charge" shall mean, for a billing period, the product of: (i) any positive value of Other Energy Mismatch for the billing period, multiplied by (ii) the Gas Energy Rate for the billing period.

"Other Energy Rate" shall mean, for each Billing Unit Entity, the rate applicable to that Billing Unit Entity's use of energy from Available Other Capacity as set forth in Exhibit A-1 to Rate Schedule A.

"Other FPPCA" shall mean Fuel and Purchase Power Cost Adjustor determined for a FPPCA Period for Other Resources, Supplemental Purchase as made for each Billing Unit Entity, and S&G PPA for each Billing Unit Entity having an ACP interest in S&G PPA.

"Other Fuel Adjustor Cost" shall mean, for a billing period for each Billing Unit Entity, the sum of the Total Other Energy Cost, Other Transmission Wheeling Cost, plus, for those Billing Unit Entities with interests in S&G PPA Capacity or Supplemental Capacity, Supplemental Demand Charge, Supplemental Wheeling Cost, S&G PPA Purchase Demand Charge and S&G PPA Wheeling Cost.

"Other Fuel Bank" shall mean, for a billing period for each Billing Unit Entity, the accumulation of Other Over or Under Collections.

"Other Incremental Unit Cost" shall mean, for a billing period for each Billing Unit Entity, the difference obtained by subtracting (i) the sum of (a) Other Power Cost Adjustor Base plus (b) Other Power Cost Adjustor Rate from (ii) Other Adjustor Per Unit Cost, for such Billing Unit Entity for such period.

"Other Over or Under Collection" shall mean, for a billing period for each Billing Unit Entity, the product of (i) Other Incremental Unit Cost, multiplied by (ii) Total Other Billing Energy, for such Billing Unit Entity for such period.

"Other Power Cost Adjustor Base" shall mean the Power Cost Adjustor Base for Other Resources as set forth in the Tariff.

"Other Power Cost Adjustor Rate" shall mean the Power Cost Adjustor Rate for Other Resources as set forth in the Tariff.

"Other Resources" shall mean all gas-fired combustion turbine and gas-fired steam Generating Resources that are Existing Resources located at Apache Generating Station, in which each Class A Member has an ACP, which include GT-1, Steam 1, GT-2, GT-3 and GT-4.

"Other Schedule" shall mean, for each Member*, its Pre-Schedules and Real-Time Schedules provided to AEPCO by Member*'s Scheduling Agent pertaining to such Member*'s use of its Available Other Capacity and, separately identified, of its Available S&G PPA Capacity, if any, as such Pre-Schedules and Real-Time Schedules are determined consistent with Schedule B to its Partial Requirements Capacity and Energy Agreement.

"Other Transmission Wheeling Cost" shall mean, for each Billing Unit Entity for a billing period, the product of (i) the costs recorded in RUS Uniform System of Accounts 565 Transmission of Electricity by Others or its successor, and allocated to Other Resources, for the same billing period, multiplied by (ii) the Billing Unit Entity's ACP in Existing Resources.

"Partial Requirements Member" shall mean MEC, SSVEC, TRICO or any other Class A Member of AEPCO that executes and delivers a Partial Requirements Capacity and Energy Agreement.

"Planning Contract Member" shall mean a Partial Requirements Member which has contracted separately from the Partial Requirements Capacity and Energy Agreement to obtain Planning Services from AEPCO.

"Post-Base Load" shall mean, for CARM or a Member* CA, the load of such Billing Unit Entity that remains after assignment of such Billing Unit Entity's Post-S&G And Supplemental Load to that Billing Unit Entity's Available Base Capacity.

"Post-Base Other Schedule" shall mean, for a Member*, the portion of the Total Schedule of such Member* that remains after assignment of such Member*'s Base Schedule to that Member*'s Available Base Capacity.

"Post-Base Transfer Load" shall mean, for CARM or a Member* CA, any load of such Billing Unit Entity that remains after assignment of such Billing Unit Entity's Post-S&G And Supplemental Transfer Load to Base Transfers of other Billing Unit Entities.

"Post-Base Transfer Other Schedule" shall mean, for Member*, any Post-S&G And Supplemental Other Schedule that remains after assignment of such Member*'s Post S&G And Supplemental Transfer Other Schedule to Base Transfers from other Billing Unit Entities.

"Post-Sales Base Capacity" shall mean, for each Billing Unit Entity, any Post Transfer Base Capacity that remains after its allocation to Base Economy Sales.

"Post-S&G And Supplemental Load" shall mean, for CARM or a Member* CA, the load of such Billing Unit Entity that remains after assignment of such Billing Unit Entity's load to that Billing Unit Entity's allocated share of S&G PPA Capacity and Supplemental Capacity.

"Post-S&G And Supplemental Transfer Load" shall mean, for CARM or a Member* CA, the load of such Billing Unit Entity that remains after assignment of S&G And Supplemental Transfers from another Billing Unit Entity to that Billing Unit Entity's Post-Base Load.

"Post-S&G And Supplemental Transfer Other Schedule" shall mean, for Member*, the Post-Base Other Schedule that remains after allocation of S&G And Supplemental Transfers from CARM or a Member* CA.

"Post-Transfer Base Capacity" shall mean, for a Billing Unit Entity, each hour's Excess Base Capacity remaining after energy from its Excess Base Capacity has been assigned as Base Transfers.

"Post-Transfer Load" shall mean, for CARM or a Member* CA, the load of such Billing Unit Entity that remains after assignment of such Billing Unit Entity's Post-Base Load to that Billing Unit Entity's allocated share of S&G And Supplemental Transfers and of Base Transfers from other Billing Unit Entities.

"Post-Transfer Other Schedule" shall mean, for a Member*, the Total Schedule of such Member* that remains after assignment of such Member*'s allocated share of S&G And Supplemental Transfers from other Billing Unit Entities to its Post-Base Other Schedule, and then assignment of such Member*s allocated share of Base Transfers from other Billing Unit Entities to that Member*'s Post-S&G And Supplemental Transfer Other Schedule.

"Post-Transfer S&G And Supplemental Capacity" shall mean, for CARM or Member* CA having an ACP in S&G PPA and/or an interest in Supplemental Purchase, each hour's Excess S&G And Supplemental Capacity remaining after energy from its Excess S&G And Supplemental Capacity has been assigned as an S&G And Supplemental

Transfer, accumulated for a billing period separately for Daytime Hours and Nighttime Hours.

"Power Sales Resource Demand Revenues" shall mean, for a billing period for each Billing Unit Entity, the product of (i) the demand-related revenue received pursuant to Power Sales Resource contracts as recorded in RUS Uniform System of Account 447 Sales for Resale, or its successor, for that billing period, multiplied by (ii) the Billing Unit Entity's ACP in Existing Resources.

"Power Sales Resource Energy Revenue" shall mean, for a billing period the energy-related revenue received pursuant to Power Sales Resource contracts as recorded in RUS Uniform System of Account 447 Sales for Resale or its successor, for that billing period.

"Pre-Schedule" shall mean a Schedule submitted by a Scheduling Agent to AEPCO for the use of Resources for the following Scheduling Day as defined by WECC.

"PRM" shall mean a Partial Requirement Member.

"Real-Time Schedule" shall mean any Schedule submitted by a Scheduling Agent to AEPCO that changes a previously submitted Tag or that requires a new Tag to be created for a Future Scheduling Hour of the current operating day.

"Remaining Base Energy Cost" shall mean, for a billing period, the total of Remaining Coal Energy Cost, Hydro Energy Charge, Base Economy Purchase Cost and Power Sales Resource Energy Revenue, for the same billing period as allocated to each Billing Unit Entity based on the ratio of (i) the Billing Unit Entity's Base Billing Energy for that billing period to (ii) the total of all Billing Unit Entities' Base Billing Energy for the same billing period.

"Remaining Coal Energy Cost" shall mean, for a billing period, Coal Energy Cost for the billing period less the sum of Base Transfer Sales Credits and Base Economy Sales Credits for all Billing Unit Entities for the same billing period.

"Replacement Purchase" shall mean any purchase of energy made to replace energy that is not available from any AEPCO Resource due to forced outage, scheduled outage or deration of such AEPCO Resource.

"S&G And Supplemental Sales Credit" shall mean, for a billing period for each Billing Unit Entity with an ACP in S&G PPA or an interest in Supplemental Purchase, the product of the Economy Purchase Rate multiplied by S&G And Supplemental Transfer, for such Billing Unit Entity for such billing period.

"S&G And Supplemental Transfer" shall mean, for a Billing Unit Entity with an ACP in S&G PPA and/or an interest in Supplemental Purchase, energy from its Excess S&G And Supplemental Capacity that has been assigned and allocated to another Billing Unit

Entity in an hour pursuant to the Billing Unit Program, accumulated for a billing period separately for Daytime Hours and Nighttime Hours.

"S&G And Supplemental Transfer Billing Energy" shall mean, for a Billing Unit Entity, energy from the Excess S&G And Supplemental Capacity of another Billing Unit Entity with an ACP in S&G PPA and/or an interest in Supplemental Purchase that has been assigned and allocated to the Billing Unit Entity in an hour pursuant to the Billing Unit Program as an S&G And Supplemental Transfer from the other Billing Unit Entity, accumulated for a billing period.

"S&G And Supplemental Transfer Purchase Cost" shall mean, for a billing period for each Billing Unit Entity that is assigned an S&G And Supplemental Transfer pursuant to the Billing Unit Program, the product of the Economy Purchase Rate multiplied by S&G And Supplemental Transfer Billing Energy, for such Billing Unit Entity for such billing period.

"S&G PPA" shall mean either or both of the following purchase power agreements: (i) the Confirmation Agreement dated August 17, 2004, between AEPCO and South Point Energy Center, LLC (South Point), by which AEPCO purchases between 25 MW and 55 MW of electric capacity and associated energy in Daylight Hours of May through October of each year from 2008 through 2014; and (ii) the Confirmation Agreement dated August 19, 2004, between AEPCO and Griffith Energy, LLC, as currently assigned pursuant to Assignment and Consent Agreement dated March 14, 2008, by which AEPCO purchases 25 MW of electric capacity and associated energy in WECC Peak Hours of May through October of each year from 2008 through 2014.

"S&G PPA Billing Energy" shall mean, for a billing period for a Billing Unit Entity with an ACP in S&G PPA, the energy from its Available S&G PPA Capacity assigned and allocated in each hour pursuant to the Billing Unit Program to its load and its S&G PPA Transfers, accumulated for a billing period.

"S&G PPA Capacity" shall mean capacity from S&G PPA.

"S&G PPA Demand Charge" shall mean, for a billing period for each Billing Unit Entity with an ACP in S&G PPA, the product of (i) the total cost incurred by AEPCO for capacity from S&G PPA during the billing period multiplied by (ii) the Billing Unit Entity's ACP in S&G PPA.

"S&G PPA Energy Charge" shall mean, for a billing period for each Billing Unit Entity with an ACP in S&G PPA, the product of (i) the total cost incurred by AEPCO for all energy from S&G PPA during the billing period multiplied by (ii) the Billing Unit Entity's ACP in S&G PPA.

"S&G PPA Schedule" shall mean, for a Member* with an ACP in S&G PPA, its Pre-Schedules and Real-Time Schedules provided to AEPCO by its Scheduling Agent pertaining to its use of its Available S&G PPA Capacity.

"S&G PPA Wheeling Cost" shall mean, for a billing period for each Billing Unit Entity with an ACP in S&G PPA, the product of (i) the cost incurred by AEPCO for wheeling energy from S&G PPA during the billing period multiplied by (ii) the Billing Unit Entity's ACP in S&G PPA.

"Schedule" shall mean, for each Member*, any of its Base Schedule, its Other Schedule, and, if applicable, its S&G PPA Schedule.

"Scheduling Agent" shall mean the entity designated by a Member* to provide Pre-Schedules and Real-Time Schedules to AEPCO for such Member*'s hourly use of its AC in AEPCO Resources.

"Supplemental Billing Energy" shall mean, for a billing period for a Billing Unit Entity with an interest in Supplemental Purchase, the energy from its Available Supplemental Capacity assigned and allocated in each hour pursuant to the Billing Unit Program to its load and its Supplemental Transfers, accumulated for a billing period.

"Supplemental Capacity" shall mean capacity from Supplemental Purchase.

"Supplemental Demand Charge" shall mean, for a billing period for each Billing Unit Entity with an interest in Supplemental Purchase, the product of (i) the total cost incurred by AEPCO for capacity from Supplemental Purchase during the billing period multiplied by (ii) the Billing Unit Entity's ACP in Supplemental Purchase.

"Supplemental Energy Charge" shall mean, for a billing period for each Billing Unit Entity with an interest in Supplemental Purchase, the product of (i) the total cost incurred by AEPCO for all energy from Supplemental Purchase during the billing period multiplied by (ii) the Billing Unit Entity's ACP in the Supplemental Purchase.

"Supplemental Purchase" shall mean, in a billing period, any purchase of firm energy made for a period of less than a year to serve load of CARM or a Planning Contract Member in excess of CARM's or the Planning Contract Member's ACP shares of capacity of S&G PPA and Existing Resources.

"Supplemental Purchase Cost" shall mean, for a billing period, the total cost incurred by AEPCO (including transmission expenses, including losses, incurred in delivery from the source of such purchase to an SWTC Point of Receipt, if any) for all Supplemental Purchases during the billing period.

"Supplemental Wheeling Cost" shall mean, for a billing period for each Billing Unit Entity with an interest in Supplemental Purchase, the product of (i) the cost incurred by AEPCO for wheeling energy from Supplemental Purchase during the billing period multiplied by (ii) the Billing Unit Entity's ACP in Supplemental Purchase.

"Tariff" shall mean, at any time, the currently effective form setting forth the various AEPCO rates and charges applicable to each Billing Unit Entity as approved by the ACC.

"Third Party Economy Sales" shall mean, for each of Daytime Hours and Nighttime Hours, any transactions in which AEPCO sells at wholesale energy from available AEPCO Resources to a third party, which transaction is not a Power Sales Resource, and which is recorded and reported as an economy sale by AEPCO to RUS Uniform System of Accounts Number 447.

"Total Other Billing Energy" shall mean, for a billing period for each Billing Unit Entity, the sum of S&G And Supplemental Transfer Billing Energy, S&G PPA Billing Energy, Supplemental Billing Energy, Other Billing Energy and Base Transfer Billing Energy for such Billing Unit Entity for such billing period.

"Total Other Energy Cost" shall mean, for a billing period for each Billing Unit Entity, the sum of Other Energy Cost, S&G PPA Energy Charge, Supplemental Purchase Cost, S&G And Supplemental Transfer Purchase Cost, S&G And Supplemental Sales Credit, Directed Sales Credit, Base Transfer Purchase Cost, and Other Economy Sales Credit.

"Total Schedule" shall mean, for each Member*, its Base Schedule, plus its Other Schedule, plus, if applicable, its S&G PPA Schedule.

3. BILLING UNIT PROGRAM METHODOLOGY:

The Billing Unit Program shall be assembled and maintained to reflect AEPCO's economic dispatch philosophy and priority as further set forth in Schedule B to the Partial Requirements Capacity and Energy Agreements. The Parties have divided and defined AEPCO Resources based on the respective interests therein as assigned under the Billing Unit Program, the definition of which is set forth in Appendix A to this Exhibit A-4, attached hereto and a part hereof.

The Billing Unit Program is established hereunder to account for hourly energy, separately for Daytime and Nighttime hours, first, for each Billing Unit Entity, its Minimum Other Capacity, then for each Billing Unit Entity having an ACP in S&G PPA or an interest in Supplemental Purchase, from its interests in Available Supplemental Capacity and Available S&G PPA Capacity (as dispatched by AEPCO under governing purchase contracts), then for each Billing Unit Entity its Available Base Capacity and finally its remaining Available Other Capacity. These hourly amounts for each Billing Unit Entity are assigned first to any Directed Sales of a Member* CA, to the loads of the CARM and Member* CA and to each Member*'s Total Schedule, but only to the extent required by the load of the CARM, by the Directed Sales and load of the Member* CA and by the Member*'s Total Schedule.

If a Billing Unit Entity has load or a Schedule that is not satisfied by its Available Base Capacity, Available Supplemental Capacity and Available S&G PPA Capacity, the Billing Unit Entity shall be assigned S&G And Supplemental Transfers and Base

Transfers from other Billing Unit Entities' Excess S&G And Supplemental Capacity and Excess Base Capacity pursuant to the Billing Unit Program, proportionately based on the need of each Billing Unit Entity for Other Resources to the need of all Billing Unit Entities for Other Resources. To the extent a Billing Unit Entity still has load or a Schedule that is not satisfied, energy shall be assigned to it from its Available Other Capacity.

On the other hand, if a Billing Unit Entity has any Excess S&G And Supplemental Capacity or Excess Base Capacity, it shall be assigned pursuant to the Billing Unit Program proportionately based on available excess as S&G And Supplemental Transfers and Base Transfers. Then any Post-Transfer Base Capacity shall be assigned pursuant to the Billing Unit Program proportionately based on the amounts of such excess in the hour as Base Economy Sales, if any, or shall be assigned as Base Energy Mismatch or Other Energy Mismatch, as applicable.

Finally pursuant to the Billing Unit Program, the Other Economy Sales accumulated for the billing period will be allocated to each Billing Unit Entity proportionately based on each Billing Unit Entity's proportionate share of the billing period's accumulated totals of Post-Transfer S&G And Supplemental Capacity, each Member*'s Other Billing Energy, CARM Other Billing Energy, and each Member* CA's Other Billing Energy.

The Parties agree that all such assignments and allocations represent sale and purchase transactions to and from the Dispatch Pool Resources for which each Billing Unit Entity shall be credited or billed pursuant to Section 4 below.

Base Energy Mismatch and Other Energy Mismatch may occur due to operating conditions experienced during any billing period when the assignment and allocation of energy pursuant to the Billing Unit Program may be more or less than the amount of energy actually produced by the Dispatch Pool Resources; the causes of which may include, but are not limited to: (i) energy received from resources of third parties or provided to third parties for losses repayment; (ii) variations between loss accounting and actual hourly losses occurring on the system; (iii) energy interchange with other utilities; (iv) metering errors; and (v) inadvertent flows between AEPCO and its Balancing Authority. The Billing Unit Program shall compute for each billing period the total net Base Energy Mismatch and total Other Energy Mismatch and assign a credit or charge for the period, as applicable, which shall be recovered through the appropriate FPPCA.

The initial logic flow diagram of the Billing Unit Program is attached hereto as Appendices B through D to this Exhibit A-4 and is a part hereof. The Billing Unit Program shall be the sole and exclusive method for billing purposes of assigning energy billing units from Dispatch Pool Resources to Billing Unit Entities, and may only be modified by a written amendment agreed to by the CEOs of all Billing Unit Entities.

4. <u>METHODOLOGY FOR DETERMINING TARIFF ENERGY RATES</u>:

The following describes the method AEPCO shall use to formulate the Base Energy Rate and the Other Energy Rate.

4.1 Tariff Base Energy Rate.

The Base Energy Rate of the Tariff shall be the quotient obtained by dividing (i) the Base Energy Cost of the test period, as adjusted for changes expected in the foreseeable period beyond the test period, inclusive of each Billing Unit Entity's Base Transfer Sales Credits, Base Transfer Energy Cost, Base Economy Sales Credits, Base Economy Sales Cost and Remaining Base Energy Cost, by (ii) each Billing Unit Entity's Base Billing Energy of the test period, as adjusted for changes expected in the foreseeable period beyond the test period, as determined pursuant to the Billing Unit Program.

4.1.1 The Base Energy Rate of each All Requirements Member shall be the same as the Base Energy Rate for CARM.

4.1.2 The Base Power Cost Adjustor Base for each All Requirements Member shall be the same as the Base Power Cost Adjustor Base determined for CARM.

4.1.3 The Base Billing Energy of each All Requirements Member shall be the product of (i) the Base Billing Energy of CARM, multiplied by (ii) that All Requirements Member's ARM ECR.

4.2 Tariff Other Energy Rate.

The Other Energy Rate of the Tariff shall be the quotient obtained by dividing (i) the Total Other Energy Cost of each Billing Unit Entity of the test period, as adjusted for changes expected in the foreseeable period beyond the test period, inclusive of each Billing Unit Entity's applicable Base Transfer Purchase Cost, S&G PPA Energy Cost, Supplemental Purchase Cost, S&G And Supplemental Transfer Purchase Cost, S&G And Supplemental Transfer Sales Credit, Other Economy Sales Credit and its share of Base Mismatch Energy Credit, Base Mismatch Energy Charge, Other Mismatch Energy Credit, Other Mismatch Energy Charge and, if any, by (ii) the Total Other Billing Energy as applicable to each Billing Unit Entity for the test period, as adjusted for changes expected in the foreseeable period beyond the test period, as determined pursuant to the Billing Unit Program.

4.2.1 The Other Energy Rate of each All Requirements Member shall be the same as the Other Energy Rate for CARM.

4.2.2 The Other Power Cost Adjustor Base for each All Requirements Member shall be the same as the Other Power Cost Adjustor Base determined for CARM.

4.2.3 The Total Other Billing Energy of each All Requirements Member shall be the product of (i) the Total Other Billing Energy of CARM, multiplied by (ii) that All Requirements Member's ARM ECR.

5. DETERMINING BASE AND OTHER ENERGY CHARGES:

5.1 Each billing period, AEPCO shall charge each Billing Unit Entity a Base Energy Charge, Base Fuel Adjustor Charge, Total Other Energy Charge and Other Fuel Adjustor Charge as defined in the Tariff. For each billing period, AEPCO shall compute each Billing Unit Entity's Base Over or Under Collection and Other Over or Under Collection for each billing period, which AEPCO shall accumulate and use to establish future Base Fuel Adjustor Rates and Other Fuel Adjustor Rates.

5.1.1 Base Energy Charge: The Base Energy Charge for each Billing Unit Entity for a billing period shall equal the product of the Base Billing Energy of the Billing Unit Entity, multiplied by the Base Energy Rate as set forth in the Tariff.

5.1.2 Base Fuel Adjustor Charge: The Base Fuel Adjustor Charge for each Billing Unit Entity for a billing period shall equal the product of the Base Billing Energy of the Billing Unit Entity, multiplied by the Base Fuel Power Cost Adjustor Rate as set forth in the Tariff.

5.1.3 Base Over or Under Collection: The Base Over and Under Collection for each Billing Unit Entity for a billing period shall be determined pursuant to the methodology approved by the ACC related to the product of (a) any difference between (i) the Base Adjustor Per Unit Cost and (ii) the sum of the Base Power Cost Adjustor Base plus the Base Power Cost Adjustor Rate in the Tariff, multiplied by (b) the Base Billing Energy of each Billing Unit Entity for that period.

5.1.4 Other Energy Charge: The Other Energy Charge for each Billing Unit Entity for a billing period shall equal the product of the Total Other Billing Energy of the Billing Unit Entity, multiplied by the Other Energy Rate as set forth in the Tariff.

5.1.5 Other Fuel Adjustor Charge: The Other Fuel Adjustor Charge for each Billing Unit Entity for a billing period shall equal the product of the Total Other Billing Energy of the Billing Unit Entity, multiplied by the Other Fuel Power Cost Adjustor Rate as set forth in the Tariff.

5.1.6 Other Over or Under Collection: The Other Over and Under Collection for each Billing Unit Entity for a billing period shall be determined pursuant to the methodology approved by the ACC related to the product of (a) any difference between (i) the Other Adjustor Per Unit Cost and (ii) the sum of the Other Power Cost Adjustor Base plus the Other Power Cost Adjustor Rate in the Tariff, multiplied by (b) the Total Other Billing Energy of each Billing Unit Entity for that period.

6. ENERGY COST ACCOUNTING PROCESS:

The following describes the method of the Energy Cost Accounting Process (ECAP) AEPCO shall use to formulate for each billing period each Billing Unit Entity's Base Energy Cost, Base Fuel Adjustor Cost, Total Other Energy Cost and Other Fuel Adjustor Cost, from which AEPCO shall compute each Billing Unit Entity's Base Adjustor Per Unit Cost and Other Adjustor Per Unit Cost for the billing period, which shall be used to calculate for each billing period (i) Base Over and Under Collection and Other Over or Under Collection for such energy and (ii) fuel adjustor costs, which AEPCO shall accumulate and use to establish future Base Fuel Adjustor Rates and Other Fuel Adjustor Rates.

The initial logic flow diagram of the ECAP is attached hereto as Appendices E and F to this Exhibit A-4 and is a part hereof.

6.1 Formulating Base Energy Cost.

For each billing period, the ECAP shall first compute the Coal Energy Cost and use it to calculate the Coal Energy Rate based on the Coal Energy Generated.

The ECAP shall then use Base Transfer for the billing period to compute, separately for Daytime and Nighttime, Base Transfer Sales Credit based on the Coal Energy Rate, and use Base Transfer Billing Energy to compute, separately for Daytime and Nighttime, Base Transfer Energy Cost, based on the Economy Purchase Rate. Using the billing units determined for the billing period pursuant to the Billing Unit Program, the Base Transfer Sales Credits and Base Transfer Energy Cost will then be allocated to each Billing Unit Entity. Similarly, the ECAP shall use Base Economy Sales for the billing period to compute Base Economy Sales Credits (separately for Daytime and Nighttime) and Base Economy Sales Cost, based on Economy Sales Price (separately for Daytime and Nighttime) and the Coal Energy rate, respectively, and shall then allocate such Base Economy Sales Credits and Base Economy Sales Cost to each Billing Unit Entity pursuant to the billing units assigned by the Billing Unit Program.

The ECAP shall then calculate Base Billing Energy Cost for the billing period, by adding Remaining Coal Energy Cost, Hydro Energy Charge, Base Economy Purchases and Power Sales Resource Energy Revenue, and shall allocate such Base Billing Energy Cost to each Billing Unit Entity pursuant to the billing units assigned by the Billing Unit Program.

Finally, the ECAP shall calculate for the billing period each Billing Unit Entity's (i) Base Energy Cost, which shall be the total of the Billing Unit Entity's Base Transfer Sales Credit, Base Transfer Energy Cost, Base Economy Sales Credit, Base Economy Sales Cost and Remaining Base Energy Cost, and (ii) Base Average Energy Rate, which shall be the quotient of the Billing Unit Entity's Base Energy Cost divided by its Base Billing Energy determined pursuant to the billing units assigned by the Billing Unit Program.

6.2 Formulating Base Adjustor Per Unit Cost.

The ECAP shall allocate to each Billing Unit Entity based on the Billing Unit Entity's Allocated Capacity Percentage the billing period's total Hydro Demand Charge, Base Transmission Wheeling Cost and Power Sales Resource Demand Cost, which allocation ECAP shall add to the Billing Unit Entity's Base Energy Cost to formulate the Billing Unit Entity's Base Fuel Adjustor Cost.

The ECAP shall then determine each Billing Unit Entity's Base Adjustor Per Unit Cost for the billing period, which shall be the quotient of the Billing Unit Entity's Base Fuel Adjustor Cost divided by its Base Billing Energy pursuant to the billing units assigned by the Billing Unit Program.

6.3 Formulating Base Over or Under Collection.

The ECAP shall then determine for the billing period each Billing Unit Entity's (a) Base Incremental Unit Cost, which shall be equal to the Billing Unit Entity's Base Adjustor Per Unit Cost less the sum of (i) its Base Power Cost Adjustor Base and (ii) its Base Power Cost Adjustor Rate, and (b) Base Over or Under Collection, which shall be the product of the Billing Unit Entity's Base Incremental Unit Cost multiplied by its Base Billing Energy. Each Billing Unit Entity's Base Over or Under Collection shall then be added to the balance in its Base Fuel Bank.

6.4 Formulating Total Other Energy Cost.

Each billing period, the ECAP shall use the Economy Purchase Rate (separately for Daytime and Nighttime) to determine S&G And Supplemental Purchase Cost and S&G And Supplemental Sales Credit based on S&G And Supplemental Transfer. Such S&G And Supplemental Purchase Cost and S&G And Supplemental Sales Credit shall then be allocated as appropriate to each Billing Unit Entity pursuant to the billing units assigned by the Billing Unit Program.

The ECAP shall allocate to each Billing Unit Entity pursuant to the billing units assigned by the Billing Unit Program (i) the billing period's Other Economy Sales Credit as appropriate based on the Billing Unit Entity's proportionate share of the billing period's Post-Transfer S&G And Supplemental Capacity and Other Billing Energy, and (ii) the billing period's Other Energy Cost based on the Billing Unit

Entity's Other Billing Energy. The ECAP shall then assign to each Billing Unit Entity pursuant to the Billing Unit Entity's ACP and/or interest in and the billing units assigned by the Billing Unit Program, as applicable, the Billing Unit Entity's S&G PPA Energy Charge, Supplemental Energy Charge, Base Transfer Purchase Cost, Other Energy Cost, Directed Sales Credit, and its share of Base Mismatch Energy Credit, Base Mismatch Energy Cost, and Other Mismatch Energy Credit.

Finally, the ECAP shall determine for the billing period (i) each Billing Unit Entity's Total Other Energy Cost, which shall be equal to the sum of all the credits and costs allocated or assigned to the Billing Unit Entity as described in this Section 6.4, and (ii) each Billing Entity's Other Average Energy Rate, which shall be the quotient of its Total Other Energy Cost divided by its Total Other Billing Energy.

6.5 Formulating Other Adjustor Per Unit Cost.

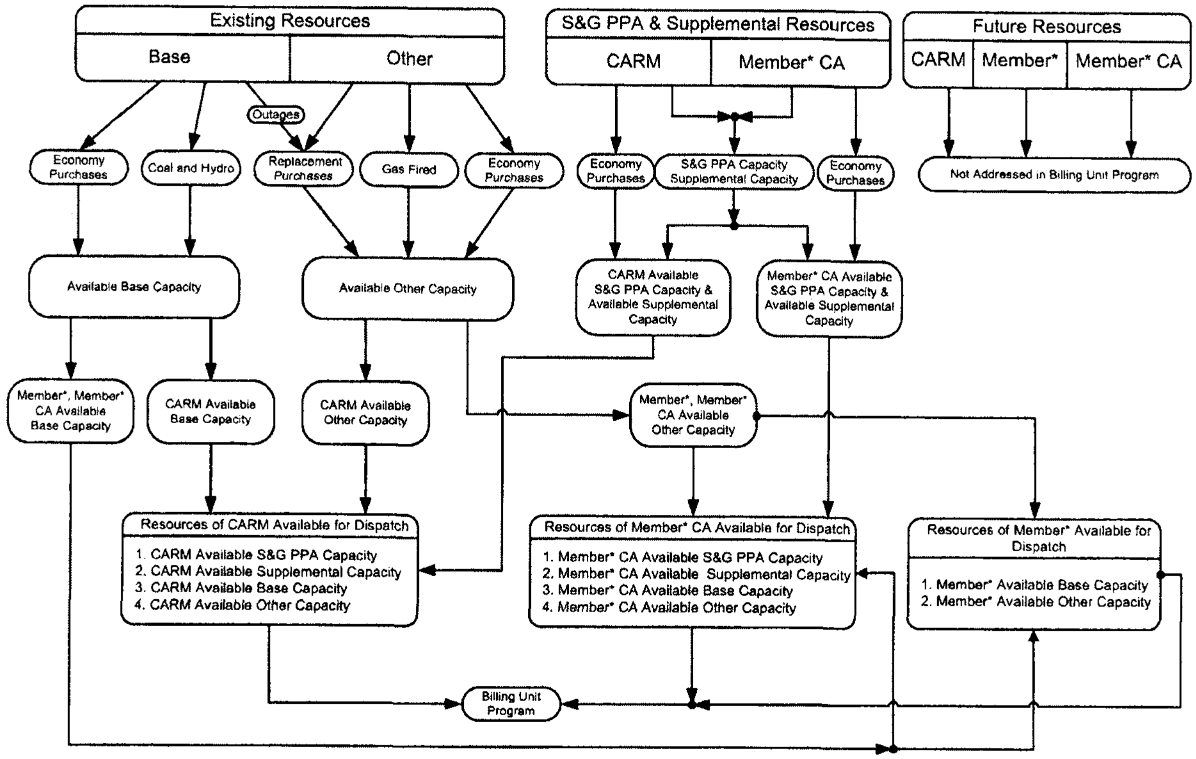
The ECAP shall allocate to each Billing Unit Entity the billing period's (i) total Other Transmission Wheeling Cost based on the Billing Unit Entity's Allocated Capacity Percentage, and (ii) S&G PPA Demand Charge, S&G PPA Wheeling Cost, Supplemental Demand Charge and Supplemental Wheeling Charge, pursuant to the Billing Unit Entity's ACP share or interest therein, if any. The ECAP shall then add such allocations to each Billing Unit Entity's Total Other Energy Cost to formulate the Billing Unit Entity's Other Fuel Adjustor Cost.

The ECAP shall then determine each Billing Unit Entity's Other Adjustor Per Unit Cost for the billing period, which shall be the quotient of the Billing Unit Entity's Other Fuel Adjustor Cost divided by its Total Other Billing Energy pursuant to the billing units assigned by the Billing Unit Program.

6.6 Formulating Other Over or Under Collection.

The ECAP shall then determine for the billing period each Billing Unit Entity's (a) Other Incremental Unit Cost, which shall be equal to the Billing Unit Entity's Other Adjustor Per Unit Cost less the sum of (i) its Other Power Cost Adjustor Base, plus (ii) its Other Power Cost Adjustor Rate, and (b) Other Over or Under Collection, which shall be the product of the Billing Unit Entity's Other Incremental Unit Cost multiplied by its Other Billing Energy. Each Billing Unit Entity's Other Over or Under Collection shall then be added to the balance in its Other Fuel Bank.

Appendix A to Exhibit A-4 to Rate Schedule A: AEPCO Resources Definitions Flow Diagram



Appendix B Footnotes:

(1) Subroutine: CARM Post S&G And Supplemental Load is first assigned to CARM Minimum Other Capacity.
(1a) Subroutine: CARM Load is first assigned to CARM Minimum Other Capacity.
(2) Subroutine: Determines the extent to which other Billing Unit Entities need Excess Base Capacity of other Billing Unit Entities for their Post S&G and Supplemental Transfer Other Schedule or Post S&G And Supplemental Transfer Load.
(3) Subroutine: CARM Excess S&G And Supplemental Capacity is allocated as CARM S&G And Supplemental Transfers proportionately based on need to Member* Other Schedule and Member* CA Post Base Load, until such CARM Excess S&G And Supplemental Capacity is consumed, or until Member* Other Schedule and Member* CA Post Base Load are satisfied.
(4) Subroutine: Member*, Member* CA Excess Base Capacity is allocated proportionately based on need to CARM and Member* CA Post-S&G And Supplemental TransferLoad and Member* Post-S&G And Supplmental Transfer Other Schedule until such Member*, Member* CA Excess Base Capacity is consumed, or until such CARM and Member* CA Post S&G and Supplemental Transfer Load and Member* Post-S&G And Supplemental Transfer Other Schedule are satisfied.
(5) Subroutine: CARM Excess Base Capacity is allocated proportionately based on need to Member* Post S&G And Supplemental Transfer Other Schedule and Member* CA Post S&G And Supplemental Transfer Load until such CARM Excess Base Capacity is consumed, or until Member* Post S&G And Supplemental Transfer Other Schedule and Member* CA Post S&G And Supplemental TransferLoad are satisfied.
(6) Subroutine: CARM Post Transfer Base Capacity, Member* CA Post Transfer Base Capacity, and Member* Post Transfer Base Capacity are assigned hourly to Base Economy Sales
(7) Subroutine: CARM Post Transfer S&G And Supplemental Capacity, Member* CA Post Transfer S&G And Supplemental Capacity, CARM Other Billing Energy, Member* CA Other Billing Energy, and Member* Other Billing Energy are used to apportion and allocate monthly Other Economy Sales.

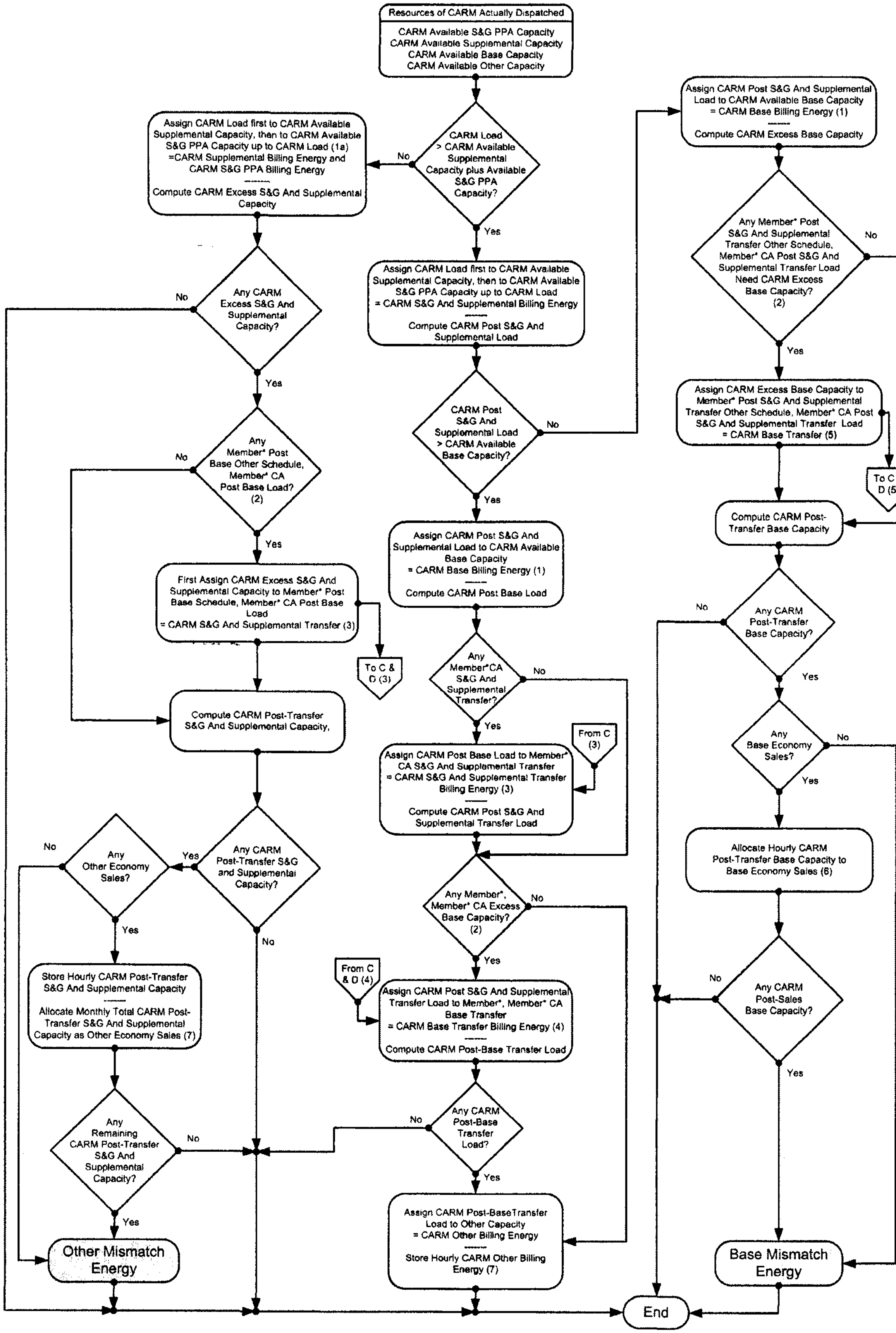
Appendix C Footnotes:

(1) Subroutine: Member* CA Post S&G And Supplemental Load is first assigned to Member* CA Minimum Other Capacity.
(1a) Subroutine: Member* CA Directed Sales and Load is first assigned to Member* CA Minimum Other Capacity.
(2) Subroutine: Determines the extent to which other Billing Unit Entities need Excess Base Capacity of other Billing Unit Entities for their Post S&G And Supplemental Transfers Other Schedule or Post S&G And Supplemental TransferLoad which can be assigned to this Billing Unit Entity's Excess Base Capacity.
(3) Subroutine. Member* CA Excess S&G And Supplemental Capacity is allocated as Member* CA S&G And Supplemental Transfers proportionately based on need to Member* Post Base Other Schedule, CARM Post Base Load, and other Member* CA Post Base Load, until such Member* CA Excess S&G And Supplemental Capacity is consumed, or until Member* Other Schedule, other Member* CA Post Base Load and CARM Post Base Load are satisfied.
(4) Subroutine: Member*, CARM, and other Member* CA Excess Base Capacity are allocated proportionately based on need to CARM and other Member* CA Post-S&G And Supplemental Transfer Load and Member* Post-S&G And Supplemental Transfer Other Schedule until such Member*, CARM and other Member* CA Excess Base Capacity are consumed, or until such CARM and other Member*CA Post-S&G And Supplemental Transfer Load and Member* Post-S&G And Supplemental Other Schedule are satisfied.
(5) Subroutine: Member* CA Excess Base Capacity is allocated proportionately based on need to Member* Post-S&G And Supplemental Transfer Other Schedule, other Member * CA Post-S&G And Supplemental TransferLoad, and CARM Post-S&G And Supplemental Transfer Load until such Member* CA Excess Base Capacity is consumed, or until Member* Post-S&G And Supplemental Transfer Other Schedule, other Member* CA Post-S&G And Supplemental Transfer Load and CARM Post-S&G And Supplemental Transfer Load are satisfied.
(6) Subroutine: CARM Post Transfer Base Capacity, Member* CA Post Transfer Base Capacity, and Member* Post Transfer Base Capacity are assigned hourly to Base Economy Sales.
(7) Subroutine: CARM Post Transfer S&G And Supplemental Capacity, Member* CA Post Transfer S&G And Supplemental Capacity, CARM Other Billing Energy, Member* CA Other Billing Energy, and Member* Other Billing Energy are used to apportion and allocate monthly Other Economy Sales.

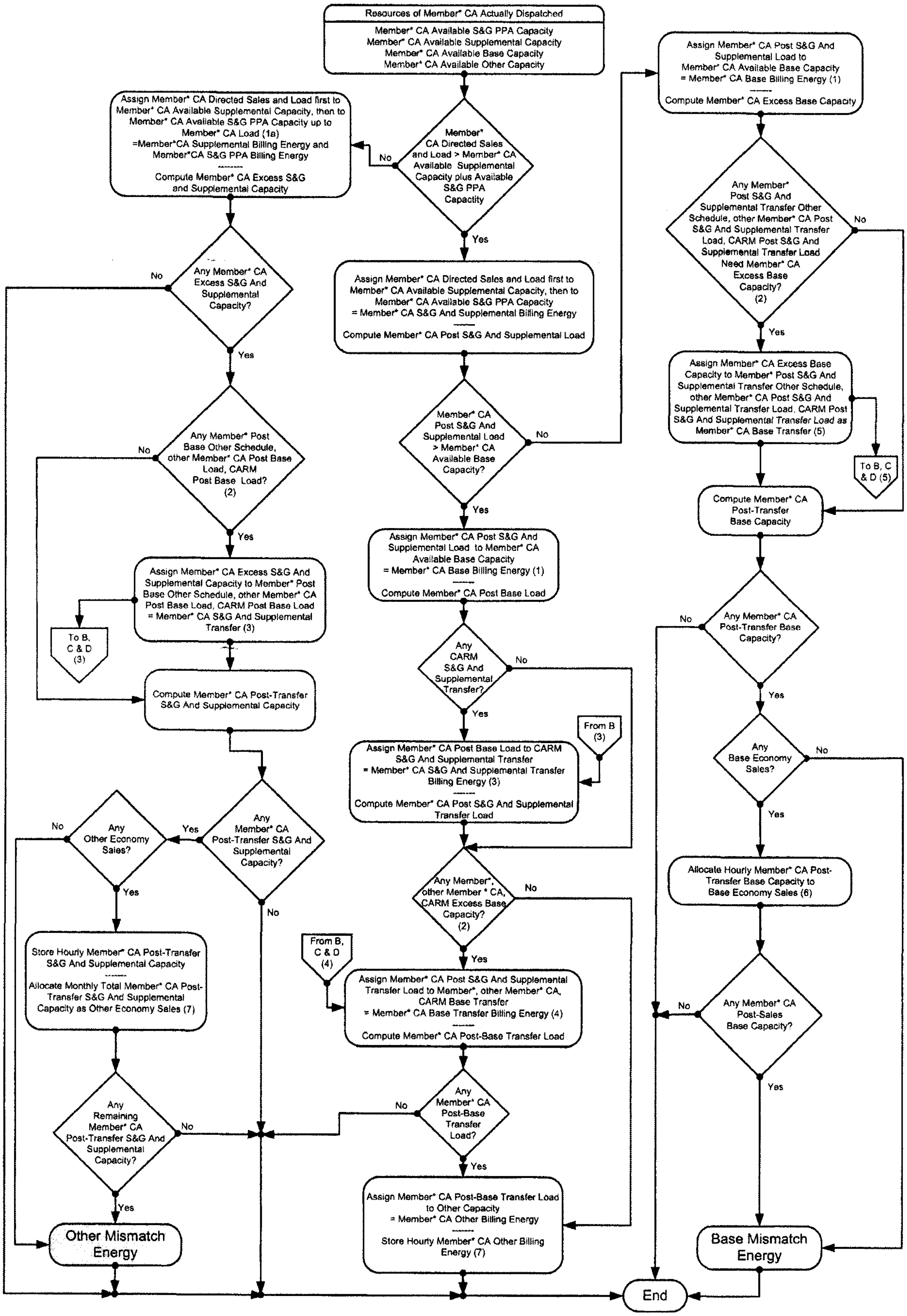
Appendix D Footnotes:

(1) Subroutine: Member* Base Schedule is first assigned to Member* Minimum Other Capacity.
(2) Subroutine: (2) Subroutine: Determines the extent to which other Billing Unit Entities need Excess Base Capacity of other Billing Unit Entities for their Post S&G And Supplemental Transfers Other Schedule or Post S&G And Supplemental TransferLoad which can be assigned to this Billing Unit Entity's Excess Base Capacity.
(3) Subroutine: Member* CA and CARM Excess S&G And Supplemental Capacity are allocated as Member* CA S&G And Supplemental Transfers proportionately based on need to Member* Post Base Other Schedule, CARM Post Base Load, and other Member* CA Post Base Load, until such Member* CA Excess S&G And Supplemental Capacity is consumed, or until Member* Post Base Other Schedule, other Member* CA Post Base Load and CARM Post Base Load are satisfied.
(4) Subroutine: Member*, CARM, and other Member* CA Excess Base Capacity are allocated proportionately based on need to CARM and other Member* CA Post-S&G And Supplemental Transfer Load and Member* Post-S&G And Supplemental Transfer Other Schedule until such Member*, CARM and other Member* CA Excess Base Capacity are consumed, or until such CARM and other Member*CA Post-S&G And Supplemental Transfer Load and Member* Post-S&G And Supplemental Other Schedule are satisfied.
(5) Subroutine: Member* Excess Base Capacity is allocated proportionately based on need to each Member* Post-S&G And Supplemental Transfer Other Schedule, other Member * CA Post-S&G And Supplemental TransferLoad, and CARM Post-S&G And Supplemental Transfer Load until such Member* CA Excess Base Capacity is consumed, or until Member* Post-S&G And Supplemental Transfer Other Schedule, other Member* CA Post-S&G And Supplemental Transfer Load and CARM Post-S&G And Supplemental Transfer Load are satisfied.
(6) Subroutine: CARM Post Transfer Base Capacity, Member* CA Post Transfer Base Capacity, and Member* Post Transfer Base Capacity are assigned hourly to Base Economy Sales.
(7) Subroutine: CARM Post Transfer S&G And Supplemental Capacity, Member* CA Post Transfer S&G And Supplemental Capacity, CARM Other Billing Energy, Member* CA Other Billing Energy, and Member* Other Billing Energy are used to apportion and allocate monthly Other Economy Sales.
(8) No Partial Requirements Member with an interest in S&G PPA currently plans to operate outside the AEPCO pseudo-control area. In the event that a Partial Requirements Member with such an interest chooses to operate outside the AEPCO pseudo-control area in the future, the Appendix D flow chart for such a Member* will need to be modified.

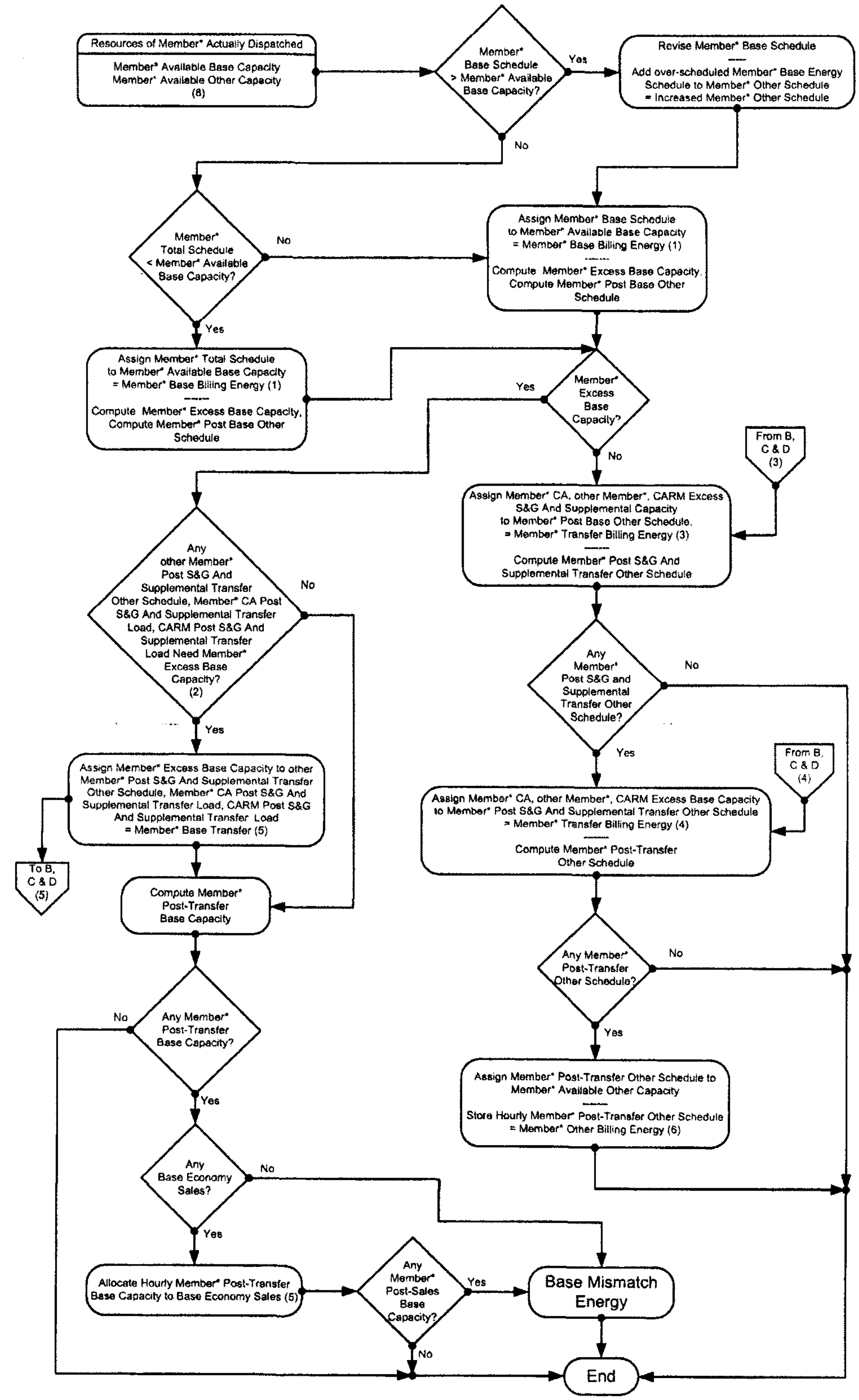
Appendix B to Exhibit A-4 to Rate Schedule A: Billing Unit Program Flow Diagram
CARM Load Use of AEPCO Resources and Assignments as Additional and Base Transfers and AEPCO Third Party Sales



Appendix C to Exhibit A-4 to Rate Schedule A: Billing Unit Program Flow Diagram
Member* CA Load use of AEPCO Resources and Assignments as S&G PPA and Base Transfers and AEPCO Third Party Sales

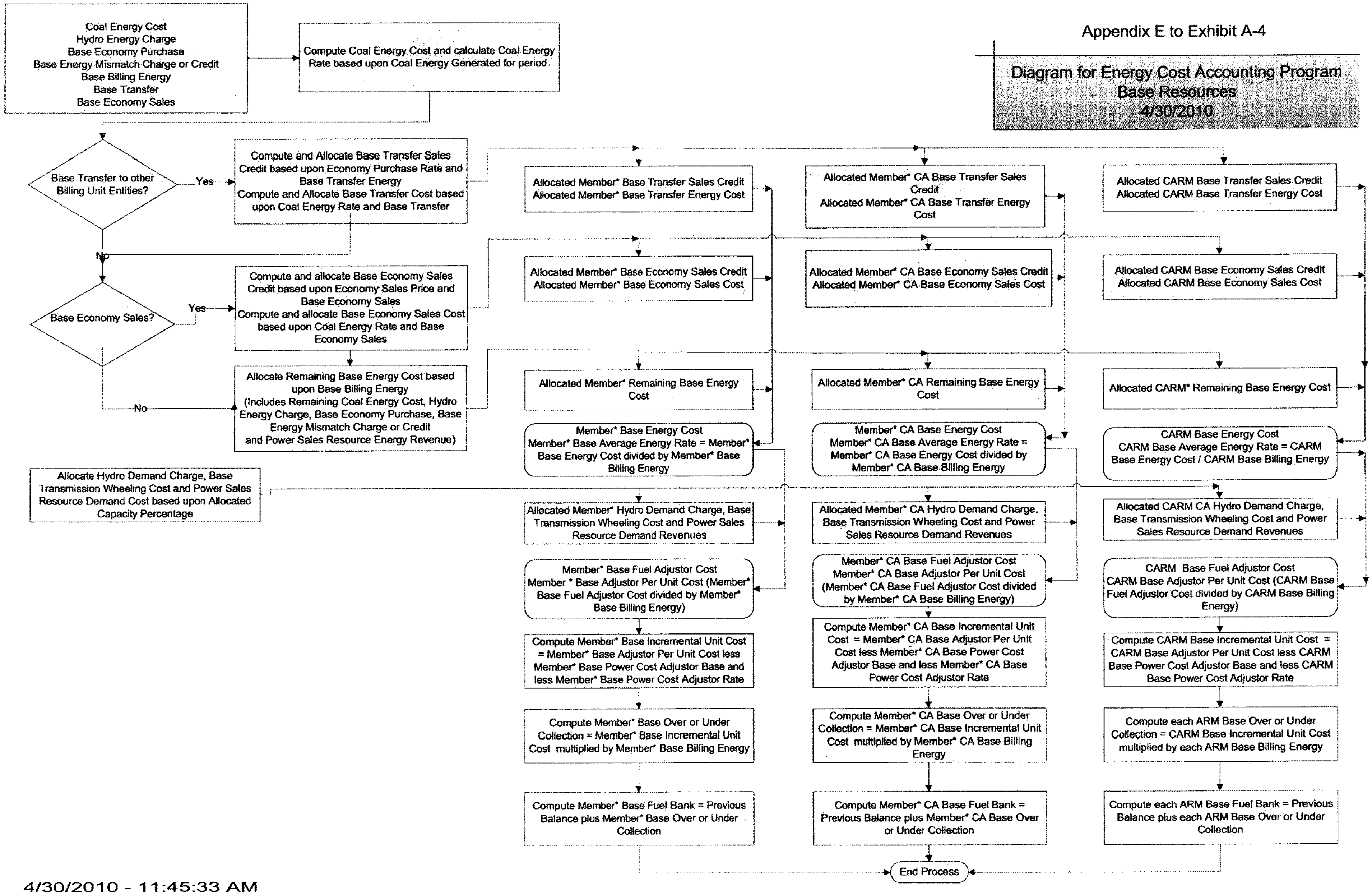


Appendix D to Exhibit A-4 to Rate Schedule A: Billing Unit Program Flow Diagram
Member* Use of AEPCO Resources and Assignments as Base Transfers and AEPCO Third Party Sales



Appendix E to Exhibit A-4

Diagram for Energy Cost Accounting Program
Base Resources
4/30/2010



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Appendix F to Exhibit A-4

Diagram for Energy Cost Accounting Program
Other Resources
4/30/2010

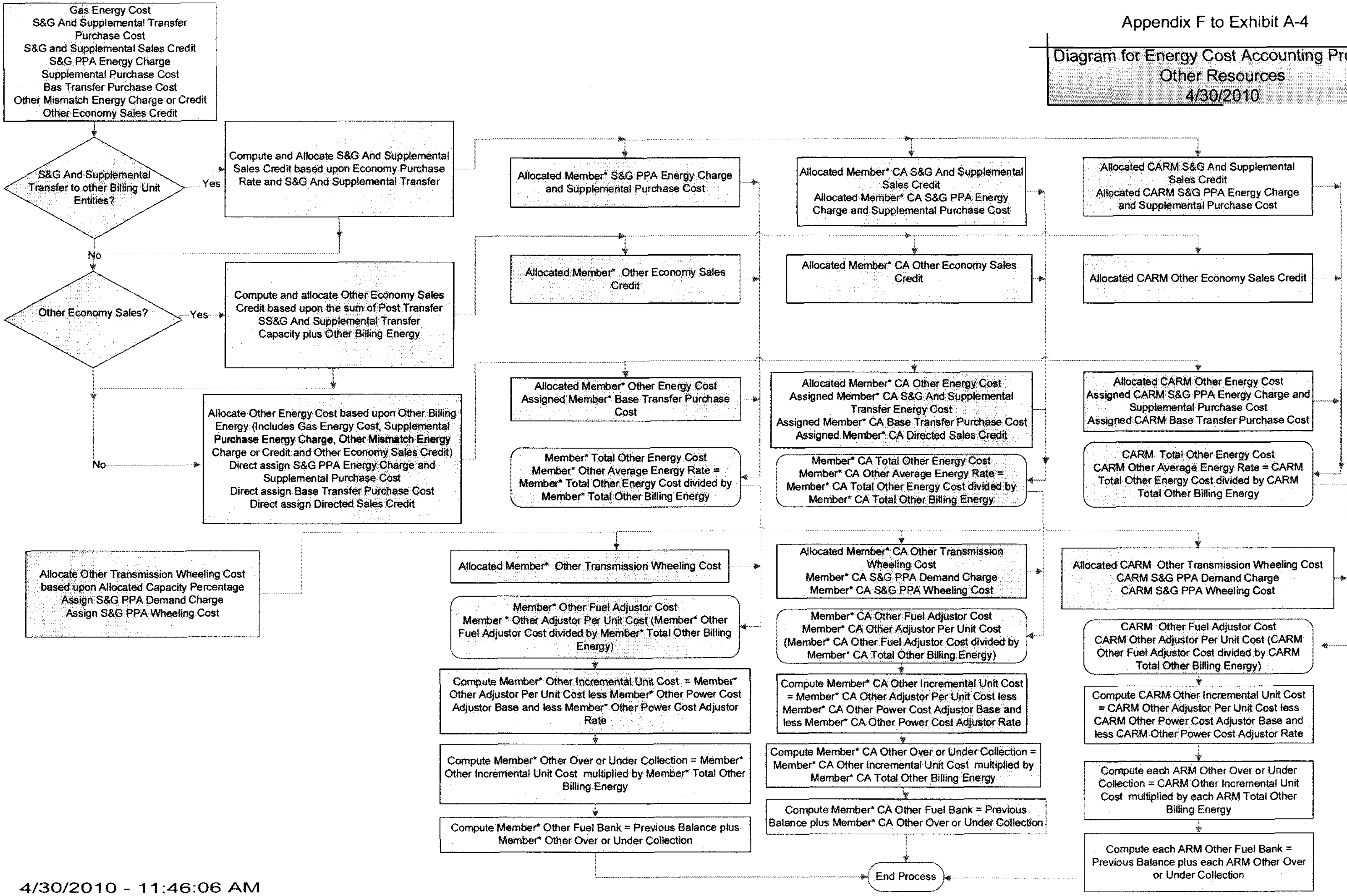

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Exhibit A-5 to Rate Schedule A
Allocated Capacity Percentages (ACP),
Allocated Capacity (AC)
and Reserves

ACP and AC DETERMINATION

An Allocated Capacity Percentage (ACP) was developed for Existing Resources as of the Effective Date for each Class A Member based on load forecasts from the 1996 Power Requirements Study (1996 PRS). The ACP in Existing Resources is used to calculate the Allocated Capacity (AC) for each Partial Requirements Member (PRM), and each All Requirements Member (ARM) in Existing Resources.

At the outset of AEPCO's restructuring, AEPCO, all AEPCO Class A Members, and RUS had approved the use of the 1996 PRS for planning purposes. AEPCO and its Class A Members agreed to the specific use of the 1996 PRS and forecast year 2000 as the basis for calculating the ACP in Existing Resources because: (i) the annual coincident peak of AEPCO best matched the Existing Resources in forecast year 2000, and (ii) after forecast year 2000, AEPCO was projected to need additional Resources. The calculation used in determining the ACP in Existing Resources is summarized in Part A of Appendix A to this Exhibit A-5. The ACP calculation for Existing Resources utilized the forecasted year 2000 monthly coincident peaks of the Class A Members, which were obtained by multiplying: (a) each Member's forecasted monthly non-coincident peak as identified in the 1996 PRS, by (b) a historical three-year average coincident factor. The resulting twelve monthly coincident peaks were summed both for each Class A Member and for all Class A Members. The ACP for each Class A Member represents the percentage quotient of (a) the sum of the monthly coincident peaks for that Class A Member divided by (b) the sum of the monthly coincident peaks for all Class A Members. The ACP of an ARM in Existing Resources shall be used to determine its AC in Existing Resources in the event such ARM elects to become a Partial Requirements Member pursuant to the Conversion Agreement between the Class A Members and AEPCO dated August 1, 2001 (Conversion Agreement). The sum of the ACP's of the ARMs shall be the ACP of the Collective ARM (CARM) for purposes of Rate Schedule A to Existing Wholesale Power Contracts.

The monthly AC assigned to each PRM and the CARM from Existing Resources has been calculated by: (1) determining the capacity (in MW) of the generating units that comprise Existing Resources; (2) determining the Reserve percentage (described hereinafter) to be set aside from the generating units that comprise Existing Resources; (3) subtracting the Power Sales Resources as of the Closing Date of AEPCO's restructuring, including associated reserves and delivery losses attributable to such Power Sales: (4) further reducing the Existing Resource generating unit capacity for AEPCO generating unit reserves and delivery losses; (5) adding the monthly capacity from the Federal Hydro Power Agreements; and (6) multiplying such net capacity of Existing Resources by the ACP of each PRM and the CARM.

The AC in Existing Resources of each PRM and the CARM is further subdivided into Available Base Capacity and Available Other Capacity and shall be as shown on Appendix B to this Exhibit A-5. The Available Base Capacity of each PRM and the CARM shall be the respective

ACP shares of Base Resources after reduction for delivery losses. The Available Other Capacity shall be the respective ACP share of Other Resources after reduction for reserves and delivery losses.

For AEPCO Resources added and not included as Existing Resources (currently the S&G PPA Resource), each Class A Member participating in the added Resource accepts an ACP in that Resource pursuant to its agreement with AEPCO. That ACP shall be derived by a method determined by AEPCO based on adequacy of Resources to meet the forecasted loads of participating Class A Members under a method adopted by the AEPCO Board of Directors prior to AEPCO's commitment to the added Resource. Each participating Class A Member's AC in the Resource shall be the product of its ACP in the added Resource multiplied by the capacity of the Resource after reduction for delivery losses, and if required, reserves.

The ACP of the participating Class A Members as a PRM or as a part of CARM in an added Resource shall be set forth in a revision to Appendix A to this Exhibit A-5. The AC of such participating Class A Members as a PRM and as the CARM in an added Resource shall be set forth in a revision to Appendix B to this Exhibit A-5. Both the Appendices A and B as so revised shall be provided by AEPCO to all Class A Members at the time of the commitment by AEPCO to the added Resource. No such revision of Appendices A and B shall affect the ACP and AC of the non-participating Class A Members.

The ACP for the S&G PPA Resource for TRICO and the CARM shall be as set forth in the attached Appendix A to this Exhibit A-5, and the AC for the S&G PPA Resource for TRICO and the CARM shall be as set forth in the attached Appendix B to this Exhibit A-5. Neither the ACP nor the AC of the S&G PPA Resource shall be changed absent the agreement of TRICO and the participating ARMs that comprise the CARM.

RESERVE PERCENTAGE DETERMINATION:

In accordance with WECC reliability criteria, AEPCO is required to have in reserve access to generation sufficient to cover AEPCO's largest single generating unit hazard. AEPCO's largest single generating hazard consists of an outage of 188 MW of coal-fired steam generating unit capacity (which includes 13 MW of spinning reserve capacity), and after the first hour of such an outage includes an additional 29 MW, which 29 MW is subject to call from AEPCO by other members of the Southwest Reserve Sharing Group pursuant to the Southwest Reserve Sharing Group agreement, to which AEPCO is party. For the first hour of the outage, AEPCO currently relies on the generating support of other members of the Southwest Reserve Sharing Group to cover AEPCO's largest single generating unit outage.

Based on the above, AEPCO shall seek to reduce the MW of generation that would be required to be set aside for coverage of AEPCO's largest single generating unit by purchasing reserved transmission capacity from Southwest Transmission Cooperative, Inc., Mohave Electric Cooperative, Inc. and others as available, in that order of priority. AEPCO shall seek such transmission capacity in amounts necessary to realize AEPCO's reserve generating unit capacity percentage as 6.7% from 2011 through 2020, and 7.0% for the period from 2021 through 2035, which are the reserve capacity percentages as set forth in Appendix B to this Exhibit A-5. AEPCO and SWTC shall annually agree to a plan for AEPCO to follow to seek to obtain such transmission capacity, which shall be provided to the Class A Members for review. To the extent AEPCO obtains transmission capacity in accordance with the established plan, the Class A Members agree that AEPCO shall include the costs of such transmission capacity in AEPCO's rates to such Class A Members.

In the event AEPCO is unsuccessful or less than fully successful in its attempts to timely purchase such reserved transmission capacity in advance of the start of any calendar year, AEPCO shall have the unilateral right to increase the reserve capacity percentage of Appendix B to this Exhibit A-5 for such calendar year. In such event, AEPCO shall provide, timely in advance of the start of such calendar year, a revised Appendix B to this Exhibit A for such calendar year that shows the effect of such increased reserve capacity percentage on the Available Base Capacity and Available Other Capacity of each PRM and the CARM. AEPCO and the Class A Members shall use such revised Available Base Capacity and Available Other Capacity for the purposes of Exhibit A-4 in the affected calendar year.

Appendix A to Exhibit A-5

Schedule of Allocated Capacity Percentages

A. The schedule and calculation of the Allocated Capacity Percentages (ACP) for AEPCO Existing Resources existing as of August 1, 2001 (consisting of Existing Resources as set forth in Appendix B to Exhibit A-5) is shown below:

Allocated Capacity Percentage

1996 PRS Coincident Peak Demand Forecast – MW

Col. Ln.	Year 2000	1 Anza	2 Duncan	3 Graham	4 Mohave	5 Sulphur	6 Trico	7 Total
1	January	6.0	3.2	15.9	70.5	80.8	57.1	233.5
2	February	5.6	2.9	15.1	62.7	76.9	48.7	211.9
3	March	5.8	2.9	15.7	60.4	70.9	44.2	199.9
4	April	4.8	2.8	15.8	64.4	66.8	44.0	198.7
5	May	5.2	3.1	19.5	80.2	77.3	44.4	229.7
6	June	6.6	3.8	25.0	105.4	87.3	49.3	277.4
7	July	6.7	4.3	26.3	127.0	92.6	67.4	324.4
8	August	8.0	4.4	25.0	130.5	88.7	69.0	325.6
9	September	7.7	3.8	22.3	120.8	85.1	60.9	300.7
10	October	6.5	3.2	16.8	106.5	78.0	52.7	263.7
11	November	5.7	3.0	16.1	79.5	77.0	49.1	230.4
12	December	5.8	3.4	16.2	76.4	79.2	51.4	232.4
13	Annual Total	74.6	40.8	229.8	1084.3	960.6	638.1	3028.2
14	ACP	2.5%	1.3%	7.6%	35.8%	31.7%	21.1%	100.0%

Notes: Line 13 = sum of lines 1 through 12
Line 14, Col. 1 = Line 13, Col. 1 / Line 13, Col. 7
Line 14, Col. 2 = Line 13, Col. 2 / Line 13, Col. 7
Line 14, Col. 3 = Line 13, Col. 3 / Line 13, Col. 7
Line 14, Col. 4 = Line 13, Col. 4 / Line 13, Col. 7
Line 14, Col. 5 = Line 13, Col. 5 / Line 13, Col. 7
Line 14, Col. 6 = Line 13, Col. 6 / Line 13, Col. 7

B. The Allocated Capacity Percentages (ACP's) for the S&G PPA I Resource consisting of the South Point and Griffth PPAs is 0% for both MEC and SSVEC. For the remaining Class A Members and the CARM, the resulting ACP's for the S&G PPA Resource are as follows:

Allocated Capacity %	Anza	DVEC	GCEC	CARM	TRICO	Total
	0.1%	0.1%	3.0%	3.2%	96.8%	100%

APPENDIX B to Exhibit A-5 to Rate Schedules A
PRM and CARM Monthly Allocated Capacity for 2011

All Values in MW Unless Indicated		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Existing Resources													
Apache ST-2 Coal-fired		175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0
Apache ST-3 Coal-fired		175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0
Subtotal Base Units		350.0	350.0	350.0	350.0	350.0	350.0	350.0	350.0	350.0	350.0	350.0	350.0
Fed Hydro - SLCA IP PPA (1)		1.6	1.6	1.4	6.9	7.0	7.3	8.2	7.8	6.8	1.4	1.4	1.6
Fed Hydro - Parker-Davis PPA (1)		17.3	17.3	22.4	22.4	22.4	22.4	22.4	22.4	22.4	17.3	17.3	17.3
Sub Total Base Resources		368.9	368.9	373.8	379.3	379.4	379.7	380.6	380.2	379.2	368.7	368.7	368.9
Apache CC-1		82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0
Apache GT-2		20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0
Apache GT-3		65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0
Apache GT-4		38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0
Subtotal Other Resources		205.0	205.0	205.0	205.0	205.0	205.0	205.0	205.0	205.0	205.0	205.0	205.0
Subtotal Existing Resource Units		555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0
Subtotal Fed Hydro PPA (1)		18.9	18.9	23.8	29.3	29.4	29.7	30.6	30.2	29.2	18.7	18.7	18.9
Total Existing Resources		573.9	573.9	578.8	584.3	584.4	584.7	585.6	585.2	584.2	573.7	573.7	573.9
Reserve Caculation													
2nd Hr Reserves Reqd for LSH Plus 29 MW (2)		217.0	217.0	217.0	217.0	217.0	217.0	217.0	217.0	217.0	217.0	217.0	217.0
Less: WW-Mead-Davis Displacement		50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0
Less: AEPCO Wheeling Available		40.0	40.0	40.0	40.0	15.0	15.0	15.0	15.0	15.0	15.0	40.0	40.0
Less: SWTC Transmission Reserved		90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0
Less: Western/MEC Transmission Reserved		0.0	0.0	0.0	0.0	25.0	25.0	25.0	25.0	25.0	25.0	0.0	0.0
Less: Transmission Import Capacity (3)		180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0
Remaining Reserve Requrement (MW)		37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0
Reserve Requrement (% of Unit Cap) (3)		6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%
Power Sales Resources MW													
Electrical District 2 Firm		8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0
Salt River Project Firm		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Power Sales Resources		8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0
Less Power Sales Losses (4)	2.97%	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Less Power Sales Reserves - MW		0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
SubTotal for Power Sales Resources		8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7
Net Existing Resource Capacity													
Existing Resoucre Units after Pwr Sales		546.3	546.3	546.3	546.3	546.3	546.3	546.3	546.3	546.3	546.3	546.3	546.3
Less Member Losses after Reserves (4)	2.31%	11.8	11.8	11.8	11.8	11.8	11.8	11.8	11.8	11.8	11.8	11.8	11.8
Net Existing Resource Unit Capacity		534.5	534.5	534.5	534.5	534.5	534.5	534.5	534.5	534.5	534.5	534.5	534.5
Existing Fed Hydro Capacity		18.9	18.9	23.8	29.3	29.4	29.7	30.6	30.2	29.2	18.7	18.7	18.9
Total Existing Resource Capacity		553.4	553.4	558.3	563.8	563.9	564.2	565.1	564.7	563.7	553.2	553.2	553.4
Portion of Member Capacity Net of Losses													
CARM Existing Resource @ ACP	11.4%	63.1	63.1	63.7	64.3	64.3	64.3	64.4	64.4	64.3	63.1	63.1	63.1
TRICO Existing Resource @ ACP	21.1%	116.8	116.8	117.8	119.0	119.0	119.1	119.2	119.2	118.9	116.7	116.7	116.8
MEC Existing Resource @ ACP	35.8%	198.1	198.1	199.9	201.9	201.9	202.0	202.3	202.2	201.8	198.1	198.1	198.1
SSVEC Existing Resource @ ACP	31.7%	175.4	175.4	177.0	178.7	178.8	178.9	179.1	179.0	178.7	175.4	175.4	175.4
Member Reserve Shares (MW)													
CARM Reserves		4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2
TRICO Reserves		7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7
MEC Reserves (5)		13.0	13.0	13.0	13.1	13.0	13.0	13.0	13.1	13.0	13.1	13.1	13.0
SSVEC Reserves		11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6
Less: EuroFresh Reserve Credit (6)		(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)
Net SSVEC from Existing Resources		7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6
Total Reserves Req'd of Class A Members		36.5	36.5	36.5	36.6	36.5	36.5	36.5	36.6	36.5	36.6	36.6	36.5
S&G PPA Resources													
Griffith Purchased Power		0.0	0.0	0.0	0.0	25.0	25.0	25.0	25.0	25.0	25.0	0.0	0.0
South Point Purchased Power		0.0	0.0	0.0	0.0	25.0	25.0	25.0	25.0	25.0	25.0	0.0	0.0
Total S&G PPA Resources		0.0	0.0	0.0	0.0	50.0	50.0	50.0	50.0	50.0	50.0	0.0	0.0
Total After Network Losses		0.0	0.0	0.0	0.0	48.8	48.8	48.8	48.8	48.8	48.8	0.0	0.0
CARM Available S&G Capacity	3.2%	0.0	0.0	0.0	0.0	1.6	1.6	1.6	1.6	1.6	1.6	0.0	0.0
TRICO Available S&G Capcity	96.8%	0.0	0.0	0.0	0.0	47.2	47.2	47.2	47.2	47.2	47.2	0.0	0.0
Member Total Allocated Capacity (MW)													
CARM Total AC		58.9	58.9	59.5	60.1	61.7	61.7	61.8	61.8	61.7	60.5	58.9	58.9
TRICO Total AC		109.1	109.1	110.1	111.3	158.5	158.6	158.7	158.7	158.4	156.2	109.0	109.1
MEC Total AC		185.1	185.1	186.9	188.8	188.9	189.0	189.3	189.1	188.8	185.0	185.0	185.1
SSVEC Total AC		167.8	167.8	169.4	171.1	171.2	171.3	171.5	171.4	171.1	167.8	167.8	167.8
Total		520.9	520.9	525.9	531.3	580.3	580.6	581.3	581.0	580.0	569.5	520.7	520.9
Member Available Base Capacity After Power Sales, Losses (MW)													
CARM Available Base Capacity (8)	11.4%	40.2	40.2	40.8	41.4	41.4	41.4	41.5	41.5	41.4	40.2	40.2	40.2
TRICO Available Base Capacity (8)	21.1%	74.5	74.5	75.5	76.7	76.7	76.8	76.9	76.9	76.6	74.4	74.4	74.5
MEC Available Base Capacity (8)	35.8%	126.3	126.3	128.1	130.0	130.1	130.2	130.5	130.3	130.0	126.2	126.2	126.3
SSVEC Available Base Capacity (8)	31.7%	111.8	111.8	113.4	115.1	115.2	115.3	115.5	115.4	115.1	111.8	111.8	111.8
Subtotal Base	100.0%	352.8	352.8	357.8	363.2	363.4	363.7	364.4	364.1	363.1	352.6	352.6	352.8
Member Available Other Capacity After Losses, Reserves (MW)													
CARM Available Other Capacity (8)	11.4%	18.7	18.7	18.7	18.7	18.7	18.7	18.7	18.7	18.7	18.7	18.7	18.7
TRICO Available Other Capacity (8)	21.1%	34.6	34.6	34.6	34.6	34.6	34.6	34.6	34.6	34.6	34.6	34.6	34.6
MEC Available Other Capacity (8)	35.8%	58.8	58.8	58.8	58.8	58.8	58.8	58.8	58.8	58.8	58.8	58.8	58.8
SSVEC Available Other Capacity (8)	31.7%	56.0	56.0	56.0	56.0	56.0	56.0	56.0	56.0	56.0	56.0	56.0	56.0
Subtotal Available Other Cap		168.1	168.1	168.1	168.1	168.1	168.1	168.1	168.1	168.1	168.1	168.1	168.1
Member Total Available Capacity with Available S&G Capacity (MW)													
CARM Total Available Capacity		58.9	58.9	59.5	60.1	61.7	61.7	61.8	61.8	61.7	60.5	58.9	58.9
TRICO Total Available Capacity		109.1	109.1	110.1	111.3	158.5	158.6	158.7	158.7	158.4	156.2	109.0	109.1
MEC Total Available Capacity		185.1	185.1	186.9	188.8	188.9	189.0	189.3	189.1	188.8	185.0	185.0	185.1
SSVEC Total Available Capacity		167.8	167.8	169.4	171.1	171.2	171.3	171.5	171.4	171.1	167.8	167.8	167.8
Total		520.9	520.9	525.9	531.3	580.3	580.6	581.3	581.0	580.0	569.5	520.7	520.9

Notes:
(1) Federal Hydro Estimated - AEPCO will establish Fed Hydro portion of Available Base Capacity monthly pursuant to the Federal Hydro Power Agreements.
(2) The 29 MW value added to LSH Reserves of 188 MW of Coal Unit capacity (includes spinning reserve capability) is required to restore SRSG Operating Reserves.
(3) The Class A Members have agreed that AEPCO will purchase transmission import capacity from SWTC or others as needed to hold generating reserves to 6.7%.
(4) The SWTC loss factors are subject to change from time to time as changes are implemented to such loss factors pursuant to SWTC's OATT Tariff.
(5) MEC Reserve fraction is rounded to ensure total reserves match totall reserves required of Class A members.
(6) Credit for Operating Reserve contribution from EuroFresh generation controlled by SSVEC pursuant to AEPCO-SSVEC agreement.
(7) Griffith PPA is available only in WECC Peak Hours; SouthPoint PPA is available only in Daytime Hours..
(8) Class A Member Available Base and Other Capacity fractions are rounded up and down as needed to match total AC.

APPENDIX B to Exhibit A-5 to Rate Schedules A
PRM and CARM Monthly Allocated Capacity for 2012

All Values in MW Unless Indicated			Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Existing Resources														
Apache ST-2 Coal-fired			175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0
Apache ST-3 Coal-fired			175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0
Subtotal Base Units			350.0	350.0	350.0	350.0	350.0	350.0	350.0	350.0	350.0	350.0	350.0	350.0
Fed Hydro - SLCA IP PPA	(1)		1.6	1.6	1.4	6.9	7.0	7.3	8.2	7.8	6.8	1.4	1.4	1.6
Fed Hydro - Parker-Davis PPA	(1)		17.3	17.3	22.4	22.4	22.4	22.4	22.4	22.4	22.4	17.3	17.3	17.3
Sub Total Base Resources			368.9	368.9	373.8	379.3	379.4	379.7	380.6	380.2	379.2	368.7	368.7	368.9
Apache CC-1			82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0
Apache GT-2			20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0
Apache GT-3			65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0
Apache GT-4			38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0
Subtotal Other Resources			205.0	205.0	205.0	205.0	205.0	205.0	205.0	205.0	205.0	205.0	205.0	205.0
Subtotal Existing Resource Units			555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0
Subtotal Fed Hydro PPA	(1)		18.9	18.9	23.8	29.3	29.4	29.7	30.6	30.2	29.2	18.7	18.7	18.9
Total Existing Resources			573.9	573.9	578.8	584.3	584.4	584.7	585.6	585.2	584.2	573.7	573.7	573.9
Reserve Caculation														
2nd Hr Reserves Reqd for LSH Plus 29 MW	(2)		217.0	217.0	217.0	217.0	217.0	217.0	217.0	217.0	217.0	217.0	217.0	217.0
Less: WW-Mead-Davis Displacement			50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0
Less: AEPCO Wheeling Available			40.0	40.0	40.0	40.0	5.0	5.0	5.0	5.0	5.0	5.0	40.0	40.0
Less: SWTC Transmission Reserved			90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0
Less: Western/MEC Transmission Reserved			0.0	0.0	0.0	0.0	35.0	35.0	35.0	35.0	35.0	35.0	0.0	0.0
Less: Transmission Import Capacity	(3)		180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0
Remaining Reserve Requrement (MW)			37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0
Reserve Requrement (% of Unit Cap)	(3)		6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%
Power Sales Resources MW														
Electrical District 2 Firm			8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0
Salt River Project Firm			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Power Sales Resources			8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0
Less Power Sales Losses	(4)	2.97%	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Less Power Sales Reserves - MW			0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
SubTotal for Power Sales Resources			8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7
Net Existing Resource Capacity														
Existing Resoucre Units after Pwr Sales			546.3	546.3	546.3	546.3	546.3	546.3	546.3	546.3	546.3	546.3	546.3	546.3
Less Member Losses after Reserves	(4)	2.31%	11.8	11.8	11.8	11.8	11.8	11.8	11.8	11.8	11.8	11.8	11.8	11.8
Net Existing Resource Unit Capacity			534.5	534.5	534.5	534.5	534.5	534.5	534.5	534.5	534.5	534.5	534.5	534.5
Existing Fed Hydro Capacity			18.9	18.9	23.8	29.3	29.4	29.7	30.6	30.2	29.2	18.7	18.7	18.9
Total Existing Resource Capacity			553.4	553.4	558.3	563.8	563.9	564.2	565.1	564.7	563.7	553.2	553.2	553.4
Portion of Member Capacity Net of Losses														
CARM Existing Resource @ ACP		11.4%	63.1	63.1	63.7	64.3	64.3	64.3	64.4	64.4	64.3	63.1	63.1	63.1
TRICO Existing Resource @ ACP		21.1%	116.8	116.8	117.8	119.0	119.0	119.1	119.2	119.2	118.9	116.7	116.7	116.8
MEC Existing Resource @ ACP		35.8%	198.1	198.1	199.9	201.9	201.9	202.0	202.3	202.2	201.8	198.1	198.1	198.1
SSVEC Existing Resource @ ACP		31.7%	175.4	175.4	177.0	178.7	178.8	178.9	179.1	179.0	178.7	175.4	175.4	175.4
Member Reserve Shares (MW)														
CARM Reserves			4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2
TRICO Reserves			7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7
MEC Reserves	(5)		13.0	13.0	13.0	13.1	13.0	13.0	13.0	13.1	13.0	13.1	13.1	13.0
SSVEC Reserves			11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6
Less: EuroFresh Reserve Credit	(6)		(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)
Net SSVEC from Existing Resources			7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6
Total Reserves Req'd of Class A Members			36.5	36.5	36.5	36.6	36.5	36.5	36.5	36.6	36.5	36.6	36.6	36.5
S&G PPA Resources														
Griffith Purchased Power			0.0	0.0	0.0	0.0	25.0	25.0	25.0	25.0	25.0	25.0	0.0	0.0
South Point Purchased Power			0.0	0.0	0.0	0.0	35.0	35.0	35.0	35.0	35.0	35.0	0.0	0.0
Total S&G PPA Resources			0.0	0.0	0.0	0.0	60.0	60.0	60.0	60.0	60.0	60.0	0.0	0.0
Total After Network Losses			0.0	0.0	0.0	0.0	58.6	58.6	58.6	58.6	58.6	58.6	0.0	0.0
CARM Available S&G Capacity		3.2%	0.0	0.0	0.0	0.0	1.9	1.9	1.9	1.9	1.9	1.9	0.0	0.0
TRICO Available S&G Capcity		96.8%	0.0	0.0	0.0	0.0	56.7	56.7	56.7	56.7	56.7	56.7	0.0	0.0
Member Total Allocated Capacity (MW)														
CARM Total AC			58.9	58.9	59.5	60.1	62.0	62.0	62.1	62.1	62.0	60.8	58.9	58.9
TRICO Total AC			109.1	109.1	110.1	111.3	168.0	168.1	168.2	168.2	167.9	165.7	109.0	109.1
MEC Total AC			185.1	185.1	186.9	188.8	188.9	189.0	189.3	189.1	188.8	185.0	185.0	185.1
SSVEC Total AC			167.8	167.8	169.4	171.1	171.2	171.3	171.5	171.4	171.1	167.8	167.8	167.8
Total			520.9	520.9	525.9	531.3	590.1	590.4	591.1	590.8	589.8	579.3	520.7	520.9
Member Available Base Capacity After Power Sales, Losses (MW)														
CARM Available Base Capacity	(8)	11.4%	40.2	40.2	40.8	41.4	41.4	41.4	41.5	41.5	41.4	40.2	40.2	40.2
TRICO Available Base Capacity	(8)	21.1%	74.5	74.5	75.5	76.7	76.7	76.8	76.9	76.9	76.6	74.4	74.4	74.5
MEC Available Base Capacity	(8)	35.8%	126.3	126.3	128.1	130.0	130.1	130.2	130.5	130.3	130.0	126.2	126.2	126.3
SSVEC Available Base Capacity	(8)	31.7%	111.8	111.8	113.4	115.1	115.2	115.3	115.5	115.4	115.1	111.8	111.8	111.8
Subtotal Base		**100.0%**	352.8	352.8	357.8	363.2	363.4	363.7	364.4	364.1	363.1	352.6	352.6	352.8
Member Available Other Capacity After Losses, Reserves (MW)														
CARM Available Other Capacity	(8)	11.4%	18.7	18.7	18.7	18.7	18.7	18.7	18.7	18.7	18.7	18.7	18.7	18.7
TRICO Available Other Capacity	(8)	21.1%	34.6	34.6	34.6	34.6	34.6	34.6	34.6	34.6	34.6	34.6	34.6	34.6
MEC Available Other Capacity	(8)	35.8%	58.8	58.8	58.8	58.8	58.8	58.8	58.8	58.8	58.8	58.8	58.8	58.8
SSVEC Available Other Capacity	(8)	31.7%	56.0	56.0	56.0	56.0	56.0	56.0	56.0	56.0	56.0	56.0	56.0	56.0
Subtotal Available Other Cap			168.1	168.1	168.1	168.1	168.1	168.1	168.1	168.1	168.1	168.1	168.1	168.1
Member Total Available Capacity with Available S&G Capacity (MW)														
CARM Total Available Capacity			58.9	58.9	59.5	60.1	62.0	62.0	62.1	62.1	62.0	60.8	58.9	58.9
TRICO Total Available Capacity			109.1	109.1	110.1	111.3	168.0	168.1	168.2	168.2	167.9	165.7	109.0	109.1
MEC Total Available Capacity			185.1	185.1	186.9	188.8	188.9	189.0	189.3	189.1	188.8	185.0	185.0	185.1
SSVEC Total Available Capacity			167.8	167.8	169.4	171.1	171.2	171.3	171.5	171.4	171.1	167.8	167.8	167.8
Total			520.9	520.9	525.9	531.3	590.1	590.4	591.1	590.8	589.8	579.3	520.7	520.9
									a					

Notes: (1) Federal Hydro Estimated - AEPCO will establish Fed Hydro portion of Available Base Capacity monthly pursuant to the Federal Hydro Power Agreements.
(2) The 29 MW value added to LSH Reserves of 188 MW of Coal Unit capacity (includes spinning reserve capability) is required to restore SRSG Operating Reserves.
(3) The Class A Members have agreed that AEPCO will purchase transmission import capacity from SWTC or others as needed to hold generating reserves to 6.7%.
(4) The SWTC loss factors are subject to change from time to time as changes are implemented to such loss factors pursuant to SWTC's OATT Tariff.
(5) MEC Reserve fraction is rounded to ensure total reserves match totall reserves required of Class A members.
(6) Credit for Operating Reserve contribution from EuroFresh generation controlled by SSVEC pursuant to AEPCO-SSVEC agreement.
(7) Griffith PPA is available only in WECC Peak Hours; SouthPoint PPA is available only in Daytime Hours..
(8) Class A Member Available Base and Other Capacity fractions are rounded up and down as needed to match total AC.

APPENDIX B to Exhibit A-5 to Rate Schedules A

PRM and CARM Monthly Allocated Capacity for 2013

All Values in MW Unless Indicated			Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Existing Resources														
Apache ST-2 Coal-fired			175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0
Apache ST-3 Coal-fired			175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0
Subtotal Base Units			350.0	350.0	350.0	350.0	350.0	350.0	350.0	350.0	350.0	350.0	350.0	350.0
Fed Hydro - SLCA IP PPA	(1)		1.6	1.6	1.4	6.9	7.0	7.3	8.2	7.8	6.8	1.4	1.4	1.6
Fed Hydro - Parker-Davis PPA	(1)		17.3	17.3	22.4	22.4	22.4	22.4	22.4	22.4	22.4	17.3	17.3	17.3
Sub Total Base Resources			368.9	368.9	373.8	379.3	379.4	379.7	380.6	380.2	379.2	368.7	368.7	368.9
Apache CC-1			82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0
Apache GT-2			20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0
Apache GT-3			65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0
Apache GT-4			38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0
Subtotal Other Resources			205.0	205.0	205.0	205.0	205.0	205.0	205.0	205.0	205.0	205.0	205.0	205.0
Subtotal Existing Resource Units			555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0
Subtotal Fed Hydro PPA	(1)		18.9	18.9	23.8	29.3	29.4	29.7	30.6	30.2	29.2	18.7	18.7	18.9
Total Existing Resources			573.9	573.9	578.8	584.3	584.4	584.7	585.6	585.2	584.2	573.7	573.7	573.9
Reserve Caculation														
2nd Hr Reserves Reqd for LSH Plus 29 MW	(2)		217.0	217.0	217.0	217.0	217.0	217.0	217.0	217.0	217.0	217.0	217.0	217.0
Less: WW-Mead-Davis Displacement			50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0
Less: AEPCO Wheeling Available			40.0	40.0	40.0	40.0	(5.0)	(5.0)	(5.0)	(5.0)	(5.0)	(5.0)	40.0	40.0
Less: SWTC Transmission Reserved			90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0
Less: Western/MEC Transmission Reserved			0.0	0.0	0.0	0.0	45.0	45.0	45.0	45.0	45.0	45.0	0.0	0.0
Less: Transmission Import Capacity	(3)		180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0
Remaining Reserve Requrement (MW)			37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0
Reserve Requrement (% of Unit Cap)	(3)		6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%
Power Sales Resources MW														
Electrical District 2 Firm			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Salt River Project Firm			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Power Sales Resources			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Less Power Sales Losses	(4)	2.97%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Less Power Sales Reserves - MW			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SubTotal for Power Sales Resources			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Net Existing Resource Capacity														
Existing Resoucre Units after Pwr Sales			555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0
Less Member Losses after Reserves	(4)	2.31%	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0
Net Existing Resource Unit Capacity			543.0	543.0	543.0	543.0	543.0	543.0	543.0	543.0	543.0	543.0	543.0	543.0
Existing Fed Hydro Capacity			18.9	18.9	23.8	29.3	29.4	29.7	30.6	30.2	29.2	18.7	18.7	18.9
Total Existing Resource Capacity			561.9	561.9	566.8	572.3	572.4	572.7	573.6	573.2	572.2	561.7	561.7	561.9
Portion of Member Capacity Net of Losses														
CARM Existing Resource @ ACP		11.4%	64.100	64.1	64.6	65.2	65.3	65.3	65.4	65.3	65.2	64.0	64.0	64.1
TRICO Existing Resource @ ACP		21.1%	118.600	118.6	119.6	120.8	120.8	120.8	121.0	121.0	120.7	118.5	118.5	118.6
MEC Existing Resource @ ACP		35.8%	201.200	201.2	202.9	204.9	204.9	205.0	205.4	205.2	204.9	201.1	201.1	201.2
SSVEC Existing Resource @ ACP		31.7%	178.100	178.1	179.7	181.4	181.5	181.6	181.8	181.7	181.4	178.1	178.1	178.1
Member Reserve Shares (MW)														
CARM Reserves			4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2
TRICO Reserves			7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8
MEC Reserves	(5)		13.3	13.3	13.3	13.3	13.3	13.3	13.3	13.3	13.3	13.3	13.3	13.3
SSVEC Reserves			11.7	11.7	11.7	11.7	11.7	11.7	11.7	11.7	11.7	11.7	11.7	11.7
Less: EuroFresh Reserve Credit	(6)		(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)
Net SSVEC from Existing Resources			7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7
Total Reserves Req'd of Class A Members			37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0
S&G PPA Resources														
Griffith Purchased Power			0.0	0.0	0.0	0.0	25.0	25.0	25.0	25.0	25.0	25.0	0.0	0.0
South Point Purchased Power			0.0	0.0	0.0	0.0	45.0	45.0	45.0	45.0	45.0	45.0	0.0	0.0
Total S&G PPA Resources			0.0	0.0	0.0	0.0	70.0	70.0	70.0	70.0	70.0	70.0	0.0	0.0
Total After Network Losses			0.0	0.0	0.0	0.0	68.4	68.4	68.4	68.4	68.4	68.4	0.0	0.0
CARM Available S&G Capacity		3.2%	0.0	0.0	0.0	0.0	2.2	2.2	2.2	2.2	2.2	2.2	0.0	0.0
TRICO Available S&G Capcity		96.8%	0.0	0.0	0.0	0.0	66.2	66.2	66.2	66.2	66.2	66.2	0.0	0.0
Member Total Allocated Capacity (MW)														
CARM Total AC			59.9	59.9	60.4	61.0	63.3	63.3	63.4	63.3	63.2	62.0	59.8	59.9
TRICO Total AC			110.8	110.8	111.8	113.0	179.2	179.2	179.4	179.4	179.1	176.9	110.7	110.8
MEC Total AC			187.9	187.9	189.6	191.6	191.6	191.7	192.1	191.9	191.6	187.8	187.8	187.9
SSVEC Total AC			170.4	170.4	172.0	173.7	173.8	173.9	174.1	174.0	173.7	170.4	170.4	170.4
Total			529.0	529.0	533.8	539.3	607.9	608.1	609.0	608.6	607.6	597.1	528.7	529.0
Member Available Base Capacity After Power Sales, Losses (MW)														
CARM Available Base Capacity	(8)	11.4%	41.2	41.2	41.7	42.3	42.4	42.4	42.5	42.4	42.3	41.1	41.1	41.2
TRICO Available Base Capacity	(8)	21.1%	76.2	76.2	77.2	78.4	78.4	78.4	78.6	78.6	78.3	76.1	76.1	76.2
MEC Available Base Capacity	(8)	35.8%	129.1	129.1	130.9	132.8	132.9	133.0	133.3	133.2	132.8	129.1	129.1	129.1
SSVEC Available Base Capacity	(8)	31.7%	114.4	114.4	116.0	117.7	117.8	117.9	118.1	118.0	117.7	114.4	114.4	114.4
Subtotal Base		100.0%	360.9	360.9	365.8	371.2	371.5	371.7	372.5	372.2	371.1	360.7	360.7	360.9
Member Available Other Capacity After Losses, Reserves (MW)														
CARM Available Other Capacity	(8)	11.4%	18.7	18.7	18.7	18.7	18.7	18.7	18.7	18.7	18.7	18.7	18.7	18.7
TRICO Available Other Capacity	(8)	21.1%	34.6	34.6	34.6	34.6	34.6	34.6	34.6	34.6	34.6	34.6	34.6	34.6
MEC Available Other Capacity	(8)	35.8%	58.8	58.8	58.8	58.8	58.8	58.8	58.8	58.8	58.8	58.8	58.8	58.8
SSVEC Available Other Capacity	(8)	31.7%	56.0	56.0	56.0	56.0	56.0	56.0	56.0	56.0	56.0	56.0	56.0	56.0
Subtotal Available Other Cap			168.1	168.1	168.1	168.1	168.1	168.1	168.1	168.1	168.1	168.1	168.1	168.1
Member Total Available Capacity with Available S&G Capacity (MW)														
CARM Total Available Capacity			59.9	59.9	60.4	61.0	63.3	63.3	63.4	63.3	63.2	62.0	59.8	59.9
TRICO Total Available Capacity			110.8	110.8	111.8	113.0	179.2	179.2	179.4	179.4	179.1	176.9	110.7	110.8
MEC Total Available Capacity			187.9	187.9	189.7	191.6	191.7	191.8	192.1	192.0	191.6	187.9	187.9	187.9
SSVEC Total Available Capacity			170.4	170.4	172.0	173.7	173.8	173.9	174.1	174.0	173.7	170.4	170.4	170.4
Total			529.0	529.0	533.9	539.3	608.0	608.2	609.0	608.7	607.6	597.2	528.8	529.0

Notes: (1) Federal Hydro Estimated - AEPCO will establish Fed Hydro portion of Available Base Capacity monthly pursuant to the Federal Hydro Power Agreements.
(2) The 29 MW value added to LSH Reserves of 188 MW of Coal Unit capacity (includes spinning reserve capability) is required to restore SRSG Operating Reserves.
(3) The Class A Members have agreed that AEPCO will purchase transmission import capacity from SWTC or others as needed to hold generating reserves to 6.7%.
(4) The SWTC loss factors are subject to change from time to time as changes *are implemented* to such loss factors pursuant to SWTC's OATT Tariff.
(5) MEC Reserve fraction is rounded to ensure total reserves match totall reserves required of Class A members.
(6) Credit for Operating Reserve contribution from EuroFresh generation controlled by SSVEC pursuant to AEPCO-SSVEC agreement.
(7) Griffith PPA is available only in WECC Peak Hours; SouthPoint PPA is available only in Daytime Hours..
(8) Class A Member Available Base and Other Capacity fractions are rounded up and down as needed to match total AC.

APPENDIX B to Exhibit A-5 to Rate Schedules A
PRM and CARM Monthly Allocated Capacity for 2014

All Values in MW Unless Indicated			Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Existing Resources														
Apache ST-2 Coal-fired			175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0
Apache ST-3 Coal-fired			175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0
Subtotal Base Units			350.0	350.0	350.0	350.0	350.0	350.0	350.0	350.0	350.0	350.0	350.0	350.0
Fed Hydro - SLCA IP PPA	(1)		1.6	1.6	1.4	6.9	7.0	7.3	8.2	7.8	6.8	1.4	1.4	1.6
Fed Hydro - Parker-Davis PPA	(1)		17.3	17.3	22.4	22.4	22.4	22.4	22.4	22.4	22.4	17.3	17.3	17.3
Sub Total Base Resources			368.9	368.9	373.8	379.3	379.4	379.7	380.6	380.2	379.2	368.7	368.7	368.9
Apache CC-1			82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0
Apache GT-2			20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0
Apache GT-3			65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0
Apache GT-4			38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0
Subtotal Other Resources			205.0	205.0	205.0	205.0	205.0	205.0	205.0	205.0	205.0	205.0	205.0	205.0
Subtotal Existing Resource Units			555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0
Subtotal Fed Hydro PPA	(1)		18.9	18.9	23.8	29.3	29.4	29.7	30.6	30.2	29.2	18.7	18.7	18.9
Total Existing Resources			573.9	573.9	578.8	584.3	584.4	584.7	585.6	585.2	584.2	573.7	573.7	573.9
Reserve Caculation														
2nd Hr Reserves Reqd for LSH Plus 29 MW	(2)		217.0	217.0	217.0	217.0	217.0	217.0	217.0	217.0	217.0	217.0	217.0	217.0
Less: WW-Mead-Davis Displacement			50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0
Less: AEPCO Wheeling Available			40.0	40.0	40.0	40.0	(15.0)	(15.0)	(15.0)	(15.0)	(15.0)	(15.0)	40.0	40.0
Less: SWTC Transmission Reserved			90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0
Less: Western/MEC Transmission Reserved			0.0	0.0	0.0	0.0	55.0	55.0	55.0	55.0	55.0	55.0	0.0	0.0
Less: Transmission Import Capacity	(3)		180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0
Remaining Reserve Requrement (MW)			37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0
Reserve Requrement (% of Unit Cap)	(3)		6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%
Power Sales Resources MW														
Electrical District 2 Firm			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Salt River Project Firm			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Power Sales Resources			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Less Power Sales Losses	(4)	2.97%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Less Power Sales Reserves - MW			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SubTotal for Power Sales Resources			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Net Existing Resource Capacity														
Existing Resoucre Units after Pwr Sales			555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0
Less Member Losses after Reserves	(4)	2.31%	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0
Net Existing Resource Unit Capacity			543.0	543.0	543.0	543.0	543.0	543.0	543.0	543.0	543.0	543.0	543.0	543.0
Existing Fed Hydro Capacity			18.9	18.9	23.8	29.3	29.4	29.7	30.6	30.2	29.2	18.7	18.7	18.9
Total Existing Resource Capacity			561.9	561.9	566.8	572.3	572.4	572.7	573.6	573.2	572.2	561.7	561.7	561.9
Portion of Member Capacity Net of Losses														
CARM Existing Resource @ ACP		11.4%	64.100	64.1	64.6	65.2	65.3	65.3	65.4	65.3	65.2	64.0	64.0	64.1
TRICO Existing Resource @ ACP		21.1%	118.600	118.6	119.6	120.8	120.8	120.8	121.0	121.0	120.7	118.5	118.5	118.6
MEC Existing Resource @ ACP		35.8%	201.200	201.2	202.9	204.9	204.9	205.0	205.4	205.2	204.9	201.1	201.1	201.2
SSVEC Existing Resource @ ACP		31.7%	178.100	178.1	179.7	181.4	181.5	181.6	181.8	181.7	181.4	178.1	178.1	178.1
Member Reserve Shares (MW)														
CARM Reserves			4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2
TRICO Reserves			7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8
MEC Reserves	(5)		13.3	13.3	13.3	13.3	13.3	13.3	13.3	13.3	13.3	13.3	13.3	13.3
SSVEC Reserves			11.7	11.7	11.7	11.7	11.7	11.7	11.7	11.7	11.7	11.7	11.7	11.7
Less: EuroFresh Reserve Credit	(6)		(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)
Net SSVEC from Existing Resources			7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7
Total Reserves Req'd of Class A Members			37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0
S&G PPA Resources														
Griffith Purchased Power	(7)		0.0	0.0	0.0	0.0	25.0	25.0	25.0	25.0	25.0	25.0	0.0	0.0
South Point Purchased Power	(7)		0.0	0.0	0.0	0.0	55.0	55.0	55.0	55.0	55.0	55.0	0.0	0.0
Total S&G PPA Resources			0.0	0.0	0.0	0.0	80.0	80.0	80.0	80.0	80.0	80.0	0.0	0.0
Total After Network Losses			0.0	0.0	0.0	0.0	78.2	78.2	78.2	78.2	78.2	78.2	0.0	0.0
CARM Available S&G Capacity		3.2%	0.0	0.0	0.0	0.0	2.5	2.5	2.5	2.5	2.5	2.5	0.0	0.0
TRICO Available S&G Capcity		96.8%	0.0	0.0	0.0	0.0	75.7	75.7	75.7	75.7	75.7	75.7	0.0	0.0
Member Total Allocated Capacity (MW)														
CARM Total AC			59.9	59.9	60.4	61.0	63.6	63.6	63.7	63.6	63.5	62.3	59.8	59.9
TRICO Total AC			110.8	110.8	111.8	113.0	188.7	188.7	188.9	188.9	188.6	186.4	110.7	110.8
MEC Total AC			187.9	187.9	189.6	191.6	191.6	191.7	192.1	191.9	191.6	187.8	187.8	187.9
SSVEC Total AC			170.4	170.4	172.0	173.7	173.8	173.9	174.1	174.0	173.7	170.4	170.4	170.4
Total			529.0	529.0	533.8	539.3	617.7	617.9	618.8	618.4	617.4	606.9	528.7	529.0
Member Available Base Capacity After Power Sales, Losses (MW)														
CARM Available Base Capacity	(8)	11.4%	41.2	41.2	41.7	42.3	42.4	42.4	42.5	42.4	42.3	41.1	41.1	41.2
TRICO Available Base Capacity	(8)	21.1%	76.2	76.2	77.2	78.4	78.4	78.4	78.6	78.6	78.3	76.1	76.1	76.2
MEC Available Base Capacity	(8)	35.8%	129.1	129.1	130.9	132.8	132.9	133.0	133.3	133.2	132.8	129.1	129.1	129.1
SSVEC Available Base Capacity	(8)	31.7%	114.4	114.4	116.0	117.7	117.8	117.9	118.1	118.0	117.7	114.4	114.4	114.4
Subtotal Base		100.0%	360.9	360.9	365.8	371.2	371.5	371.7	372.5	372.2	371.1	360.7	360.7	360.9
Member Available Other Capacity After Losses, Reserves (MW)														
CARM Available Other Capacity	(8)	11.4%	18.7	18.7	18.7	18.7	18.7	18.7	18.7	18.7	18.7	18.7	18.7	18.7
TRICO Available Other Capacity	(8)	21.1%	34.6	34.6	34.6	34.6	34.6	34.6	34.6	34.6	34.6	34.6	34.6	34.6
MEC Available Other Capacity	(8)	35.8%	58.8	58.8	58.7	58.8	58.7	58.7	58.8	58.7	58.8	58.7	58.7	58.8
SSVEC Available Other Capacity	(8)	31.7%	56.0	56.0	56.0	56.0	56.0	56.0	56.0	56.0	56.0	56.0	56.0	56.0
Subtotal Available Other Cap			168.1	168.1	168.0	168.1	168.0	168.0	168.1	168.0	168.1	168.0	168.0	168.1
Member Total Available Capacity with Available S&G Capacity (MW)														
CARM Total Available Capacity			59.9	59.9	60.4	61.0	63.6	63.6	63.7	63.6	63.5	62.3	59.8	59.9
TRICO Total Available Capacity			110.8	110.8	111.8	113.0	188.7	188.7	188.9	188.9	188.6	186.4	110.7	110.8
MEC Total Available Capacity			187.9	187.9	189.6	191.6	191.6	191.7	192.1	191.9	191.6	187.8	187.8	187.9
SSVEC Total Available Capacity			170.4	170.4	172.0	173.7	173.8	173.9	174.1	174.0	173.7	170.4	170.4	170.4
Total			529.0	529.0	533.8	539.3	617.7	617.9	618.8	618.4	617.4	606.9	528.7	529.0

Notes:
(1) Federal Hydro Estimated - AEPCO will establish Fed Hydro portion of Available Base Capacity monthly pursuant to the Federal Hydro Power Agreements.
(2) The 29 MW value added to LSH Reserves of 188 MW of Coal Unit capacity (includes spinning reserve capability) is required to restore SRSG Operating Reserves.
(3) The Class A Members have agreed that AEPCO will purchase transmission import capacity from SWTC or others as needed to hold generating reserves to 6.7%.
(4) The SWTC loss factors are subject to change from time to time as changes are implemented to such loss factors pursuant to SWTC's OATT Tariff.
(5) MEC Reserve fraction is rounded to ensure total reserves match totall reserves required of Class A members.
(6) Credit for Operating Reserve contribution from EuroFresh generation controlled by SSVEC pursuant to AEPCO-SSVEC agreement.
(7) Griffith PPA is available only in WECC Peak Hours; SouthPoint PPA is available only in Daytime Hours..
(8) Class A Member Available Base and Other Capacity fractions are rounded up and down as needed to match total AC.

APPENDIX B to Exhibit A-5 to Rate Schedules A
PRM and CARM Monthly Allocated Capacity for 2015 thru 2020

All Values in MW Unless Indicated			Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Existing Resources														
Apache ST-2 Coal-fired			175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0
Apache ST-3 Coal-fired			175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0
Subtotal Base Units			350.0	350.0	350.0	350.0	350.0	350.0	350.0	350.0	350.0	350.0	350.0	350.0
Fed Hydro - SLCA IP PPA	(1)		1.6	1.6	1.4	6.9	7.0	7.3	8.2	7.8	6.8	1.4	1.4	1.6
Fed Hydro - Parker-Davis PPA	(1)		17.3	17.3	22.4	22.4	22.4	22.4	22.4	22.4	22.4	17.3	17.3	17.3
Sub Total Base Resources			368.9	368.9	373.8	379.3	379.4	379.7	380.6	380.2	379.2	368.7	368.7	368.9
Apache CC-1			82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0
Apache GT-2			20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0
Apache GT-3			65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0
Apache GT-4			38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0
Subtotal Other Resources			205.0	205.0	205.0	205.0	205.0	205.0	205.0	205.0	205.0	205.0	205.0	205.0
Subtotal Existing Resource Units			555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0
Subtotal Fed Hydro PPA	(1)		18.9	18.9	23.8	29.3	29.4	29.7	30.6	30.2	29.2	18.7	18.7	18.9
Total Existing Resources			573.9	573.9	578.8	584.3	584.4	584.7	585.6	585.2	584.2	573.7	573.7	573.9
Reserve Caculation														
2nd Hr Reserves Reqd for LSH Plus 29 MW	(2)		217.0	217.0	217.0	217.0	217.0	217.0	217.0	217.0	217.0	217.0	217.0	217.0
Less: WW-Mead-Davis Displacement			50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0
Less: AEPCO Wheeling Available			40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0
Less: SWTC Transmission Reserved			90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0
Less: Western/MEC Transmission Reserved			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Less: Transmission Import Capacity	(3)		180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0
Remaining Reserve Requrement (MW)			37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0
Reserve Requrement (% of Unit Cap)	(3)		6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%
Power Sales Resources MW														
Electrical District 2 Firm			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Salt River Project Firm			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Power Sales Resources			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Less Power Sales Losses	(4)	2.97%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Less Power Sales Reserves - MW			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SubTotal for Power Sales Resources			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Net Existing Resource Capacity														
Existing Resoucre Units after Pwr Sales			555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0
Less Member Losses after Reserves	(4)	2.31%	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0
Net Existing Resource Unit Capacity			543.0	543.0	543.0	543.0	543.0	543.0	543.0	543.0	543.0	543.0	543.0	543.0
Existing Fed Hydro Capacity			18.9	18.9	23.8	29.3	29.4	29.7	30.6	30.2	29.2	18.7	18.7	18.9
Total Existing Resource Capacity			561.9	561.9	566.8	572.3	572.4	572.7	573.6	573.2	572.2	561.7	561.7	561.9
Portion of Member Capacity Net of Losses														
CARM Existing Resource @ ACP		11.4%	64.100	64.1	64.6	65.2	65.3	65.3	65.4	65.3	65.2	64.0	64.0	64.1
TRICO Existing Resource @ ACP		21.1%	118.600	118.6	119.6	120.8	120.8	120.8	121.0	121.0	120.7	118.5	118.5	118.6
MEC Existing Resource @ ACP		35.8%	201.200	201.2	202.9	204.9	204.9	205.0	205.4	205.2	204.9	201.1	201.1	201.2
SSVEC Existing Resource @ ACP		31.7%	178.100	178.1	179.7	181.4	181.5	181.6	181.8	181.7	181.4	178.1	178.1	178.1
Member Reserve Shares (MW)														
CARM Reserves			4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2
TRICO Reserves			7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8
MEC Reserves	(5)		13.3	13.3	13.3	13.3	13.3	13.3	13.3	13.3	13.3	13.3	13.3	13.3
SSVEC Reserves			11.7	11.7	11.7	11.7	11.7	11.7	11.7	11.7	11.7	11.7	11.7	11.7
Less: EuroFresh Reserve Credit	(6)		(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)
Net SSVEC from Existing Resources			7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7
Total Reserves Req'd of Class A Members			37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0
S&G PPA Resources														
Griffith Purchased Power			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
South Point Purchased Power			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total S&G PPA Resources			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total After Network Losses			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CARM Available S&G Capacity		0.0%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
TRICO Available S&G Capcity		0.0%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Member Total Allocated Capacity (MW)														
CARM Total AC			59.9	59.9	60.4	61.0	61.1	61.1	61.2	61.1	61.0	59.8	59.8	59.9
TRICO Total AC			110.8	110.8	111.8	113.0	113.0	113.0	113.2	113.2	112.9	110.7	110.7	110.8
MEC Total AC			187.9	187.9	189.6	191.6	191.6	191.7	192.1	191.9	191.6	187.8	187.8	187.9
SSVEC Total AC			170.4	170.4	172.0	173.7	173.8	173.9	174.1	174.0	173.7	170.4	170.4	170.4
Total			529.0	529.0	533.8	539.3	539.5	539.7	540.6	540.2	539.2	528.7	528.7	529.0
Member Available Base Capacity After Power Sales, Losses (MW)														
CARM Available Base Capacity	(7)	11.4%	41.2	41.2	41.7	42.3	42.4	42.4	42.5	42.4	42.3	41.1	41.1	41.2
TRICO Available Base Capacity	(7)	21.1%	76.2	76.2	77.2	78.4	78.4	78.4	78.6	78.6	78.3	76.1	76.1	76.2
MEC Available Base Capacity	(7)	35.8%	129.1	129.1	130.9	132.8	132.9	133.0	133.3	133.2	132.8	129.1	129.1	129.1
SSVEC Available Base Capacity	(7)	31.7%	114.4	114.4	116.0	117.7	117.8	117.9	118.1	118.0	117.7	114.4	114.4	114.4
Subtotal Base		100.0%	360.9	360.9	365.8	371.2	371.5	371.7	372.5	372.2	371.1	360.7	360.7	360.9
Member Available Other Capacity After Losses, Reserves (MW)														
CARM Available Other Capacity	(7)	11.4%	18.7	18.7	18.7	18.7	18.7	18.7	18.7	18.7	18.7	18.7	18.7	18.7
TRICO Available Other Capacity	(7)	21.1%	34.6	34.6	34.6	34.6	34.6	34.6	34.6	34.6	34.6	34.6	34.6	34.6
MEC Available Other Capacity	(7)	35.8%	58.8	58.8	58.7	58.8	58.7	58.7	58.8	58.7	58.8	58.7	58.7	58.8
SSVEC Available Other Capacity	(7)	31.7%	56.0	56.0	56.0	56.0	56.0	56.0	56.0	56.0	56.0	56.0	56.0	56.0
Subtotal Available Other Cap			168.1	168.1	168.0	168.1	168.0	168.0	168.1	168.0	168.1	168.0	168.0	168.1
Member Total Available Capacity with Available S&G Capacity (MW)														
CARM Total Available Capacity			59.9	59.9	60.4	61.0	61.1	61.1	61.2	61.1	61.0	59.8	59.8	59.9
TRICO Total Available Capacity			110.8	110.8	111.8	113.0	113.0	113.0	113.2	113.2	112.9	110.7	110.7	110.8
MEC Total Available Capacity			187.9	187.9	189.6	191.6	191.6	191.7	192.1	191.9	191.6	187.8	187.8	187.9
SSVEC Total Available Capacity			170.4	170.4	172.0	173.7	173.8	173.9	174.1	174.0	173.7	170.4	170.4	170.4
Total			529.0	529.0	533.8	539.3	539.5	539.7	540.6	540.2	539.2	528.7	528.7	529.0

Notes: (1) Federal Hydro Estimated - AEPCO will establish Fed Hydro portion of Available Base Capacity monthly pursuant to the Federal Hydro Power Agreements.
(2) The 29 MW value added to LSH Reserves of 188 MW of Coal Unit capacity (includes spinning reserve capability) is required to restore SRSG Operating Reserves.
(3) The Class A Members have agreed that AEPCO will purchase transmission import capacity from SWTC or others as needed to hold generating reserves to 6.7%.
(4) The SWTC loss factors are subject to change from time to time as changes are implemented to such loss factors pursuant to SWTC's OATT Tariff.
(5) MEC Reserve fraction is rounded to ensure total reserves match totall reserves required of Class A members.
(6) Credit for Operating Reserve contribution from EuroFresh generation controlled by SSVEC pursuant to AEPCO-SSVEC agreement.
(7) Class A Member Available Base and Other Capacity fractions are rounded up and down as needed to match total AC.

APPENDIX B to Exhibit A-5 to Rate Schedules A
PRM and CARM Monthly Allocated Capacity for 2021 thru 2035

All Values in MW Unless Indicated			Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Existing Resources														
Apache ST-2 Coal-fired			175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0
Apache ST-3 Coal-fired			175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0
Subtotal Base Units			350.0	350.0	350.0	350.0	350.0	350.0	350.0	350.0	350.0	350.0	350.0	350.0
Fed Hydro - SLCA IP PPA	(1)		1.6	1.6	1.4	6.9	7.0	7.3	8.2	7.8	6.8	1.4	1.4	1.6
Fed Hydro - Parker-Davis PPA	(1)		17.3	17.3	22.4	22.4	22.4	22.4	22.4	22.4	22.4	17.3	17.3	17.3
Sub Total Base Resources			368.9	368.9	373.8	379.3	379.4	379.7	380.6	380.2	379.2	368.7	368.7	368.9
Apache CC-1			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Apache GT-2			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Apache GT-3			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Apache GT-4			38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0
Subtotal Other Resources			38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0
Subtotal Existing Resource Units			388.0	388.0	388.0	388.0	388.0	388.0	388.0	388.0	388.0	388.0	388.0	388.0
Subtotal Fed Hydro PPA	(1)		18.9	18.9	23.8	29.3	29.4	29.7	30.6	30.2	29.2	18.7	18.7	18.9
Total Existing Resources			406.9	406.9	411.8	417.3	417.4	417.7	418.6	418.2	417.2	406.7	406.7	406.9
Reserve Caculation														
2nd Hr Reserves Reqd for LSH Plus 29 MW	(2)		217.0	217.0	217.0	217.0	217.0	217.0	217.0	217.0	217.0	217.0	217.0	217.0
Less: WW-Mead-Davis Displacement			50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0
Less: AEPCO Wheeling Available			40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0
Less: SWTC Transmission Reserved			100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
Less: Western/MEC Transmission Reserved			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Less: Transmission Import Capacity	(3)		190.0	190.0	190.0	190.0	190.0	190.0	190.0	190.0	190.0	190.0	190.0	190.0
Remaining Reserve Requrement (MW)			27.0	27.0	27.0	27.0	27.0	27.0	27.0	27.0	27.0	27.0	27.0	27.0
Reserve Requrement (% of Unit Cap)	(3)		7.0%	7.0%	7.0%	7.0%	7.0%	7.0%	7.0%	7.0%	7.0%	7.0%	7.0%	7.0%
Power Sales Resources MW														
Electrical District 2 Firm			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Salt River Project Firm			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Power Sales Resources			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Less Power Sales Losses	(4)	2.97%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Less Power Sales Reserves - MW			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SubTotal for Power Sales Resources			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Net Existing Resource Capacity														
Existing Resoucre Units after Pwr Sales			388.0	388.0	388.0	388.0	388.0	388.0	388.0	388.0	388.0	388.0	388.0	388.0
Less Member Losses after Reserves	(4)	2.31%	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3
Net Existing Resource Unit Capacity			379.7	379.7	379.7	379.7	379.7	379.7	379.7	379.7	379.7	379.7	379.7	379.7
Existing Fed Hydro Capacity			18.9	18.9	23.8	29.3	29.4	29.7	30.6	30.2	29.2	18.7	18.7	18.9
Total Existing Resource Capacity			398.6	398.6	403.5	409.0	409.1	409.4	410.3	409.9	408.9	398.4	398.4	398.6
Portion of Member Capacity Net of Losses														
CARM Existing Resource @ ACP		11.4%	45.4	45.4	46.0	46.6	46.6	46.7	46.8	46.7	46.6	45.4	45.4	45.4
TRICO Existing Resource @ ACP		21.1%	84.1	84.1	85.1	86.3	86.3	86.4	86.6	86.5	86.3	84.1	84.1	84.1
MEC Existing Resource @ ACP		35.8%	142.7	142.7	144.4	146.4	146.4	146.6	146.9	146.7	146.4	142.6	142.6	142.7
SSVEC Existing Resource @ ACP		31.7%	126.4	126.3	127.9	129.6	129.7	129.8	130.1	129.9	129.6	126.3	126.3	126.3
Member Reserve Shares (MW)														
CARM Reserves			3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1
TRICO Reserves			5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7
MEC Reserves	(5)		9.6	9.6	9.6	9.6	9.6	9.6	9.6	9.6	9.6	9.6	9.6	9.6
SSVEC Reserves			8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6
Less: EuroFresh Reserve Credit	(6)		(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)
Net SSVEC from Existing Resources			4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6
Total Reserves Req'd of Class A Members			27.0	27.0	27.0	27.0	27.0	27.0	27.0	27.0	27.0	27.0	27.0	27.0
S&G PPA Resources														
Griffith Purchased Power			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
South Point Purchased Power			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total S&G PPA Resources			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total After Network Losses			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CARM Available S&G Capacity		3.2%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
TRICO Available S&G Capcity		96.8%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Member Total Allocated Capacity (MW)														
CARM Total AC			42.3	42.3	42.9	43.5	43.5	43.6	43.7	43.6	43.5	42.3	42.3	42.3
TRICO Total AC			78.4	78.4	79.4	80.6	80.6	80.7	80.9	80.8	80.6	78.4	78.4	78.4
MEC Total AC			133.1	133.1	134.8	136.8	136.8	137.0	137.3	137.1	136.8	133.0	133.0	133.1
SSVEC Total AC			121.8	121.7	123.3	125.0	125.1	125.2	125.5	125.3	125.0	121.7	121.7	121.7
Total			375.6	375.5	380.4	385.9	386.0	386.5	387.4	386.8	385.9	375.4	375.4	375.5
Member Available Base Capacity After Power Sales, Losses (MW)														
CARM Available Base Capacity	(7)	11.4%	41.1	41.1	41.7	42.3	42.3	42.4	42.5	42.4	42.3	41.1	41.1	41.1
TRICO Available Base Capacity	(7)	21.1%	76.1	76.1	77.1	78.3	78.3	78.4	78.6	78.5	78.3	76.1	76.1	76.1
MEC Available Base Capacity	(7)	35.8%	129.2	129.2	130.9	132.9	132.9	133.1	133.4	133.2	132.9	129.1	129.1	129.2
SSVEC Available Base Capacity	(7)	31.7%	114.4	114.3	115.9	117.6	117.7	117.8	118.1	117.9	117.6	114.3	114.3	114.3
Subtotal Base		100.0%	360.8	360.7	365.6	371.1	371.2	371.7	372.6	372.0	371.1	360.6	360.6	360.7
Member Available Other Capacity After Losses, Reserves (MW)														
CARM Available Other Capacity	(7)	11.4%	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2
TRICO Available Other Capacity	(7)	21.1%	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3
MEC Available Other Capacity	(7)	35.8%	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9
SSVEC Available Other Capacity	(7)	31.7%	7.4	7.4	7.4	7.4	7.4	7.4	7.4	7.4	7.4	7.4	7.4	7.4
Subtotal Available Other Cap			14.8	14.8	14.8	14.8	14.8	14.8	14.8	14.8	14.8	14.8	14.8	14.8
Member Total Available Capacity with Available S&G Capacity (MW)														
CARM Total Available Capacity			42.3	42.3	42.9	43.5	43.5	43.6	43.7	43.6	43.5	42.3	42.3	42.3
TRICO Total Available Capacity			78.4	78.4	79.4	80.6	80.6	80.7	80.9	80.8	80.6	78.4	78.4	78.4
MEC Total Available Capacity			133.1	133.1	134.8	136.8	136.8	137.0	137.3	137.1	136.8	133.0	133.0	133.1
SSVEC Total Available Capacity			121.8	121.7	123.3	125.0	125.1	125.2	125.5	125.3	125.0	121.7	121.7	121.7
Total			375.6	375.5	380.4	385.9	386.0	386.5	387.4	386.8	385.9	375.4	375.4	375.5

Notes: (1) Federal Hydro Estimated - AEPCO will establish Fed Hydro portion of Available Base Capacity monthly pursuant to the Federal Hydro Power Agreements.
(2) The 29 MW value added to LSH Reserves of 188 MW of Coal Unit capacity (includes spinning reserve capability) is required to restore SRSG Operating Reserves.
(3) The Class A Members have agreed that AEPCO will purchase transmission import capacity from SWTC or others as needed to hold generating reserves to 6.7%.
(4) The SWTC loss factors are subject to change from time to time as changes are implemented to such loss factors pursuant to SWTC's OATT Tariff.
(5) MEC Reserve fraction is rounded to ensure total reserves match totall reserves required of Class A members.
(6) Credit for Operating Reserve contribution from EuroFresh generation controlled by SSVEC pursuant to AEPCO-SSVEC agreement.
(7) Class A Member Available Base and Other Capacity fractions are rounded up and down as needed to match total AC.

Exhibit A-6: Sample Bill

CARM		ACP %		
DATE:				February 10, 2011
January, 2011				
				Total $
Fixed Charge				
O&M Charge				
		kwh	$/kwh	Total $
Base Billing Energy				
Base Energy Fuel Adjustor				
Other Billing Energy				
Supplemental Billing Energy				
Supplemental Billing Energy Fuel Adjustor				
S&G PPA Billing Energy				
S&G PPA Energy Fuel Adjustor				
Other Billing Energy				
Other Energy Fuel Adjustor				
Minimum Base Capacity Charge				
Minimum Other Capacity Charge				
	DOAF			
Demand Overrun Adjustment	%			
Overrun Energy Charge				
	mkW	12MORA		
Power Factor Adjustor				
ACC Gross Operating Revenue Assessment				

Exhibit A-6: Sample Data for Bill
CARM

	Monthly MWH
Supplemental Billing Energy	
Supplemental Transfers delivered	
Off-peak	
On-Peak	
S & G Billing Energy	
S & G Transfers delivered	
Off-peak	
On-Peak	
Base Billing Energy	
Base Economy Purchases	
Off-peak	
On-Peak	
Base Transfer delivered	
Off-peak	
On-Peak	
Base Economy Sales credits	
Off-peak	
On-Peak	
Base Mismatch Energy	
Other Billing Energy	
Off-peak	
On-Peak	
Supplemental Transfer Billing Energy received	
Off-peak	
On-Peak	
S & G PPA Transfer Billing Energy received	
Off-peak	
On-Peak	
Base Transfer Billing Energy received	
Off-peak	
On-Peak	
Total Other Energy	
Off-peak	
On-Peak	

Exhibit A-6: Sample Bill

INVOICE

To: ARM
Address
City, AZ

'ATTN:

Energy Cost Responsibility

CARM Member 1 **Demand Ratio Share**

DATE: **February 10, 2011**

January, 2011				
		DRS	CARM $	Total $
Fixed Charge				
O&M Charge				
		ECR	CARM $	Total $
Base Billing Energy				
Base Energy Fuel Adjustor				
Other Billing Energy				
Supplemental Billing Energy				
Supplemental Billing Energy Fuel Adjustor				
S&G PPA Billing Energy				
S&G PPA Energy Fuel Adjustor				
Other Billing Energy				
Other Energy Fuel Adjustor				
Minimum Base Capacity Charge				
	DOAF			
Minimum Other Capacity Charge	%			
Demand Overrun Adjustment				
	mkW	12MORA		
Overrun Energy Charge				
Power Factor Adjustor				
ACC Gross Operating Revenue Assessment				

Exhibit A-6: Sample Data for Bill
ARM MEMBER 1 15% of CARM

	Monthly MWH
Supplemental Billing Energy	
Supplemental Transfer delivered	
Off-peak	
On-Peak	
S&G Billing Energy	
S&G Transfer delivered	
Off-peak	
On-Peak	
Base Billing Energy	
Base Economy Purchases	
Off-peak	
On-Peak	
Base Transfer delivered	
Off-peak	
On-Peak	
Base Economy Sales credits	
Off-peak	
On-Peak	
Base Mismatch Energy	
Other Billing Energy	
Off-peak	
On-Peak	
Supplemental Transfer Billing Energy received	
Off-peak	
On-Peak	
S&G PPA Transfer Billing Energy received	
Off-peak	
On-Peak	
Base Transfer Billing Energy received	
Off-peak	
On-Peak	
Total Other Energy	
Off-peak	
On-Peak	

EXHIBIT B

SEVENTH AMENDMENT TO WHOLESALE POWER CONTRACT

This Seventh Amendment to Wholesale Power Contract (Amendment) is entered into this 11 day of May, 2010, by and between Graham County Electric Cooperative, Inc., a non-profit corporation organized and existing under the laws of the State of Arizona/California (Member) and Arizona Electric Power Cooperative, Inc., a non-profit cooperative corporation organized and existing under the generation and transmission electric cooperative laws of the State of Arizona ("AEPCO" or "Generating Cooperative"). Member and AEPCO are also hereinafter referred to individually as "Party" or collectively as "Parties."

WHEREAS, the Parties have entered into that certain Wholesale Power Contract dated February 15, 1962, as amended and supplemented on March 15, 1971, November 1, 1974, November 3, 1982, February 2, 1984, October 1, 1986, November 15, 2001, and May 1, 2003(Wholesale Power Contract), such that Member pursuant to the Wholesale Power Contract is an "AEPCO All Requirements Member," as that term is defined in the Amended and Restated Appendix A dated May 11 2010 attached hereto and referred to herein as the "2010 Definition Appendix";

WHEREAS, the Parties intend to modify as among themselves the manner in which rates and charges for electrical service to Member are formulated and designed in order to effect resolution of certain Rate Allocation Issues and Rate Design Issues, which have developed among AEPCO and the AEPCO Class A Members, as all such capitalized terms are defined in the 2010 Definition Appendix, pursuant to the Rate Settlement Agreement dated May 14, 2010 (Rate Settlement Agreement);

WHEREAS, the Parties recognize the benefit in entering into this Amendment in order to settle the Rate Allocation Issues and Rate Design Issues by providing for a fair, equitable and repeatable allocation of costs and revenues at issue between the Partial Requirements Members (PRM) and the All Requirements Members (ARM) based on principles of cost causation;

WHEREAS, the Parties intend that this Amendment to the Wholesale Power Contract shall be an integral component of the Rate Settlement Agreement;

WHEREAS, AEPCO filed on October 1, 2009, an application with the Arizona Corporation Commission (ACC) in ACC Docket No. E-01773A-09-0472 to modify its rates and charges (AEPCO 2009 Rate Application);

WHEREAS, this Amendment is intended to be entered into contemporaneously with certain other substantially identical amendments to individual wholesale power contracts between AEPCO and each of the other AEPCO ARMs;

WHEREAS, it is in the best interest of Member and its members to enter into this Amendment to effect the changes in AEPCO's rate formulation and services provision herein contemplated, thereby partially implementing the Rate Settlement Agreement; and
WHEREAS, the Parties wish to amend the Wholesale Power Contract, as set forth in this

WHEREAS, the Parties wish to amend the Wholesale Power Contract, as set forth in this Amendment;

NOW, THEREFORE, in consideration of the premises set forth above and for good and valuable consideration, the receipt and sufficiency of which the Parties hereby acknowledge, the Parties hereto, intending to be legally bound, mutually agree as follows:

Section 1. Amendment to Part I Section 4 (a) of the Wholesale Power Contract.

Part I, Section 4 (a) is hereby amended by adding to it concluding sentences, as follows:

"For purposes of specifying and calculating rates and charges pursuant to this Rate Schedule A, Member and other Members receiving all requirements electric service from the Generating Cooperative are individually referred to as an "ARM" and collectively referred to as "Collective ARM" or "CARM." When specified in Rate Schedule A, Member's All Requirements Member's Demand Ratio Share (ARM DRS) of certain CARM rates and charges shall be equal to the quotient of Member's 12 month rolling average demand divided by CARM's 12 month rolling average demand. Also, Member's Energy Cost Ratio Share (ARM ECR) for purposes of Rate Schedule A shall be the percentage share for each billing period of Member in the CARM S&G PPA Energy Charge, CARM Supplemental Purchase Cost, CARM Base Energy Cost, and CARM Total Other Energy Cost, determined in such billing period as the ratio expressed in percent of Member's Member Billing Energy to CARM Billing Energy."

Section 2. Amendment to Part I, Section 4 (b) of the Wholesale Power Contract.

Part I, Section 4(b) is hereby amended by replacing the term, "rate or rates" wherever it may appear therein with the term, "rate and charge" or "rates and charges," as appropriate.

Section 3. Addition of New Section 13 to Part I of the Wholesale Power Contract.

Part I is hereby amended by adding the new Section 13, which is set forth in its entirety as Attachment 1, attached hereto.

Section 4. 2010 Definition Appendix.

Attached hereto are definitions for terms not defined herein, applicable to this Amendment and other related agreements as the Amended and Restated Appendix A dated May 11 2010.

Section 5. Amendment to Rate Schedule A and all revisions thereto adopted by the Generating Cooperative, attached to the Wholesale Power Contract.

Rate Schedule A attached to the Wholesale Power Contract and all revisions thereto adopted by the Generating Cooperative shall be amended in their entirety and replaced with the Rate Schedule A, dated May 11, 2010, attached hereto as Attachment 2.

Section 6. The Rural Utilities Service and the Arizona Corporation Commission.

This Seventh Amendment shall become effective on the first day of the month following the latter of 1) the date of its approval by the Rural Utilities Service (RUS), 2) the date of approval by the ACC or 3) the effective date of a non-appealable decision in AEPCO's 2009 Rate Application, or its replacement.

Section 7. Miscellaneous.

(a) Extent of Amendment. Except as expressly herein set forth, all of the terms and conditions of the Wholesale Power Contract are hereby ratified and confirmed and shall remain in full force and effect.

(b) Counterparts. This Amendment may be executed in any number of counterparts, and all of which when taken together shall constitute one and the same instrument. The Parties hereto may execute this Amendment by signing any such counterpart.

(c) Binding Effect. This Amendment shall be binding upon the Parties and their respective successors and assigns.

(d) References to Rural Electrification Administration. Any references in the Wholesale Power Contract to the Rural Electrification Administration shall be replaced with the title of its successor agency, the RUS.

IN WITNESS WHEREOF, the undersigned have duly executed this Seventh Amendment to the Wholesale Power Contract, effective as of the date set forth below.

ARIZONA ELECTRIC POWER COOPERATIVE, INC.

By:____________________

Name: Gary G. Grim

Title: Senior Vice President and Chief Operating Officer

Date: 5/11/10

-and-

ANZA ELECTRIC COOPERATIVE, INC.

By:______________________________

Name:____________________________

Title:_____________________________

Date:_____________________________

-or-

DUNCAN VALLEY ELECTRIC COOPERATIVE, INC.

By:______________________________

Name:____________________________

Title:_____________________________

Date:_____________________________

-or-

GRAHAM COUNTY ELECTRIC COOPERATIVE, INC.

By: Gene Robert Larson

Name: GENE ROBERT LARSON

Title: BOARD PRESIDENT

Date: 5/11/10

APPENDIX A

AMENDED AND RESTATED: DEFINITIONS
DATED May 11, 2010

1. These Definitions shall have the respective meanings set forth herein for use in the following agreements and their exhibits and schedules (unless the context in which the term is used in a particular agreement clearly requires otherwise):

   1. MEC Partial Requirements Capacity and Energy Agreement;
   2. SSVEC Partial Requirements Capacity and Energy Agreement;
   3. TRICO Partial Requirements Capacity and Energy Agreement;
   4. Resource Integration Agreement;
   5. SSVEC Transmission Agreement;
   6. MEC Transmission Agreement;
   7. TRICO Transmission Agreement;
   8. Network Service Agreement;
   9. Member Agreement between AEPCO, SWTC, Sierra and ANZA, DVEC, GCEC, MEC, SSVEC and TRICO.

2. These Definitions shall not be amended or modified without advance notice, review and approval by all parties to any of the agreements listed above, and RUS (as hereinafter defined), which remain executory, and after providing to all parties in advance a listing of any such agreements in which a proposed amended or modified defined term is contained.

3. The following shall be used in interpreting these Definitions and the agreements listed above:

   3.1 Unless otherwise required by the context in which any term appears:

   (a) Capitalized terms used in any agreement listed above shall have the meanings specified in this Appendix A or, if used solely within an Agreement, as set forth in such agreement.

   (b) The singular shall include the plural and the masculine shall include the feminine and neuter.

   (c) References to "Articles," "Sections," "Schedules," "Appendices" or "Exhibits" shall be to articles, sections, schedules, appendices, or exhibits of the agreement(s) specified, and references to paragraphs shall be to separate paragraphs of the section or subsection in which the reference occurs.

   (d) The words "herein," "hereof", "hereinbelow" and "hereunder" shall refer to an agreement, specified as a whole and not to any particular section or subsection of such agreement; the words "include," "includes" or "including" shall mean "including, but not limited to"; and the words "best effort(s)" shall mean a level of effort which, in the exercise of reasonable judgment in the light of facts known at the time a decision is made, can be expected to accomplish the desired result at a reasonable cost, consistent with Prudent Utility Practice (as hereinafter defined).

(e) Except where the context otherwise indicates, the term "day" shall mean a calendar day, and whenever an event is to be performed by a particular date, or a period ends on a particular date, and the date in question falls on a weekend, a legal holiday in the State of Arizona, or a day when the relevant cooperative is not open for business, the event shall be performed, or the period shall end, on the next succeeding business day.

(f) All accounting terms not specifically defined herein or by specified Accounting Requirements (as hereinafter defined) shall be construed in accordance with Generally Accepted Accounting Principles in the United States of America, consistently applied.

3.2 All references herein to the term "cooperative" shall be to AEPCO, TRANSCO, CSP or a Member (as hereinafter defined) cooperative as appropriate from the context in an agreement.

3.3 All references to a particular entity shall include such entity's successor and permitted assigns.

3.4 All references herein to any agreement, including its schedules, exhibits and appendices, shall be to such agreement as amended, supplemented or modified.

3.5 All references herein to any Law (as hereinafter defined) shall be to such Law as amended, supplemented, modified or replaced.

3.6 The titles of the articles and sections of the agreements have been inserted as a matter of convenience of reference only and shall not control or affect the meaning or construction of any of the terms or provisions thereof.

3.7 The parties have agreed to the wording of the agreements, and none of the provisions thereof shall be construed against one party on the ground that any party is the author of such agreement or any part thereof.

3.8 In any defined term which begins with the word "PRM*," the word PRM* may be replaced with the name of a Partial Requirements Member. When the name of a Partial Requirements Member is substituted, the definition remains the same but is applicable only to the named Partial Requirements Member. For example, "'PRM* Transmission Service' shall mean Network Integration Transmission Service and all Ancillary Services used to deliver the AC and associated energy of PRM* to PRM* AEPCO Load." If MEC is substituted, "'MEC Transmission Service' shall mean Network Integration Transmission Service and all Ancillary Services used to deliver the AC and associated energy of MEC to MEC AEPCO Load."

"AC" shall mean Allocated Capacity.

"ACC" shall mean Arizona Corporation Commission or any State of Arizona regulatory agency succeeding to its powers and functions.

"Accounting Report" shall mean the report prepared by TRANSCO that accounts for all of the installed cost of each transmission facility constructed or acquired by TRANSCO as a part of the TTS and classifies such facility or portion thereof and apportions its installed cost as an All Requirements Resource Facility, an Existing System Facility, a Load Growth System Facility, a Power Sale Resource System Facility, a Resource Facility, or a Reliability System Facility, for the purposes of Sections 2 and 6 hereof and consistent with Accounting Requirements.

"Accounting Requirements" shall mean the requirements of any system of accounts prescribed by the RUS as long as RUS is the holder of any obligation of a cooperative; provided, however, that if a cooperative is specifically required by another Governmental Authority to employ the system of accounts prescribed by that Governmental Authority, then "Accounting Requirements" means the system of accounts prescribed by that Governmental Authority; provided, further, however, that if RUS is not a holder of any obligation or, if a holder, RUS does not prescribe a system of accounts applicable to the cooperative, and the cooperative is not specifically required by another Governmental Authority to employ that entity's system of accounts, then "Accounting Requirements" means the requirements of Generally Accepted Accounting Principles or another comprehensive basis of accounting applicable to like entities conducting business similar to that of the cooperative. Generally Accepted Accounting Principles refers to a common set of accounting standards and procedures that are either promulgated by an authoritative accounting rulemaking body or accepted as appropriate due to widespread application in the United States.

"Additional AEPCO Contract" shall mean each additional contract (set forth on Schedule 1 of the Member Agreement and Schedule 6 of the Restructuring Agreement as the case may be) which either the Member Agreement or the Restructuring Agreement requires to be executed and delivered by AEPCO.

"Additional CSP Contract" shall mean each additional contract (set forth on Schedule 1 of the Member Agreement and Schedule 6 of the Restructuring Agreement as the case may be) which either the Member Agreement or the Restructuring Agreement requires to be executed and delivered by CSP.

"Additional TRANSCO Contract" shall mean each additional contract (set forth on Schedule 1 of the Member Agreement and Schedule 6 of the Restructuring Agreement as the case may be) which either the Member Agreement or the Restructuring Agreement requires to be executed and delivered by TRANSCO.

"Administrator" shall mean the Administrator of RUS or any other federal regulatory agency or department succeeding to the Administrator's power or functions as a lender or mortgagee to a cooperative.

"AEPCO" shall mean Arizona Electric Power Cooperative, Inc., a non-profit generation and transmission cooperative corporation organized under the Laws of the State of Arizona.

"AEPCO Available Resource(s)" shall mean that portion of AEPCO Resources representing operating reserves which can be sold on an interruptible basis and surplus to AEPCO Total Load.

"AEPCO By-law Amendments" shall mean the amendments to the AEPCO By-laws relating to governance, in the form adopted by AEPCO in accordance with the terms of the AEPCO By-laws and the Laws of the State of Arizona.

"AEPCO By-laws" shall mean the By-laws adopted and amended by the Members or Board of Directors of AEPCO in accordance with the Laws of the State of Arizona.

"AEPCO Class A Member" shall mean (i) any Class A Member which purchases power and energy from AEPCO pursuant to any Existing Wholesale Power Contract or Partial Requirements Capacity and Energy Agreement and is listed in Recital B to the Partial Requirements Capacity and Energy Agreement; or (ii) is determined to be a Class A member by the terms of the AEPCO By-laws.

"AEPCO Closing Date Allocation and Attribution" shall mean the allocations and attributions to be made by AEPCO on the Closing Date, as set forth in Section 2.6 of the Member Agreement and Section 2.3 of the Restructuring Agreement.

"AEPCO Delivered Load" shall mean the aggregate of the demand requirements and the associated energy requirements of all electric loads served from AEPCO Resources (including distribution losses but not including reserves or transmission losses), and shall consist of:

1. The loads of All Requirements Members served from AEPCO Resources;
2. PRM*AEPCO Load;
3. PRM*AEPCO Sales;
4. Power Sales Loads; and
5. CSP AEPCO Load.

"AEPCO Employees" shall mean those individuals employed by AEPCO as of the Closing Date.

"AEPCO Federal Hydro Power Capacity" shall mean that amount of capacity on an hourly basis scheduled by AEPCO pursuant to Federal Hydro Power Agreements.

"AEPCO Load Forecast" shall mean a listing of the demand and associated energy requirements of AEPCO Total Load (by month for the Resource Forecast Period) to be served from AEPCO Resources

"AEPCO's Member Peak Demand" shall mean the highest thirty (30) minute integrated demand in kW experienced during the billing period of the aggregate demands of all Class A

Members purchased pursuant to the Partial Requirements Capacity and Energy Agreements and the Existing Wholesale Power Contracts.

"AEPCO Minimum Base Capacity" shall mean the capacity from Available Base Capacity that must be operated from time to time to maintain system reliability or for other reasons, reflecting AEPCO's determination as to the schedule of energy from the Federal Hydro Power Agreements and AEPCO Minimum Coal Capacity.

"AEPCO Minimum Coal Capacity" shall mean the minimum output for safe and reliable operation of Apache Units 2 and 3.

"AEPCO Mortgage" shall mean the Consolidated Mortgage and Security Agreement, dated as of June 14, 1989, by and among AEPCO, as mortgagor, and the Government acting through the Administrator of the RUS, and CFC, as mortgagees, as amended and consolidated, or restated from time to time, which secures the obligations thereunder and creates a lien on substantially all of the real and tangible personal property of AEPCO in favor of such mortgagees, additional substitute mortgagees and other secured parties.

"AEPCO Notes" shall mean written instruments or notes which evidence the obligation of AEPCO for loans that in whole or in part financed the construction of AEPCO's generation and transmission facilities, the payment of which is guaranteed by the Government pursuant to the REAct, and those written instruments or notes of AEPCO outstanding on the Effective Date (with respect to the MEC Partial Requirements Capacity and Energy Agreement), the Agreement Date (with respect to the SSVEC Partial Requirements Capacity and Energy Agreement), or the Approval Date (with respect to the TRICO Partial Requirements Capacity and Energy Agreement) payable to the Government evidencing loans made by the Government, acting by and through the Administrator of RUS, pursuant to the REAct, or evidencing reimbursement obligations of AEPCO to the Government with respect to the Government's guarantee of the payment of certain notes payable to the order of FFB and all amendments, supplements, extensions, and replacements to, of, or for, such notes, and loans made by, or securities issued to, or obligations undertaken to, others, including the Financial Entities. AEPCO Notes in the future will also include written instruments, which may evidence additional or new loans or advances that AEPCO may obtain to finance the construction or purchase of new facilities, Future Resources or the modification of Existing Resources, as applicable.

"AEPCO Resource" shall mean a Resource owned or purchased from others by AEPCO.

"AEPCO Retained Personnel" shall mean AEPCO management and other personnel designated as such by the chief executive officer of AEPCO.

"AEPCO's Revenue Requirement" shall mean the total revenues, from any source whatsoever, necessary to enable AEPCO, utilizing a twelve (12) month test period to: (i) meet all its anticipated fixed, variable, fuel, and all other costs, obligations and expenses and payments (including all payments on account of Indebtedness of AEPCO); (ii) establish and maintain reasonable financial reserves; and, (iii) include appropriate levels of margins and working capital to satisfy, at a minimum, applicable prescribed annual coverage ratios or any other financial covenants or tests imposed by the Financial Entities, as may exist from time to time, determined in accordance with Accounting Requirements.

"AEPCO's Revenue Requirement from AEPCO's Class A Members" shall mean that portion of AEPCO's Revenue Requirement less revenues anticipated by AEPCO from all other sources than the AEPCO Class A Members.

"AEPCO's Revenue Requirement From Partial Requirements Members" shall mean that portion of AEPCO's Revenue Requirement from AEPCO Class A Members allocated to Partial Requirements Members in accordance with Section 5 of the Partial Requirements Capacity and Energy Agreements and Section 3 of Rate Schedules A.

"AEPCO Scheduling Portal" shall mean an Internet web site maintained by AEPCO and accessible by all Class A Members for the purpose of AEPCO posting ongoing information relating to the availability and minimum must run requirements for AEPCO Resources.

"AEPCO Secured Obligations" shall mean the AEPCO Notes, loans made by, or securities issued to, or debt obligations entitled to the lien created by the AEPCO Mortgage.

"AEPCO Total Load" shall mean the aggregate of the demand requirements and the associated energy requirements of: (i) AEPCO Delivered Load plus, (ii) losses related thereto from the transmission of power and energy, plus, (iii) applicable only to the demand requirement computation: the greater of (a) applicable installed capacity margin, or (b) operating reserve requirements.

"Agreement Date" shall mean the first day of the month following the date upon which the SSVEC Partial Requirements Capacity and Energy Agreement, the SSVEC Transmission Agreement and the Resource Integration Agreement, as amended to include SSVEC, shall have been executed and delivered by the necessary parties and approved by the RUS and, if required, by the ACC and FERC.

"All Requirements Member" shall mean any Class A Member of AEPCO that is currently a party to any Wholesale Power Contract with AEPCO which provides for the purchase from AEPCO of all such Member's requirements of electric power, which as of the Effective Date consisted of ANZA, DVEC, GCEC, SSVEC AND TRICO, which as of the Agreement Date consisted of ANZA, DVEC, GCEC and TRICO, and which as of the Approval Date shall consist of ANZA, DVEC and GCEC.

"All Requirements Resource Facility" shall mean any System Facility, or portion hereof, or Direct Assignment Facility that is required to interconnect with and to deliver to the TTS the capacity and energy of any Resource Modification or Future resource in which MEC and SSVEC have no ACP.

"Allocated Capacity" or "AC" shall mean the amount of capacity of AEPCO Resources from which a Partial Requirements Member is entitled to schedule energy in any month as set forth in its Partial Requirements Capacity and Energy Agreement. The AC for each month for the term of such agreement is set forth in Appendix B to Exhibit A-5 to Rate Schedule A of such agreement.

"Allocated Capacity Percentage" or "ACP" of a Class A Member shall mean the percentage allocation with respect to an AEPCO Resource, for which, if it is a Partial Requirements Member, such Member is responsible, including the allocation of electric capacity, cost responsibility and revenues, as set forth in its Partial Requirements Capacity and Energy Agreement. Appendix A to Exhibit A-5 to Rate Schedule A sets forth the ACP for each Class A Member with respect to Existing Resources and the S&G PPA.

"Ancillary Services" shall mean the ancillary services required by FERC to be made available with transmission service in accordance with the FERC pro-forma open access transmission tariff, including; but not limited to scheduling, system control and dispatch service; reactive supply and voltage control from generation sources service; regulation and frequency response service; energy imbalance service; operations reserve-spinning reserve service, and; operating reserve - supplemental reserve service, all as such terms are further defined by FERC in Order No. 888 and 889 and identified in transmission tariffs and service agreements of TRANSCO.

"Annual Planning Report" shall mean the annual written report and analysis given to AEPCO of a Class A Member's short, intermediate and long-range forecast of load and such other planning data required by the Resource Integration Agreement.

"Annual Transmission Requirements Report" shall have the meaning set forth in Section 5 of Schedule B hereto (Transmission Planning Policies).

"ANZA" shall mean Anza Electric Cooperative, Inc., a non-profit electric cooperative corporation organized and existing under the Laws of the State of California.

"Applicable Additional Contract" shall mean each additional contract as set forth on Schedule 1 of the Member Agreement and Schedule 6 of the Restructuring Agreement, which either the Restructuring Agreement or the Member Agreement requires to be executed by each party to the Agreements.

"Approval Date" shall mean the first day of the month, no earlier than December 1, 2010, following the latter of 1) the date upon which the TRICO Transmission Agreement and the TRICO PRC&EA shall have been approved by the RUS, 2) the date upon which the TRICO PRC&EA shall have been approved by the ACC or 3) the effective date of a non-appealable decision in AEPCO's 2009 Rate Application, or its replacement.

"ARM Energy Cost Responsibility Share or ARM ECR" shall mean the percentage share for each billing period of an individual All Requirements Member in CARM S&G PPA Energy Charge, CARM Supplemental Purchase Cost, CARM Base Energy Cost, and CARM Total Other Energy Cost, determined in such billing period as the ratio expressed in percent of each All Requirements Member's Member Billing Energy to CARM Billing Energy.

"Assignment for Security" shall mean an assignment, transfer, mortgage or pledge of a party's interest in an Agreement made as security for any obligation secured by any indenture, mortgage, deed, deed of trust, security instrument, or similar lien on its system assets, without limitation on the right of the secured party to further assign such Agreement.

"Authorized Representative" shall mean a representative designated by a party pursuant to the terms of an Agreement and authorized to act for such party in certain matters as set forth in the relevant terms of such Agreement.

"Available Base Capacity" shall mean the energy from Base Resources, including Base Economy Purchases, available for dispatch in a Future Scheduling Hour, less losses in delivery to Class A Members, and excluding (i) any coal-fired capacity that is not available due to forced outage or scheduled maintenance outage or temporary deration, (ii) capacities of Power Sales Resources, and (iii) allocations for losses in delivery of such Power Sales Resources; and for each Billing Unit Entity, shall mean that Billing Unit Entity's ACP share of such Available Base Capacity.

"Available Other Capacity" shall mean the amount of capacity that is available for dispatch as determined by AEPCO for any Future Scheduling Hour equal to the sum of (i) the aggregate of the capacities of Other Resources, which shall be as set forth in Appendix B to Exhibit A-5 of Rate Schedule A to each Partial Requirements Capacity and Energy Agreement, as may be amended, plus (ii) the capacity of any concurrent Replacement Purchases for Base Resources, less (iii) capacity set aside for Reserves and allocations for losses in delivery; and for each Billing Unit Entity, shall mean that Billing Unit Entity's ACP share of such Available Other Capacity.

"Available Resource(s)" shall mean the Pooled Resource(s) surplus to Pooled Load available for sale or dispatch as Merchant Sales.

"Available S&G PPA Capacity" shall mean S&G PPA Capacity, less an allocation for losses for delivery, that is available for dispatch by AEPCO for any Future Scheduling Hour; and for each Billing Unit Entity having an ACP in S&G PPA, shall mean that Billing Unit Entity's ACP share of such Available S&G PPA Capacity.

"Available Supplemental Capacity" shall mean Supplemental Capacity, less an allocation for losses for delivery, that is available for dispatch by AEPCO for any Future Scheduling Hour; and for each Billing Unit Entity having an interest in a Supplemental Purchase, shall mean that Billing Unit Entity's percentage share of such Available Supplemental Capacity.

"Available Transmission Resources" shall mean the transmission facilities and contract rights of the Parties (as set forth in Schedule E attached) required for the delivery of Pooled Resources to Pooled Loads.

"Base Adjustor Per Unit Cost" shall mean, for a billing period for each Billing Unit Entity, the Base Fuel Adjustor Cost divided by the Base Billing Energy for the same Billing Unit Entity for the same billing period.

"Base Average Energy Rate" shall mean, for a billing period for each Billing Unit Entity, the rate obtained by dividing the Billing Unit Entity's Base Energy Cost of the billing period by Billing Unit Entity's Base Billing Energy for the same period.

"Base Billing Energy" shall mean, for a Billing Unit Entity, the energy from its Available Base Capacity assigned and allocated in each hour pursuant to the Billing Unit Program to its Base Schedule or load, accumulated for a billing period.

"Base Capacity" shall mean for Base Resources the sum of (i) the capacity from Federal Hydro Power Agreements as adjusted to reflect seasonal and Peak Hours vs. Off-Peak Hours variations; plus (ii) 350 MW of capacity of AEPCO's coal-fired units.

"Base Economy Purchase" shall mean a purchase of energy by AEPCO from a third party, including wheeling charges recorded in RUS Uniform System of Accounts 565 Transmission of Electricity by Others or its successor for delivery of the purchase to an SWTC Point of Receipt, if any, which is made at a lower average energy rate over the purchase period than that associated with energy available from Base Resources during such period, and which AEPCO chooses to make in lieu of dispatching energy available from such Base Resources.

"Base Economy Purchase Cost" shall mean, for all hours of a billing period, the purchase energy cost incurred by AEPCO for all Base Economy Purchases made in such billing period, including wheeling costs incurred in delivery from the source of such purchase to an SWTC Point of Receipt, if any.

"Base Economy Sales" shall mean, for a billing period, the energy from Post-Transfer Excess Base Capacity assigned in each hour to each Billing Unit Entity pursuant to the Billing Unit Program as Third Party Economy Sales.

"Base Economy Sales Cost" shall mean, for each Billing Unit Entity for a billing period, the product of Base Economy Sales multiplied by the Coal Energy Rate.

"Base Economy Sales Credit" shall mean, for each Billing Unit Entity, the product of the Economy Sales Price, for each of Daytime Hours and Nighttime Hours of a billing period, multiplied by the Billing Unit Entity's Base Economy Sales for Daytime Hours and for Nighttime Hours, respectively, of the same billing period.

"Base Energy Cost" shall mean, for a billing period for each Billing Unit Entity, the sum of Remaining Base Energy Cost plus Base Transfer Sales Credits, Base Transfer Energy Cost, Base Economy Sales Credit and Base Economy Sales Cost for the same Billing Unit Entity.

"Base Energy Mismatch" shall mean, for a billing period, the accumulated net difference in energy obtained from subtracting (i) the energy from Available Base Capacity assigned and allocated in the billing period in accordance with the Billing Unit Program, from (ii) the energy actually produced from Available Base Capacity during that billing period.

"Base Energy Mismatch Charge" shall mean, for a billing period, the product of (i) any positive value of Base Energy Mismatch for the billing period, multiplied by (ii) the Coal Energy Rate for the billing period.

“Base Energy Mismatch Credit” shall mean, for a billing period, the product of (i) the absolute value of any negative value of Base Energy Mismatch for the billing period, multiplied by (ii) the Coal Energy Rate for the billing period.

“Base Energy Rate” shall mean, for each Billing Unit Entity, the rate applicable to that Billing Unit Entity’s use of energy from Available Base Capacity as set forth in Exhibit A-1 to Rate Schedule A.

“Base FPPCA” shall mean Fuel and Purchase Power Cost Adjustor determined for a FPPCA Period for the Base Resources for each Billing Unit Entity.

“Base Fuel Adjustor Cost” shall mean, for a billing period for each Billing Unit Entity, the sum of the Base Energy Cost, Hydro Demand Charge, Base Transmission Wheeling Cost and Power Sales Resource Demand Revenues for the same Billing Unit Entity for the same billing period.

“Base Fuel Bank” shall mean, for a billing period for each Billing Unit Entity, the accumulation of Base Over or Under Collections.

“Base Incremental Unit Cost” shall mean, for a billing period for each Billing Unit Entity, the difference obtained by subtracting (i) the sum of (a) Base Power Cost Adjustor Base, plus (b) Base Power Cost Adjustor Rate, from (ii) Member Base Adjustor Per Unit Cost, for such Billing Unit Entity for such period.

“Base Over or Under Collection” shall mean, for a billing period for each Billing Unit Entity, the product of (i) Base Incremental Unit Cost multiplied by (ii) Base Billing Energy, for such Billing Unit Entity for such period.

“Base Power Cost Adjustor Base” shall mean the Power Cost Adjustor Base for Base Resources as set forth in the Tariff.

“Base Power Cost Adjustor Rate” shall mean the Power Cost Adjustor Rate for Base Resources as set forth in the Tariff.

“Base Resources” shall mean the Federal Hydro Power Agreements and two coal-fired steam Generating Resources that are Existing Resources located at the Apache Generating Station, in which each Class A Member has an ACP.

“Base Schedule” shall mean, for each Member*, its Pre-Schedules and Real-Time Schedules provided to AEPCO by such Member* or its Scheduling Agent pertaining to Member*’s use of its Available Base Capacity, as such Pre-Schedules and Real-Time Schedules are determined consistent with Schedule B to the Partial Requirements Capacity and Energy Agreements.

“Base Transfer” shall mean, for a Billing Unit Entity, energy from the Billing Unit Entity’s Excess Base Capacity that has been assigned and allocated to the load or Other Schedule of other Billing Unit Entities in an hour pursuant to the Billing Unit Program, accumulated for a billing period separately for Daytime Hours and Nighttime Hours.

"Base Transfer Billing Energy" shall mean, for a Billing Unit Entity, energy from the Excess Base Capacity of other Billing Unit Entities that has been assigned and allocated to the Billing Unit Entity in an hour pursuant to the Billing Unit Program, accumulated for a billing period separately for Daytime Hours and Nighttime Hours.

"Base Transfer Energy Cost" shall mean, for each Billing Unit Entity for a billing period, Coal Energy Rate multiplied by Base Transfer.

"Base Transfer Purchase Cost" shall mean, for each Billing Unit Entity that has been assigned Base Transfer Billing Energy, for each of separately accumulated Daytime Hours and Nighttime Hours of a billing period, the product of its Base Transfer Billing Energy, multiplied by the Economy Purchase Rate of Daytime Hours or Nighttime Hours, as applicable.

"Base Transfer Sales Credit" shall mean, for each Billing Unit Entity, for each of separately accumulated Daytime Hours and Nighttime Hours of a billing period, the product of (i) the Economy Purchase Rate of Daytime Hours or Nighttime Hours, as applicable, multiplied by (ii) its Base Transfer Energy of Daytime Hours or Nighttime Hours, as applicable.

"Base Transmission Wheeling Cost" shall mean, for each Billing Unit Entity for a billing period, the product of (i) the costs recorded in RUS Uniform System of Accounts 565 Transmission of Electricity by Others or its successor, and allocated to Base Resources, for the same billing period, multiplied by (ii) the Billing Unit Entity's ACP in Existing Resources.

"Billing Energy" shall mean the energy of each billing period determined pursuant to the Billing Unit Program to have served the entirety of the Schedule of each Member*, or the entirety of the load of CARM or the entirety of the Directed Sales and load of a Member* CA in such billing period, consisting of the sum of the Billing Unit Entity's Base Billing Energy, S&G PPA Billing Energy, Other Billing Energy, Base Transfer Billing Energy, Supplemental Billing Energy, and S&G And Supplemental Transfer Billing Energy.

"Billing Unit Entity" shall mean any of CARM, a Member* or a Member* CA.

"Billing Unit Program" shall mean the software program and subroutines that are used by AEPCO's Power Trading and Scheduling Department for the purpose of determining monthly each Billing Unit Entity's Billing Energy from Base Resources, Other Resources, S&G PPA and Supplemental Purchase by hourly allocation and assignment of energy from Available Base Capacity, Available Other Capacity, Available S&G PPA Capacity and Available Supplemental Capacity to each of (i) the loads of the CARM; (ii) the Directed Sales and load of a Member* CA; (iii) the Schedules; (iv) Base Transfers; (v) S&G And Supplemental Transfers; and (vi) Third Party Economy Sales.

"Bonds" shall mean the CFC Guaranteed Solid Waste Disposal Revenue Bonds (Series 1994Adw) and the CFC Guaranteed Pollution Control Revenue Refunding Bonds (Series 1997C).

"CARM or Collective ARM" shall mean all of the All Requirements Members.

"CARM ACP" shall mean the sum of the ACPs in Existing Resources applicable to each All Requirements Member of AEPCO as set forth in Appendix A to Exhibit A-5 to the Rate Schedule A of the ARM Wholesale Power Contracts.

"CFC" shall mean the National Rural Utilities Cooperative Finance Corporation, a corporation organized under the Laws of the District of Columbia, or similar successor agency.

"Class A Member" shall mean any entity which is or becomes such a Member of AEPCO, TRANSCO or CSP under the relevant cooperative's By-laws.

"Closing" shall mean the execution and delivery of any and all documents and the tendering, transferring or delivering of all payments required to be made or otherwise necessary or desirable to consummate the transactions contemplated by the Restructuring Agreement and the Member Agreement, including such actions and documents described in the Closing Memorandum as specified in Section 8.1 of both the Restructuring Agreement and the Member Agreement, following satisfaction or waiver, if any, of the conditions for Closing therein.

"Closing Date" shall mean the date on which the Closing occurs.

"Closing Memorandum" shall mean the memorandum agreed to by the parties to the Member Agreement prior to the Pre-Closing which sets forth the consents, assignments, transfers, delivery of other approvals, documents, legal opinions, payments and transaction documents to be furnished by the parties, other conditions for Closing, and events and actions required to effect the Closing

"Coal Energy Cost" shall mean, for a billing period, the accumulated costs of coal and natural gas expensed during that billing period, related to the operation and dispatch during that billing period of two coal-fired steam Generating Resources that are Existing Resources located at the Apache Generating Station, as recorded in RUS Uniform System of Accounts 501 or its successor for that billing period.

"Coal Energy Rate" shall mean, for a billing period, Coal Energy Cost divided by the product of Coal Energy Generated multiplied by the difference obtained by subtracting the Network Loss Factor from one (1).

"Coal Energy Generated" shall mean, for a billing period, the net energy output at the 230 kv bus of the two coal-fired steam Generating Resources that are Existing Resources located at the Apache Generating Station.

"Collected Funds" shall mean deposited funds in a banking institution that are immediately available for use without any float restrictions.

"Contract Rate of Interest" shall mean the lesser of: (i) the interest rate equal to the effective "Prime Rate" per annum as specified in the "Money Rates" section of the Wall Street Journal or, (ii) the maximum interest rate permitted by applicable Law in the State of Arizona if any is so stated.

"Cost Causation" shall mean the identification of all direct and indirect costs, revenue and billing units associated with individual Resources and services, such that costs, revenue and billing units can be accounted for and billed separately to the specific Class A Members participating in such Resource or receiving such service.

"CSP" shall mean Sierra Southwest Cooperative Services, Inc., a non-profit corporation organized under the generation and transmission cooperative corporation Laws of the State of Arizona.

"CSP Actual AEPCO Load Data" shall have the meaning set forth in Section 4 of the Resource Planning Policies.

"CSP AEPCO Load" shall mean the sum of the demand and associated energy requirements, including distribution losses, but not including reserves or transmission losses, of the Member JMP Load of each Class A Member and of those other loads for which CSP purchases capacity and energy from AEPCO as specified in separate sales agreements between AEPCO and CSP.

"CSP AEPCO Load Forecast" shall have the meaning set forth in Section 4 of the Resource Planning Policies.

"CSP Assets" shall mean all capital stock of TSEPP, personal property, authorization to make Retail Sales, intangible assets, employee benefit plans, intellectual property, software licenses, employee or consultant agreements, equipment leases and contracts, licenses, any chose in action, and other agreements related to the performance of the CSP Business identified on Schedule 2 to the Restructuring Agreement.

"CSP Business" shall mean (i) the business of power sales and retail sales; (ii) the provision of personnel and consulting services to AEPCO, TRANSCO, and others pursuant to contract; and, (iii) the ownership and use of the CSP Assets, including responsibility for CSP Liabilities.

"CSP JMP Load" shall mean the demand and energy requirements, including distribution losses but not including reserves or transmission losses, of those loads within a Member's Distribution Service Area served using capacity and energy provided by CSP from CSP Resources pursuant to a Joint Marketing Agreement between a Class A Member and CSP.

"CSP Liabilities" shall mean (i) the CSP liabilities identified on Schedule 2 to the Restructuring Agreement, as such obligations exist as of the Closing Date; and (ii) such other obligations relating to the performance of the CSP Business as CSP, AEPCO and TRANSCO may agree upon from time to time in other agreements; and (iii) any liabilities which CSP assumes in accordance with its By-laws.

"CSP Member" shall mean AEPCO, TRANSCO and the Class A Members of AEPCO on the Closing Date and any Person, which has become and retains membership in CSP in accordance with the CSP By-laws.

"CSP Resource" shall mean a Resource owned or purchased by CSP from third parties.

"Daytime Hours" shall mean the 16 hours of each day beginning Hour Ending 0700 through Hour Ending 2200 Pacific Prevailing Time, including Sundays and Holidays.

"Debt Service Coverage Ratio" or "DSC" shall mean the financial ratio determined, based on figures shown on RUS Form 12 for each calendar year-end as submitted in accordance with Accounting Requirements by AEPCO or TRANSCO, by: (1) adding (a) depreciation and amortization expense, (b) interest on long-term debt (increased by one-third of the amount, if any, by which long-term leases exceed two percent of total margins and equities less regulatory assets), and (c) net patronage capital or margins and (2) dividing the sum obtained by the total of interest and principal billed under long-term debt and debt service requirements.

"Deficiency Purchase" shall mean the purchase of additional capacity and energy through the First Right(s) of Refusal among AEPCO and MEC pursuant to Section 10.1.1 herein, which purchase is required to supply capacity and associated energy to meet AEPCO Total Load, if it is the Purchasing Party, or MEC Total Load if MEC is the Purchasing Party.

"Delivery Point" shall mean the interconnection between the TTS and the transmission, distribution system or load of a Class A Member at which TRANSCO is to deliver capacity or energy pursuant to the Transmission Agreement or the Network Service Agreement.

"Demand Overrun Adjustments" shall have the meaning set forth in Section 2.2 of Rate Schedule A.

"Direct Assignment Facilities" shall mean those transmission lines, substation facilities (or components thereof) and firm wheeling purchased by TRANSCO, for the sole use and benefit of a TRANSCO Member or of a particular transmission customer receiving service under the TRANSCO Tariff.

"Directed Sales" shall mean any transactions in which, at the advance direction of a Member* CA, AEPCO for such Member* CA's benefit sells to a third party at wholesale energy from such Member* CA's available AC in AEPCO Resources.

"Directed Sales Credit" shall mean the revenue realized from Directed Sales.

"Dispatch Pool Resources" shall mean Existing Resources, the S&G PPA and Supplemental Purchases.

"DVEC" shall mean Duncan Valley Electric Cooperative, Inc., an electric cooperative non-profit membership corporation organized and existing under the Laws of the State of Arizona.

"Economy Purchase(s)" shall mean a wholesale purchase of capacity and/or energy for a term not to exceed one year (including all renewal periods) entered into by AEPCO.

"Economy Purchase Cost" shall mean, separately accumulated for Daytime Hours and Nighttime Hours of a billing period, the total cost incurred by AEPCO (including transmission expenses, including losses, incurred in delivery from the source of such purchase to an SWTC Point of Receipt, if any) for Non-Base Economy Purchases and Replacement Purchases in effect in such Daytime Hours or Nighttime Hours of the billing period.

"Economy Purchase Rate shall mean, separately calculated for Daytime Hours and Nighttime Hours of a billing period, the rate obtained by dividing Economy Purchase Cost of Daytime Hours or Nighttime Hours of that billing period, by energy received from Non-Base Economy Purchases and Replacement Purchases in effect in such Daytime Hours or Nighttime Hours of that billing period.

"Economy Sale(s)" shall mean a wholesale sale by AEPCO of capacity and energy from AEPCO Available Resources made for monthly, daily or hourly periods of the next twelve months on a pre-scheduled basis.

"Economy Sales Price" shall mean for Third Party Economy Sales, for each of Daytime Hours and Nighttime Hours, the quotient obtained by dividing (i) the numerator equal to the sum of the revenue from all Third Party Economy Sales during the billing period in Daytime Hours and Nighttime Hours, respectively, reduced by any payments to SWTC or third parties for transmission used in delivery of such sales, by (ii) a denominator equal to the MWh of energy delivered as Third Party Economy Sales during such hours.

"Effective Date" shall mean either (i)________________, or (ii) the Closing Date.

"Eligible Customer For TRANSCO " shall mean any of the following: (i) any electric utility (including AEPCO, CSP or any power marketer), Federal Power Marketing Agency, or any Person generating electric energy for sale for resale (electric energy sold or produced by any such entity may be produced in the United States, Canada or Mexico) or (ii) any Person offering retail electric service to others or taking retail service pursuant to a state requirement that TRANSCO offer unbundled transmission service or to a voluntary offer of such service by TRANSCO.

"Energy Cost Accounting Process" or "ECAP" shall mean the software program and subroutines that are used by AEPCO's Financial Services Department for the purpose of determining monthly each Billing Unit Entity's costs for energy from Base Resources, Other Resources, S&G PPA, and Supplemental Resources.

"Engineering Analysis Requirement" shall mean have the meaning set forth in Section 3.3.2 of the Partial Requirements Capacity and Energy Agreement.

"Equity" shall be defined in accordance with Accounting Requirements.

"Excess Base Capacity" shall mean, for a billing period for each Billing Unit Entity, the separately accumulated Daytime and Nighttime billing period totals of Available Base Capacity that is not assigned in an hour pursuant to the Billing Unit Program as Base Billing Energy

"Excess S&G And Supplemental Capacity" shall mean, for a billing period for each Billing Unit Entity having an ACP interest in S&G PPA and/or Supplemental Purchase, Available S&G PPA Capacity and/or Available Supplemental Capacity, that is not assigned in an hour pursuant to the Billing Unit Program as S&G and Supplemental Billing Energy.

"Exercise Date" shall mean date certain on or before which The Possible Selling Party or Parties shall provide notice to the Purchasing Party or Parties of an election pursuant to Section 10.1.1 herein to exercise The First Right of Refusal among AEPCO and MEC.

"Existing Resource(s)" shall mean the AEPCO Resource(s) as set forth and designated as Existing Resources in Appendix B to Exhibit A-5 to Rate Schedule A, consisting of Base Resource(s) and Other Resource(s).

"Existing System Facility" shall mean any System Facility that is in service or has been acquired as of the Agreement Date, and improvements thereto and replacements thereof occurring during the term of the Agreement.

"Existing Wholesale Power Contract" shall mean the Wholesale Power Contract between AEPCO and a Class A Member, and when used in the plural shall mean such contract and similar contracts between AEPCO and each of the Class A Members pursuant to which, in either case, such Class A Member purchases or purchased all its requirements of electric power from AEPCO prior to its becoming a Partial Requirements Member.

"FERC" shall mean the Federal Energy Regulatory Commission, an agency of the United States Department of Energy, or regulatory agency succeeding to the powers and functions thereof.

"Federal Hydro Power Agreement(s) shall mean the following contracts:

a) Contract No. 87-BCA-10001 for Firm Electric Service between Western Area Power Administration and Arizona Power Pooling Association, dated March 9, 1989 as it may be amended from time to time, and its successor agreement(s) (SLCA Integrated Projects Agreement); and
b) Contract No. 87-BCA-10085 Electric Service between Western Area Power Administration and Arizona Power Pooling Association, dated February 25, 1988 as it may be amended from time to time, and its successor agreement(s) (Parker-Davis Project Agreement).

"FFB" shall mean the Federal Financing Bank, an instrumentality and wholly owned corporation of the Government or any agency or department of the Government succeeding to the powers and functions thereof.

"Final Load Ratio Share of PRM*" shall mean the Load Ratio Share of PRM* in effect as of the Last Service Date.

"Financial Entities" shall mean collectively RUS, CFC, FFB, the trustees and bondholders of the Bonds and other lending institutions or issuers of debt who have made loans to or hold securities or other obligations of a cooperative.

"First Right(s) of Refusal" shall mean reciprocal one-time rights of first refusal to sell capacity and associated energy granted by the purchasing party to the selling party pursuant to Section 10.1 of the Resource Integration Agreement. Certain conditional first rights of refusal provided by CSP to AEPCO as set forth in Section 14 of the Resource Integration Agreement shall not be deemed to form a part of this defined term.

"First Right(s) of Refusal Period" shall mean the time period during which the First Right(s) of Refusal among AEPCO and MEC pursuant to Section 10.1 of the Resource Integration Agreement shall be in effect commencing on the Effective Date and ending on September 1, 2001.

"Fixed Charge" shall mean the charge computed in accordance with Section 5.2 of a Partial Requirements Capacity and Energy Agreement which recovers the share of a Partial Requirements Member of certain fixed costs and expenses of AEPCO.

"Force Majeure" shall mean the occurrence or non-occurrence of any act, event or cause beyond the control of a party to an Agreement whereby the party is unable to perform its obligation, other than the obligation to pay money, which act, event or cause by that party's exercise of due diligence could not have reasonably been expected and avoided, or which even with the exercise of due diligence, the party has not been able to overcome or avoid or cause to be avoided. Such act, event or cause shall include, but not be limited to: acts of God; failure or threat of immediate failure of facilities; explosions, flood, drought, earthquake, storm, fire, pestilence, lightning and other natural catastrophes; epidemic; war; riot; civil disturbance or disobedience, strike, or labor disturbance, disputes or unrest of whatever nature; civil disputes or unrest of whatever nature; labor, material or fuel shortage; sabotage; vandalism; restraint by court order or public authority; a failure or threat of failure of any generating or transmission facility, which is likely to cause an outage of electric service to customers served from that party's system (including transmission curtailments by a transmission provider) or to cause such party to experience a rapid decline in system voltage or frequency; and, action or non action by or inability to obtain the necessary authorizations or approvals from any Governmental Authority (but not including the ACC or RUS), provided however, that no act, event or cause that is the result of the lack of necessary financial resources shall constitute an event of "Force Majeure," nor shall an act, event or cause that is the result of the negligence of the party claiming Force Majeure constitute an event of "Force Majeure."

"Form 12A Balance Sheet" shall mean RUS Form 12a, Section B, Balance Sheet.

"FPPCA" shall mean Fuel and Purchase Power Cost Adjustor determined for the applicable AEPCO Resources.

"FPPCA Period" shall mean the period of months over which AEPCO is to record S&G PPA Energy Charge, Supplemental Purchase Cost, Base Energy Cost and Other Energy Cost for billing or credit to the Class A Members pursuant to the Tariff.

"Future Resource" shall mean (i) any new AEPCO Generating Resource, or (ii) any AEPCO Power Purchase Resource with a term of greater than one (1) year; either of which Resource would require the assignment of a new ACP to each Class A Member participating in such Resource and an amendment, or a new Exhibit to Rate Schedule A.

"Future Scheduling Hour" shall mean a clock hour beginning more than sixty (60) minutes after the current hour.

"Gas Energy Cost" shall mean, for a billing period, the accumulated costs of natural gas expensed during that billing period, related to the operation and dispatch during that billing period of the gas-fired Generating Resources that are Existing Resources located at the Apache Generating Station, as recorded in RUS Uniform System of Accounts 547 or its successor for that billing period.

"Gas Energy Generated" shall mean, for a billing period, the net energy output at the applicable bus of the gas-fired Generating Resources that are Existing Resources located at the Apache Generating Station.

"Gas Energy Rate" shall mean, for a billing period, Gas Energy Cost divided by the product of Gas Energy Generated.

"GCEC" shall mean Graham County Electric Cooperative, Inc., an electric cooperative non-profit membership corporation organized and existing under the Laws of the State of Arizona

"Generally Accepted Auditing Standards" shall mean a common set of auditing standards and procedures that have been developed over time by several auditing boards, the most current set of standards and procedures of which is the Auditing Standards Board.

"Generating Resource" shall mean an interest in any existing, additional, modified or repowered generating facility or unit, which may be owned (jointly or individually), leased or otherwise acquired by AEPCO, provided that in connection with any lease of an Existing Resource, such leasehold interest shall not be deemed to be a Future Resource for purposes of the Partial Requirements Capacity and Energy Agreement.

"Generation Business" shall mean with respect to AEPCO: (i) the business of generation of electricity; (ii) operation of the Resource Pool; and, (iii) the use, ownership, rights, obligations and duties associated with the generation assets including its agreements for Power Purchase Resources, Power Sales Resources, Economy Purchases and Economy

Sales including, but not limited to, the Existing Wholesale Power Contracts and the Partial Requirements Capacity and Energy Agreement.

"Government" shall mean the federal government of the United States of America.

"Governmental Authority" shall mean any local, state, regional, federal, or national administrative, legal, judicial, or executive governmental agency, commission, department, or other governmental entity having jurisdiction over AEPCO, TRANSCO, CSP, their respective Members, or any of their activities.

"Hydro Demand Charge" shall mean, for a billing period, demand charges associated with Federal Hydro Power Agreements as recorded in RUS Uniform System of Accounts 555 or its successor for the billing period.

"Hydro Energy Charge" shall mean, for a billing period, energy charges associated with Federal Hydro Power Agreements as recorded in RUS Uniform System of Accounts 555 or its successor for the billing period.

"Indebtedness" shall mean:

(1) debt incurred or assumed by a cooperative for borrowed money, or debt incurred for the reimbursement of money advanced under any credit support agreements if in either case categorized as debt according to Accounting Requirements;

(2) lease obligations, if categorized as debt according to Accounting Requirements;

(3) debt incurred or obligations assumed for facilities or power purchases included in a Member's ACP;

(4) debt incurred or obligations issued to finance the amount of a pre-payment; or

(5) debt for any Person (other than debt otherwise treated as Indebtedness hereunder) described in clauses (1), (2), (3) or (4) above which are guaranteed (whether by payment or collection) by the cooperative, provided that none of the following shall constitute Indebtedness:

    (A) guarantees of performance or payment by, or any obligations of, any Person under contracts to pay for fuel for the system; and

    (B) guarantees of performance by any Person for other than payment of debt incurred or assumed for borrowed money, or any obligation if categorized as debt according to Accounting Requirements, including, without limitation, all debt (other than indebtedness otherwise treated as Indebtedness hereunder) for borrowed money or the acquisition, construction or improvement of property or capitalized lease obligations guaranteed directly or indirectly, in any manner by a cooperative, or in effect guaranteed, directly or indirectly, by such cooperative through an agreement, contingent or otherwise, to assume any such indebtedness or to advance or supply funds for the payment or purchase of any such indebtedness or to purchase property or services primarily for the purpose of enabling the debtor or seller to make payment of such indebtedness, or to assure the owner of the indebtedness against loss, because of such indebtedness or to supply funds to or in any other manner invest in the debtor (including any agreement to pay for property or services irrespective of whether or not such property is delivered or such services are rendered) or otherwise.

"Interest Expense" shall mean an amount constituting interest on long-term Indebtedness (less any interest during construction and allowance for funds used during construction including an interest rate swap collar, floor forward or other hedging agreement, arrangement or security, however denominated) and other interest expense computed in accordance with Accounting Requirements.

"Intra-Day Schedule" shall mean a Real-Time Schedule.

"Joint Marketing Agreement" shall mean an agreement by and between CSP and a Class A Member pertaining to joint competitive retail electric marketing and sales activities, in accordance with applicable Law, within such Member's Distribution Service Area.

"Joint Marketing Plan" shall mean a plan designed by and entered into between CSP and a Class A Member concerning Retail Sales, the form of which is set forth in Exhibit B to the Joint Marketing Agreement.

"Last Service Date" shall mean the last date on which TRANSCO provides service to PRM* pursuant to Section 2 of a PRM* Transmission Agreement, unless otherwise extended by mutual agreement of the Parties as set forth in writing.

"Law" shall mean any applicable treaty, statute, code, constitutional provision, ordinance, rule, regulation, order, judgment, decree, decision, injunction, process or any similar form of legally binding decision or directive issued by any Governmental Authority including permits and regulatory approvals and any applicable common law.

"Legal Requirement" shall mean any obligation of AEPCO or TRANSCO required by Law.

"Load Forecast" shall mean he projections of monthly coincident peak kilowatt and total monthly kilowatt-hour loads of a party to an Agreement.

"Load Growth System Facility" shall mean any System Facility or portion thereof that is not an All Requirements Resource Facility or a Resource Facility and is constructed or acquired by TRANSCO to deliver the power and energy of any Future Resource or Resource Modification to All Requirements Members for serving the portion of total load of All Requirements Members that is in excess of the sum of the collective AC of All Requirements Members in Existing Resources with all Power Sales Resources reduced to zero.

"Load Pool" shall mean those Pooled Loads served from Pooled Resources.

"Load Ratio Share" shall have the meaning set forth in the TRANSCO Tariff.

"Load Ratio Share of PRM*" shall mean the ratio, expressed as a decimal, that results from dividing: (i) the demand of PRM* AEPCO Load at the time of the TRANSCO system Peak, by (ii) the sum of: (a) the actual total of the demands of all firm loads of all TRANSCO customers at the time of the TRANSCO system peak, including PRM* plus (b) the reserved transmission capacity of all TRANSCO customers receiving firm point to point transmission service under the TRANSCO Tariff, less (c) the actual demands at the time of the TRANSCO system peak of the loads of TRANSCO's customers receiving firm point to point transmission service under the TRANSCO Tariff. Such ratio shall be calculated on a rolling twelve month basis.

"Long Term" shall mean with respect to a forecast deficiency of AEPCO Resources with respect to AEPCO Total Load, a time period extending beyond the subsequent five calendar years.

"Long Term Debt" shall have the meaning given in accordance with Accounting Requirements.

"MEC" shall mean Mohave Electric Cooperative, Inc., an electric cooperative non-profit membership corporation organized and existing under the Laws of the State of Arizona.

"Member" shall mean a member of AEPCO, a CSP Member or a TRANSCO Member, as applicable.

"Member Actual AEPCO Load Data" shall have the meaning set forth in Section 3 of the Resource Planning Policies.

"Member AEPCO Load Forecast" shall have the meaning set forth in Section 3 of the Resource Planning Policies.

"Member Agreement" shall mean the Member Agreement as executed and delivered by and among the Class A Members, AEPCO, TRANSCO and CSP, dated July 2, 2001.

"Member Billing Demand" shall mean as to Member, the demand of Member in kW integrated over the thirty (30) minute period occurring coincident in time with the AEPCO's Member Peak Demand purchased by Member from AEPCO pursuant to a PRM* Partial Requirements Capacity and Energy Agreement, which consists of the demands of PRM* AEPCO Load and PRM* AEPCO Sales.

"Member Billing Energy" shall mean the energy in kWh received by PRM* from AEPCO during the billing period pursuant to a PRM* Partial Requirements Capacity and Energy Agreement which consists of the energy requirements of PRM* AEPCO Load and PRM* AEPCO Sales.

"Member JMP Load" shall mean the demand and energy requirements, including distribution losses but not including reserves or transmission losses of loads located within a Member's Distribution Service Area served using capacity and energy provided by CSP as a result of a Joint Marketing Agreement between CSP and a Class A Member, for which CSP purchases capacity and energy from AEPCO.

"Member Transaction" shall mean (i) the consolidation or merger by the Partial Requirements Member with any other Person; (ii) the reorganization or change of the form of the Partial Requirements Member's business organization from an electric cooperative non-profit membership-owned corporation; or, (iii) the sale, transfer, lease, or other disposal of all or substantially all the Partial Requirements Member's assets to any Person (or any effort or agreement therefor), whether accomplished in a single transaction or contemplated through a series of transactions as set forth in Section 12 of the Partial Requirements Capacity and Energy Agreement and the Transmission Agreement.

"Member*" shall mean a PRM whose load is not assigned to the SWTC metered subsystem of the Western Area Lower Colorado Balancing Authority in the Desert Southwest Region.

"Member* CA" shall mean a PRM whose load is assigned to the SWTC metered subsystem of the Western Area Lower Colorado Balancing Authority in the Desert Southwest Region.

"Member's Distribution Service Area" shall mean the geographical electric service territory of a Class A Member as certificated by the ACC, the California Public Utility Commission or the New Mexico Public Utility Commission, as applicable, to supply distribution service as well as all other territory so served by such Class A Member pursuant to applicable Law, or any inter-utility border agreement.

"Merchant Purchase(s)" shall mean a wholesale purchase of capacity and/or energy (pursuant to Section 11 herein) for periods occurring in the next twelve months and for a duration not to exceed twelve consecutive months (including all renewal periods) arranged for and entered into by AEPCO as operator of Pooled Resources to: (i) minimize the cost of energy production from Pooled Resources, and (ii) displace energy from Pooled Resources of higher Pool Price.

"Merchant Sale(s)" shall mean a wholesale sale of capacity and/or energy (pursuant to Section 11 herein) from Surplus Resources for periods occurring in the next twelve months and for a duration not to exceed twelve consecutive months (including all renewal periods) arranged for and entered into by AEPCO as operator of Pooled Resources to use Surplus Resources for the economic benefit of the Pool Resource Owners.

"Minimum Other Capacity" shall mean the capacity from Available Other Capacity that must be operated from time to time to maintain system reliability or for other reasons as described in Section 4.2 of Schedule B to the Partial Requirements Capacity and Energy Agreements.

"Minor Resource Modification" shall mean an addition, improvement, repair or modification to an AEPCO Generating Resource or the modification or extension of an AEPCO Power Purchase Resource for five years or less, undertaken by AEPCO in its sole discretion, which will not: (i) increase of greater than ten percent the capacity of the AEPCO Resource being modified; (ii) result in an increase of greater than five percent in AEPCO's Revenue Requirement From AEPCO's Class A Members upon the operation of such addition, improvement, repair and modification or extension, as the case may be; or, (iii) extend the term of any Existing Wholesale Power Contract or Partial Requirements Capacity and Energy Agreement.

"Must-Pool Load(s)" shall mean those loads of AEPCO, CSP and MEC which Section 3 herein requires be served from the Resource Pool.

"Must-Pool Resources" shall mean AEPCO Resources and those Resources of CSP and the Partial Requirements Member, which are required to be included in the Resource Pool.

"Native Load" shall mean (i) for AEPCO, the electric load of wholesale power customers of AEPCO on whose behalf AEPCO, by Law, tariff or contract, has undertaken an obligation to construct, or otherwise obtain, reliably operate and provide AEPCO Resources (including Purchase Power Resources of AEPCO) to meet the electric requirements of such customers and shall include, but not be limited to, AEPCO Delivered Load, (ii) for TRANSCO, "Native Load" shall mean the electric loads of the TTS customers on whose behalf TRANSCO, by Law, tariff or contract (including as TTS successor to AEPCO) has undertaken an obligation to construct and operate the TTS and shall include, but not be limited to, AEPCO Delivered Load, and (iii) for a Member, "Native Load" shall mean the electric load of the customers of a Member to whom such Member sells power and/or energy and on whose behalf the Member, by Law, tariff, or contract, has undertaken an obligation to construct, or otherwise obtain, and reliably operate the Member's system to meet the power supply requirements of such customers.

"Near Term" shall mean" shall mean with respect to a forecast deficiency of AEPCO Resources with respect to AEPCO Total Load, a time period not to exceed the subsequent two calendar years.

"NERC" shall mean the North American Electric Reliability Council, or entity or agency succeeding to its powers and functions.

"Net Utility Plant" shall mean total utility plant less accumulated depreciation as computed consistent with Accounting Requirements.

"Network Integration Transmission Service" shall described in Part III of the TRANSCO Tariff.

"Network Loads" shall have the meaning set forth in Section 1 of the TRANSCO Tariff. The Delivery Points of the Network Loads of Member served pursuant to this Agreement are set forth in Schedule C hereto.

"Network Loss Factor" shall mean the adjustment factor for transmission losses assigned for network service under the Southwest Transmission Cooperative, Inc. Open Access Transmission Tariff as in effect from time to time.

"Network Resources" shall have the meaning set forth in Section 1 of the TRANSCO Tariff.

"Network Service Agreement" shall mean the Network Service Agreement by and between TRANSCO, AEPCO and the All Requirements Members, substantially in the form attached as Exhibit B-1 to the Member Agreement.

"Nighttime Hours" shall mean the eight (8) hours beginning Hour Ending 2300 of one day continuing through Hour Ending 0600 of the following day, Pacific Prevailing Time.

"Non-Base Economy Purchase" shall mean any purchase of energy by AEPCO from a third party that is not a Base Economy Purchase which is made at a lower average energy rate over the purchase period than that which would be associated with energy dispatched from Available Other Capacity or Available S&G PPA Capacity during such period, and which is made in lieu of dispatching energy from such capacity.

"Non-Generation Assets" shall mean as determined in accordance with Accounting Requirements, all assets of AEPCO of every kind, description, and location which shall be acquired by TRANSCO from AEPCO, as of the Closing Date, which are set forth in Schedule 1 to the Restructuring Agreement.

"Non-Pool Loads" shall mean those loads of a Partial Requirements Member or CSP or applicable portions of such loads which are not included in Pooled Loads.

"Non-Pool Resource" shall mean any Resource obtained by a Partial Requirements Member or CSP and which is not included in the Resource Pool.

"O&M" shall mean the general accounting term used to describe activities and expenses involved with the use, operation, maintenance and repair of a cooperative's plant and facilities including expenses associated with activities intended to prevent or remedy an impending or actual breakdown of those facilities. The term O&M does not include the enlargement or improvement of the property owned or leased and operated by a cooperative nor does it include the replacement of retirement units.

"O&M Charge" shall mean the charge computed in accordance with 5.3 of a Partial Requirements Capacity and Energy Agreement which recovers the share of a Partial Requirements Member of certain fixed costs and expenses of AEPCO.

"Off-Peak Hours" shall mean those hours defined by the Western Systems Coordinating Council to represent off-peak load periods, which for each day consist of the eight hours of the hour ending at 2300 through hour ending at 0600, Mountain Standard Time, and the remaining hours of each Sunday and of each of six holidays (New Years Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas Day).

"Operating Committee" shall mean the standing committee(s) established in the Partial Requirements Capacity and Energy Agreement and assigned by the parties thereto to deal on a prompt and orderly basis with certain technical and operating issues that may arise in connection with system development or operations.

"Operating Reserve Purchases" shall mean any purchases of operating reserve capacity to avoid curtailing any energy from any more economical AEPCO Resource that would otherwise be required to provide such operating reserve capacity.

"Optional Pool Resources" shall mean those Resources which a party may commit to the Resource Pool.

"Order No. 888" shall mean that certain FERC order Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities, Order No. 888, 61 Fed. Reg. 21,540 (1996), FERC Stats. & Regs. para. 31,036 (1996), order on reh'g, Order No. 888-A, 62 Fed. Reg. 12,274 (1997), FERC Stats. & Regs. para. 31,048 (1997), order on reh'g, Order No. 888-B, 81 FERC para. 61,248 (1997), order on reh'g, Order No. 888-C, 82 FERC para. 61,046 (1998).

"Order No. 889" shall mean that certain FERC order Open Access Same-Time Information System and Standards of Conduct, Order No. 889, 61 Fed. Reg. 21,737 (1996), FERC Stats. & Regs. para. 31,035 (1996), order on reh'g, Order No. 889-A, 62 Fed. Reg. 12,484 (1997), FERC Stats. & Regs. para. 31,049 (1997), order on reh'g, Order No. 889-B, 81 FERC 61,253 (1997).

"Other Adjustor Per Unit Cost" shall mean, for a billing period for each Billing Unit Entity, the Other Fuel Adjustor Cost divided by the Total Other Billing Energy for the same Billing Unit Entity for the same billing period.

"Other Average Energy Rate" shall mean, for a billing period for a Billing Unit Entity, the rate obtained by dividing its Total Other Energy Cost of the billing period by its Other Billing Energy for the same period.

"Other Billing Energy" shall mean, for a Billing Unit Entity, the energy from Available Other Capacity assigned and allocated in each hour pursuant to the Billing Unit Program to its Other Schedule or load, accumulated for a billing period.

"Other Economy Sales" shall mean, for a billing period, the energy from dispatched Other Capacity and from Post-Transfer S&G And Supplemental Capacity assigned in each hour to each Billing Unit Entity pursuant to the Billing Unit Program as Third Party Economy Sales.

"Other Economy Sales Credit" shall mean, for each Billing Unit Entity, the product of the Other Economy Energy Sales Revenue of Daytime Hours and Nighttime Hours, as applicable, multiplied by the ratio of (i) for each of separately accumulated Daytime Hours and Nighttime Hours of the billing period, the Post-Transfer S&G And Supplemental Capacity energy in the case of a Billing Unit Entity with an ACP in such capacity, the Other Schedule in the case of a Member*, and in the case of CARM or a Member* CA, its load's use of Available Other Capacity, to (ii) the total of such Post-Transfer S&G And Supplemental Capacity, such Other Schedules and such uses of Available Other Capacity by all Billing Unit Entities for the same time periods.

"Other Economy Sales Revenue" shall mean the difference obtained by subtracting the Base Economy Sales Credit from the revenue of all Third Party Economy Sales during a billing period.

"Other Energy Cost" shall mean, for a billing period for each Billing Unit Entity, the costs of purchased energy and natural gas fuel and oil fuel expensed during that billing period, related to the operation and dispatch of Available Other Capacity during that billing period, as recorded in Accounts described in Section 4.0 of Exhibit A-2 to Rate Schedule A and reported to RUS by AEPCO for that billing period, including purchased energy expenses, wheeling charges and costs of any transmission losses related to Other Economy Purchases and Replacement Purchases for Base Resources and Other Resources as incurred during that billing period.

"Other Energy Mismatch" shall mean, for a billing period, the accumulated net difference in energy obtained from subtracting (i) the total energy from Available Other Capacity, Available Supplemental Capacity, and Available S&G PPA Capacity assigned and allocated in the billing period in accordance with the Billing Unit Program, from (ii) the energy actually produced from Available Other Capacity, Available Supplemental Capacity, and Available S&G PPA Capacity during that billing period.

"Other Energy Mismatch Credit" shall mean, for a billing period, the product of: (i) the absolute value of any negative value of Other Energy Mismatch for the billing period, multiplied by (ii) the Gas Energy Rate for the billing period.

"Other Energy Mismatch Charge" shall mean, for a billing period, the product of: (i) any positive value of Other Energy Mismatch for the billing period, multiplied by (ii) the Gas Energy Rate for the billing period.

"Other Energy Rate" shall mean, for each Billing Unit Entity, the rate applicable to that Billing Unit Entity's use of energy from Available Other Capacity as set forth in Exhibit A-1 to Rate Schedule A.

"Other FPPCA" shall mean, Fuel and Purchase Power Cost Adjustor determined for a FPPCA Period for Other Resources, Supplemental Purchase as made for each Billing Unit Entity, and S&G PPA for each Billing Unit Entity having an ACP interest in S&G PPA.

"Other Fuel Adjustor Cost" shall mean, for a billing period for each Billing Unit Entity, the sum of the Total Other Energy Cost, Other Transmission Wheeling Cost, plus, for those Billing Unit Entities with interests in S&G PPA Capacity or Supplemental Capacity, Supplemental Demand Charge, Supplemental Wheeling Cost, S&G PPA Purchase Demand Charge and S&G PPA Wheeling Cost.

"Other Fuel Bank" shall mean, for a billing period for each Billing Unit Entity, the accumulation of Other Over or Under Collections.

"Other Incremental Unit Cost" shall mean, for a billing period for each Billing Unit Entity, the difference obtained by subtracting (i) the sum of (a) Other Power Cost Adjustor Base plus (b) Other Power Cost Adjustor Rate from (ii) Other Adjustor Per Unit Cost, for such Billing Unit Entity for such period.

"Other Over or Under Collection" shall mean, for a billing period for each Billing Unit Entity, the product of (i) Other Incremental Unit Cost, multiplied by (ii) Total Other Billing Energy, for such Billing Unit Entity for such period.

"Other Power Cost Adjustor Base" shall mean the Power Cost Adjustor Base for Other Resources as set forth in the Tariff.

"Other Power Cost Adjustor Rate" shall mean the Power Cost Adjustor Rate for Other Resources as set forth in the Tariff.

"Other Resources" shall mean all gas-fired combustion turbine and gas-fired steam Generating Resources that are Existing Resources located at Apache Generating Station, in which each Class A Member has an ACP, which include GT-1, Steam 1, GT-2, GT-3 and GT-4.

"Other Schedule" shall mean, for each Member*, its Pre-Schedules and Real-Time Schedules provided to AEPCO by Member*'s Scheduling Agent pertaining to such Member*'s use of its Available Other Capacity and, separately identified, of its Available S&G PPA Capacity, if any, as such Pre-Schedules and Real-Time Schedules are determined consistent with Schedule B to its Partial Requirements Capacity and Energy Agreement.

"Other Transmission Wheeling Cost" shall mean, for each Billing Unit Entity for a billing period, the product of (i) the costs recorded in RUS Uniform System of Accounts 565 Transmission of Electricity by Others or its successor, and allocated to Other Resources, for the same billing period, multiplied by (ii) the Billing Unit Entity's ACP in Existing Resources.

"Partial Requirements Member" shall mean MEC, SSVEC, TRICO or any other Class A Member of AEPCO that executes and delivers a Partial Requirements Capacity and Energy Agreement.

"Peak Hours" shall mean all hours of each day which are not Off-Peak Hours.

"Performance Default" shall meant the default by either party to a Partial Requirements Capacity and Energy Agreement, a Transmission Agreement, a Network Service Agreement, or a Joint Marketing Agreement, whereby, as provided by the terms of each such Agreement, such party fails to comply, after any notice of such failure and opportunity to cure, with any of the respective terms, conditions, obligations or covenants of such Agreement.

"Person" shall mean an individual, partnership, association, limited liability company, corporation, membership corporation, business trust, joint stock company, trust, cooperative, unincorporated organization, joint venture, or other entity.

"PGR Purchase Agreement" shall mean the Power Purchase Agreement between Panda Gila River, L.P., and AEPCO, dated April 15, 2003, as amended.

"Planning Contract Member" shall mean a Partial Requirements Member which has contracted separately from the Partial Requirements Capacity and Energy Agreement to obtain Planning Services from AEPCO.

"Planning Services" shall mean bulk power supply planning and Future Resource procurement services.

"Pool Price" shall mean the price, in mills/kWh, established for a Pooled Resource pursuant to Appendix A-2 of the Resource Pooling Policies.

"Pool Resource Owner" shall mean a Party that has committed Resources to the Resource Pool pursuant to Section 4 herein.

"Pooled Loads" shall mean the aggregate total electric load and sales of the parties that are to be served by Pooled Resources, including distribution losses and not including reserves or transmission losses.

"Pooled Resources" shall mean those Resources which have been committed to the Resource Pool.

"Possible Selling Party" shall have the meaning set forth in Section 10.1 of the Resource Integration Agreement.

"Post-Base Load" shall mean, for CARM or a Member* CA, the load of such Billing Unit Entity that remains after assignment of such Billing Unit Entity's Post-S&G And Supplemental Load to that Billing Unit Entity's Available Base Capacity.

"Post-Base Other Schedule" shall mean, for a Member*, the portion of the Total Schedule of such Member* that remains after assignment of such Member*'s Base Schedule to that Member*'s Available Base Capacity.

"Post-Base Transfer Load" shall mean, for CARM or a Member* CA, any load of such Billing Unit Entity that remains after assignment of such Billing Unit Entity's Post-S&G And Supplemental Transfer Load to Base Transfers of other Billing Unit Entities.

"Post-Base Transfer Other Schedule" shall mean, for Member*, any Post-S&G And Supplemental Other Schedule that remains after assignment of such Member*'s Post S&G And Supplemental Transfer Other Schedule to Base Transfers from other Billing Unit Entities.

"Post-Sales Base Capacity" shall mean, for each Billing Unit Entity, any Post Transfer Base Capacity that remains after its allocation to Base Economy Sales.

"Post-S&G And Supplemental Load" shall mean, for CARM or a Member* CA, the load of such Billing Unit Entity that remains after assignment of such Billing Unit Entity's load to that Billing Unit Entity's allocated share of S&G PPA Capacity and Supplemental Capacity.

"Post-S&G And Supplemental Transfer Load" shall mean, for CARM or a Member* CA, the load of such Billing Unit Entity that remains after assignment of S&G And Supplemental Transfers from another Billing Unit Entity to that Billing Unit Entity's Post-Base Load.

"Post-S&G And Supplemental Transfer Other Schedule" shall mean, for Member*, the Post-Base Other Schedule that remains after allocation of S&G And Supplemental Transfers from CARM or a Member* CA.

"Post-Transfer Base Capacity" shall mean, for a Billing Unit Entity, each hour's Excess Base Capacity remaining after energy from its Excess Base Capacity has been assigned as Base Transfers.

"Post-Transfer Load" shall mean, for CARM or a Member* CA, the load of such Billing Unit Entity that remains after assignment of such Billing Unit Entity's Post-Base Load to that Billing Unit Entity's allocated share of S&G And Supplemental Transfers and of Base Transfers from other Billing Unit Entities.

"Post-Transfer Other Schedule" shall mean, for a Member*, the Total Schedule of such Member* that remains after assignment of such Member*'s allocated share of S&G And Supplemental Transfers from other Billing Unit Entities to its Post-Base Other Schedule, and then assignment of such Member*s allocated share of Base Transfers from other Billing Unit Entities to that Member*'s Post-S&G And Supplemental Transfer Other Schedule.

"Post-Transfer S&G And Supplemental Capacity" shall mean, for CARM or Member* CA having an ACP in S&G PPA and/or an interest in Supplemental Purchase, each hour's Excess S&G And Supplemental Capacity remaining after energy from its Excess S&G And Supplemental Capacity has been assigned as an S&G And Supplemental Transfer, accumulated for a billing period separately for Daytime Hours and Nighttime Hours.

"Power Factor" shall mean the cosine of the phase angle between the voltage and the current. Power Factor can be lagging or leading indicating whether the current is lagging or leading the applied voltage.

"Power Factor Adjustment" shall have the meaning set forth in Section 2.2 of Rate Schedule A.

"Power Purchase Resource" shall mean capacity and energy or energy purchased by a party under a contract with a term greater than one year, including any such capacity and energy or energy purchased or acquired pursuant to (i) the Public Utility Regulatory Policies Act of 1978, as it may be amended from time to time, or (ii) the Environmental Portfolio Standard set forth in A.A.C. R14-2-1618, as it may be amended from time to time, as adopted by the Arizona Corporation Commission.

"Power Sale(s)" shall mean a wholesale sale of capacity or energy for a term of one year or more. Power Sales do not include Retail Sales.

"Power Sales Load" shall mean the demand and energy requirements of the load associated with Power Sales Resource(s).

"Power Sales Resource" shall mean a sale of capacity and energy from Existing Resources made by AEPCO with a contract term greater than one year (other than sales to Class A Members pursuant to a Wholesale Power Contract and the Partial Requirements Capacity and Energy Agreement) including sales to Class B and Class C Members of AEPCO.

"Power Sales Resource Demand Revenues" shall mean, for a billing period for each Billing Unit Entity, the product of (i) the demand-related revenue received pursuant to Power Sales Resource contracts as recorded in RUS Uniform System of Account 447 Sales for Resale, or its successor, for that billing period, multiplied by (ii) the Billing Unit Entity's ACP in Existing Resources.

"Power Sales Resource Energy Revenue" shall mean, for a billing period, the energy-related revenue received pursuant to Power Sales Resource contracts as recorded in RUS Uniform System of Account 447 Sales for Resale or its successor, for that billing period

"Power Sales Resource System Facility" shall mean any System Facility or portion thereof that is required to enable delivery of capacity and energy to Class A Members from expired Power Sales Resources which existed as of the Effective Date.

"Pre-Closing" shall mean the execution and delivery of all documents that are a condition to Closing, as further described in the Closing Memorandum.

"Pre-Schedule" shall mean a Schedule submitted by a Scheduling Agent to AEPCO for the use of Resources for the following Scheduling Day as defined by WECC.

"Pre-Schedule Day" shall mean the day on which a Pre-Schedule must be submitted for the next Scheduling Day.

"PRM" shall mean a Partial Requirements Member.

"PRM*" shall mean a term in definitions which may be replaced with the name of a PRM so that the definition would apply only to the specified PRM (see Section 3.8 above).

"PRM* AEPCO Load" shall mean the demand and energy requirements, including distribution losses but not including reserves or transmission losses, of loads located within the Member's Distribution Service Area (or served from line extensions therefrom) for which PRM* purchases capacity and energy pursuant to the PRM* Partial Requirements Capacity and Energy Agreement, but shall not include PRM* Wheeling Load. Such demand and energy requirements are included within PRM* Metered kW and PRM* Metered kWh. The demand component of PRM* AEPCO Load numerically consists of the coincident aggregate, at a specific time, of: (i) PRM* Metered kW; less (ii) kW of PRM* Wheeling Load; less (iii) kW of Member JMP Load of PRM*; less (iv) kW of CSP JMP Load of PRM*; (v) less Kw of PRM* Internal Load. The energy component of PRM* AEPCO Load numerically consists of the aggregate during a specific time interval of: (i) PRM* Metered kWh; less (ii) kWh of PRM* Wheeling Load; less (iii) kWh of Member JMP Load of PRM*; less (iv) kWh of CSP JMP Load of PRM*; less, (v) kWh of PRM* Internal Load.

"PRM* AEPCO Sales" shall mean the demand and associated energy requirements, including any distribution losses and not including reserves or transmission losses, of those sales of PRM* to wholesale buyers or to end use loads which are external to Member's Distribution Service Area of PRM* for which PRM* purchases capacity and energy pursuant to the PRM* Partial Requirements Capacity and Energy Agreement. The demand and energy requirements of PRM* AEPCO Sales shall be metered (or determined) as agreed between PRM* and TRANSCO, on the basis of actual capacity and energy supplied at the applicable points of delivery.

"PRM* External Load" shall mean the demand and energy requirements, including distribution losses but not including reserves or transmission losses, of loads located external to the Member's Distribution Service Area of PRM* (and not served from line extensions therefrom) for which PRM* sells capacity and energy from PRM* Resources. The demand and energy requirements of PRM* External Load are not included in PRM* Metered kW and Member* Metered kWh, respectively.

"PRM* Internal Load" shall mean the demand and energy requirements, including distribution losses but not including reserves or transmission losses, of loads located within the Member's Distribution Service Area of PRM* (or served from line extensions therefrom) for which Member* sells capacity and energy from PRM* Resources. The demand and energy requirements of PRM* Internal Load are included in PRM* Metered kW and PRM* Metered kWh, respectively.

"PRM* Metered kW" shall have the meaning set forth in Section 1 of the PRM* Partial Requirements Capacity and Energy Agreement.

"PRM* Metered kWh " shall have the meaning set forth in Section 1 of the PRM* Partial Requirements Capacity and Energy Agreement.

"PRM* Partial Requirements Capacity and Energy Agreement" shall mean the Partial Requirements Capacity and Energy Agreement, by and between AEPCO and PRM*.
"PRM* Resource(s)" shall mean a Resource of a Partial Requirements Member of AEPCO; PRM* Resource does not include the capacity and energy purchased from AEPCO under the PRM* Partial Requirements Capacity and Energy Agreement, or purchased by AEPCO under separate contract.

"PRM* Transmission Agreement" shall mean the Transmission Agreement by and between TRANSCO and PRM* for the purposes of PRM* Transmission Service.

"PRM* Transmission Service" shall mean Network Integration Transmission Service and all Ancillary Services used to deliver the AC and associated energy of PRM* to PRM* AEPCO Load.

"PRM* Wheeling Load" shall mean the demand and energy requirements, including distribution losses but not including reserves or transmission losses, of loads located within Member's Distribution Service Area of PRM* (or served from line extensions therefrom), which are supplied by capacity and energy from third parties (and not from Member Resources or the AC of PRM*) and for which PRM* provides delivery services over its distribution system. The demand and energy requirements of PRM* Wheeling Load are included within PR* Metered kW and PRM* Metered kWh, respectively.

"Project Approval" shall mean the approval required by Section 3.4.5 of the Partial Requirements Capacity and Energy Agreement for a Resource Modification.

"Proposal and Analysis" shall have the meaning set forth in Section 3.4.3 of the Partial Requirements Capacity and Energy Agreement.

"Prudent Utility Practice" shall mean any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts that, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety, and expedition. Prudent Utility Practice is not intended to be limited to the optimum practice, method, or act, to the exclusion of all others, but rather to include a spectrum of possible practices, methods, or acts generally acceptable in the region that could be expected to accomplish the desired result at a reasonable cost consistent with reliability, safety and expedition in light of the circumstances.

"Purchasing Party" shall have the meaning set forth in Section 10.1 of the Resource Integration Agreement.

"Rate Schedule A" shall mean the Schedule A to the Partial Requirements Capacity and Energy Agreements or to an Existing Wholesale Power Contract.

"REAct" shall mean the Rural Electrification Act of 1936.

"Real-Time Schedule" shall mean any Schedule submitted by a Scheduling Agent to AEPCO that changes a previously submitted Tag or that requires a new Tag to be created for a Future Scheduling Hour of the current operating day.

"Receipt Point" shall mean the interconnection between the TTS and the transmission, sub-transmission, generating resource or distribution facilities at which TRANSCO is to accept capacity or energy from AEPCO Resources for delivery pursuant to the Transmission Agreement or Network Service Agreement, and from which TRANSCO provides transmission service to the Delivery Point.

"Reliability System Facilities" shall mean System Facilities and/or improvements that are constructed and installed or acquired by TRANSCO to enhance or maintain the reliability of the TTS as required by the transmission system performance criteria of the NERC, as applied within the WECC, consistent with Prudent Utility Practice.

"Remaining Base Energy Cost" shall mean, for a billing period, the total of Remaining Coal Energy Cost, Hydro Energy Charge, Base Economy Purchase Cost and Power Sales Resource Energy Revenue, for the same billing period as allocated to each Billing Unit Entity based on the ratio of (i) the Billing Unit Entity's Base Billing Energy for that billing period to (ii) the total of all Billing Unit Entities' Base Billing Energy for the same billing period.

"Remaining Coal Energy Cost" shall mean, for a billing period, Coal Energy Cost for the billing period less the sum of Base Transfer Sales Credits and Base Economy Sales Credits for all Billing Unit Entities for the same billing period.

"Remaining Equity Investment of TRANSCO" shall mean that portion of the installed cost of a System Facility or Direct Assignment Facility financed by an equity contribution of TRANSCO (with interest accrued thereon) which remains undepreciated on the Last Service Date (or the date of closing of a transaction between the parties involving the disposition of a Direct Assignment Facility).

"Remaining Indebtedness of TRANSCO" shall mean the principal balance remaining unamortized as of the Last Service Date (or the Date of Closing of a transaction between the Parties involving the disposition of a Direct Assignment Facility) of that portion of the installed cost of a System Facility or Direct Assignment Facility financed by TRANSCO debt, with interest accrued thereon, which remains unamortized on the Last Service Date or termination or exercise of an option to purchase the Direct Assignment Facilities serving SSVEC (plus any actual prepayment penalties incurred from the prepayment of such debt).

"Replacement Purchase" shall mean any purchase of energy made to replace energy that is not available from any AEPCO Resource due to forced outage, scheduled outage or deration of such AEPCO Resource.

"Required Modification" shall have the meaning set forth in Section 3.3.2 of the Partial Requirements Capacity and Energy Agreement.
"Resource" shall mean either a Generating Resource or Power Purchase Resource.

"Resource Acquisition" shall mean the performance of analyses of Resource needs or Resource sales proposals, the recommendation of a Power Purchase Resource or Generating Resource, and the negotiation of and acquisition for AEPCO of a Resource.

"Resource Deficiency" shall mean a deficiency in AEPCO Resources available to serve Class A Members and Power Sales Loads.

"Resource Facility" shall mean any System Facility, or portion thereof, or Direct Assignment Facility required to interconnect with and to deliver to the TTS the capacity and energy of any Resource Modification or Future Resource in which SSVEC has all ACP.

"Resource Forecast Period" shall mean the period beginning January 1 of the next calendar year (following the year in which the forecast is prepared) and ending upon the earlier of:(a)the twentieth anniversary thereafter or (b) the last service date of a Class A Member's Wholesale Power Contract, as set forth in the Resource Planning Policies.

"Resource Integration Agreement" shall mean the multi-party agreement by and between CSP, TRANSCO, AEPCO and MEC and dated July 2, 2001, as amended to include SSVEC and TRICO as parties.

"Resource Modification" shall mean any addition, improvement, repair or modification to a Generating Resource or the modification or extension of the term of an existing Power Purchase Resource made by AEPCO which would: (i) increase the capacity of the AEPCO Resource by more than ten percent; or (ii) result in an increase of more than five percent in AEPCO's Revenue Requirement upon the operation of such addition, improvement, repair and modification, or extension, as the case may be, or (iii) require an extension of the term of an Existing Wholesale Power Contract or Partial Requirements Capacity and Energy Agreement. A Resource Modification shall not be construed to include a Minor Resource Modification.

"Resource Operation Policies" shall mean the resource operation policies set forth in Schedule B to the Resource Integration Agreement and Exhibit B2 to Schedule B of the Partial Requirements Capacity and Energy Agreement.

"Resource Planning" shall mean the process used to identify a deficiency in the amount of existing Resources needed to reliably meet anticipated load requirements (including reserves). Resource Planning includes a review of alternative Resources and the selection of the preferred Resources to be constructed or acquired to meet the deficiency.

"Resource Planning Policies" shall mean the resource planning policies set forth in resource planning and acquisition documents.

"Resource Pool" shall mean the capacity and energy pool which integrates the electric capacity and associated energy of AEPCO Resources with Resources owned or contracted for by the Partial Requirements Members and CSP, which the Partial Requirements Member or CSP is required to include or has designated for inclusion in such pool.

"Resource Pool Operation" shall mean that load and resource integration service provided by AEPCO.

"Resource Pooling Policies" shall mean the resource pooling policies set forth in Schedule A of the Resource Integration Agreement.

"Resource Pre-Schedule" shall mean a schedule of energy needed from the Resources of the Resource Pool to meet the aggregate of the Pooled Loads made on a least energy cost and a day-ahead basis.

"Restructuring Agreement" shall mean the Restructuring Agreement as executed and delivered by and among AEPCO, TRANSCO and CSP, dated the 11th day of October 2000.

"Retail Sales" shall mean sales arranged or made by CSP in the competitive retail electric market, including sales at retail from Surplus AEPCO Resources. Retail Sales do not include Power Sales.

"Revenue Shortfall" shall mean the failure of a cooperative to receive sufficient revenue to cover its revenue requirement.

"Rights of Way" shall mean the various rights of way and easements held by TRANSCO from time to time.

"RUS" shall mean the Rural Utilities Service, as successor-in-interest to the Rural Electrification Administration, which is an agency of the United States Department of Agriculture, or any agency of the Government succeeding to its powers and functions

"S&G And Supplemental Sales Credit" shall mean, for a billing period for each Billing Unit Entity with an ACP in S&G PPA or an interest in Supplemental Purchase, the product of the Economy Purchase Rate multiplied by S&G And Supplemental Transfer, for such Billing Unit Entity for such billing period.

"S&G And Supplemental Transfer" shall mean, for a Billing Unit Entity with an ACP in S&G PPA and/or an interest in Supplemental Purchase, energy from its Excess S&G And Supplemental Capacity that has been assigned and allocated to another Billing Unit Entity in an hour pursuant to the Billing Unit Program, accumulated for a billing period separately for Daytime Hours and Nighttime Hours.

"S&G And Supplemental Transfer Billing Energy" shall mean, for a Billing Unit Entity, energy from the Excess S&G And Supplemental Capacity of another Billing Unit Entity with an ACP in S&G PPA and/or an interest in Supplemental Purchase that has been assigned and allocated to the Billing Unit Entity in an hour pursuant to the Billing Unit Program as a S&G And Supplemental Transfer from the other Billing Unit Entity, accumulated for a billing period.

"S&G And Supplemental Transfer Purchase Cost" shall mean, for a billing period for each Billing Unit Entity that is assigned an S&G And Supplemental Transfer pursuant to the Billing Unit Program, the product of the Economy Purchase Rate multiplied by S&G And Supplemental Transfer Billing Energy, for such Billing Unit Entity for such billing period.

"S&G PPA" shall mean either or both of the following purchase power agreements: (i) the Confirmation Agreement dated August 17, 2004, between AEPCO and South Point Energy Center, LLC (South Point), by which AEPCO purchases between 25 MW and 55 MW of electric capacity and associated energy in Daylight Hours of May through October of each year from 2008 through 2014; and (ii) the Confirmation Agreement dated August 19, 2004, between AEPCO and Griffith Energy, LLC, as currently assigned pursuant to Assignment and Consent Agreement dated March 14, 2008, by which AEPCO purchases 25 MW of electric capacity and associated energy in WECC Peak Hours of May through October of each year from 2008 through 2014.

"S&G PPA Billing Energy" shall mean, for a billing period for a Billing Unit Entity with an ACP in S&G PPA, the energy from its Available S&G PPA Capacity assigned and allocated in each hour pursuant to the Billing Unit Program to its load and its S&G PPA Transfers, accumulated for a billing period.

"S&G PPA Capacity" shall mean capacity from S&G PPA.

"S&G PPA Demand Charge" shall mean, for a billing period for each Billing Unit Entity with an ACP in S&G PPA, the product of (i) the total cost incurred by AEPCO for capacity from S&G PPA during the billing period multiplied by (ii) the Billing Unit Entity's ACP in S&G PPA.

"S&G PPA Energy Charge" shall mean, for a billing period for each Billing Unit Entity with an ACP in S&G PPA, the product of (i) the total cost incurred by AEPCO for all energy from S&G PPA during the billing period multiplied by (ii) the Billing Unit Entity's ACP in S&G PPA.

"S&G PPA Schedule" shall mean, for a Member* with an ACP in S&G PPA, its Pre-Schedules and Real-Time Schedules provided to AEPCO by its Scheduling Agent pertaining to its use of its Available S&G PPA Capacity.

"S&G PPA Wheeling Cost" shall mean, for a billing period for each Billing Unit Entity with an ACP in S&G PPA, the product of (i) the cost incurred by AEPCO for wheeling energy from S&G PPA during the billing period multiplied by (ii) the Billing Unit Entity's ACP in S&G PPA.

"Schedule" shall mean for each Member*, any of its Base Schedule, its Other Schedule, and, if applicable, its S&G PPA Schedule.

"Scheduled Day" shall mean the Scheduling Day, as defined by WECC, for which a Pre-Schedule has been submitted.

"Scheduling Agent" shall mean the entity designated by a Member* to provide Pre-Schedules and Real-Time Schedules to AEPCO for such Member*'s hourly use of its AC in AEPCO Resources.

"Scheduling Party" shall mean the owner of an Optional Pool Resource that qualifies to be a Pooled Resource but is not included in the Resource Pool and which is separately scheduled by such owner.

"SEC" shall mean the Securities and Exchange Commission, or any agency of the Government succeeding to its powers and functions.

"Separation of Functions and Standards of Conduct" shall mean the Separation of Functions and Standards of Conduct referenced in Section 15 of the Resource Integration Agreement and set forth as Schedule F attached thereto.

"Service Agreement" shall mean the agreement entered into by a transmission customer or network customer and TRANSCO for transmission service or network service under Part II or Part III respectively, of the TRANSCO Tariff.

"Service Agreement(s) for Firm and Non-Firm Transmission and Ancillary Services" shall mean any Service Agreement by and between TRANSCO and AEPCO for transmission service pursuant to Part II of the TRANSCO tariff, substantially in the form of agreement attached to the TRANSCO Tariff.

"Short Term" shall mean with respect to a forecast deficiency of AEPCO Resources with respect to AEPCO Total Load, a time period greater than the subsequent two calendar years but lasting less than five calendar years.

"Southwest" shall mean TRANSCO.

"SSVEC" shall mean Sulphur Springs Valley Electric Cooperative, Inc., an electric cooperative non-profit membership corporation organized and existing under the Laws of the State of Arizona.

"Staffing Agreement" shall mean each of the individual staffing agreements whereby CSP shall furnish personnel services to TRANSCO or AEPCO, respectively.

"Standards of Conduct" shall mean the Separation of Functions and Standards of Conduct as set forth as Schedule F to the Resource Integration Agreement.

"Stranded Costs" shall mean any actual charge or cost (including any transmission or distribution surcharges, fee, competition transition charge, wires charge, adjustment, rate, system benefit charge, regulatory charge, regulatory asset surcharge, exit fee or any other mechanism or systematic recovery program approved for use for the recovery of stranded investments) that are permitted by the ACC pursuant to the ACC Electric Competition Rules, A.A.C. R14-2-1601, et seq. or successor rule, or otherwise assessed or levied in order to recover the expenses and liabilities associated with stranded investments including without limitation, regulatory assets, or costs associated with the introduction of competition in the retail sales of electric energy and capacity.

"Supplemental Billing Energy" shall mean, for a billing period for a Billing Unit Entity with an interest in Supplemental Purchase, the energy from its Available Supplemental Capacity assigned and allocated in each hour pursuant to the Billing Unit Program to its load and its Supplemental Transfers, accumulated for a billing period.

"Supplemental Capacity" shall mean capacity from Supplemental Purchase.

"Supplemental Demand Charge" shall mean, for a billing period for each Billing Unit Entity with an interest in Supplemental Purchase, the product of (i) the total cost incurred by AEPCO for capacity from Supplemental Purchase during the billing period multiplied by (ii) the Billing Unit Entity's ACP in Supplemental Purchase.

"Supplemental Energy Charge" shall mean, for a billing period for each Billing Unit Entity with an interest in Supplemental Purchase, the product of (i) the total cost incurred by AEPCO for all energy from Supplemental Purchase during the billing period multiplied by (ii) the Billing Unit Entity's ACP in the Supplemental Purchase

"Supplemental Energy Intrachange" shall have the meaning set forth in Section 6 of the Resource Pooling Policies.

"Supplemental Purchase" shall mean, in a billing period, any purchase of firm energy made by AEPCO for a period of less than a year to serve load of CARM or a Member* CA Planning Contract Member in excess of CARM's or such Planning Contract Member's ACP shares of capacity of S&G PPA and Existing Resources.

"Supplemental Purchase Cost" shall mean, for a billing period, the total cost incurred by AEPCO (including transmission expenses, including losses, incurred in delivery from the source of such purchase to an SWTC Point of Receipt, if any) for all Supplemental Purchases during the billing period.

"Supplemental Wheeling Cost" shall mean, for a billing period for each Billing Unit Entity with an interest in Supplemental Purchase, the product of (i) the cost incurred by AEPCO for wheeling energy from Supplemental Purchase during the billing period multiplied by (ii) the Billing Unit Entity's ACP in Supplemental Purchase.

"Surplus AEPCO Resource(s)" shall mean AEPCO Resources available and not necessary or used to serve AEPCO Total Load.

"Surplus Resource" shall mean a Pooled Resource(s) that is surplus to Pooled Load and its operating reserves as determined by a Pool Resource Owner in accordance with Prudent Utility Practice.

"System Facilities" shall mean the transmission lines, substation facilities or components thereof and firm wheeling purchased by TRANSCO, which do not constitute Direct Assignment Facilities and are used to deliver capacity and energy to the Members and other transmission customers of TRANSCO.

"Tag" shall mean the collection of information in the electronic form of request and subsequent response as part of the process implemented by the North American Electric Reliability Corporation for electronically communicating a request for, securing approval of, and recording an energy transaction via the Internet.

"Tariff" shall mean at any time, the currently effective form setting forth the various AEPCO rates and charges applicable to each Billing Unit Entity as approved by the ACC.

"Third Party Economy Sale" shall mean, for each of Daytime Hours and Nighttime Hours, any transactions in which AEPCO sells at wholesale energy from available AEPCO Resources to a third party, which transaction is not a Power Sales Resource, and which is recorded and reported by AEPCO as an economy sale to RUS Uniform System of Accounts Number 447.

"Times Interest Earned Ratio" or "TIER" " shall mean the financial ratio determined based on figures shown on Form 12 Balance Sheet for each calendar year-end as submitted in accordance with Accounting Requirements by AEPCO or TRANSCO, by: (1) adding (a) net patronage capital or margins and (b) Interest Expense on long-term Indebtedness, and (2) dividing the sum obtained by Interest Expense on long-term Indebtedness.

"Total Assets" shall mean an amount constituting the total assets of a Class A Member determined in accordance with Accounting Requirements.

"Total Other Billing Energy" shall mean, for a billing period for each Billing Unit Entity, the sum of S&G And Supplemental Transfer Billing Energy, S&G PPA Billing Energy, Supplemental Billing Energy, Other Billing Energy and Base Transfer Billing Energy for such Billing Unit Entity for such billing period.

"Total Other Energy Cost" shall mean, for a billing period for each Billing Unit Entity, the sum of Other Energy Cost, S&G PPA Energy Charge, Supplemental Purchase Cost, S&G And Supplemental Transfer Purchase Cost, S&G And Supplemental Sales Credit, Directed Sales Credit, Base Transfer Purchase Cost, and Other Economy Sales Credit.

"Total Schedule" shall mean for each Member*, its Base Schedule, plus its Other Schedule, plus, if applicable, its S&G PPA Schedule.

"TRANSCO", which is also known as "Southwest", shall mean Southwest Transmission Cooperative, Inc., a non-profit corporation organized under the Laws of the State of Arizona.

"TRANSCO Assumed AEPCO Debt" shall mean that portion of AEPCO's Indebtedness that TRANSCO assumes pursuant to the TRANSCO CFC Note (if required), the TRANSCO FFB Note(s), the TRANSCO RUS Note(s) and the TRANSCO Assumption and Indemnity Agreements, in each case, in accordance with applicable Law.

"TRANSCO Assumption and Indemnity Agreements" shall mean collectively the Assumption and Indemnity Agreements between TRANSCO and AEPCO and the trustees of certain financial instruments, the forms of which are set forth in Appendix A to the Restructuring Agreement pursuant to which TRANSCO will agree to assume the obligation to pay that portion of AEPCO's debt secured under the AEPCO Mortgage that AEPCO and TRANSCO have agreed will be assumed as part of the payment of the purchase price for such assets and liabilities.

"TRANSCO By-laws" shall mean the By-laws, in the form adopted by the TRANSCO Board of Directors or the TRANSCO Members, as appropriate.

"TRANSCO Employees" shall mean all persons employed by TRANSCO, including TRANSCO Management and systems operations personnel designated by the chief executive officer of TRANSCO, but shall not include persons employed by CSP or any other contractor.

"TRANSCO FFB Note(s)" shall mean the note(s) in the form required by FFB pursuant to which TRANSCO will assume and replace AEPCO as an obligor with respect to that portion of AEPCO's Indebtedness to the FFB outstanding as of the Effective Date that each of

AEPCO and TRANSCO have agreed will be assumed as part of the payment of the purchase price for such assets and liabilities.

"TRANSCO Member" or "Southwest Member" shall mean any of the Class A Members of TRANSCO, and others, including AEPCO and CSP, that become members of TRANSCO in accordance with the TRANSCO By-laws.

"TRANSCO Mortgage" shall mean the Mortgage and Security Agreement, dated as of the Effective Date, made by and among TRANSCO, RUS and CFC which secures the TRANSCO Secured Obligations.

"TRANSCO Notes" shall mean written instruments or notes which evidence the obligation of TRANSCO for its assumption of a portion of the AEPCO Indebtedness (the TRANSCO Assumed AEPCO Debt) to purchase the Transmission Business as evidenced and effected by delivery of the TRANSCO FFB Note(s) and the TRANSCO RUS Note(s), payable to or guaranteed by the Government, acting through the RUS, and by its assumption of the repayment obligations of a portion of the loans made by, or securities issued to, or obligations undertaken to the Financial Entities, and which in the future will also include written instruments which may evidence additional or new loans or advances TRANSCO may obtain to finance the construction or purchase of new facilities for the TTS or the modification of existing TTS facilities, as applicable.

"TRANSCO RUS Note" shall mean the simple allocation of the AEPCO Note owed to RUS.

"TRANSCO Secured Obligations" shall mean collectively, the TRANSCO Notes, certain of the loans made by others to TRANSCO, or securities issued to others by TRANSCO, or debt obligations entitled to the lien created by the TRANSCO Mortgage.

"TRANSCO Tariff" or "Southwest Tariff" shall mean the open access transmission tariff under which transmission services and Ancillary Services are offered by TRANSCO.

"TRANSCO Transmission System" or "TTS" shall mean the electric transmission system of TRANSCO including all transmission lines, substations, microwave and telecommunication facilities, system control and data acquisition system, inventories, works in progress, contract rights to provide or receive transmission services, leases, interests in joint transmission projects, licenses, other related transmission agreements and all other such transmission related assets.

"Transferee" shall mean any of the following Persons: (i) the Person formed as a result of a Member Transaction by any consolidation of the Partial Requirements Member with any other Person; (ii) the survivor of any merger or reorganization of the Partial Requirements Member; (iii) or a Person that acquires or leases all or substantially all of the electric assets of the Partial Requirements Member.

"Transmission Agreement" shall mean the Transmission Agreement by and between TRANSCO and a Partial Requirements Member.

"Transmission Business" shall mean the performance of transmission services and Ancillary Services, and the ownership and use of any rights, obligations, duties, approvals and licenses to the Non-Generation Assets, including the Transmission Resources, and shall include responsibility for the Non-Generation Liabilities.

"Transmission Forecast" shall mean with respect to any Person, such Person's forecast, on an annual basis, of its transmission requirements from TRANSCO.

"Transmission Forecast Period" shall mean the period beginning January 1 of the next calendar year (following the year in which the forecast is prepared) and ending at least the tenth anniversary thereafter.

"Transmission Planning" shall mean the process by which the performance of an electric transmission system is evaluated with respect to specified load-serving capability in accordance with Prudent Utility Practice and by which future modifications, improvements and additions to such electric transmission system are determined by TRANSCO.

"Transmission Requirements Study" shall have the meaning set forth in Section 4 of the Network Service Agreement.

"TRICO" shall mean Trico Electric Cooperative, Inc., an electric cooperative non-profit corporation organized and existing under the Laws of the State of Arizona.

"TRS Work Plan" shall have the meaning set forth in Section 4 of the Network Service Agreement.

"TSEPP" shall mean TSE Promotional Products, Inc., an Arizona corporation.

"TTS" shall mean TRANSCO Transmission System.

"WECC" shall mean Western Electricity Coordinating Council, a regional division of NERC, and successor to WSCC.

"Wholesale Power Contract" shall mean a contract, including its amendments and modifications, including the Existing Wholesale Power Contract and the Partial Requirements Capacity and Energy Agreement, between AEPCO and a Class A Member of AEPCO, for the wholesale sale by AEPCO of electric power or electric power and transmission services to such Class A Member.

"Withdrawal Agreement" shall mean the form of withdrawal agreement attached to the Member Agreement as Exhibit D.

"WSCC" shall mean Western System Coordinating Council, a regional division of NERC.

ATTACHMENT 1 to Seventh Amendment to Wholesale Power Contract

Section 13. Operations Review Committee.

13.1 The Class A Members of Generating Cooperative (Class A Members), including Member, shall have an opportunity to make recommendations to the Operations and Construction Committee (OCC) and the Finance and Audit Committee (FAC) of the Board of Directors of Generating Cooperative (AEPCO) and to the AEPCO Board as described below on any matters that relate to the service and cost of the service provided by AEPCO to Member through the representative of each (Representative) on a committee herein designated as the Operations Review Committee (Committee).

13.2 The Committee shall consist of one authorized Representative from each Class A Member and a Representative designated by AEPCO, who shall serve as Chairperson of the Committee. Each Class A Member shall designate as its Representative an employee of such Class A Member with experience in the areas in which the Committee will function and AEPCO shall designate the Chairperson, who shall be an AEPCO employee.

13.3 Each Class A Member shall evidence the appointment of its Representative by written notice to the other Class A Members and AEPCO, and by similar notice, any Class A Member or AEPCO may change its Representative on the Committee at any time. The list of Committee Representatives will be updated by the Chairperson and distributed to each of the Class A Members with appropriate contact information as necessary to keep the list current as to representation on the Committee.

13.4 Each Class A Member shall be entitled to one vote through its Representative on matters that come before the Committee. In the absence of unanimous consent, the various positions of the Representatives shall be compiled, referred and communicated to the OCC and or FAC by those Representatives electing to do so.

13.5 The Committee shall meet in person or telephonically quarterly except as otherwise determined by the Committee, but in no event less frequently than annually. The Representatives shall determine the agenda of the Committee and have access to all information related to the resources used by AEPCO to provide service.

13.6 Prior to the beginning of each calendar year, and as may be required during any such calendar year, an agenda for the Committee meeting will be solicited from the Representatives and the Committee will receive, consider and review all information requested by the Committee including but not limited to the Apache Station Operations and Maintenance Budget, Capital Budget and Construction Work Plans, A & G expenses proposed by AEPCO management, load forecasts, financial forecasts, cash flow forecasts, rate filings and forecasts, and review variances, updates and amendments thereto and such other operations data as may be requested. Following consideration thereof by the Committee, the Chairperson will promptly report to either the OCC or the FAC, as appropriate, such recommendations concerning any issues considered together with alternatives raised by a Representative. The Representatives may make reports through the AEPCO Director for the Member they represent on the positions they sponsor if they differ from the Committee recommendation report to the OCC or the FAC. Such reports to the OCC and the FAC given by the Chairman and the sponsoring Director(s) shall present all alternatives considered by the Committee in addition to the recommendations of the Committee. Representatives of the Committee may assist in the presentation by their Director(s) of alternatives considered by the Committee for the Board's review in making the final Board decision.

ATTACHMENT 2 to Seventh Amendment to Wholesale Power Contract

Rate Schedule A for ARMs

All Requirements Members

RATE SCHEDULE A

Dated __May 11________, 2010

1. INTRODUCTION:

This Rate Schedule A specifies the rates and charges and the methodology for developing and administering those rates and the charges for capacity and energy sales made by AEPCO to Member pursuant to its Existing Wholesale Power Contract (the "Agreement") to which this Rate Schedule A is attached. For purposes of specifying and calculating rates and charges pursuant to this Rate Schedule A, Member and other All Requirements Members are individually referred to as an "ARM" and collectively referred to as "Collective ARM" or "CARM." When specified, Member's All Requirements Member's Demand Ratio Share (ARM DRS) of certain CARM rates and charges shall be equal to the quotient of Member's 12 month rolling average demand divided by CARM's 12 month rolling average demand.

Exhibit A-1 to this Rate Schedule A sets forth the rates and charges which are currently in effect in accordance with the Agreement. Exhibit A-2 specifies the methodology for calculating the rates and charges, utilizing the treatment of expenses and certain revenues or credits depicted in Exhibit A-3 and the calculation of ACP and AC in Exhibit A-5. "CARM ACP" shall mean the sum of the ACPs in Existing Resources applicable to each All Requirements Member of AEPCO as set forth in Appendix A to Exhibit A-5 to this Rate Schedule A. Exhibit A-4 sets forth the methodologies for determining billing units, energy rates and energy charges using cost causation principles. Exhibit A-6 sets forth a sample of the bill to be presented to Member by AEPCO for services provided pursuant to the Agreement.

This Rate Schedule A applies to Existing Resources, the S&G PPA and Supplemental Purchases (the "Dispatch Pool Resources"). AEPCO may include the Dispatch Pool Resources in a larger pool for dispatch purposes, provided that the Billing Unit Program is maintained pursuant to Exhibit A-4 and the rights and benefits of each Class A Member are not diminished. No additional members may be added to the existing Class A Members with rights in the Dispatch Pool Resources, and changes in the membership shall be subject to applicable provisions of the Agreement.

AEPCO shall not enter into contracts for or acquire (i) any new AEPCO Generating Resource; or (ii) any AEPCO Power Purchase Resource with a term of greater than one year, unless AEPCO has first entered into a written agreement between AEPCO and all Class A Members agreeing to participate in such Resource, under which no related direct and indirect costs, charges and revenues derived from such Resource would be assigned to any non-participating Class A Members.

2. CONDITIONS OF SERVICE:

2.1 Applicability.

The rates, charges, and adjustments and the methodology for setting and adjusting such rates, charges and adjustments are set forth in this Rate Schedule A. Member shall make payment for electric service under the Agreement through the rates, charges and adjustments established by AEPCO in accordance with the Agreement and this Rate Schedule A. Member shall remain obligated at all times during the term of the Agreement, including periods in which a Force Majeure has been declared, to pay its Fixed Charge and O&M Charge as determined in accordance with this Rate Schedule A.

2.2 Power Factor Adjustment.

If the Power Factor of Member measured at the aggregated Member's Delivery Point(s) at the time of Member peak demand is outside a bandwidth of 95% leading to 95% lagging, a Power Factor Adjustment shall be separately charged to such Member. The Power Factor Adjustment shall be the product of Member's power factor adjustment (as set forth below) multiplied by the quotient of Member's ARM DRS of the CARM O&M Charge divided by the sum of CARM's 12 month rolling average demand. The power factor adjustment shall be any non-negative number determined from the following formula:

$$pfakW = ((mkW / mpf)(bpf)) - mkW$$

Where:

pfakW	=	power factor adjustment in kW; and
mkW	=	Member Metered kW, and
mpf	=	measured power factor at the time of Member peak demand, and
bpf	=	0.95.

2.3 Demand Overrun Adjustment.

If CARM's metered load in any hour exceeds its Allocated Capacity, then AEPCO shall compute a Demand Overrun Adjustment for CARM, and Member shall be charged a portion of such Demand Overrun Adjustment in proportion to Member's ARM DRS. Such Demand Overrun Adjustment shall equal the product of CARM's Fixed Charge multiplied by the demand overrun adjustment factor. The demand overrun adjustment factor shall be any non-negative number determined from the following formula:

$$doaf = ((\ mbdkW) / AC) - 1$$

Where:

doaf	=	demand overrun adjustment factor
mbdkW	=	Metered kW of CARM, and
AC	=	Allocated Capacity of CARM, in kW.

In addition, Member shall pay for the energy associated with the Demand Overrun Adjustment at the then-applicable Other Energy Rate.

2.4 Capacity and Energy Below AC.

If CARM is utilizing a Future Resource, Supplemental Purchase or S&G PPA in any hour to serve Native Load and CARM fails to take its required share of Minimum Base Capacity or Minimum Other Capacity, CARM shall pay a charge as set forth in this Section 2.4.

2.4.1 CARM Minimum Base Capacity Charge - In the event that CARM has replaced its use of AEPCO Resources with a Future Resource, Supplemental Purchase or S&G PPA to serve Native Load in any hour and fails to utilize energy from AEPCO sufficient to meet its share of Minimum Base Capacity, AEPCO shall charge and the CARM shall pay a charge in an amount obtained by multiplying the lesser of (i) the amount of Future Resource, Supplemental Purchase or S&G PPA used in such hour, or (ii) the amount of CARM's deficiency in its share of Minimum Base Capacity in such hour, by the Coal Energy Rate as defined in Exhibit A-4 of Rate Schedule A and as determined for the billing period. CARM shall only be subject to CARM Minimum Base Capacity Charge to the extent that Available Base Capacity dispatched for Class A Members as a whole is below Minimum Base Capacity.

2.4.2 CARM Minimum Other Capacity Charge - In the event that CARM has replaced its use of AEPCO Resources with a Future Resource, Supplemental Purchase or S&G PPA to serve Native Load in any hour and fails to utilize energy from AEPCO sufficient to meet its share of Minimum Other Capacity, AEPCO shall charge and CARM shall pay an amount obtained by multiplying the lesser of (i) the amount of Future Resource, Supplemental Purchase or S&G PPA used in such hour, or (ii) the amount of CARM's deficiency in its share of Minimum Other Capacity in such hour, by the Gas Energy Rate as defined in Exhibit A-4 of Rate Schedule A and as determined for the billing period.

2.4.3 In the event that in any hour both Sections 2.4.1 and 2.4.2 would apply, the CARM Minimum Other Capacity Charge will be determined first as set forth in Section 2.4.2 above, and the associated CARM Minimum Base Capacity Charge shall be an amount obtained by multiplying the lesser of (i) the amount of Future Resource, Supplemental Purchase or S&G PPA used in such hour less the amount of energy used as the basis for the

CARM Minimum Other Capacity Charge, or (ii) the amount of CARM's deficiency in its share of Minimum Base Capacity in such hour, by the Coal Energy Rate as defined in Exhibit A-4 of Rate Schedule A and as determined for the billing period.

2.5 Taxes and/or Assessments.

The rates and charges set forth in Exhibit A-1 to Rate Schedule A herein do not include sales taxes, transaction privilege taxes or regulatory assessments or similar governmental impositions which are, or may in the future be, levied on AEPCO by any Governmental Authority having jurisdiction and which are not included in the AEPCO Revenue Requirement used to develop the rates and charges. Therefore, bills rendered under the terms of this Rate Schedule A shall include all such federal, state and local sales taxes, transaction privilege taxes, assessments or similar governmental impositions. Such taxes and/or assessments shall be itemized and added to the bill in addition to the rates and charges for capacity and energy sales for payment by Member.

2.6 Charges.

The monthly charge billed to Member in accordance with Section 5.1 of the Agreement and as provided for in applicable provisions of Section 5 of the Agreement, shall consist of the following:

1. Member's ARM DRS of CARM's Fixed Charge as such Fixed Charge is set forth in Exhibit A-1 hereof; plus,

2. Member's ARM DRS of CARM's O&M Charge as such O&M Charge is set forth in Exhibit A-1 hereof; plus,

3. Member's ARM ECR of CARM's Base Energy Charge and Base Fuel Cost Adjustor Charge, as such terms are defined in and charges are calculated pursuant to Exhibit A-4; plus

4. Member's ARM ECR of CARM's Other Energy Charge and Other Fuel Cost Adjustor Charge, as such terms are defined in and charges are calculated pursuant to Exhibit A-4; plus

5. Any Power Factor Adjustment pursuant to Section 2.2 hereof; plus,

6. Member's ARM DRS of CARM's Demand Overrun Adjustment as such Demand Overrun Adjustment is calculated pursuant to Section 2.3 hereof; plus,

7. All taxes and/or assessments pursuant to Section 2.5 hereof, if any.

2.7 Sample Bill.

A form of bill which sets forth for illustrative purposes rates, charges and adjustments to be made by AEPCO to Member pursuant to the Agreement, including this Rate Schedule A, is attached to this Rate Schedule A as Exhibit A-6 and made a part hereof. Actual billings made by AEPCO to Member pursuant to Section 5.1 of the Agreement shall be substantially in the form of, and contain the information set forth in, such sample bill.

3. RATE DEVELOPMENT:

3.1 Rate Administration.

The Board of Directors of AEPCO shall review the level of revenues generated by the rates and charges set forth in Exhibits A-1 to Rate Schedules A and revenues generated from other rates and charges to the Class A Members, together with revenues generated from all other sources, to determine their sufficiency to meet AEPCO's Revenue Requirement. In the event that the rates and charges as set forth in Exhibits A-1 to Rate Schedules A and revenues generated from other rates and charges to the Class A Members do not provide revenues sufficient, but only sufficient, to satisfy AEPCO's Revenue Requirements from Class A Members, the Board of Directors of AEPCO shall establish new rates and new charges for electric service to Member pursuant to the procedures set forth in Section 5.6 of the Agreement and otherwise comply with those provisions pertaining to rates and the charges as set forth in Section 5 of the Agreement. Such new rates and charges established in conjunction with new rates and charges for all other Class A Members shall be submitted to the RUS and shall become effective unless they have been disapproved in writing by the RUS, and Exhibits A-1 (and other Exhibits, as may be applicable) to Rate Schedules A shall be modified to reflect such new rates and charges in effect.

3.2 Development of Cost of Service and Revenue Requirement.

AEPCO rates and the charges developed under this Rate Schedule A for charging Member and rates and charges for charging the other Class A Members shall be based upon AEPCO's Revenue Requirement, and cost of service studies utilizing a twelve-month test period ending not more than six months before proposed rates and charges based on such cost of service studies and Revenue Requirement are approved by the AEPCO Board of Directors. Accounting data for such test period shall be taken from the books and records of AEPCO.

The test period data for the cost of service studies shall be adjusted to reflect known and measurable changes to expenses and billing determinants that have occurred during the test period and/or are expected to continue to occur after the test period, i.e., data shall be normalized for the test period. The cost of service studies may also be normalized for changes that are known and measurable which will occur after the test period (out of period changes).

The fixed, O&M and energy components of all Class A Members shall be developed pursuant to this Rate Schedule A.

3.3 Classification of Expenses.

The expenses and revenue credits included in the cost of service studies shall be classified as fixed, O&M, or energy as set forth in Exhibit A-2 and depicted in Exhibit A-3 hereto.

3.4 Development of Rates, Charges, and Billing Determinants.

Once the components of fixed, O&M, and energy of AEPCO's Revenue Requirement from All Class A Members are determined pursuant to Section 3.2, and all expenses are classified pursuant to Section 3.3, the rates and charges for electric service pursuant to the Agreement shall be determined in accordance with Exhibit A-2. The billing determinants for the CARM Fixed Charge and the CARM O&M Charge shall be the ACP as specified in Section 3.5 below. The billing determinants for the energy rates shall be determined pursuant to Exhibit A-4 and as set forth in Section 5.4 of Exhibit A-2.

3.5 Allocated Capacity Percentage (ACP) and Allocated Capacity (AC).

Appendix A to Exhibit A-5 sets forth the Allocated Capacity Percentages (ACP) that shall be used to develop the CARM ACP, which will be used to develop the Fixed Charge and O&M Charge for CARM. Appendix B to Exhibit A-5 to this Rate Schedule A identifies AEPCO Resources in the Dispatch Pool as well as the Allocated Capacity (AC) for CARM. In each case, Member's share of such charges shall be determined based on Member's ARM DRS.

Exhibit A-1 to Rate Schedule A

All Requirements Member
Rates and Fixed Charge
(Effective as of Agreement Date)

Fixed Charge	$_______	per month *
O&M Charge	$_______	per month *
Energy Rates:		
Base Energy Rate	$_______	per kWh * of base resources used during the billing period.
Other Energy Rate	$_______	per kWh * of other resources used during the billing period.
Power Cost Adjustor Rate for FPPCA:		
Base Resources	$_______	per kWh *
Other Resources	$_______	per kWh *

*Based on test year data with pro forma adjustments as approved by the ACC.

All Requirements Members
Exhibit A-2 to Rate Schedule A
Development of Rates and Fixed Charge

1.0 INTRODUCTION:

This Exhibit A-2 specifies the methodology for the development of rates and the charges applicable for AEPCO Resources in which Member has an ACP. This methodology shall be applied to AEPCO expenses and revenues described herein which are maintained under the RUS Uniform System of Accounts and classified as (a) fixed, (b) O&M, or (c) energy. All amounts described hereunder and included in such accounts shall be those amounts recorded in AEPCO's financial records for the test period used in the applicable cost of service study from which the rates and charges are to be developed. Such amounts when adjusted for appropriate credits and normalized with appropriate adjustments are the AEPCO costs and expenses which shall be used as the basis for the cost of service which determines AEPCO's Revenue Requirement which is the sum of: (i) revenues to be recovered from Member through charging the rates and charges developed pursuant to the Agreement, plus (ii) revenues to be recovered from the Partial Requirements Members through rates and charges pursuant to their Partial Requirements Capacity and Energy Agreements; plus (iii) revenues to be recovered from other All Requirements Members through rates and charges pursuant to their Existing Wholesale Power Contracts, plus (iv) AEPCO revenues from all other sources.

2.0 CLASSIFICATION OF EXPENSES AND REVENUES:

2.1 Classifications.

For purposes of this Exhibit A-2 to Rate Schedule A, classifications shall be made of the AEPCO expenses and revenues from sources other than sales to AEPCO Class A Members and maintained and identified using the RUS Uniform System of Accounts, for the purpose of identifying such expenses as either: (a) fixed (F), (b) Operations and Maintenance (O&M) (O), or(c) energy (E), as follows:

(The account numbers refer to accounts maintained under the RUS Uniform System of Accounts by AEPCO in its financial records.)

Amounts in Accounts 500 through 554, with the exception of Accounts 501 and 547, shall each be classified as Production-O (consisting of operations and maintenance expenses related to steam and other power generation).

Amounts in Accounts 501 and 547 shall be separated and classified either as: Fuel-F (consisting of O&M and gas transportation reservation charges), or as Fuel-E (consisting of remaining Accounts 501 and 547 Expenses).

Amounts in Accounts 555 shall be separated and classified as: Purchased Power-F (capacity or demand charges), Purchased Power-O (O&M related charges), or as Purchased Power-E (energy charges).

Amounts in Accounts 556 and 557 shall be classified as: Other Power Supply-O (System Control, dispatching and O&M charges).

Amounts in Account 565 shall be separated and classified as: Wheeling Expense-O (consisting of firm wheeling charges), or as Wheeling Expense-E (consisting of non-firm wheeling charges).

Amounts in Accounts 901-916, which consist of consumer accounts, customer accounts and sales expense, shall be classified as Customer-O.

Based on the respective ratios of labor expenses in (a) Steam Power Generation (Accounts 500-507 and 510-514) and Other Power Production (Accounts 546-554) and (b) Other Power Supply (Accounts 556 and 557), compared to the sum of all such labor expenses, the amounts in Accounts 920-923 and 927-932 shall each be separated and classified as either: (a) Administrative & General I-O, or as (b) Administrative & General I-E.

Based on the portions of Production Plant (Accounts 300-316) and General Plant (Accounts 389-399) respectively associated with (a) fixed, (b) O&M, and (c) energy, compared to the sum of such expenses, the amounts in Account 924 shall be respectively separated and classified as either: (a) Administrative & General II-F, (b) Administrative & General II-O, or as (c) Administrative & General II-E.

Based on the respective ratios of labor expenses in (a) Steam Power Generation (Accounts 500-507 and 510-514) and Other Power Production (Accounts 546-554), (b) Other Power Supply (Accounts 556 and 557), (c) Sales Expense (Accounts 911-916) and (d) Administrative and General (Accounts 920-923 and 927-932), compared to the sum of such labor expenses, the amounts in Accounts 925 and 926 shall each be separated and classified as either: (a) Administrative & General III-O, or as (b) Administrative & General III-E.

The revenue amounts in Accounts 447-456 shall be first aggregated into credits and classified as either: (a) Credits-F, (b) Credits-O, or (c) Credits-E.

Margins shall be classified and assigned to the fixed category.

2.2 Depiction.

The expense and revenue accounts and their classification into fixed, O&M and energy specified in this Exhibit A-2 are depicted in tabular form in Exhibit A-3.

3.0 FIXED CAPACITY AND O&M COMPONENT:

3.1 Purpose and Elements.

The purpose of this Section 3.1 and Sections 3.2 and 3.3 hereof is to set forth the methodology for the development of the rates and charges attributable to electric service under the Agreement. The fixed capacity component and the O&M component shall be used to calculate and determine the Fixed Charge as provided in Section 5.2 hereof, and the O&M Charge as provided in Section 5.3 hereof.

3.2 Fixed Capacity Component.

The fixed capacity component for CARM shall be the sum of either the amounts in the following accounts, or the portion of such amounts classified as fixed, as applicable pursuant to Section 2 hereof, to the extent attributable to the AEPCO Resources in which CARM has an ACP:

Account 403	(Depreciation & Amortization Expense),
Account 408	(Ad Valorem Taxes),
Accounts 427-428	(Interest on Long Term Debt, Interest Charged to Construction, Other Interest Expense, and Other Deductions),
Account 501	(Fuel-F only),
Account 547	(Fuel-F only),
	Account 555 (Purchased Power - F only),
Account 924	(Administrative & General II-F only),
Plus Margin	in an amount sufficient to assure AEPCO of, at a minimum, a reasonable level of working capital and maintenance of annual coverage ratios, or any other financial covenants or tests prescribed or imposed by RUS or any other applicable Financial Entities, and
Less Accts 447-456	(Credits – F) which include: (a) a portion of the revenues from Power Sales Resources, consisting of total Power Sales Resources' revenues less Power Sales Resources' energy revenues, to be credited to

CARM in an amount equal to the product of CARM ACP expressed in decimal units multiplied by the amount of such revenues; and (b) a portion as described in footnote 7 of Exhibit A-3 of any other revenues received by AEPCO for any goods or services or other such services, but excluding the sales of power in subparagraph a above; such portion to be credited to CARM in an amount equal to the product of CARM ACP expressed in decimal units multiplied by the amount of such net revenues.

3.3 O&M Component.

The CARM O&M component shall be the sum of either the amounts in the following accounts, or the portion of such amounts classified as O&M, as applicable pursuant to Section 2 hereof, to the extent attributable to the AEPCO Resources in which CARM has an ACP:

Accounts 500-554, except for Accounts 501 and 547 (Production-O only),

Account 555	(Purchased Power-O only),
Accounts 556, 557	(Other Power Supply-O only),
Account 565	(Wheeling Expense-O only),
Accounts 901-916	(Customer-O only),
Accounts 920-923	(Administrative & General I-O only),
Account 924	(Administrative & General II-O only),
Accounts 925-926	(Administrative & General III-O only),
Accounts 927-932	(Administrative & General I-O only), and
Less Accts 447-456	(Credits-O) consisting of : (a) Scheduling Revenues – the scheduling revenues resulting from providing scheduling and trading services for customers other than Class A Members of AEPCO, excluding energy-related revenues, to be credited to CARM in an amount equal to the product of the total of such revenues multiplied by the CARM ACP; and (b) a portion as described in footnote 7 of Exhibit A-3 of any other revenues received by AEPCO for any goods or services or other such services; such portion to be credited to CARM in an amount equal to the product of CARM ACP expressed in decimal units multiplied by the amount of such net revenues.

4.0 ENERGY COMPONENT:

The CARM energy component shall be the sum of either the amounts in the following accounts, or the portion of such amounts classified as energy, as applicable, pursuant to Section 2 hereof, to the extent attributable to the AEPCO Resources in which CARM has an ACP:

Accounts 501 and 547	(Fuel-E only),
Accounts 555	(Purchased Power-E only),
Account 565	(Wheeling Power-E only),
Accounts 920-923	(Administrative & General I-E only),
Account 924	(Administrative & General II-E only),
Accounts 925-926	(Administrative & General III-E only), and
Accounts 927-932	(Administrative & General I-E only),
Less Accts 447-456	(Credits-E only).

5.0 MEMBER RATES AND CHARGES:

5.1 Elements.

The rates and charges for electric service under the Agreement to Member shall consist of (a) the Fixed Charge, composed of an appropriate allocated fixed capacity component, including a margin, (b) an O&M Charge, (c) Base Energy Rate, and (d) Other Energy Rate.

5.2 Fixed Charge.

The monthly CARM Fixed Charge stated in dollars, shall equal: the quotient of (a) the product of (i) the expenses less revenue credits used to determine the current fixed capacity component in Section 3.2 of this Exhibit A-2, and shall include prior period losses (negative equity) resulting from deficiencies or shortfalls caused by failures of Class A Members to meet their portion of AEPCO's Revenue Requirement, multiplied by (ii) the CARM ACP , (b) divided by twelve (12) to convert to a monthly charge. Member's share of the monthly CARM Fixed Charge shall be determined based on Member's ARM DRS.

5.3 O&M Charge.

The CARM O&M Charge shall be equal to the quotient of (a) the product of (i) the annual test year O&M component as calculated in Section 3.3 of this Exhibit A-2, multiplied by (ii) the CARM ACP , (b) divided by twelve (12) to convert to a monthly charge. Member's Share of the monthly CARM O&M Charge shall be determined based on Member's ARM DRS.

5.4 Base Energy Rate and Other Energy Rate.

The CARM Base Energy Rate and CARM Other Energy Rate shall be established based on the methodology contained in Exhibit A-4, and shall together equal the energy component comprised of the expenses, less revenue credits as identified in Section 4.0 of this Exhibit A-2 and calculated pursuant to the methodology in Exhibit A-4, divided by the aggregate test year energy billing units (stated in kWh) developed pursuant to Exhibit A-4 in the cost of service study for the Class A Members, adjusted for known and measurable changes.

6.0 REVENUE SHORTFALLS:

Any deficiencies or shortfalls in collections of AEPCO's Revenue Requirement from Class A Members will be recovered through appropriate adjustments to: (a) the O&M Charge, or (b) the margin included in the Fixed Charge. An adjustment will be made to the O&M Charge to the extent such deficiencies or shortfalls are attributable to the collection of revenues for operations and maintenance expenses. An adjustment will be made to the margin included in the Fixed Charge for all other such deficiencies or shortfalls. Such deficiencies or shortfalls may also be recovered through a combination of appropriate adjustments to the O&M Charge or the margins.

7.0 NO ADJUSTMENT FOR TRANSMISSION LOSSES:

The billing determinants included in the cost of service study and used to develop and implement the rates and charges shall be based on Schedules or on metered data at the Delivery Points. Consequently, AEPCO's Revenue Requirement developed as a result of such cost of service study reflects the costs of generating or acquiring sufficient capacity and energy to cover transmission losses. Therefore, the rates and charges developed as set forth herein implicitly encompass recovery of the costs associated with transmission losses and there is no need for a separate adjustment for transmission losses.

All Requirements Members

Exhibit A-3 to Rate Schedule A

Classification of Expenses

Uniform System Account No.	Description	Fixed Expenses (F)	O&M Expenses (O)	Energy Expenses (E)
	Production and Other Power Supply			
	Steam Power Generation:			
	Operation:			
500	Operation Supervision & Engineering		X	
501	Fuel	X[(1)]		X[(1)]
502	Steam Expenses		X	
505	Electric Expenses		X	
506	Miscellaneous Steam Power Expenses		X	
507	Rents		X	
	Maintenance:			
510	Supervision & Engineering		X	
511	Structures		X	
512	Boiler Plant		X	
513	Electric Plant		X	
514	Miscellaneous Steam Plant		X	
	Other Power Generation:			
	Operation:			
546	Operation Supervision & Engineering		X	
547	Fuel	X[(1)]		X[(1)]
548	Generation Expenses		X	
549	Miscellaneous Other Power Generation		X	
550	Rents		X	
	Maintenance:			

[1]All fuel related costs are assigned to the energy classification, except for gas transportation reservation charges which are assigned to the fixed classification because they do not pertain to fuel commodity costs.

Uniform System Account No.	Description	Fixed Expenses (F)	O&M Expenses (O)	Energy Expenses (E)
551	Supervision & Engineering		X	
552	Structures		X	
553	Generating and Electric Equipment		X	
554	Miscellaneous Other Power Generation		X	
	Other Power Supply Expenses:			
555	Purchased Power	X(2)	X(2)	X(2)
556	System Control & Load Dispatching		X	
557	Other Expenses		X	
565	Wheeling Expense		X(3)	X(3)
901-905	Consumer Accounts		X	
906-910	Customer Service & Information		X	
911-916	Sales Expense		X	
	Administrative & General:			
920	Salaries		X(4)	X(4)
921	Office Supplies & Expenses		X(4)	X(4)
922	A&G Expenses Transferred Credit		X(4)	X(4)
923	Outside Services		X(4)	X(4)

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[2]Purchased power, capacity or demand charges are assigned to the fixed classification, any O&M charges to the O&M classification and energy charges and interchange expenses are assigned to the energy classification.

[3]Firm wheeling charges are assigned to the O&M classification and non-firm wheeling charges are assigned to the energy classification.

[4]Administrative and general expenses are assigned to the O&M and energy classifications based upon the distribution of production and other power supply labor expenses to the O&M and energy classifications.

Uniform System Account No.	Description	Fixed Expenses (F)	O&M Expenses (O)	Energy Expenses (E)
924	Property Insurance	X[5]	X[5]	X[5]
925	Injuries & Damages		X[6]	X[6]
926	Employee Pensions & Benefits		X[6]	X[6]
927	Franchise Requirements		X[4]	X[4]
928	Regulatory Commission Expenses		X[4]	X[4]
929	Duplicate Charges Credit		X[4]	X[4]
930	Miscellaneous General Expense		X[4]	X[4]
931	Rents		X[4]	X[4]
932	Maintenance of General Plant		X[4]	X[4]
403	Depreciation & Amortization Expense	X		
408	Ad Valorem Taxes	X		
	Interest & Other Deductions:			
427	Interest on Long Term Debt	X		
427	Interest Charged to Construction	X		
427	Other Interest Expense	X		
428	Other Deductions	X		
447-456	Operating Revenues from Other Sources – Credit	X[7]	X[7]	X[7]
	Margin Component	X		

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[5]Assigned to the fixed, O&M and energy classifications based upon the distribution of production and general plant between classifications.

[6]Assigned to the O&M and energy classifications based upon the distribution of total labor expenses to the O&M and energy classifications.

[7]Excluding revenue from Power Sales Resources, revenue from sources other than AEPCO's Class A Members shall be credits to the Fixed component and to the O&M component in amounts proportionate to Fixed Revenue Requirements and O&M Revenue Requirements.

Exhibit A-4 to Rate Schedule A
Determination of Billing Units, Energy Rates and Energy Charges Using Cost Causation Principles

1. INTRODUCTION:

This Exhibit A-4 sets forth the methodology for the determination of energy billing units, energy rates and energy charges for each of AEPCO's Class A Members using cost causation allocation principles.

2. DEFINITIONS:

The following terms are used in this Exhibit and its Appendices.

"ARM Energy Cost Responsibility Share" or "ARM ECR" shall mean the percentage share for each billing period of an individual All Requirements Member in CARM S&G PPA Energy Charge, CARM Supplemental Purchase Cost, CARM Base Energy Cost, and CARM Total Other Energy Cost, determined in such billing period as the ratio expressed in percent of each All Requirements Member's Member Billing Energy to CARM Billing Energy.

"Available Base Capacity" shall mean the energy from Base Resources, including Base Economy Purchases, available for dispatch in a Future Scheduling Hour, less losses in delivery to Class A Members, and excluding (i) any coal-fired capacity that is not available due to forced outage or scheduled maintenance outage or temporary deration, (ii) capacities of Power Sales Resources, and (iii) allocations for losses in delivery of such Power Sales Resources; and for each Billing Unit Entity, shall mean that Billing Unit Entity's ACP share of such Available Base Capacity.

"Available Other Capacity" shall mean the amount of capacity that is available for dispatch as determined by AEPCO for any Future Scheduling Hour equal to the sum of (i) the aggregate of the capacities of Other Resources, which shall be as set forth in Appendix B to Exhibit A-5 of Rate Schedule A to each Partial Requirements Capacity and Energy Agreement, as may be amended, plus (ii) the capacity of any concurrent Replacement Purchases for Base Resources, less (iii) capacity set aside for Reserves and allocations for losses in delivery; and for each Billing Unit Entity, shall mean that Billing Unit Entity's ACP share of such Available Other Capacity.

"Available S&G PPA Capacity" shall mean S&G PPA Capacity, less an allocation for losses for delivery, that is available for dispatch by AEPCO for any Future Scheduling Hour; and for each Billing Unit Entity having an ACP in S&G PPA, shall mean that Billing Unit Entity's ACP share of such Available S&G PPA Capacity.

"Available Supplemental Capacity" shall mean Supplemental Capacity, less an allocation for losses for delivery, that is available for dispatch by AEPCO for any Future

Scheduling Hour; and for each Billing Unit Entity having a percentage interest in a Supplemental Purchase, shall mean that Billing Unit Entity's percentage share of such Available Supplemental Capacity.

"Base Adjustor Per Unit Cost" shall mean, for a billing period for each Billing Unit Entity, the Base Fuel Adjustor Cost divided by the Base Billing Energy for the same Billing Unit Entity for the same billing period.

"Base Average Energy Rate" shall mean, for a billing period for each Billing Unit Entity, the rate obtained by dividing the Billing Unit Entity's Base Energy Cost of the billing period by Billing Unit Entity's Base Billing Energy for the same period.

"Base Billing Energy" shall mean, for a Billing Unit Entity, the energy from its Available Base Capacity assigned and allocated in each hour pursuant to the Billing Unit Program to its Base Schedule or load, accumulated for a billing period.

"Base Capacity" shall mean for Base Resources the sum of (i) the capacity from Federal Hydro Power Agreements as adjusted to reflect seasonal and Peak Hours vs. Off-Peak Hours variations; plus (ii) 350 MW of capacity of AEPCO's coal-fired units.

"Base Economy Purchase" shall mean a purchase of energy by AEPCO from a third party, including wheeling charges recorded in RUS Uniform System of Accounts 565 Transmission of Electricity by Others or its successor for delivery of the purchase to an SWTC Point of Receipt, if any, which is made at a lower average energy rate over the purchase period than that associated with energy available from Base Resources during such period, and which AEPCO chooses to make in lieu of dispatching energy available from such Base Resources.

"Base Economy Purchase Cost" shall mean, for all hours of a billing period, the purchase energy cost incurred by AEPCO for all Base Economy Purchases made in such billing period, including wheeling costs incurred in delivery from the source of such purchase to an SWTC Point of Receipt, if any.

"Base Economy Sales" shall mean, for a billing period, the energy from Post-Transfer Excess Base Capacity assigned in each hour to each Billing Unit Entity pursuant to the Billing Unit Program as Third Party Economy Sales.

"Base Economy Sales Cost" shall mean, for each Billing Unit Entity for a billing period, the product of Base Economy Sales multiplied by the Coal Energy Rate.

"Base Economy Sales Credit" shall mean, for each Billing Unit Entity, the product of the Economy Sales Price, for each of Daytime Hours and Nighttime Hours of a billing period, multiplied by the Billing Unit Entity's Base Economy Sales for Daytime Hours and for Nighttime Hours, respectively, of the same billing period.

"Base Energy Cost" shall mean, for a billing period for each Billing Unit Entity, the sum of Remaining Base Energy Cost plus Base Transfer Sales Credits, Base Transfer Energy Cost, Base Economy Sales Credit and Base Economy Sales Cost for the same Billing Unit Entity.

"Base Energy Mismatch" shall mean, for a billing period, the accumulated net difference in energy obtained from subtracting (i) the energy from Available Base Capacity assigned and allocated in the billing period in accordance with the Billing Unit Program, from (ii) the energy actually produced from Available Base Capacity during that billing period.

"Base Energy Mismatch Charge" shall mean, for a billing period, the product of (i) any positive value of Base Energy Mismatch for the billing period, multiplied by (ii) the Coal Energy Rate for the billing period.

"Base Energy Mismatch Credit" shall mean, for a billing period, the product of (i) the absolute value of any negative value of Base Energy Mismatch for the billing period, multiplied by (ii) the Coal Energy Rate for the billing period.

"Base Energy Rate" shall mean, for each Billing Unit Entity, the rate applicable to that Billing Unit Entity's use of energy from Available Base Capacity as set forth in Exhibit A-1 to Rate Schedule A.

"Base FPPCA" shall mean Fuel and Purchase Power Cost Adjustor determined for a FPPCA Period for the Base Resources for each Billing Unit Entity.

"Base Fuel Adjustor Cost" shall mean for a billing period for each Billing Unit Entity, the sum of the Base Energy Cost, Hydro Demand Charge, Base Transmission Wheeling Cost and Power Sales Resource Demand Revenues for the same Billing Unit Entity for the same billing period.

"Base Fuel Bank" shall mean, for a billing period for each Billing Unit Entity, the accumulation of Base Over or Under Collections.

"Base Incremental Unit Cost" shall mean, for a billing period for each Billing Unit Entity, the difference obtained by subtracting (i) the sum of (a) Base Power Cost Adjustor Base, plus (b) Base Power Cost Adjustor Rate, from (ii) Member Base Adjustor Per Unit Cost, for such Billing Unit Entity for such period.

"Base Over or Under Collection" shall mean, for a billing period for each Billing Unit Entity, the product of (i) Base Incremental Unit Cost multiplied by (ii) Base Billing Energy, for such Billing Unit Entity for such period.

"Base Power Cost Adjustor Base" shall mean the Power Cost Adjustor Base for Base Resources as set forth in the Tariff.

"Base Power Cost Adjustor Rate" shall mean the Power Cost Adjustor Rate for Base Resources as set forth in the Tariff.

"Base Resources" shall mean the Federal Hydro Power Agreements and two coal-fired steam Generating Resources that are Existing Resources located at the Apache Generating Station, in which each Class A Member has an ACP.

"Base Schedule" shall mean, for each Member*, its Pre-Schedules and Real-Time Schedules provided to AEPCO by such Member* or its Scheduling Agent pertaining to Member*'s use of its Available Base Capacity, as such Pre-Schedules and Real-Time Schedules are determined consistent with Schedule B to the Partial Requirements Capacity and Energy Agreements.

"Base Transfer" shall mean, for a Billing Unit Entity, energy from the Billing Unit Entity's Excess Base Capacity that has been assigned and allocated to the load or Other Schedule of other Billing Unit Entities in an hour pursuant to the Billing Unit Program, accumulated for a billing period separately for Daytime Hours and Nighttime Hours.

"Base Transfer Billing Energy" shall mean, for a Billing Unit Entity, energy from the Excess Base Capacity of other Billing Unit Entities that has been assigned and allocated to the Billing Unit Entity in an hour pursuant to the Billing Unit Program, accumulated for a billing period separately for Daytime Hours and Nighttime Hours.

"Base Transfer Energy Cost" shall mean, for each Billing Unit Entity for a billing period, Coal Energy Rate multiplied by Base Transfer.

"Base Transfer Purchase Cost" shall mean, for each Billing Unit Entity that has been assigned Base Transfer Billing Energy, for each of separately accumulated Daytime Hours and Nighttime Hours of a billing period, the product of its Base Transfer Billing Energy, multiplied by the Economy Purchase Rate of Daytime Hours or Nighttime Hours, as applicable.

"Base Transfer Sales Credit" shall mean, for each Billing Unit Entity, for each of separately accumulated Daytime Hours and Nighttime Hours of a billing period, the product of (i) the Economy Purchase Rate of Daytime Hours or Nighttime Hours, as applicable, multiplied by (ii) its Base Transfer of Daytime Hours or Nighttime Hours, as applicable.

"Base Transmission Wheeling Cost" shall mean, for each Billing Unit Entity for a billing period, the product of (i) the costs recorded in RUS Uniform System of Accounts 565 Transmission of Electricity by Others or its successor, and allocated to Base Resources, for the same billing period, multiplied by (ii) the Billing Unit Entity's ACP in Existing Resources.

"Billing Energy" shall mean the energy of each billing period determined pursuant to the Billing Unit Program to have served the entirety of the Schedule of each Member*, or the entirety of the load of CARM or the entirety of the Directed Sales and load of a Member* CA in such billing period, consisting of the sum of the Billing Unit Entity's Base Billing Energy, S&G PPA Billing Energy, Other Billing Energy, Base Transfer Billing Energy, Supplemental Billing Energy, and S&G And Supplemental Transfer Billing Energy.

"Billing Unit Entity" shall mean any of CARM, a Member* or a Member* CA.

"Billing Unit Program" shall mean the software program and subroutines that are used by AEPCO's Power Trading and Scheduling Department for the purpose of determining monthly each Billing Unit Entity's Billing Energy from Base Resources, Other Resources, S&G PPA and Supplemental Purchase by hourly allocation and assignment of energy from Available Base Capacity, Available Other Capacity, Available S&G PPA Capacity and Available Supplemental Capacity to each of (i) the loads of the CARM; (ii) the Directed Sales and load of a Member* CA; (iii) the Schedules; (iv) Base Transfers; (v) S&G And Supplemental Transfers; and (vi) Third Party Economy Sales.

"CARM" or "Collective ARM" shall mean all of the All Requirements Members.

"CARM ACP" shall mean the sum of the ACPs in Existing Resources and in S&G PPA, as applicable to each All Requirements Member as set forth in Appendix A to Exhibit A-5 to Rate Schedule A to the ARM Wholesale Power Contracts.

"Coal Energy Cost" shall mean, for a billing period, the accumulated costs of coal and natural gas expensed during that billing period, related to the operation and dispatch during that billing period of two coal-fired steam Generating Resources that are Existing Resources located at the Apache Generating Station, as recorded in RUS Uniform System of Accounts 501 or its successor for that billing period.

"Coal Energy Rate" shall mean, for a billing period, Coal Energy Cost divided by the product of Coal Energy Generated multiplied by the difference obtained by subtracting the Network Loss Factor from one (1).

"Coal Energy Generated" shall mean, for a billing period, the net energy output at the 230 kv bus of the two coal-fired steam Generating Resources that are Existing Resources located at the Apache Generating Station.

"Daytime Hours" shall mean the 16 hours of each day beginning Hour Ending 0700 through Hour Ending 2200 Pacific Prevailing Time, including Sundays and Holidays.

"Directed Sales" shall mean any transactions in which, at the advance direction of a Member* CA, AEPCO for such Member* CA's benefit sells to a third party at wholesale energy from such Member* CA's available AC in AEPCO Resources.
"Directed Sales Credit" shall mean the revenue realized from Directed Sales.

"Dispatch Pool Resources" shall mean Existing Resources, the S&G PPA and Supplemental Purchases.

"Economy Purchase Cost" shall mean, separately accumulated for Daytime Hours and Nighttime Hours of a billing period, the total cost incurred by AEPCO (including transmission expenses, including losses, incurred in delivery from the source of such purchase to an SWTC Point of Receipt, if any) for Non-Base Economy Purchases and Replacement Purchases in effect in such Daytime Hours or Nighttime Hours of the billing period.

"Economy Purchase Rate" shall mean, separately calculated for Daytime Hours and Nighttime Hours of a billing period, the rate obtained by dividing Economy Purchase Cost of Daytime Hours or Nighttime Hours of that billing period, by energy received from Non-Base Economy Purchases and Replacement Purchases in effect in such Daytime Hours or Nighttime Hours of that billing period.

"Economy Sales Price" shall mean, for Third Party Economy Sales, for each of Daytime Hours and Nighttime Hours, the quotient obtained by dividing (i) the numerator equal to the sum of the revenue from all Third Party Economy Sales during the billing period in Daytime Hours and Nighttime Hours, respectively, reduced by any payments to SWTC or third parties for transmission used in delivery of such sales, by (ii) a denominator equal to the MWh of energy delivered as Third Party Economy Sales during such hours.

"Energy Cost Accounting Process" or "ECAP" shall mean the software program and subroutines that are used by AEPCO's Financial Services Department for the purpose of determining monthly each Billing Unit Entity's costs for energy from Base Resources, Other Resources, S&G PPA, and Supplemental Resources.

"Excess Base Capacity" shall mean, for a billing period for each Billing Unit Entity, the separately accumulated Daytime and Nighttime billing period totals of Available Base Capacity that is not assigned in an hour pursuant to the Billing Unit Program as Base Billing Energy.

"Excess S&G And Supplemental Capacity" shall mean, for a billing period for each Billing Unit Entity having an ACP interest in S&G PPA and/or Supplemental Purchase, Available S&G PPA Capacity and/or Available Supplemental Capacity, that is not assigned in an hour pursuant to the Billing Unit Program as S&G PPA Billing Energy and Supplemental Billing Energy.

"Federal Hydro Power Agreement(s)" shall mean the following contracts:

a) Contract No. 87-BCA-10001 for Firm Electric Service between Western Area Power Administration and Arizona Power Pooling Association, dated March 9, 1989 as it may be amended from time to time, and its successor agreement(s) (SLCA Integrated Projects Agreement); and

b) Contract No. 87-BCA-10085 Electric Service between Western Area Power Administration and Arizona Power Pooling Association, dated February 25, 1988 as it may be amended from time to time, and its successor agreement(s) (Parker-Davis Project Agreement).

"FPPCA" shall mean Fuel and Purchase Power Cost Adjustor determined for the applicable AEPCO Resources.

"FPPCA Period" shall mean the period of months over which AEPCO is to record S&G PPA Energy Charge, Supplemental Purchase Cost, Base Energy Cost and Other Energy Cost for billing or credit to the Class A Members pursuant to the Tariff.

"Future Scheduling Hour" shall mean a clock hour beginning more than sixty (60) minutes after the current hour.

"Gas Energy Cost" shall mean, for a billing period, the accumulated costs of natural gas expensed during that billing period, related to the operation and dispatch during that billing period of the gas-fired Generating Resources that are Existing Resources located at the Apache Generating Station, as recorded in RUS Uniform System of Accounts 547 or its successor for that billing period.

"Gas Energy Generated" shall mean, for a billing period, the net energy output at the applicable bus of the gas-fired Generating Resources that are Existing Resources located at the Apache Generating Station.

"Gas Energy Rate" shall mean, for a billing period, Gas Energy Cost divided by the product of Gas Energy Generated.

"Hydro Demand Charge" shall mean, for a billing period, demand charges associated with Federal Hydro Power Agreements as recorded in RUS Uniform System of Accounts 555 or its successor for the billing period.

"Hydro Energy Charge" shall mean, for a billing period, energy charges associated with Federal Hydro Power Agreements as recorded in RUS Uniform System of Accounts 555 or its successor for the billing period.

"Member*" shall mean a PRM whose load is not assigned to the SWTC metered subsystem of the Western Area Lower Colorado Balancing Authority in the Desert Southwest Region.

"Member* CA" shall mean a PRM whose load is assigned to the SWTC metered subsystem of the Western Area Lower Colorado Balancing Authority in the Desert Southwest Region.

"Minimum Other Capacity" shall mean the capacity from Available Other Capacity that must be operated from time to time to maintain system reliability or for other reasons as described in Section 4.2 of Schedule B to the Partial Requirements Capacity and Energy Agreements.

"Network Loss Factor" shall mean the adjustment factor for transmission losses assigned for network service under the Southwest Transmission Cooperative, Inc. Open Access Transmission Tariff as in effect from time to time.

"Nighttime Hours" shall mean the eight (8) hours beginning Hour Ending 2300 of one day continuing through Hour Ending 0600 of the following day, Pacific Prevailing Time.

"Non-Base Economy Purchase" shall mean any purchase of energy by AEPCO from a third party that is not a Base Economy Purchase which is made at a lower average energy rate over the purchase period than that which would be associated with energy dispatched from Available Other Capacity or Available S&G PPA Capacity during such period, and which is made in lieu of dispatching energy from such capacity.

"Operating Reserve Purchases" shall mean any purchases of operating reserve capacity to avoid curtailing any energy from any more economical AEPCO Resource that would otherwise be required to provide such operating reserve capacity.

"Other Adjustor Per Unit Cost" shall mean, for a billing period for each Billing Unit Entity, the Other Fuel Adjustor Cost divided by the Total Other Billing Energy for the same Billing Unit Entity for the same billing period.

"Other Average Energy Rate" shall mean, for a billing period for a Billing Unit Entity, the rate obtained by dividing its Total Other Energy Cost of the billing period by its Other Billing Energy for the same period.

"Other Billing Energy" shall mean, for a Billing Unit Entity, the energy from Available Other Capacity assigned and allocated in each hour pursuant to the Billing Unit Program to its Other Schedule or load, accumulated for a billing period.

"Other Economy Sales" shall mean, for a billing period, the energy from dispatched Other Capacity and from Post-Transfer S&G And Supplemental Capacity assigned in each hour to each Billing Unit Entity pursuant to the Billing Unit Program as Third Party Economy Sales.

"Other Economy Sales Credit" shall mean, for each Billing Unit Entity, the product of the Other Economy Energy Sales Revenue of Daytime Hours and Nighttime Hours, as applicable, multiplied by the ratio of (i) for each of separately accumulated Daytime Hours and Nighttime Hours of the billing period, the Post-Transfer S&G And Supplemental Capacity energy in the case of a Billing Unit Entity with an ACP in such capacity, the Other Schedule in the case of a Member*, and in the case of CARM or a Member* CA, its load's use of Available Other Capacity, to (ii) the total of such Post-Transfer S&G And Supplemental Capacity, such Other Schedules and such uses of Available Other Capacity by all Billing Unit Entities for the same time periods.

"Other Economy Sales Revenue" shall mean the difference obtained by subtracting the Base Economy Sales Credit from the revenue of all Third Party Economy Sales during a billing period.

"Other Energy Cost" shall mean, for a billing period for each Billing Unit Entity, the costs of purchased energy and natural gas fuel and oil fuel expensed during that billing period, related to the operation and dispatch of Available Other Capacity during that billing period, as recorded in Accounts described in Section 4.0 of Exhibit A-2 to Rate Schedule A and reported to RUS by AEPCO for that billing period, including purchased energy expenses, wheeling charges and costs of any transmission losses related to Other Economy Purchases and Replacement Purchases for Base Resources and Other Resources as incurred during that billing period.

"Other Energy Mismatch" shall mean, for a billing period, the accumulated net difference in energy obtained from subtracting (i) the total energy from Available Other Capacity, Available Supplemental Capacity, and Available S&G PPA Capacity assigned and allocated in the billing period in accordance with the Billing Unit Program, from (ii) the energy actually produced from Available Other Capacity, Available Supplemental Capacity, and Available S&G PPA Capacity during that billing period.

"Other Energy Mismatch Credit" shall mean, for a billing period, the product of: (i) the absolute value of any negative value of Other Energy Mismatch for the billing period, multiplied by (ii) the Gas Energy Rate for the billing period.

"Other Energy Mismatch Charge" shall mean, for a billing period, the product of: (i) any positive value of Other Energy Mismatch for the billing period, multiplied by (ii) the Gas Energy Rate for the billing period.

"Other Energy Rate" shall mean, for each Billing Unit Entity, the rate applicable to that Billing Unit Entity's use of energy from Available Other Capacity as set forth in Exhibit A-1 to Rate Schedule A.

"Other FPPCA" shall mean Fuel and Purchase Power Cost Adjustor determined for a FPPCA Period for Other Resources, Supplemental Purchase as made for each Billing Unit Entity, and S&G PPA for each Billing Unit Entity having an ACP interest in S&G PPA.

"Other Fuel Adjustor Cost" shall mean, for a billing period for each Billing Unit Entity, the sum of the Total Other Energy Cost, Other Transmission Wheeling Cost, plus, for those Billing Unit Entities with interests in S&G PPA Capacity or Supplemental Capacity, Supplemental Demand Charge, Supplemental Wheeling Cost, S&G PPA Purchase Demand Charge and S&G PPA Wheeling Cost.

"Other Fuel Bank" shall mean, for a billing period for each Billing Unit Entity, the accumulation of Other Over or Under Collections.

"Other Incremental Unit Cost" shall mean, for a billing period for each Billing Unit Entity, the difference obtained by subtracting (i) the sum of (a) Other Power Cost Adjustor Base plus (b) Other Power Cost Adjustor Rate from (ii) Other Adjustor Per Unit Cost, for such Billing Unit Entity for such period.

"Other Over or Under Collection" shall mean, for a billing period for each Billing Unit Entity, the product of (i) Other Incremental Unit Cost, multiplied by (ii) Total Other Billing Energy, for such Billing Unit Entity for such period.

"Other Power Cost Adjustor Base" shall mean the Power Cost Adjustor Base for Other Resources as set forth in the Tariff.

"Other Power Cost Adjustor Rate" shall mean the Power Cost Adjustor Rate for Other Resources as set forth in the Tariff.

"Other Resources" shall mean all gas-fired combustion turbine and gas-fired steam Generating Resources that are Existing Resources located at Apache Generating Station, in which each Class A Member has an ACP, which include GT-1, Steam 1, GT-2, GT-3 and GT-4.

"Other Schedule" shall mean, for each Member*, its Pre-Schedules and Real-Time Schedules provided to AEPCO by Member*'s Scheduling Agent pertaining to such Member*'s use of its Available Other Capacity and, separately identified, of its Available S&G PPA Capacity, if any, as such Pre-Schedules and Real-Time Schedules are determined consistent with Schedule B to its Partial Requirements Capacity and Energy Agreement.

"Other Transmission Wheeling Cost" shall mean, for each Billing Unit Entity for a billing period, the product of (i) the costs recorded in RUS Uniform System of Accounts 565 Transmission of Electricity by Others or its successor, and allocated to Other Resources, for the same billing period, multiplied by (ii) the Billing Unit Entity's ACP in Existing Resources.

"Partial Requirements Member" shall mean MEC, SSVEC, TRICO or any other Class A Member of AEPCO that executes and delivers a Partial Requirements Capacity and Energy Agreement.

"Planning Contract Member" shall mean a Partial Requirements Member which has contracted separately from the Partial Requirements Capacity and Energy Agreement to obtain Planning Services from AEPCO.

"Post-Base Load" shall mean, for CARM or a Member* CA, the load of such Billing Unit Entity that remains after assignment of such Billing Unit Entity's Post-S&G And Supplemental Load to that Billing Unit Entity's Available Base Capacity.

"Post-Base Other Schedule" shall mean, for a Member*, the portion of the Total Schedule of such Member* that remains after assignment of such Member*'s Base Schedule to that Member*'s Available Base Capacity.

"Post-Base Transfer Load" shall mean, for CARM or a Member* CA, any load of such Billing Unit Entity that remains after assignment of such Billing Unit Entity's Post-S&G And Supplemental Transfer Load to Base Transfers of other Billing Unit Entities.

"Post-Base Transfer Other Schedule" shall mean, for Member*, any Post-S&G And Supplemental Other Schedule that remains after assignment of such Member*'s Post S&G And Supplemental Transfer Other Schedule to Base Transfers from other Billing Unit Entities.

"Post-Sales Base Capacity" shall mean, for each Billing Unit Entity, any Post Transfer Base Capacity that remains after its allocation to Base Economy Sales.

"Post-S&G And Supplemental Load" shall mean, for CARM or a Member* CA, the load of such Billing Unit Entity that remains after assignment of such Billing Unit Entity's load to that Billing Unit Entity's allocated share of S&G PPA Capacity and Supplemental Capacity.

"Post-S&G And Supplemental Transfer Load" shall mean, for CARM or a Member* CA, the load of such Billing Unit Entity that remains after assignment of S&G And Supplemental Transfers from another Billing Unit Entity to that Billing Unit Entity's Post-Base Load.

"Post-S&G And Supplemental Transfer Other Schedule" shall mean, for Member*, the Post-Base Other Schedule that remains after allocation of S&G And Supplemental Transfers from CARM or a Member* CA.

"Post-Transfer Base Capacity" shall mean, for a Billing Unit Entity, each hour's Excess Base Capacity remaining after energy from its Excess Base Capacity has been assigned as Base Transfers.

"Post-Transfer Load" shall mean, for CARM or a Member* CA, the load of such Billing Unit Entity that remains after assignment of such Billing Unit Entity's Post-Base Load to that Billing Unit Entity's allocated share of S&G And Supplemental Transfers and of Base Transfers from other Billing Unit Entities.

"Post-Transfer Other Schedule" shall mean, for a Member*, the Total Schedule of such Member* that remains after assignment of such Member*'s allocated share of S&G And Supplemental Transfers from other Billing Unit Entities to its Post-Base Other Schedule, and then assignment of such Member*s allocated share of Base Transfers from other Billing Unit Entities to that Member*'s Post-S&G And Supplemental Transfer Other Schedule.

"Post-Transfer S&G And Supplemental Capacity" shall mean, for CARM or Member* CA having an ACP in S&G PPA and/or an interest in Supplemental Purchase, each hour's Excess S&G And Supplemental Capacity remaining after energy from its Excess S&G And Supplemental Capacity has been assigned as an S&G And Supplemental

Transfer, accumulated for a billing period separately for Daytime Hours and Nighttime Hours.

"Power Sales Resource Demand Revenues" shall mean, for a billing period for each Billing Unit Entity, the product of (i) the demand-related revenue received pursuant to Power Sales Resource contracts as recorded in RUS Uniform System of Account 447 Sales for Resale, or its successor, for that billing period, multiplied by (ii) the Billing Unit Entity's ACP in Existing Resources.

"Power Sales Resource Energy Revenue" shall mean, for a billing period the energy-related revenue received pursuant to Power Sales Resource contracts as recorded in RUS Uniform System of Account 447 Sales for Resale or its successor, for that billing period.

"Pre-Schedule" shall mean a Schedule submitted by a Scheduling Agent to AEPCO for the use of Resources for the following Scheduling Day as defined by WECC.

"PRM" shall mean a Partial Requirement Member.

"Real-Time Schedule" shall mean any Schedule submitted by a Scheduling Agent to AEPCO that changes a previously submitted Tag or that requires a new Tag to be created for a Future Scheduling Hour of the current operating day.

"Remaining Base Energy Cost" shall mean, for a billing period, the total of Remaining Coal Energy Cost, Hydro Energy Charge, Base Economy Purchase Cost and Power Sales Resource Energy Revenue, for the same billing period as allocated to each Billing Unit Entity based on the ratio of (i) the Billing Unit Entity's Base Billing Energy for that billing period to (ii) the total of all Billing Unit Entities' Base Billing Energy for the same billing period.

"Remaining Coal Energy Cost" shall mean, for a billing period, Coal Energy Cost for the billing period less the sum of Base Transfer Sales Credits and Base Economy Sales Credits for all Billing Unit Entities for the same billing period.

"Replacement Purchase" shall mean any purchase of energy made to replace energy that is not available from any AEPCO Resource due to forced outage, scheduled outage or deration of such AEPCO Resource.

"S&G And Supplemental Sales Credit" shall mean, for a billing period for each Billing Unit Entity with an ACP in S&G PPA or an interest in Supplemental Purchase, the product of the Economy Purchase Rate multiplied by S&G And Supplemental Transfer, for such Billing Unit Entity for such billing period.

"S&G And Supplemental Transfer" shall mean, for a Billing Unit Entity with an ACP in S&G PPA and/or an interest in Supplemental Purchase, energy from its Excess S&G And Supplemental Capacity that has been assigned and allocated to another Billing Unit

Entity in an hour pursuant to the Billing Unit Program, accumulated for a billing period separately for Daytime Hours and Nighttime Hours.

"S&G And Supplemental Transfer Billing Energy" shall mean, for a Billing Unit Entity, energy from the Excess S&G And Supplemental Capacity of another Billing Unit Entity with an ACP in S&G PPA and/or an interest in Supplemental Purchase that has been assigned and allocated to the Billing Unit Entity in an hour pursuant to the Billing Unit Program as an S&G And Supplemental Transfer from the other Billing Unit Entity, accumulated for a billing period.

"S&G And Supplemental Transfer Purchase Cost" shall mean, for a billing period for each Billing Unit Entity that is assigned an S&G And Supplemental Transfer pursuant to the Billing Unit Program, the product of the Economy Purchase Rate multiplied by S&G And Supplemental Transfer Billing Energy, for such Billing Unit Entity for such billing period.

"S&G PPA" shall mean either or both of the following purchase power agreements: (i) the Confirmation Agreement dated August 17, 2004, between AEPCO and South Point Energy Center, LLC (South Point), by which AEPCO purchases between 25 MW and 55 MW of electric capacity and associated energy in Daylight Hours of May through October of each year from 2008 through 2014; and (ii) the Confirmation Agreement dated August 19, 2004, between AEPCO and Griffith Energy, LLC, as currently assigned pursuant to Assignment and Consent Agreement dated March 14, 2008, by which AEPCO purchases 25 MW of electric capacity and associated energy in WECC Peak Hours of May through October of each year from 2008 through 2014.

"S&G PPA Billing Energy" shall mean, for a billing period for a Billing Unit Entity with an ACP in S&G PPA, the energy from its Available S&G PPA Capacity assigned and allocated in each hour pursuant to the Billing Unit Program to its load and its S&G PPA Transfers, accumulated for a billing period.

"S&G PPA Capacity" shall mean capacity from S&G PPA.

"S&G PPA Demand Charge" shall mean, for a billing period for each Billing Unit Entity with an ACP in S&G PPA, the product of (i) the total cost incurred by AEPCO for capacity from S&G PPA during the billing period multiplied by (ii) the Billing Unit Entity's ACP in S&G PPA.

"S&G PPA Energy Charge" shall mean, for a billing period for each Billing Unit Entity with an ACP in S&G PPA, the product of (i) the total cost incurred by AEPCO for all energy from S&G PPA during the billing period multiplied by (ii) the Billing Unit Entity's ACP in S&G PPA.

"S&G PPA Schedule" shall mean, for a Member* with an ACP in S&G PPA, its Pre-Schedules and Real-Time Schedules provided to AEPCO by its Scheduling Agent pertaining to its use of its Available S&G PPA Capacity.

"S&G PPA Wheeling Cost" shall mean, for a billing period for each Billing Unit Entity with an ACP in S&G PPA, the product of (i) the cost incurred by AEPCO for wheeling energy from S&G PPA during the billing period multiplied by (ii) the Billing Unit Entity's ACP in S&G PPA.

"Schedule" shall mean, for each Member*, any of its Base Schedule, its Other Schedule, and, if applicable, its S&G PPA Schedule.

"Scheduling Agent" shall mean the entity designated by a Member* to provide Pre-Schedules and Real-Time Schedules to AEPCO for such Member*'s hourly use of its AC in AEPCO Resources.

"Supplemental Billing Energy" shall mean, for a billing period for a Billing Unit Entity with an interest in Supplemental Purchase, the energy from its Available Supplemental Capacity assigned and allocated in each hour pursuant to the Billing Unit Program to its load and its Supplemental Transfers, accumulated for a billing period.

"Supplemental Capacity" shall mean capacity from Supplemental Purchase.

"Supplemental Demand Charge" shall mean, for a billing period for each Billing Unit Entity with an interest in Supplemental Purchase, the product of (i) the total cost incurred by AEPCO for capacity from Supplemental Purchase during the billing period multiplied by (ii) the Billing Unit Entity's ACP in Supplemental Purchase.

"Supplemental Energy Charge" shall mean, for a billing period for each Billing Unit Entity with an interest in Supplemental Purchase, the product of (i) the total cost incurred by AEPCO for all energy from Supplemental Purchase during the billing period multiplied by (ii) the Billing Unit Entity's ACP in the Supplemental Purchase.

"Supplemental Purchase" shall mean, in a billing period, any purchase of firm energy made for a period of less than a year to serve load of CARM or a Planning Contract Member in excess of CARM's or the Planning Contract Member's ACP shares of capacity of S&G PPA and Existing Resources.

"Supplemental Purchase Cost" shall mean, for a billing period, the total cost incurred by AEPCO (including transmission expenses, including losses, incurred in delivery from the source of such purchase to an SWTC Point of Receipt, if any) for all Supplemental Purchases during the billing period.

"Supplemental Wheeling Cost" shall mean, for a billing period for each Billing Unit Entity with an interest in Supplemental Purchase, the product of (i) the cost incurred by AEPCO for wheeling energy from Supplemental Purchase during the billing period multiplied by (ii) the Billing Unit Entity's ACP in Supplemental Purchase.

"Tariff" shall mean, at any time, the currently effective form setting forth the various AEPCO rates and charges applicable to each Billing Unit Entity as approved by the ACC.

"Third Party Economy Sales" shall mean, for each of Daytime Hours and Nighttime Hours, any transactions in which AEPCO sells at wholesale energy from available AEPCO Resources to a third party, which transaction is not a Power Sales Resource, and which is recorded and reported as an economy sale by AEPCO to RUS Uniform System of Accounts Number 447.

"Total Other Billing Energy" shall mean, for a billing period for each Billing Unit Entity, the sum of S&G And Supplemental Transfer Billing Energy, S&G PPA Billing Energy, Supplemental Billing Energy, Other Billing Energy and Base Transfer Billing Energy for such Billing Unit Entity for such billing period.

"Total Other Energy Cost" shall mean, for a billing period for each Billing Unit Entity, the sum of Other Energy Cost, S&G PPA Energy Charge, Supplemental Purchase Cost, S&G And Supplemental Transfer Purchase Cost, S&G And Supplemental Sales Credit, Directed Sales Credit, Base Transfer Purchase Cost, and Other Economy Sales Credit.

"Total Schedule" shall mean, for each Member*, its Base Schedule, plus its Other Schedule, plus, if applicable, its S&G PPA Schedule.

3. BILLING UNIT PROGRAM METHODOLOGY:

The Billing Unit Program shall be assembled and maintained to reflect AEPCO's economic dispatch philosophy and priority as further set forth in Schedule B to the Partial Requirements Capacity and Energy Agreements. The Parties have divided and defined AEPCO Resources based on the respective interests therein as assigned under the Billing Unit Program, the definition of which is set forth in Appendix A to this Exhibit A-4, attached hereto and a part hereof.

The Billing Unit Program is established hereunder to account for hourly energy, separately for Daytime and Nighttime hours, first, for each Billing Unit Entity, its Minimum Other Capacity, then for each Billing Unit Entity having an ACP in S&G PPA or an interest in Supplemental Purchase, from its interests in Available Supplemental Capacity and Available S&G PPA Capacity (as dispatched by AEPCO under governing purchase contracts), then for each Billing Unit Entity its Available Base Capacity and finally its remaining Available Other Capacity. These hourly amounts for each Billing Unit Entity are assigned first to any Directed Sales of a Member* CA, to the loads of the CARM and Member* CA and to each Member*'s Total Schedule, but only to the extent required by the load of the CARM, by the Directed Sales and load of the Member* CA and by the Member*'s Total Schedule.

If a Billing Unit Entity has load or a Schedule that is not satisfied by its Available Base Capacity, Available Supplemental Capacity and Available S&G PPA Capacity, the Billing Unit Entity shall be assigned S&G And Supplemental Transfers and Base

Transfers from other Billing Unit Entities' Excess S&G And Supplemental Capacity and Excess Base Capacity pursuant to the Billing Unit Program, proportionately based on the need of each Billing Unit Entity for Other Resources to the need of all Billing Unit Entities for Other Resources. To the extent a Billing Unit Entity still has load or a Schedule that is not satisfied, energy shall be assigned to it from its Available Other Capacity.

On the other hand, if a Billing Unit Entity has any Excess S&G And Supplemental Capacity or Excess Base Capacity, it shall be assigned pursuant to the Billing Unit Program proportionately based on available excess as S&G And Supplemental Transfers and Base Transfers. Then any Post-Transfer Base Capacity shall be assigned pursuant to the Billing Unit Program proportionately based on the amounts of such excess in the hour as Base Economy Sales, if any, or shall be assigned as Base Energy Mismatch or Other Energy Mismatch, as applicable.

Finally pursuant to the Billing Unit Program, the Other Economy Sales accumulated for the billing period will be allocated to each Billing Unit Entity proportionately based on each Billing Unit Entity's proportionate share of the billing period's accumulated totals of Post-Transfer S&G And Supplemental Capacity, each Member*'s Other Billing Energy, CARM Other Billing Energy, and each Member* CA's Other Billing Energy.

The Parties agree that all such assignments and allocations represent sale and purchase transactions to and from the Dispatch Pool Resources for which each Billing Unit Entity shall be credited or billed pursuant to Section 4 below.

Base Energy Mismatch and Other Energy Mismatch may occur due to operating conditions experienced during any billing period when the assignment and allocation of energy pursuant to the Billing Unit Program may be more or less than the amount of energy actually produced by the Dispatch Pool Resources; the causes of which may include, but are not limited to: (i) energy received from resources of third parties or provided to third parties for losses repayment; (ii) variations between loss accounting and actual hourly losses occurring on the system; (iii) energy interchange with other utilities; (iv) metering errors; and (v) inadvertent flows between AEPCO and its Balancing Authority. The Billing Unit Program shall compute for each billing period the total net Base Energy Mismatch and total Other Energy Mismatch and assign a credit or charge for the period, as applicable, which shall be recovered through the appropriate FPPCA.

The initial logic flow diagram of the Billing Unit Program is attached hereto as Appendices B through D to this Exhibit A-4 and is a part hereof. The Billing Unit Program shall be the sole and exclusive method for billing purposes of assigning energy billing units from Dispatch Pool Resources to Billing Unit Entities, and may only be modified by a written amendment agreed to by the CEOs of all Billing Unit Entities.

4. METHODOLOGY FOR DETERMINING TARIFF ENERGY RATES:

The following describes the method AEPCO shall use to formulate the Base Energy Rate and the Other Energy Rate.

4.1 Tariff Base Energy Rate.

The Base Energy Rate of the Tariff shall be the quotient obtained by dividing (i) the Base Energy Cost of the test period, as adjusted for changes expected in the foreseeable period beyond the test period, inclusive of each Billing Unit Entity's Base Transfer Sales Credits, Base Transfer Energy Cost, Base Economy Sales Credits, Base Economy Sales Cost and Remaining Base Energy Cost, by (ii) each Billing Unit Entity's Base Billing Energy of the test period, as adjusted for changes expected in the foreseeable period beyond the test period, as determined pursuant to the Billing Unit Program.

4.1.1 The Base Energy Rate of each All Requirements Member shall be the same as the Base Energy Rate for CARM.

4.1.2 The Base Power Cost Adjustor Base for each All Requirements Member shall be the same as the Base Power Cost Adjustor Base determined for CARM.

4.1.3 The Base Billing Energy of each All Requirements Member shall be the product of (i) the Base Billing Energy of CARM, multiplied by (ii) that All Requirements Member's ARM ECR.

4.2 Tariff Other Energy Rate.

The Other Energy Rate of the Tariff shall be the quotient obtained by dividing (i) the Total Other Energy Cost of each Billing Unit Entity of the test period, as adjusted for changes expected in the foreseeable period beyond the test period, inclusive of each Billing Unit Entity's applicable Base Transfer Purchase Cost, S&G PPA Energy Cost, Supplemental Purchase Cost, S&G And Supplemental Transfer Purchase Cost, S&G And Supplemental Transfer Sales Credit, Other Economy Sales Credit and its share of Base Mismatch Energy Credit, Base Mismatch Energy Charge, Other Mismatch Energy Credit, Other Mismatch Energy Charge and, if any, by (ii) the Total Other Billing Energy as applicable to each Billing Unit Entity for the test period, as adjusted for changes expected in the foreseeable period beyond the test period, as determined pursuant to the Billing Unit Program.

4.2.1 The Other Energy Rate of each All Requirements Member shall be the same as the Other Energy Rate for CARM.

4.2.2 The Other Power Cost Adjustor Base for each All Requirements Member shall be the same as the Other Power Cost Adjustor Base determined for CARM.

4.2.3 The Total Other Billing Energy of each All Requirements Member shall be the product of (i) the Total Other Billing Energy of CARM, multiplied by (ii) that All Requirements Member's ARM ECR.

5. DETERMINING BASE AND OTHER ENERGY CHARGES:

5.1 Each billing period, AEPCO shall charge each Billing Unit Entity a Base Energy Charge, Base Fuel Adjustor Charge, Total Other Energy Charge and Other Fuel Adjustor Charge as defined in the Tariff. For each billing period, AEPCO shall compute each Billing Unit Entity's Base Over or Under Collection and Other Over or Under Collection for each billing period, which AEPCO shall accumulate and use to establish future Base Fuel Adjustor Rates and Other Fuel Adjustor Rates.

5.1.1 Base Energy Charge: The Base Energy Charge for each Billing Unit Entity for a billing period shall equal the product of the Base Billing Energy of the Billing Unit Entity, multiplied by the Base Energy Rate as set forth in the Tariff.

5.1.2 Base Fuel Adjustor Charge: The Base Fuel Adjustor Charge for each Billing Unit Entity for a billing period shall equal the product of the Base Billing Energy of the Billing Unit Entity, multiplied by the Base Fuel Power Cost Adjustor Rate as set forth in the Tariff.

5.1.3 Base Over or Under Collection: The Base Over and Under Collection for each Billing Unit Entity for a billing period shall be determined pursuant to the methodology approved by the ACC related to the product of (a) any difference between (i) the Base Adjustor Per Unit Cost and (ii) the sum of the Base Power Cost Adjustor Base plus the Base Power Cost Adjustor Rate in the Tariff, multiplied by (b) the Base Billing Energy of each Billing Unit Entity for that period.

5.1.4 Other Energy Charge: The Other Energy Charge for each Billing Unit Entity for a billing period shall equal the product of the Total Other Billing Energy of the Billing Unit Entity, multiplied by the Other Energy Rate as set forth in the Tariff.

5.1.5 Other Fuel Adjustor Charge: The Other Fuel Adjustor Charge for each Billing Unit Entity for a billing period shall equal the product of the Total Other Billing Energy of the Billing Unit Entity, multiplied by the Other Fuel Power Cost Adjustor Rate as set forth in the Tariff.

5.1.6 Other Over or Under Collection: The Other Over and Under Collection for each Billing Unit Entity for a billing period shall be determined pursuant to the methodology approved by the ACC related to the product of (a) any difference between (i) the Other Adjustor Per Unit Cost and (ii) the sum of the Other Power Cost Adjustor Base plus the Other Power Cost Adjustor Rate in the Tariff, multiplied by (b) the Total Other Billing Energy of each Billing Unit Entity for that period.

6. ENERGY COST ACCOUNTING PROCESS:

The following describes the method of the Energy Cost Accounting Process (ECAP) AEPCO shall use to formulate for each billing period each Billing Unit Entity's Base Energy Cost, Base Fuel Adjustor Cost, Total Other Energy Cost and Other Fuel Adjustor Cost, from which AEPCO shall compute each Billing Unit Entity's Base Adjustor Per Unit Cost and Other Adjustor Per Unit Cost for the billing period, which shall be used to calculate for each billing period (i) Base Over and Under Collection and Other Over or Under Collection for such energy and (ii) fuel adjustor costs, which AEPCO shall accumulate and use to establish future Base Fuel Adjustor Rates and Other Fuel Adjustor Rates.

The initial logic flow diagram of the ECAP is attached hereto as Appendices E and F to this Exhibit A-4 and is a part hereof.

6.1 Formulating Base Energy Cost.

For each billing period, the ECAP shall first compute the Coal Energy Cost and use it to calculate the Coal Energy Rate based on the Coal Energy Generated.

The ECAP shall then use Base Transfer for the billing period to compute, separately for Daytime and Nighttime, Base Transfer Sales Credit based on the Coal Energy Rate, and use Base Transfer Billing Energy to compute, separately for Daytime and Nighttime, Base Transfer Energy Cost, based on the Economy Purchase Rate. Using the billing units determined for the billing period pursuant to the Billing Unit Program, the Base Transfer Sales Credits and Base Transfer Energy Cost will then be allocated to each Billing Unit Entity. Similarly, the ECAP shall use Base Economy Sales for the billing period to compute Base Economy Sales Credits (separately for Daytime and Nighttime) and Base Economy Sales Cost, based on Economy Sales Price (separately for Daytime and Nighttime) and the Coal Energy rate, respectively, and shall then allocate such Base Economy Sales Credits and Base Economy Sales Cost to each Billing Unit Entity pursuant to the billing units assigned by the Billing Unit Program.

The ECAP shall then calculate Base Billing Energy Cost for the billing period, by adding Remaining Coal Energy Cost, Hydro Energy Charge, Base Economy Purchases and Power Sales Resource Energy Revenue, and shall allocate such Base Billing Energy Cost to each Billing Unit Entity pursuant to the billing units assigned by the Billing Unit Program.

Finally, the ECAP shall calculate for the billing period each Billing Unit Entity's (i) Base Energy Cost, which shall be the total of the Billing Unit Entity's Base Transfer Sales Credit, Base Transfer Energy Cost, Base Economy Sales Credit, Base Economy Sales Cost and Remaining Base Energy Cost, and (ii) Base Average Energy Rate, which shall be the quotient of the Billing Unit Entity's Base Energy Cost divided by its Base Billing Energy determined pursuant to the billing units assigned by the Billing Unit Program.

6.2 Formulating Base Adjustor Per Unit Cost.

The ECAP shall allocate to each Billing Unit Entity based on the Billing Unit Entity's Allocated Capacity Percentage the billing period's total Hydro Demand Charge, Base Transmission Wheeling Cost and Power Sales Resource Demand Cost, which allocation ECAP shall add to the Billing Unit Entity's Base Energy Cost to formulate the Billing Unit Entity's Base Fuel Adjustor Cost.

The ECAP shall then determine each Billing Unit Entity's Base Adjustor Per Unit Cost for the billing period, which shall be the quotient of the Billing Unit Entity's Base Fuel Adjustor Cost divided by its Base Billing Energy pursuant to the billing units assigned by the Billing Unit Program.

6.3 Formulating Base Over or Under Collection.

The ECAP shall then determine for the billing period each Billing Unit Entity's (a) Base Incremental Unit Cost, which shall be equal to the Billing Unit Entity's Base Adjustor Per Unit Cost less the sum of (i) its Base Power Cost Adjustor Base and (ii) its Base Power Cost Adjustor Rate, and (b) Base Over or Under Collection, which shall be the product of the Billing Unit Entity's Base Incremental Unit Cost multiplied by its Base Billing Energy. Each Billing Unit Entity's Base Over or Under Collection shall then be added to the balance in its Base Fuel Bank.

6.4 Formulating Total Other Energy Cost.

Each billing period, the ECAP shall use the Economy Purchase Rate (separately for Daytime and Nighttime) to determine S&G And Supplemental Purchase Cost and S&G And Supplemental Sales Credit based on S&G And Supplemental Transfer. Such S&G And Supplemental Purchase Cost and S&G And Supplemental Sales Credit shall then be allocated as appropriate to each Billing Unit Entity pursuant to the billing units assigned by the Billing Unit Program.

The ECAP shall allocate to each Billing Unit Entity pursuant to the billing units assigned by the Billing Unit Program (i) the billing period's Other Economy Sales Credit as appropriate based on the Billing Unit Entity's proportionate share of the billing period's Post-Transfer S&G And Supplemental Capacity and Other Billing Energy, and (ii) the billing period's Other Energy Cost based on the Billing Unit

Entity's Other Billing Energy. The ECAP shall then assign to each Billing Unit Entity pursuant to the Billing Unit Entity's ACP and/or interest in and the billing units assigned by the Billing Unit Program, as applicable, the Billing Unit Entity's S&G PPA Energy Charge, Supplemental Energy Charge, Base Transfer Purchase Cost, Other Energy Cost, Directed Sales Credit, and its share of Base Mismatch Energy Credit, Base Mismatch Energy Cost, and Other Mismatch Energy Credit.

Finally, the ECAP shall determine for the billing period (i) each Billing Unit Entity's Total Other Energy Cost, which shall be equal to the sum of all the credits and costs allocated or assigned to the Billing Unit Entity as described in this Section 6.4, and (ii) each Billing Entity's Other Average Energy Rate, which shall be the quotient of its Total Other Energy Cost divided by its Total Other Billing Energy.

6.5 Formulating Other Adjustor Per Unit Cost.

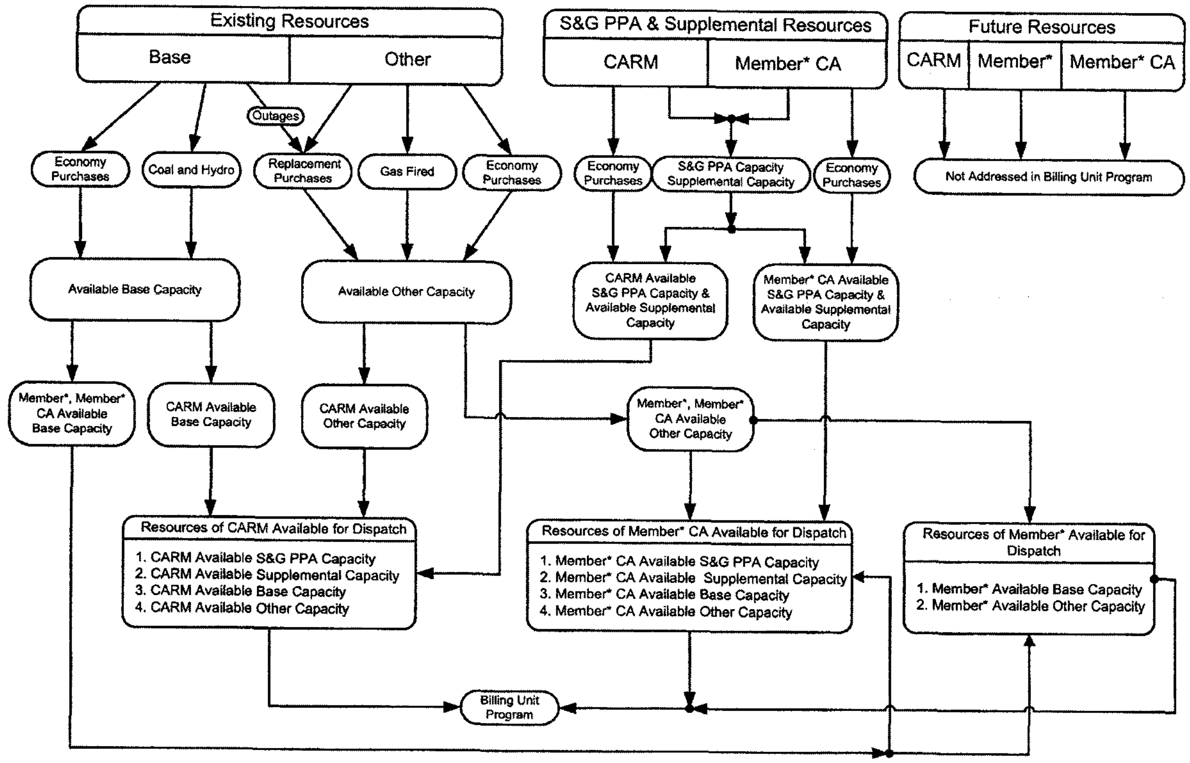
The ECAP shall allocate to each Billing Unit Entity the billing period's (i) total Other Transmission Wheeling Cost based on the Billing Unit Entity's Allocated Capacity Percentage, and (ii) S&G PPA Demand Charge, S&G PPA Wheeling Cost, Supplemental Demand Charge and Supplemental Wheeling Charge, pursuant to the Billing Unit Entity's ACP share or interest therein, if any. The ECAP shall then add such allocations to each Billing Unit Entity's Total Other Energy Cost to formulate the Billing Unit Entity's Other Fuel Adjustor Cost.

The ECAP shall then determine each Billing Unit Entity's Other Adjustor Per Unit Cost for the billing period, which shall be the quotient of the Billing Unit Entity's Other Fuel Adjustor Cost divided by its Total Other Billing Energy pursuant to the billing units assigned by the Billing Unit Program.

6.6 Formulating Other Over or Under Collection.

The ECAP shall then determine for the billing period each Billing Unit Entity's (a) Other Incremental Unit Cost, which shall be equal to the Billing Unit Entity's Other Adjustor Per Unit Cost less the sum of (i) its Other Power Cost Adjustor Base, plus (ii) its Other Power Cost Adjustor Rate, and (b) Other Over or Under Collection, which shall be the product of the Billing Unit Entity's Other Incremental Unit Cost multiplied by its Other Billing Energy. Each Billing Unit Entity's Other Over or Under Collection shall then be added to the balance in its Other Fuel Bank.

Appendix A to Exhibit A-4 to Rate Schedule A: AEPCO Resources Definitions Flow Diagram



Appendix B Footnotes:

(1) Subroutine: CARM Post S&G And Supplemental Load is first assigned to CARM Minimum Other Capacity.
(1a) Subroutine: CARM Load is first assigned to CARM Minimum Other Capacity.
(2) Subroutine: Determines the extent to which other Billing Unit Entities need Excess Base Capacity of other Billing Unit Entities for their Post S&G and Supplemental Transfer Other Schedule or Post S&G And Supplemental Transfer Load.
(3) Subroutine: CARM Excess S&G And Supplemental Capacity is allocated as CARM S&G And Supplemental Transfers proportionately based on need to Member* Other Schedule and Member* CA Post Base Load, until such CARM Excess S&G And Supplemental Capacity is consumed, or until Member* Other Schedule and Member* CA Post Base Load are satisfied.
(4) Subroutine: Member*, Member* CA Excess Base Capacity is allocated proportionately based on need to CARM and Member* CA Post-S&G And Supplemental TransferLoad and Member* Post-S&G And Supplmental Transfer Other Schedule until such Member*, Member* CA Excess Base Capacity is consumed, or until such CARM and Member* CA Post S&G and Supplemental Transfer Load and Member* Post-S&G And Supplemental Transfer Other Schedule are satisfied.
(5) Subroutine: *CARM Excess Base Capacity is allocated proportionately based on need to Member* Post S&G And Supplemental Transfer Other Schedule and Member* CA Post S&G* And Supplemental Transfer Load until such CARM Excess Base Capacity is consumed, or until Member* Post S&G And Supplemental Transfer Other Schedule and Member* CA Post S&G And Supplemental TransferLoad are satisfied.
(6) Subroutine: CARM Post Transfer Base Capacity, Member* CA Post Transfer Base Capacity, and Member* Post Transfer Base Capacity are assigned hourly to Base Economy Sales.
(7) Subroutine: CARM Post Transfer S&G And Supplemental Capacity, Member* CA Post Transfer S&G And Supplemental Capacity, CARM Other Billing Energy, Member* CA Other Billing Energy, and Member* Other Billing Energy are used to apportion and allocate monthly Other Economy Sales.

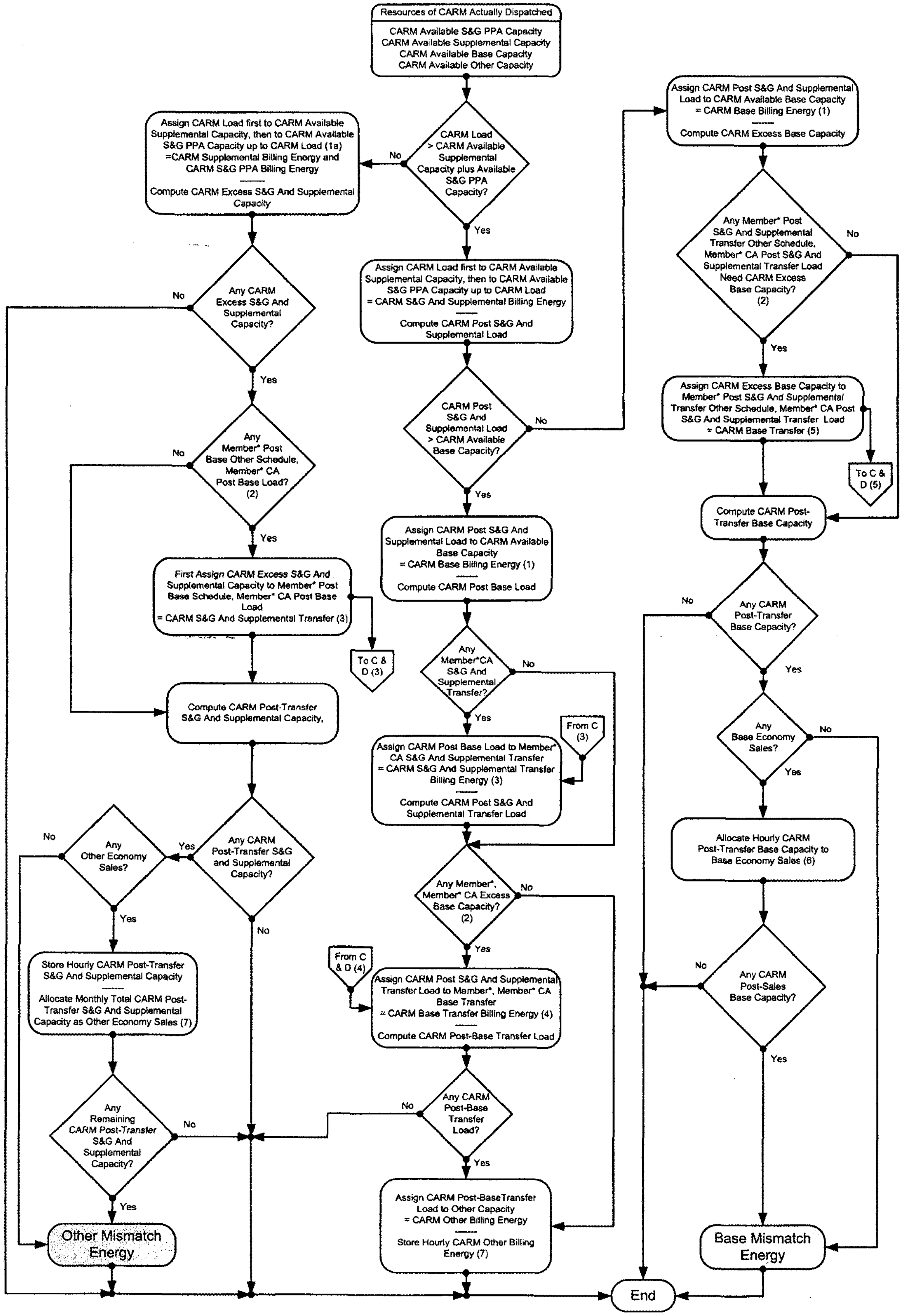
Appendix C Footnotes:

(1) Subroutine: Member* CA Post S&G And Supplemental Load is first assigned to Member* CA Minimum Other Capacity.
(1a) Subroutine: Member* CA Directed Sales and Load is first assigned to Member* CA Minimum Other Capacity.
(2) Subroutine: Determines the extent to which other Billing Unit Entities need Excess Base Capacity of other Billing Unit Entities for their Post S&G And Supplemental Transfers Other Schedule or Post S&G And Supplemental TransferLoad which can be assigned to this Billing Unit Entity's Excess Base Capacity.
(3) Subroutine: Member* CA Excess S&G And Supplemental Capacity is allocated as Member* CA S&G And Supplemental Transfers proportionately based on need to Member* Post *Base Other Schedule*, CARM Post Base Load, and other Member* CA Post Base Load, until such Member* CA Excess S&G And Supplemental Capacity is consumed, or until Member* Other Schedule, other Member* CA Post Base Load and CARM Post Base Load are satisfied.
(4) Subroutine: Member*, CARM, and other Member* CA Excess Base Capacity are allocated proportionately based on need to CARM and other Member* CA Post-S&G And Supplemental Transfer Load and Member* Post-S&G And Supplemental Transfer Other Schedule until such Member*, CARM and other Member* CA Excess Base Capacity are consumed, or until such CARM and other Member*CA Post-S&G And Supplemental Transfer Load and Member* Post-S&G And Supplemental Other Schedule are satisfied.
(5) Subroutine: Member* CA Excess Base Capacity is allocated proportionately based on need to Member* Post-S&G And Supplemental Transfer Other Schedule, other Member * CA Post-S&G And Supplemental TransferLoad, and CARM Post-S&G And Supplemental Transfer Load until such Member* CA Excess Base Capacity is consumed, or until Member* Post-S&G And Supplemental Transfer Other Schedule, other Member* CA Post-S&G And Supplemental Transfer Load and CARM Post-S&G And Supplemental Transfer Load are satisfied.
(6) Subroutine: CARM Post Transfer Base Capacity, Member* CA Post Transfer Base Capacity, and Member* Post Transfer Base Capacity are assigned hourly to Base Economy Sales.
(7) Subroutine: CARM Post Transfer S&G And Supplemental Capacity, Member* CA Post Transfer S&G And Supplemental Capacity, CARM Other Billing Energy, Member* CA Other Billing Energy, and Member* Other Billing Energy are used to apportion and allocate monthly Other Economy Sales.

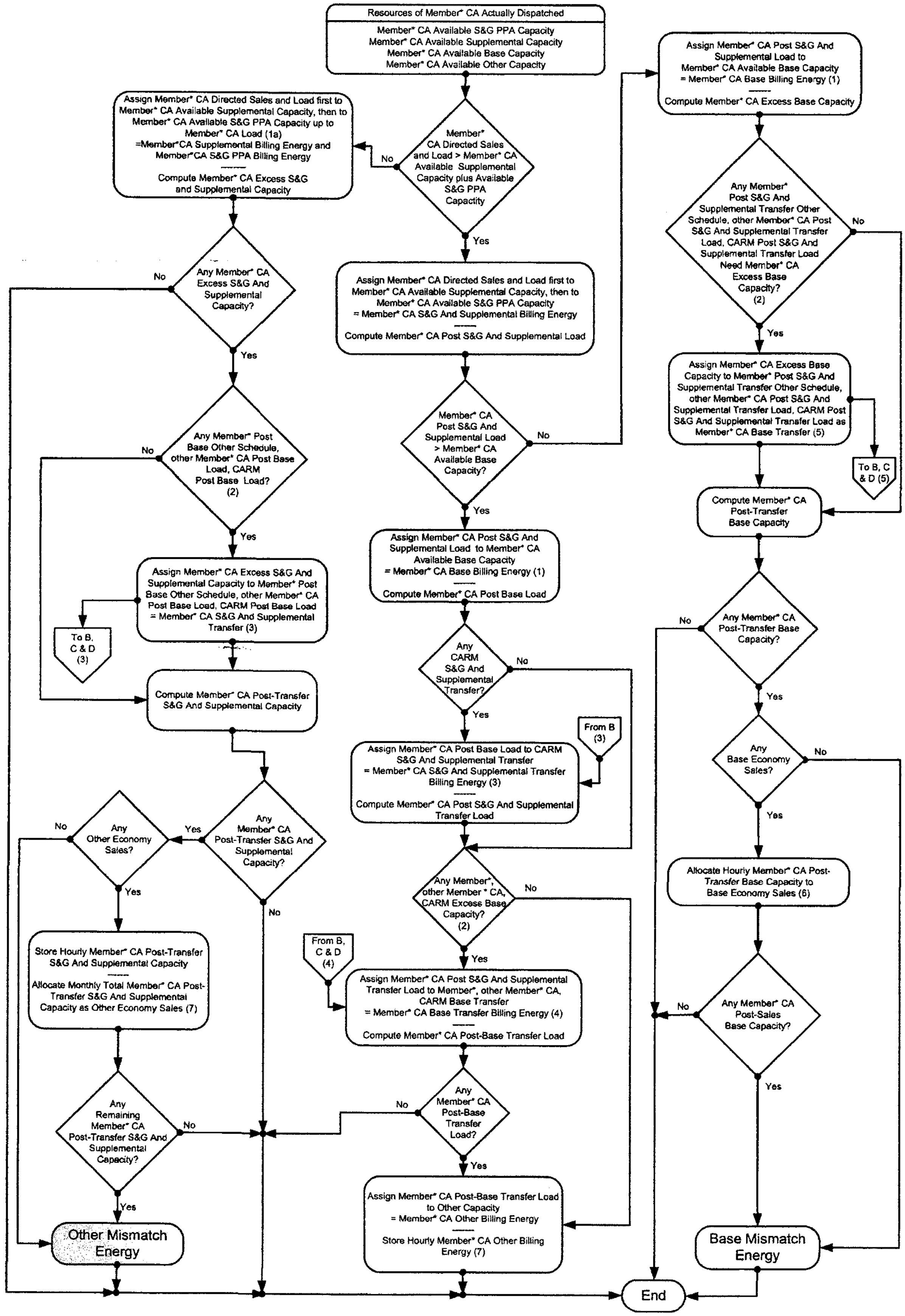
Appendix D Footnotes:

(1) Subroutine: Member* Base Schedule is first assigned to Member* Minimum Other Capacity.
(2) Subroutine: (2) Subroutine: Determines the extent to which other Billing Unit Entities need Excess Base Capacity of other Billing Unit Entities for their Post S&G And Supplemental Transfers Other Schedule or Post S&G And Supplemental TransferLoad which can be assigned to this Billing Unit Entity's Excess Base Capacity.
(3) Subroutine: Member* CA and CARM Excess S&G And Supplemental Capacity are allocated as Member* CA S&G And Supplemental Transfers proportionately based on need to Member* Post Base Other Schedule, CARM Post Base Load, and other Member* CA Post Base Load, until such Member* CA Excess S&G And Supplemental Capacity is consumed, or until Member* Post Base Other Schedule, other Member* CA Post Base Load and CARM Post Base Load are satisfied.
(4) Subroutine: Member*, CARM, and other Member* CA Excess Base Capacity are allocated proportionately based on need to CARM and other Member* CA Post-S&G And Supplemental Transfer Load and Member* Post-S&G And Supplemental Transfer Other Schedule until such Member*, CARM and other Member* CA Excess Base Capacity are consumed, or until such CARM and other Member*CA Post-S&G And Supplemental Transfer Load and Member* Post-S&G And Supplemental Other Schedule are satisfied.
(5) Subroutine: Member* Excess Base Capacity is allocated proportionately based on need to each Member* Post-S&G And Supplemental Transfer Other Schedule, other Member * CA Post-S&G And Supplemental TransferLoad, and CARM Post-S&G And Supplemental Transfer Load until such Member* CA Excess Base Capacity is consumed, or until Member* Post-S&G And Supplemental Transfer Other Schedule, other Member* CA Post-S&G And Supplemental Transfer Load and CARM Post-S&G And Supplemental Transfer Load are satisfied.
(6) Subroutine: CARM Post Transfer Base Capacity, Member* CA Post Transfer Base Capacity, and Member* Post Transfer Base Capacity are assigned hourly to Base Economy Sales.
(7) Subroutine: CARM Post Transfer S&G And Supplemental Capacity, Member* CA Post Transfer S&G And Supplemental Capacity, CARM Other Billing Energy, Member* CA Other Billing Energy, and Member* Other Billing Energy are used to apportion and allocate monthly Other Economy Sales.
(8) No Partial Requirements Member with an interest in S&G PPA currently plans to operate outside the AEPCO pseudo-control area. In the event that a Partial Requirements Member with such an interest chooses to operate outside the AEPCO pseudo-control area in the future, the Appendix D flow chart for such a Member* will need to be modified.

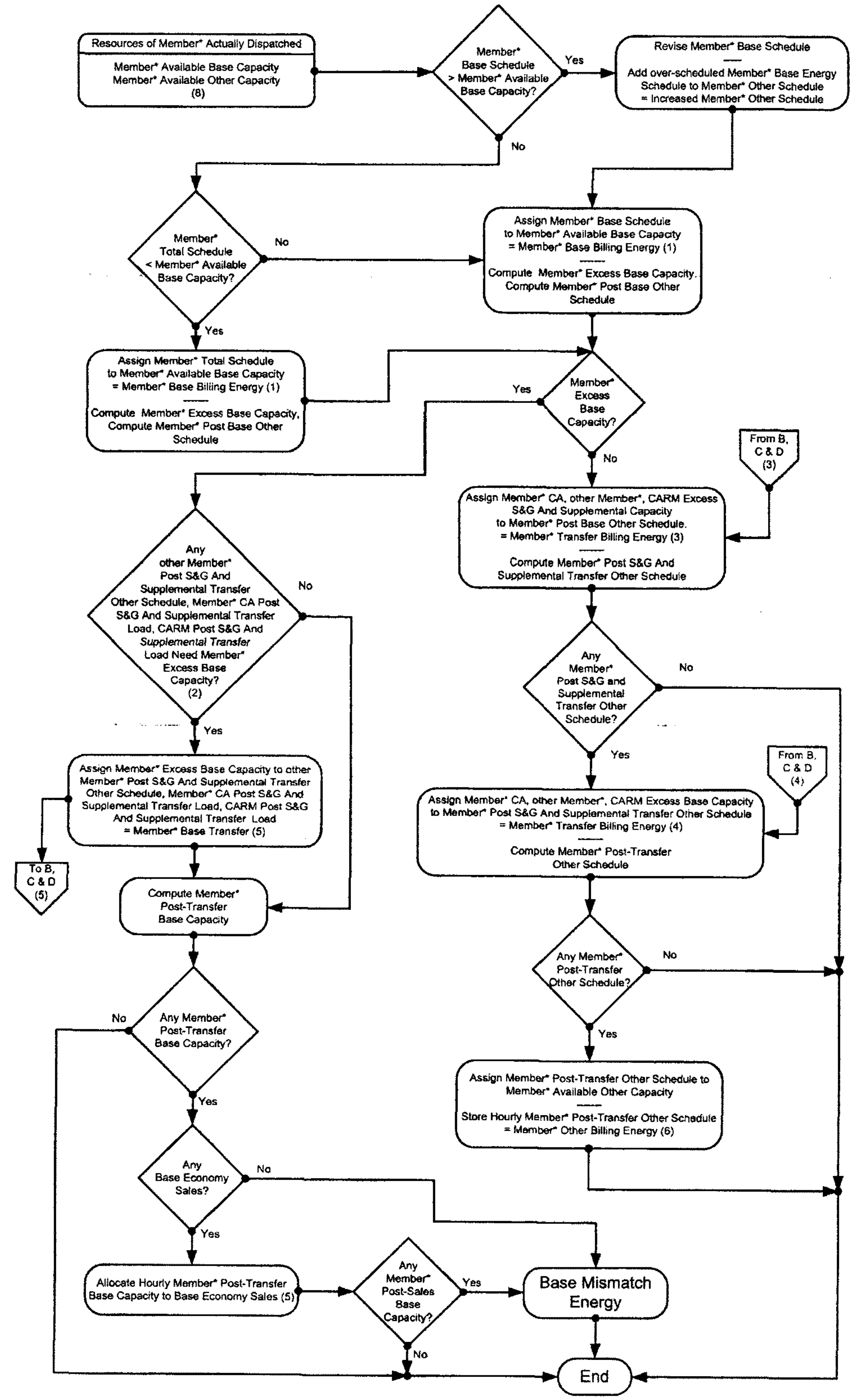
Appendix B to Exhibit A-4 to Rate Schedule A: Billing Unit Program Flow Diagram
CARM Load Use of AEPCO Resources and Assignments as Additional and Base Transfers and AEPCO Third Party Sales



Appendix C to Exhibit A-4 to Rate Schedule A: Billing Unit Program Flow Diagram
Member* CA Load use of AEPCO Resources and Assignments as S&G PPA and Base Transfers and AEPCO Third Party Sales

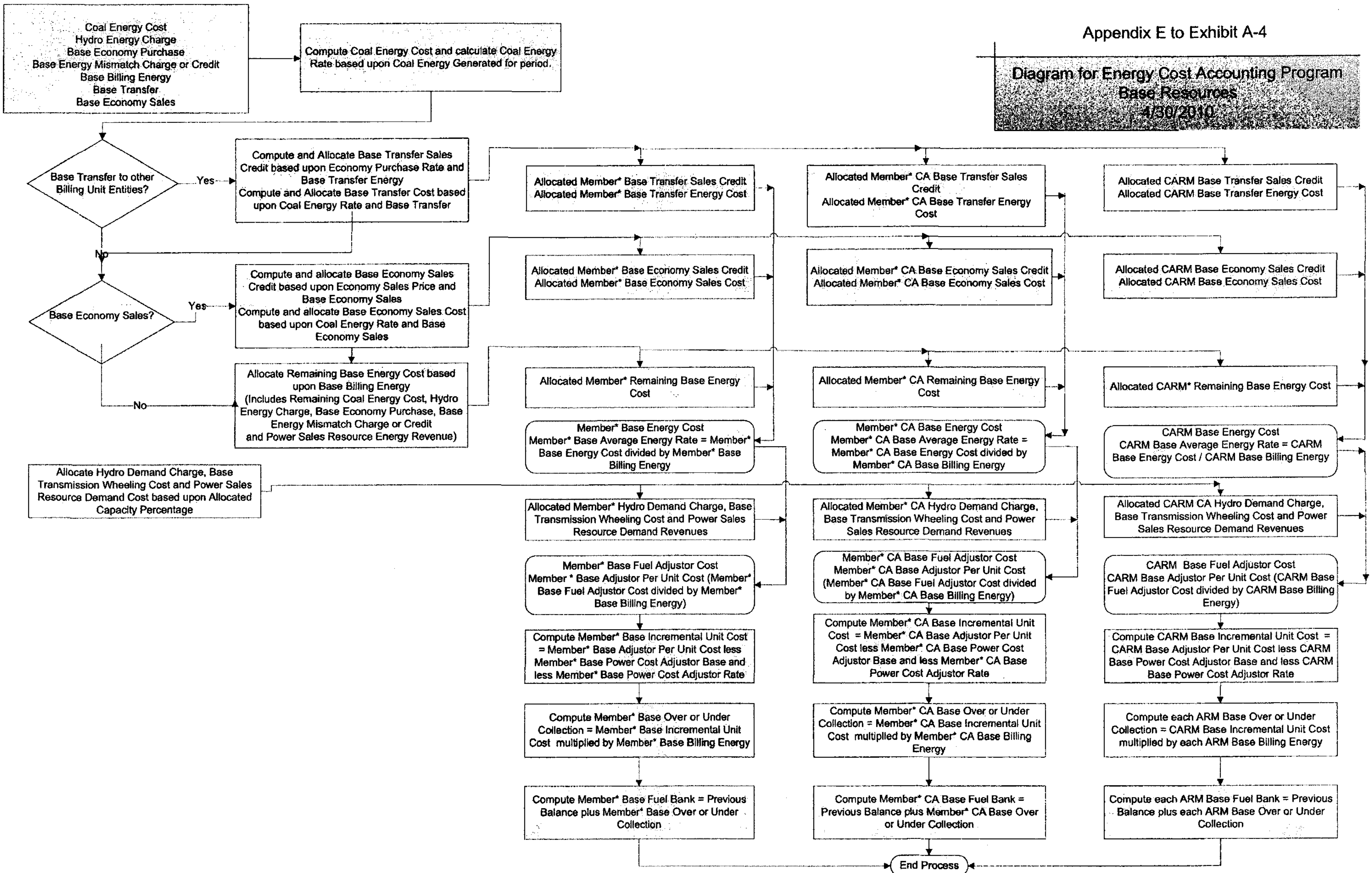


Appendix D to Exhibit A-4 to Rate Schedule A: Billing Unit Program Flow Diagram
Member* Use of AEPCO Resources and Assignments as Base Transfers and AEPCO Third Party Sales



Appendix E to Exhibit A-4

Diagram for Energy Cost Accounting Program
Base Resources
4/30/2010



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Appendix F to Exhibit A-4

Diagram for Energy Cost Accounting Program Other Resources 4/30/2010

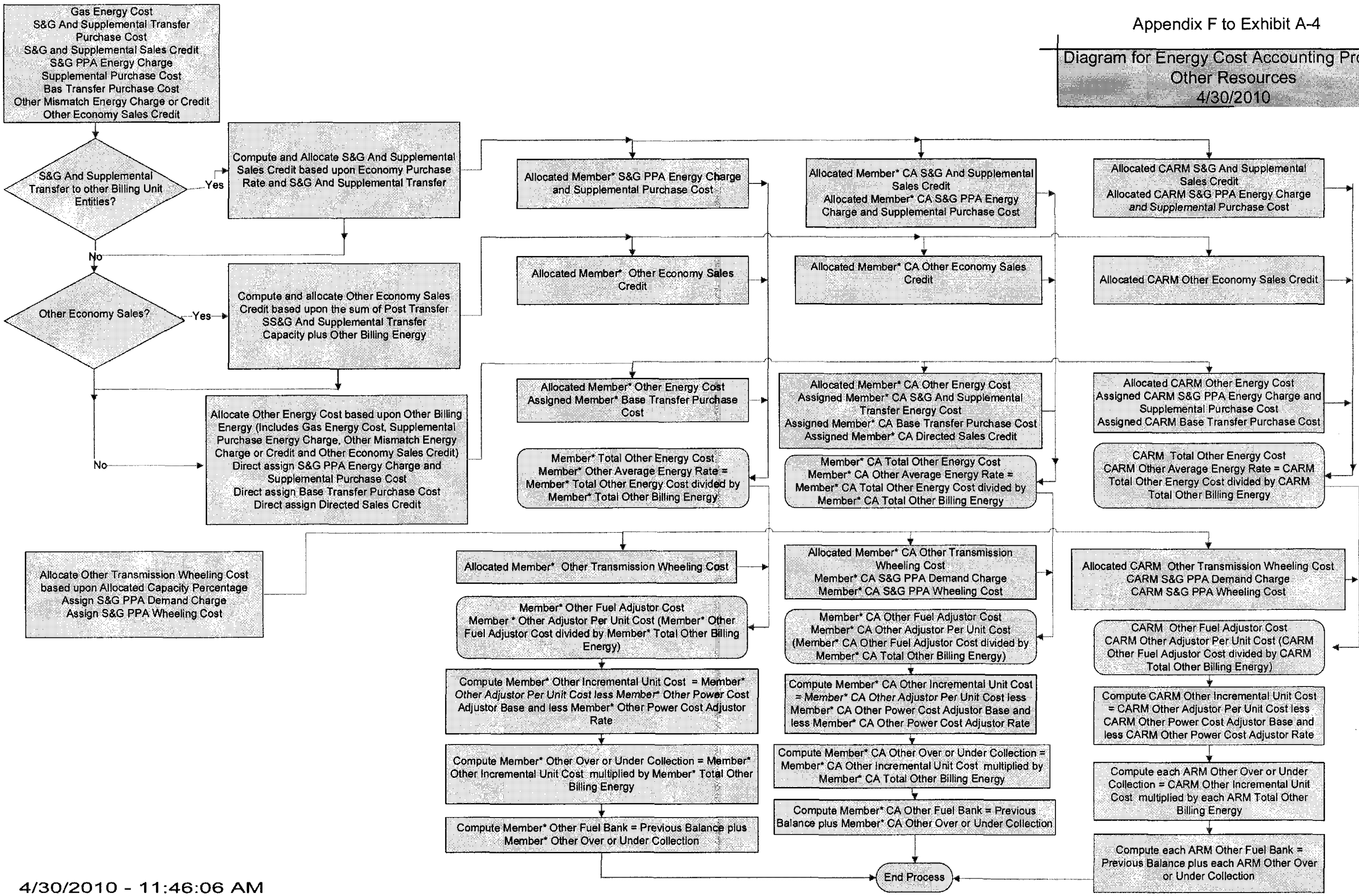

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Exhibit A-5 to Rate Schedule A
Allocated Capacity Percentages (ACP), Allocated Capacity (AC) and Reserves

ACP and AC DETERMINATION

An Allocated Capacity Percentage (ACP) was developed for Existing Resources as of the Effective Date for each Class A Member based on load forecasts from the 1996 Power Requirements Study (1996 PRS). The ACP in Existing Resources is used to calculate the Allocated Capacity (AC) for each Partial Requirements Member (PRM), and each All Requirements Member (ARM) in Existing Resources.

At the outset of AEPCO's restructuring, AEPCO, all AEPCO Class A Members, and RUS had approved the use of the 1996 PRS for planning purposes. AEPCO and its Class A Members agreed to the specific use of the 1996 PRS and forecast year 2000 as the basis for calculating the ACP in Existing Resources because: (i) the annual coincident peak of AEPCO best matched the Existing Resources in forecast year 2000, and (ii) after forecast year 2000, AEPCO was projected to need additional Resources. The calculation used in determining the ACP in Existing Resources is summarized in Part A of Appendix A to this Exhibit A-5. The ACP calculation for Existing Resources utilized the forecasted year 2000 monthly coincident peaks of the Class A Members, which were obtained by multiplying: (a) each Member's forecasted monthly non-coincident peak as identified in the 1996 PRS, by (b) a historical three-year average coincident factor. The resulting twelve monthly coincident peaks were summed both for each Class A Member and for all Class A Members. The ACP for each Class A Member represents the percentage quotient of (a) the sum of the monthly coincident peaks for that Class A Member divided by (b) the sum of the monthly coincident peaks for all Class A Members. The ACP of an ARM in Existing Resources shall be used to determine its AC in Existing Resources in the event such ARM elects to become a Partial Requirements Member pursuant to the Conversion Agreement between the Class A Members and AEPCO dated August 1, 2001 (Conversion Agreement). The sum of the ACP's of the ARMs shall be the ACP of the Collective ARM (CARM) for purposes of Rate Schedule A to Existing Wholesale Power Contracts.

The monthly AC assigned to each PRM and the CARM from Existing Resources has been calculated by: (1) determining the capacity (in MW) of the generating units that comprise Existing Resources; (2) determining the Reserve percentage (described hereinafter) to be set aside from the generating units that comprise Existing Resources; (3) subtracting the Power Sales Resources as of the Closing Date of AEPCO's restructuring, including associated reserves and delivery losses attributable to such Power Sales: (4) further reducing the Existing Resource generating unit capacity for AEPCO generating unit reserves and delivery losses; (5) adding the monthly capacity from the Federal Hydro Power Agreements; and (6) multiplying such net capacity of Existing Resources by the ACP of each PRM and the CARM.

The AC in Existing Resources of each PRM and the CARM is further subdivided into Available Base Capacity and Available Other Capacity and shall be as shown on Appendix B to this Exhibit A-5. The Available Base Capacity of each PRM and the CARM shall be the respective

ACP shares of Base Resources after reduction for delivery losses. The Available Other Capacity shall be the respective ACP share of Other Resources after reduction for reserves and delivery losses.

For AEPCO Resources added and not included as Existing Resources (currently the S&G PPA Resource), each Class A Member participating in the added Resource accepts an ACP in that Resource pursuant to its agreement with AEPCO. That ACP shall be derived by a method determined by AEPCO based on adequacy of Resources to meet the forecasted loads of participating Class A Members under a method adopted by the AEPCO Board of Directors prior to AEPCO's commitment to the added Resource. Each participating Class A Member's AC in the Resource shall be the product of its ACP in the added Resource multiplied by the capacity of the Resource after reduction for delivery losses, and if required, reserves.

The ACP of the participating Class A Members as a PRM or as a part of CARM in an added Resource shall be set forth in a revision to Appendix A to this Exhibit A-5. The AC of such participating Class A Members as a PRM and as the CARM in an added Resource shall be set forth in a revision to Appendix B to this Exhibit A-5. Both the Appendices A and B as so revised shall be provided by AEPCO to all Class A Members at the time of the commitment by AEPCO to the added Resource. No such revision of Appendices A and B shall affect the ACP and AC of the non-participating Class A Members.

The ACP for the S&G PPA Resource for TRICO and the CARM shall be as set forth in the attached Appendix A to this Exhibit A-5, and the AC for the S&G PPA Resource for TRICO and the CARM shall be as set forth in the attached Appendix B to this Exhibit A-5. Neither the ACP nor the AC of the S&G PPA Resource shall be changed absent the agreement of TRICO and the participating ARMs that comprise the CARM.

RESERVE PERCENTAGE DETERMINATION:

In accordance with WECC reliability criteria, AEPCO is required to have in reserve access to generation sufficient to cover AEPCO's largest single generating unit hazard. AEPCO's largest single generating hazard consists of an outage of 188 MW of coal-fired steam generating unit capacity (which includes 13 MW of spinning reserve capacity), and after the first hour of such an outage includes an additional 29 MW, which 29 MW is subject to call from AEPCO by other members of the Southwest Reserve Sharing Group pursuant to the Southwest Reserve Sharing Group agreement, to which AEPCO is party. For the first hour of the outage, AEPCO currently relies on the generating support of other members of the Southwest Reserve Sharing Group to cover AEPCO's largest single generating unit outage.

Based on the above, AEPCO shall seek to reduce the MW of generation that would be required to be set aside for coverage of AEPCO's largest single generating unit by purchasing reserved transmission capacity from Southwest Transmission Cooperative, Inc., Mohave Electric Cooperative, Inc. and others as available, in that order of priority. AEPCO shall seek such transmission capacity in amounts necessary to realize AEPCO's reserve generating unit capacity percentage as 6.7% from 2011 through 2020, and 7.0% for the period from 2021 through 2035, which are the reserve capacity percentages as set forth in Appendix B to this Exhibit A-5. AEPCO and SWTC shall annually agree to a plan for AEPCO to follow to seek to obtain such transmission capacity, which shall be provided to the Class A Members for review. To the extent AEPCO obtains transmission capacity in accordance with the established plan, the Class A Members agree that AEPCO shall include the costs of such transmission capacity in AEPCO's rates to such Class A Members.

In the event AEPCO is unsuccessful or less than fully successful in its attempts to timely purchase such reserved transmission capacity in advance of the start of any calendar year, AEPCO shall have the unilateral right to increase the reserve capacity percentage of Appendix B to this Exhibit A-5 for such calendar year. In such event, AEPCO shall provide, timely in advance of the start of such calendar year, a revised Appendix B to this Exhibit A for such calendar year that shows the effect of such increased reserve capacity percentage on the Available Base Capacity and Available Other Capacity of each PRM and the CARM. AEPCO and the Class A Members shall use such revised Available Base Capacity and Available Other Capacity for the purposes of Exhibit A-4 in the affected calendar year.

Appendix A to Exhibit A-5

Schedule of Allocated Capacity Percentages

A. The schedule and calculation of the Allocated Capacity Percentages (ACP) for AEPCO Existing Resources existing as of August 1, 2001 (consisting of Existing Resources as set forth in Appendix B to Exhibit A-5) is shown below:

		Allocated Capacity Percentage						
		1996 PRS Coincident Peak Demand Forecast – MW						
Col.		1	2	3	4	5	6	7
Ln.	Year 2000	Anza	Duncan	Graham	Mohave	Sulphur	Trico	Total
1	January	6.0	3.2	15.9	70.5	80.8	57.1	233.5
2	February	5.6	2.9	15.1	62.7	76.9	48.7	211.9
3	March	5.8	2.9	15.7	60.4	70.9	44.2	199.9
4	April	4.8	2.8	15.8	64.4	66.8	44.0	198.7
5	May	5.2	3.1	19.5	80.2	77.3	44.4	229.7
6	June	6.6	3.8	25.0	105.4	87.3	49.3	277.4
7	July	6.7	4.3	26.3	127.0	92.6	67.4	324.4
8	August	8.0	4.4	25.0	130.5	88.7	69.0	325.6
9	September	7.7	3.8	22.3	120.8	85.1	60.9	300.7
10	October	6.5	3.2	16.8	106.5	78.0	52.7	263.7
11	November	5.7	3.0	16.1	79.5	77.0	49.1	230.4
12	December	5.8	3.4	16.2	76.4	79.2	51.4	232.4
13	Annual Total	74.6	40.8	229.8	1084.3	960.6	638.1	3028.2
14	ACP	2.5%	1.3%	7.6%	35.8%	31.7%	21.1%	100.0%

Notes: Line 13 = sum of lines 1 through 12
Line 14, Col. 1 = Line 13, Col. 1 / Line 13, Col. 7
Line 14, Col. 2 = Line 13, Col. 2 / Line 13, Col. 7
Line 14, Col. 3 = Line 13, Col. 3 / Line 13, Col. 7
Line 14, Col. 4 = Line 13, Col. 4 / Line 13, Col. 7
Line 14, Col. 5 = Line 13, Col. 5 / Line 13, Col. 7
Line 14, Col. 6 = Line 13, Col. 6 / Line 13, Col. 7

B. The Allocated Capacity Percentages (ACP's) for the S&G PPA I Resource consisting of the South Point and Griffth PPAs is 0% for both MEC and SSVEC. For the remaining Class A Members and the CARM, the resulting ACP's for the S&G PPA Resource are as follows:

Allocated Capacity %	Anza	DVEC	GCEC	CARM	TRICO	Total
	0.1%	0.1%	3.0%	3.2%	96.8%	100%

APPENDIX B to Exhibit A-5 to Rate Schedules A

PRM and CARM Monthly Allocated Capacity for 2011

All Values in MW Unless Indicated			Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Existing Resources														
Apache ST-2 Coal-fired			175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0
Apache ST-3 Coal-fired			175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0
Subtotal Base Units			350.0	350.0	350.0	350.0	350.0	350.0	350.0	350.0	350.0	350.0	350.0	350.0
Fed Hydro - SLCA IP PPA	(1)		1.6	1.6	1.4	6.9	7.0	7.3	8.2	7.8	6.8	1.4	1.4	1.6
Fed Hydro - Parker-Davis PPA	(1)		17.3	17.3	22.4	22.4	22.4	22.4	22.4	22.4	22.4	17.3	17.3	17.3
Sub Total Base Resources			368.9	368.9	373.8	379.3	379.4	379.7	380.6	380.2	379.2	368.7	368.7	368.9
Apache CC-1			82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0
Apache GT-2			20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0
Apache GT-3			65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0
Apache GT-4			38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0
Subtotal Other Resources			205.0	205.0	205.0	205.0	205.0	205.0	205.0	205.0	205.0	205.0	205.0	205.0
Subtotal Existing Resource Units			555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0
Subtotal Fed Hydro PPA	(1)		18.9	18.9	23.8	29.3	29.4	29.7	30.6	30.2	29.2	18.7	18.7	18.9
Total Existing Resources			573.9	573.9	578.8	584.3	584.4	584.7	585.6	585.2	584.2	573.7	573.7	573.9
Reserve Caculation														
2nd Hr Reserves Reqd for LSH Plus 29 MW	(2)		217.0	217.0	217.0	217.0	217.0	217.0	217.0	217.0	217.0	217.0	217.0	217.0
Less: WW-Mead-Davis Displacement			50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0
Less: AEPCO Wheeling Available			40.0	40.0	40.0	40.0	15.0	15.0	15.0	15.0	15.0	15.0	40.0	40.0
Less: SWTC Transmission Reserved			90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0
Less: Western/MEC Transmission Reserved			0.0	0.0	0.0	0.0	25.0	25.0	25.0	25.0	25.0	25.0	0.0	0.0
Less: Transmission Import Capacity	(3)		180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0
Remaining Reserve Requrement (MW)			37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0
Reserve Requrement (% of Unit Cap)	(3)		6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%
Power Sales Resources MW														
Electrical District 2 Firm			8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0
Salt River Project Firm			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Power Sales Resources			8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0
Less Power Sales Losses	(4)	2.97%	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Less Power Sales Reserves - MW			0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
SubTotal for Power Sales Resources			8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7
Net Existing Resource Capacity														
Existing Resoucre Units after Pwr Sales			546.3	546.3	546.3	546.3	546.3	546.3	546.3	546.3	546.3	546.3	546.3	546.3
Less Member Losses after Reserves	(4)	2.31%	11.8	11.8	11.8	11.8	11.8	11.8	11.8	11.8	11.8	11.8	11.8	11.8
Net Existing Resource Unit Capacity			534.5	534.5	534.5	534.5	534.5	534.5	534.5	534.5	534.5	534.5	534.5	534.5
Existing Fed Hydro Capacity			18.9	18.9	23.8	29.3	29.4	29.7	30.6	30.2	29.2	18.7	18.7	18.9
Total Existing Resource Capacity			553.4	553.4	558.3	563.8	563.9	564.2	565.1	564.7	563.7	553.2	553.2	553.4
Portion of Member Capacity Net of Losses														
CARM Existing Resource @ ACP		11.4%	63.1	63.1	63.7	64.3	64.3	64.3	64.4	64.4	64.3	63.1	63.1	63.1
TRICO Existing Resource @ ACP		21.1%	116.8	116.8	117.8	119.0	119.0	119.1	119.2	119.2	118.9	116.7	116.7	116.8
MEC Existing Resource @ ACP		35.8%	198.1	198.1	199.9	201.9	201.9	202.0	202.3	202.2	201.8	198.1	198.1	198.1
SSVEC Existing Resource @ ACP		31.7%	175.4	175.4	177.0	178.7	178.8	178.9	179.1	179.0	178.7	175.4	175.4	175.4
Member Reserve Shares (MW)														
CARM Reserves			4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2
TRICO Reserves			7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7
MEC Reserves	(5)		13.0	13.0	13.0	13.1	13.0	13.0	13.0	13.1	13.0	13.1	13.1	13.0
SSVEC Reserves			11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6
Less: EuroFresh Reserve Credit	(6)		(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)
Net SSVEC from Existing Resources			7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6
Total Reserves Req'd of Class A Members			36.5	36.5	36.5	36.6	36.5	36.5	36.5	36.6	36.5	36.6	36.6	36.5
S&G PPA Resources														
Griffith Purchased Power			0.0	0.0	0.0	0.0	25.0	25.0	25.0	25.0	25.0	25.0	0.0	0.0
South Point Purchased Power			0.0	0.0	0.0	0.0	25.0	25.0	25.0	25.0	25.0	25.0	0.0	0.0
Total S&G PPA Resources			0.0	0.0	0.0	0.0	50.0	50.0	50.0	50.0	50.0	50.0	0.0	0.0
Total After Network Losses			0.0	0.0	0.0	0.0	48.8	48.8	48.8	48.8	48.8	48.8	0.0	0.0
CARM Available S&G Capacity		3.2%	0.0	0.0	0.0	0.0	1.6	1.6	1.6	1.6	1.6	1.6	0.0	0.0
TRICO Available S&G Capcity		96.8%	0.0	0.0	0.0	0.0	47.2	47.2	47.2	47.2	47.2	47.2	0.0	0.0
Member Total Allocated Capacity (MW)														
CARM Total AC			58.9	58.9	59.5	60.1	61.7	61.7	61.8	61.8	61.7	60.5	58.9	58.9
TRICO Total AC			109.1	109.1	110.1	111.3	158.5	158.6	158.7	158.7	158.4	156.2	109.0	109.1
MEC Total AC			185.1	185.1	186.9	188.8	188.9	189.0	189.3	189.1	188.8	185.0	185.0	185.1
SSVEC Total AC			167.8	167.8	169.4	171.1	171.2	171.3	171.5	171.4	171.1	167.8	167.8	167.8
Total			520.9	520.9	525.9	531.3	580.3	580.6	581.3	581.0	580.0	569.5	520.7	520.9
Member Available Base Capacity After Power Sales, Losses (MW)														
CARM Available Base Capacity	(8)	11.4%	40.2	40.2	40.8	41.4	41.4	41.4	41.5	41.5	41.4	40.2	40.2	40.2
TRICO Available Base Capacity	(8)	21.1%	74.5	74.5	75.5	76.7	76.7	76.8	76.9	76.9	76.6	74.4	74.4	74.5
MEC Available Base Capacity	(8)	35.8%	126.3	126.3	128.1	130.0	130.1	130.2	130.5	130.3	130.0	126.2	126.2	126.3
SSVEC Available Base Capacity	(8)	31.7%	111.8	111.8	113.4	115.1	115.2	115.3	115.5	115.4	115.1	111.8	111.8	111.8
Subtotal Base		100.0%	352.8	352.8	357.8	363.2	363.4	363.7	364.4	364.1	363.1	352.6	352.6	352.8
Member Available Other Capacity After Losses, Reserves (MW)														
CARM Available Other Capacity	(8)	11.4%	18.7	18.7	18.7	18.7	18.7	18.7	18.7	18.7	18.7	18.7	18.7	18.7
TRICO Available Other Capacity	(8)	21.1%	34.6	34.6	34.6	34.6	34.6	34.6	34.6	34.6	34.6	34.6	34.6	34.6
MEC Available Other Capacity	(8)	35.8%	58.8	58.8	58.8	58.8	58.8	58.8	58.8	58.8	58.8	58.8	58.8	58.8
SSVEC Available Other Capacity	(8)	31.7%	56.0	56.0	56.0	56.0	56.0	56.0	56.0	56.0	56.0	56.0	56.0	56.0
Subtotal Available Other Cap			168.1	168.1	168.1	168.1	168.1	168.1	168.1	168.1	168.1	168.1	168.1	168.1
Member Total Available Capacity with Available S&G Capacity (MW)														
CARM Total Available Capacity			58.9	58.9	59.5	60.1	61.7	61.7	61.8	61.8	61.7	60.5	58.9	58.9
TRICO Total Available Capacity			109.1	109.1	110.1	111.3	158.5	158.6	158.7	158.7	158.4	156.2	109.0	109.1
MEC Total Available Capacity			185.1	185.1	186.9	188.8	188.9	189.0	189.3	189.1	188.8	185.0	185.0	185.1
SSVEC Total Available Capacity			167.8	167.8	169.4	171.1	171.2	171.3	171.5	171.4	171.1	167.8	167.8	167.8
Total			520.9	520.9	525.9	531.3	580.3	580.6	581.3	581.0	580.0	569.5	520.7	520.9

Notes: (1) Federal Hydro Estimated - AEPCO will establish Fed Hydro portion of Available Base Capacity monthly pursuant to the Federal Hydro Power Agreements.

(2) The 29 MW value added to LSH Reserves of 188 MW of Coal Unit capacity (includes spinning reserve capability) is required to restore SRSG Operating Reserves.

(3) The Class A Members have agreed that AEPCO will purchase transmission import capacity from SWTC or others as needed to hold generating reserves to 6.7%.

(4) The SWTC loss factors are subject to change from time to time as changes are implemented to such loss factors pursuant to SWTC's OATT Tariff.

(5) MEC Reserve fraction is rounded to ensure total reserves match totall reserves required of Class A members.

(6) Credit for Operating Reserve contribution from EuroFresh generation controlled by SSVEC pursuant to AEPCO-SSVEC agreement.

(7) Griffith PPA is available only in WECC Peak Hours; SouthPoint PPA is available only in Daytime Hours..

(8) Class A Member Available Base and Other Capacity fractions are rounded up and down as needed to match total AC.

APPENDIX B to Exhibit A-5 to Rate Schedules A
PRM and CARM Monthly Allocated Capacity for 2012

All Values in MW Unless Indicated		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Existing Resources													
Apache ST-2 Coal-fired		175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0
Apache ST-3 Coal-fired		175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0
Subtotal Base Units		350.0	350.0	350.0	350.0	350.0	350.0	350.0	350.0	350.0	350.0	350.0	350.0
Fed Hydro - SLCA IP PPA (1)		1.6	1.6	1.4	6.9	7.0	7.3	8.2	7.8	6.8	1.4	1.4	1.6
Fed Hydro - Parker-Davis PPA (1)		17.3	17.3	22.4	22.4	22.4	22.4	22.4	22.4	22.4	17.3	17.3	17.3
Sub Total Base Resources		368.9	368.9	373.8	379.3	379.4	379.7	380.6	380.2	379.2	368.7	368.7	368.9
Apache CC-1		82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0
Apache GT-2		20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0
Apache GT-3		65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0
Apache GT-4		38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0
Subtotal Other Resources		205.0	205.0	205.0	205.0	205.0	205.0	205.0	205.0	205.0	205.0	205.0	205.0
Subtotal Existing Resource Units		555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0
Subtotal Fed Hydro PPA (1)		18.9	18.9	23.8	29.3	29.4	29.7	30.6	30.2	29.2	18.7	18.7	18.9
Total Existing Resources		573.9	573.9	578.8	584.3	584.4	584.7	585.6	585.2	584.2	573.7	573.7	573.9
Reserve Caculation													
2nd Hr Reserves Reqd for LSH Plus 29 MW (2)		217.0	217.0	217.0	217.0	217.0	217.0	217.0	217.0	217.0	217.0	217.0	217.0
Less: WW-Mead-Davis Displacement		50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0
Less: AEPCO Wheeling Available		40.0	40.0	40.0	40.0	5.0	5.0	5.0	5.0	5.0	5.0	40.0	40.0
Less: SWTC Transmission Reserved		90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0
Less: Western/MEC Transmission Reserved		0.0	0.0	0.0	0.0	35.0	35.0	35.0	35.0	35.0	35.0	0.0	0.0
Less: Transmission Import Capacity (3)		180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0
Remaining Reserve Requrement (MW)		37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0
Reserve Requrement (% of Unit Cap) (3)		6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%
Power Sales Resources MW													
Electrical District 2 Firm		8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0
Salt River Project Firm		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Power Sales Resources		8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0
Less Power Sales Losses (4)	2.97%	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Less Power Sales Reserves - MW		0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
SubTotal for Power Sales Resources		8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7
Net Existing Resource Capacity													
Existing Resoucre Units after Pwr Sales		546.3	546.3	546.3	546.3	546.3	546.3	546.3	546.3	546.3	546.3	546.3	546.3
Less Member Losses after Reserves (4)	2.31%	11.8	11.8	11.8	11.8	11.8	11.8	11.8	11.8	11.8	11.8	11.8	11.8
Net Existing Resource Unit Capacity		534.5	534.5	534.5	534.5	534.5	534.5	534.5	534.5	534.5	534.5	534.5	534.5
Existing Fed Hydro Capacity		18.9	18.9	23.8	29.3	29.4	29.7	30.6	30.2	29.2	18.7	18.7	18.9
Total Existing Resource Capacity		553.4	553.4	558.3	563.8	563.9	564.2	565.1	564.7	563.7	553.2	553.2	553.4
Portion of Member Capacity Net of Losses													
CARM Existing Resource @ ACP	11.4%	63.1	63.1	63.7	64.3	64.3	64.3	64.4	64.4	64.3	63.1	63.1	63.1
TRICO Existing Resource @ ACP	21.1%	116.8	116.8	117.8	119.0	119.0	119.1	119.2	119.2	118.9	116.7	116.7	116.8
MEC Existing Resource @ ACP	35.8%	198.1	198.1	199.9	201.9	201.9	202.0	202.3	202.2	201.8	198.1	198.1	198.1
SSVEC Existing Resource @ ACP	31.7%	175.4	175.4	177.0	178.7	178.8	178.9	179.1	179.0	178.7	175.4	175.4	175.4
Member Reserve Shares (MW)													
CARM Reserves		4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2
TRICO Reserves		7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7
MEC Reserves (5)		13.0	13.0	13.0	13.1	13.0	13.0	13.0	13.1	13.0	13.1	13.1	13.0
SSVEC Reserves		11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6
Less: EuroFresh Reserve Credit (6)		(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)
Net SSVEC from Existing Resources		7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6
Total Reserves Req'd of Class A Members		36.5	36.5	36.5	36.6	36.5	36.5	36.5	36.6	36.5	36.6	36.6	36.5
S&G PPA Resources													
Griffith Purchased Power		0.0	0.0	0.0	0.0	25.0	25.0	25.0	25.0	25.0	25.0	0.0	0.0
South Point Purchased Power		0.0	0.0	0.0	0.0	35.0	35.0	35.0	35.0	35.0	35.0	0.0	0.0
Total S&G PPA Resources		0.0	0.0	0.0	0.0	60.0	60.0	60.0	60.0	60.0	60.0	0.0	0.0
Total After Network Losses		0.0	0.0	0.0	0.0	58.6	58.6	58.6	58.6	58.6	58.6	0.0	0.0
CARM Available S&G Capacity	3.2%	0.0	0.0	0.0	0.0	1.9	1.9	1.9	1.9	1.9	1.9	0.0	0.0
TRICO Available S&G Capcity	96.8%	0.0	0.0	0.0	0.0	56.7	56.7	56.7	56.7	56.7	56.7	0.0	0.0
Member Total Allocated Capacity (MW)													
CARM Total AC		58.9	58.9	59.5	60.1	62.0	62.0	62.1	62.1	62.0	60.8	58.9	58.9
TRICO Total AC		109.1	109.1	110.1	111.3	168.0	168.1	168.2	168.2	167.9	165.7	109.0	109.1
MEC Total AC		185.1	185.1	186.9	188.8	188.9	189.0	189.3	189.1	188.8	185.0	185.0	185.1
SSVEC Total AC		167.8	167.8	169.4	171.1	171.2	171.3	171.5	171.4	171.1	167.8	167.8	167.8
Total		520.9	520.9	525.9	531.3	590.1	590.4	591.1	590.8	589.8	579.3	520.7	520.9
Member Available Base Capacity After Power Sales, Losses (MW)													
CARM Available Base Capacity (8)	11.4%	40.2	40.2	40.8	41.4	41.4	41.4	41.5	41.5	41.4	40.2	40.2	40.2
TRICO Available Base Capacity (8)	21.1%	74.5	74.5	75.5	76.7	76.7	76.8	76.9	76.9	76.6	74.4	74.4	74.5
MEC Available Base Capacity (8)	35.8%	126.3	126.3	128.1	130.0	130.1	130.2	130.5	130.3	130.0	126.2	126.2	126.3
SSVEC Available Base Capacity (8)	31.7%	111.8	111.8	113.4	115.1	115.2	115.3	115.5	115.4	115.1	111.8	111.8	111.8
Subtotal Base	100.0%	352.8	352.8	357.8	363.2	363.4	363.7	364.4	364.1	363.1	352.6	352.6	352.8
Member Available Other Capacity After Losses, Reserves (MW)													
CARM Available Other Capacity (8)	11.4%	18.7	18.7	18.7	18.7	18.7	18.7	18.7	18.7	18.7	18.7	18.7	18.7
TRICO Available Other Capacity (8)	21.1%	34.6	34.6	34.6	34.6	34.6	34.6	34.6	34.6	34.6	34.6	34.6	34.6
MEC Available Other Capacity (8)	35.8%	58.8	58.8	58.8	58.8	58.8	58.8	58.8	58.8	58.8	58.8	58.8	58.8
SSVEC Available Other Capacity (8)	31.7%	56.0	56.0	56.0	56.0	56.0	56.0	56.0	56.0	56.0	56.0	56.0	56.0
Subtotal Available Other Cap		168.1	168.1	168.1	168.1	168.1	168.1	168.1	168.1	168.1	168.1	168.1	168.1
Member Total Available Capacity with Available S&G Capacity (MW)													
CARM Total Available Capacity		58.9	58.9	59.5	60.1	62.0	62.0	62.1	62.1	62.0	60.8	58.9	58.9
TRICO Total Available Capacity		109.1	109.1	110.1	111.3	168.0	168.1	168.2	168.2	167.9	165.7	109.0	109.1
MEC Total Available Capacity		185.1	185.1	186.9	188.8	188.9	189.0	189.3	189.1	188.8	185.0	185.0	185.1
SSVEC Total Available Capacity		167.8	167.8	169.4	171.1	171.2	171.3	171.5	171.4	171.1	167.8	167.8	167.8
Total		520.9	520.9	525.9	531.3	590.1	590.4	591.1	590.8	589.8	579.3	520.7	520.9

Notes: (1) Federal Hydro Estimated - AEPCO will establish Fed Hydro portion of Available Base Capacity monthly pursuant to the Federal Hydro Power Agreements.
(2) The 29 MW value added to LSH Reserves of 188 MW of Coal Unit capacity (includes spinning reserve capability) is required to restore SRSG Operating Reserves.
(3) The Class A Members have agreed that AEPCO will purchase transmission import capacity from SWTC or others as needed to hold generating reserves to 6.7%.
(4) The SWTC loss factors are subject to change from time to time as changes are implemented to such loss factors pursuant to SWTC's OATT Tariff.
(5) MEC Reserve fraction is rounded to ensure total reserves match totall reserves required of Class A members.
(6) Credit for Operating Reserve contribution from EuroFresh generation controlled by SSVEC pursuant to AEPCO-SSVEC agreement.
(7) Griffith PPA is available only in WECC Peak Hours; SouthPoint PPA is available only in Daytime Hours..
(8) Class A Member Available Base and Other Capacity fractions are rounded up and down as needed to match total AC.

APPENDIX B to Exhibit A-5 to Rate Schedules A

PRM and CARM Monthly Allocated Capacity for 2013

All Values in MW Unless Indicated			Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Existing Resources														
Apache ST-2 Coal-fired			175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0
Apache ST-3 Coal-fired			175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0
Subtotal Base Units			350.0	350.0	350.0	350.0	350.0	350.0	350.0	350.0	350.0	350.0	350.0	350.0
Fed Hydro - SLCA IP PPA	(1)		1.6	1.6	1.4	6.9	7.0	7.3	8.2	7.8	6.8	1.4	1.4	1.6
Fed Hydro - Parker-Davis PPA	(1)		17.3	17.3	22.4	22.4	22.4	22.4	22.4	22.4	22.4	17.3	17.3	17.3
Sub Total Base Resources			368.9	368.9	373.8	379.3	379.4	379.7	380.6	380.2	379.2	368.7	368.7	368.9
Apache CC-1			82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0
Apache GT-2			20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0
Apache GT-3			65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0
Apache GT-4			38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0
Subtotal Other Resources			205.0	205.0	205.0	205.0	205.0	205.0	205.0	205.0	205.0	205.0	205.0	205.0
Subtotal Existing Resource Units			555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0
Subtotal Fed Hydro PPA	(1)		18.9	18.9	23.8	29.3	29.4	29.7	30.6	30.2	29.2	18.7	18.7	18.9
Total Existing Resources			573.9	573.9	578.8	584.3	584.4	584.7	585.6	585.2	584.2	573.7	573.7	573.9
Reserve Caculation														
2nd Hr Reserves Reqd for LSH Plus 29 MW	(2)		217.0	217.0	217.0	217.0	217.0	217.0	217.0	217.0	217.0	217.0	217.0	217.0
Less: WW-Mead-Davis Displacement			50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0
Less: AEPCO Wheeling Available			40.0	40.0	40.0	40.0	(5.0)	(5.0)	(5.0)	(5.0)	(5.0)	(5.0)	40.0	40.0
Less: SWTC Transmission Reserved			90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0
Less: Western/MEC Transmission Reserved			0.0	0.0	0.0	0.0	45.0	45.0	45.0	45.0	45.0	45.0	0.0	0.0
Less: Transmission Import Capacity	(3)		180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0
Remaining Reserve Requrement (MW)			37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0
Reserve Requrement (% of Unit Cap)	(3)		6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%
Power Sales Resources MW														
Electrical District 2 Firm			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Salt River Project Firm			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Power Sales Resources			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Less Power Sales Losses	(4)	2.97%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Less Power Sales Reserves - MW			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SubTotal for Power Sales Resources			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Net Existing Resource Capacity														
Existing Resoucre Units after Pwr Sales			555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0
Less Member Losses after Reserves (4)		2.31%	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0
Net Existing Resource Unit Capacity			543.0	543.0	543.0	543.0	543.0	543.0	543.0	543.0	543.0	543.0	543.0	543.0
Existing Fed Hydro Capacity			18.9	18.9	23.8	29.3	29.4	29.7	30.6	30.2	29.2	18.7	18.7	18.9
Total Existing Resource Capacity			561.9	561.9	566.8	572.3	572.4	572.7	573.6	573.2	572.2	561.7	561.7	561.9
Portion of Member Capacity Net of Losses														
CARM Existing Resource @ ACP		11.4%	64.100	64.1	64.6	65.2	65.3	65.3	65.4	65.3	65.2	64.0	64.0	64.1
TRICO Existing Resource @ ACP		21.1%	118.600	118.6	119.6	120.8	120.8	120.8	121.0	121.0	120.7	118.5	118.5	118.6
MEC Existing Resource @ ACP		35.8%	201.200	201.2	202.9	204.9	204.9	205.0	205.4	205.2	204.9	201.1	201.1	201.2
SSVEC Existing Resource @ ACP		31.7%	178.100	178.1	179.7	181.4	181.5	181.6	181.8	181.7	181.4	178.1	178.1	178.1
Member Reserve Shares (MW)														
CARM Reserves			4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2
TRICO Reserves			7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8
MEC Reserves	(5)		13.3	13.3	13.3	13.3	13.3	13.3	13.3	13.3	13.3	13.3	13.3	13.3
SSVEC Reserves			11.7	11.7	11.7	11.7	11.7	11.7	11.7	11.7	11.7	11.7	11.7	11.7
Less: EuroFresh Reserve Credit	(6)		(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)
Net SSVEC from Existing Resources			7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7
Total Reserves Req'd of Class A Members			37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0
S&G PPA Resources														
Griffith Purchased Power			0.0	0.0	0.0	0.0	25.0	25.0	25.0	25.0	25.0	25.0	0.0	0.0
South Point Purchased Power			0.0	0.0	0.0	0.0	45.0	45.0	45.0	45.0	45.0	45.0	0.0	0.0
Total S&G PPA Resources			0.0	0.0	0.0	0.0	70.0	70.0	70.0	70.0	70.0	70.0	0.0	0.0
Total After Network Losses			0.0	0.0	0.0	0.0	68.4	68.4	68.4	68.4	68.4	68.4	0.0	0.0
CARM Available S&G Capacity		3.2%	0.0	0.0	0.0	0.0	2.2	2.2	2.2	2.2	2.2	2.2	0.0	0.0
TRICO Available S&G Capcity		96.8%	0.0	0.0	0.0	0.0	66.2	66.2	66.2	66.2	66.2	66.2	0.0	0.0
Member Total Allocated Capacity (MW)														
CARM Total AC			59.9	59.9	60.4	61.0	63.3	63.3	63.4	63.3	63.2	62.0	59.8	59.9
TRICO Total AC			110.8	110.8	111.8	113.0	179.2	179.2	179.4	179.4	179.1	176.9	110.7	110.8
MEC Total AC			187.9	187.9	189.6	191.6	191.6	191.7	192.1	191.9	191.6	187.8	187.8	187.9
SSVEC Total AC			170.4	170.4	172.0	173.7	173.8	173.9	174.1	174.0	173.7	170.4	170.4	170.4
Total			529.0	529.0	533.8	539.3	607.9	608.1	609.0	608.6	607.6	597.1	528.7	529.0
Member Available Base Capacity After Power Sales, Losses (MW)														
CARM Available Base Capacity	(8)	11.4%	41.2	41.2	41.7	42.3	42.4	42.4	42.5	42.4	42.3	41.1	41.1	41.2
TRICO Available Base Capacity	(8)	21.1%	76.2	76.2	77.2	78.4	78.4	78.4	78.6	78.6	78.3	76.1	76.1	76.2
MEC Available Base Capacity	(8)	35.8%	129.1	129.1	130.9	132.8	132.9	133.0	133.3	133.2	132.8	129.1	129.1	129.1
SSVEC Available Base Capacity	(8)	31.7%	114.4	114.4	116.0	117.7	117.8	117.9	118.1	118.0	117.7	114.4	114.4	114.4
Subtotal Base		100.0%	360.9	360.9	365.8	371.2	371.5	371.7	372.5	372.2	371.1	360.7	360.7	360.9
Member Available Other Capacity After Losses, Reserves (MW)														
CARM Available Other Capacity	(8)	11.4%	18.7	18.7	18.7	18.7	18.7	18.7	18.7	18.7	18.7	18.7	18.7	18.7
TRICO Available Other Capacity	(8)	21.1%	34.6	34.6	34.6	34.6	34.6	34.6	34.6	34.6	34.6	34.6	34.6	34.6
MEC Available Other Capacity	(8)	35.8%	58.8	58.8	58.8	58.8	58.8	58.8	58.8	58.8	58.8	58.8	58.8	58.8
SSVEC Available Other Capacity	(8)	31.7%	56.0	56.0	56.0	56.0	56.0	56.0	56.0	56.0	56.0	56.0	56.0	56.0
Subtotal Available Other Cap			168.1	168.1	168.1	168.1	168.1	168.1	168.1	168.1	168.1	168.1	168.1	168.1
Member Total Available Capacity with Available S&G Capacity (MW)														
CARM Total Available Capacity			59.9	59.9	60.4	61.0	63.3	63.3	63.4	63.3	63.2	62.0	59.8	59.9
TRICO Total Available Capacity			110.8	110.8	111.8	113.0	179.2	179.2	179.4	179.4	179.1	176.9	110.7	110.8
MEC Total Available Capacity			187.9	187.9	189.7	191.6	191.7	191.8	192.1	192.0	191.6	187.9	187.9	187.9
SSVEC Total Available Capacity			170.4	170.4	172.0	173.7	173.8	173.9	174.1	174.0	173.7	170.4	170.4	170.4
Total			529.0	529.0	533.9	539.3	608.0	608.2	609.0	608.7	607.6	597.2	528.8	529.0

Notes: (1) Federal Hydro Estimated - AEPCO will establish Fed Hydro portion of Available Base Capacity monthly pursuant to the Federal Hydro Power Agreements.

(2) The 29 MW value added to LSH Reserves of 188 MW of Coal Unit capacity (includes spinning reserve capability) is required to restore SRSG Operating Reserves.

(3) The Class A Members have agreed that AEPCO will purchase transmission import capacity from SWTC or others as needed to hold generating reserves to 6.7%.

(4) The SWTC loss factors are subject to change from time to time as changes are implemented to such loss factors pursuant to SWTC's OATT Tariff.

(5) MEC Reserve fraction is rounded to ensure total reserves match totall reserves required of Class A members.

(6) Credit for Operating Reserve contribution from EuroFresh generation controlled by SSVEC pursuant to AEPCO-SSVEC agreement.

(7) Griffith PPA is available only in WECC Peak Hours; SouthPoint PPA is available only in Daytime Hours..

(8) Class A Member Available Base and Other Capacity fractions are rounded up and down as needed to match total AC.

APPENDIX B to Exhibit A-5 to Rate Schedules A
PRM and CARM Monthly Allocated Capacity for 2014

All Values in MW Unless Indicated		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Existing Resources													
Apache ST-2 Coal-fired		175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0
Apache ST-3 Coal-fired		175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0
Subtotal Base Units		350.0	350.0	350.0	350.0	350.0	350.0	350.0	350.0	350.0	350.0	350.0	350.0
Fed Hydro - SLCA IP PPA (1)		1.6	1.6	1.4	6.9	7.0	7.3	8.2	7.8	6.8	1.4	1.4	1.6
Fed Hydro - Parker-Davis PPA (1)		17.3	17.3	22.4	22.4	22.4	22.4	22.4	22.4	22.4	17.3	17.3	17.3
Sub Total Base Resources		368.9	368.9	373.8	379.3	379.4	379.7	380.6	380.2	379.2	368.7	368.7	368.9
Apache CC-1		82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0
Apache GT-2		20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0
Apache GT-3		65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0
Apache GT-4		38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0
Subtotal Other Resources		205.0	205.0	205.0	205.0	205.0	205.0	205.0	205.0	205.0	205.0	205.0	205.0
Subtotal Existing Resource Units		555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0
Subtotal Fed Hydro PPA (1)		18.9	18.9	23.8	29.3	29.4	29.7	30.6	30.2	29.2	18.7	18.7	18.9
Total Existing Resources		573.9	573.9	578.8	584.3	584.4	584.7	585.6	585.2	584.2	573.7	573.7	573.9
Reserve Caculation													
2nd Hr Reserves Reqd for LSH Plus 29 MW (2)		217.0	217.0	217.0	217.0	217.0	217.0	217.0	217.0	217.0	217.0	217.0	217.0
Less: WW-Mead-Davis Displacement		50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0
Less: AEPCO Wheeling Available		40.0	40.0	40.0	40.0	(15.0)	(15.0)	(15.0)	(15.0)	(15.0)	(15.0)	40.0	40.0
Less: SWTC Transmission Reserved		90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0
Less: Western/MEC Transmission Reserved		0.0	0.0	0.0	0.0	55.0	55.0	55.0	55.0	55.0	55.0	0.0	0.0
Less: Transmission Import Capacity (3)		180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0
Remaining Reserve Requrement (MW)		37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0
Reserve Requrement (% of Unit Cap) (3)		6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%
Power Sales Resources MW													
Electrical District 2 Firm		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Salt River Project Firm		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Power Sales Resources		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Less Power Sales Losses (4)	2.97%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Less Power Sales Reserves - MW		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SubTotal for Power Sales Resources		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Net Existing Resource Capacity													
Existing Resoucre Units after Pwr Sales		555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0
Less Member Losses after Reserves (4)	2.31%	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0
Net Existing Resource Unit Capacity		543.0	543.0	543.0	543.0	543.0	543.0	543.0	543.0	543.0	543.0	543.0	543.0
Existing Fed Hydro Capacity		18.9	18.9	23.8	29.3	29.4	29.7	30.6	30.2	29.2	18.7	18.7	18.9
Total Existing Resource Capacity		561.9	561.9	566.8	572.3	572.4	572.7	573.6	573.2	572.2	561.7	561.7	561.9
Portion of Member Capacity Net of Losses													
CARM Existing Resource @ ACP	11.4%	64.100	64.1	64.6	65.2	65.3	65.3	65.4	65.3	65.2	64.0	64.0	64.1
TRICO Existing Resource @ ACP	21.1%	118.600	118.6	119.6	120.8	120.8	120.8	121.0	121.0	120.7	118.5	118.5	118.6
MEC Existing Resource @ ACP	35.8%	201.200	201.2	202.9	204.9	204.9	205.0	205.4	205.2	204.9	201.1	201.1	201.2
SSVEC Existing Resource @ ACP	31.7%	178.100	178.1	179.7	181.4	181.5	181.6	181.8	181.7	181.4	178.1	178.1	178.1
Member Reserve Shares (MW)													
CARM Reserves		4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2
TRICO Reserves		7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8
MEC Reserves (5)		13.3	13.3	13.3	13.3	13.3	13.3	13.3	13.3	13.3	13.3	13.3	13.3
SSVEC Reserves		11.7	11.7	11.7	11.7	11.7	11.7	11.7	11.7	11.7	11.7	11.7	11.7
Less: EuroFresh Reserve Credit (6)		(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)
Net SSVEC from Existing Resources		7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7
Total Reserves Req'd of Class A Members		37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0
S&G PPA Resources													
Griffith Purchased Power (7)		0.0	0.0	0.0	0.0	25.0	25.0	25.0	25.0	25.0	25.0	0.0	0.0
South Point Purchased Power (7)		0.0	0.0	0.0	0.0	55.0	55.0	55.0	55.0	55.0	55.0	0.0	0.0
Total S&G PPA Resources		0.0	0.0	0.0	0.0	80.0	80.0	80.0	80.0	80.0	80.0	0.0	0.0
Total After Network Losses		0.0	0.0	0.0	0.0	78.2	78.2	78.2	78.2	78.2	78.2	0.0	0.0
CARM Available S&G Capacity	3.2%	0.0	0.0	0.0	0.0	2.5	2.5	2.5	2.5	2.5	2.5	0.0	0.0
TRICO Available S&G Capcity	96.8%	0.0	0.0	0.0	0.0	75.7	75.7	75.7	75.7	75.7	75.7	0.0	0.0
Member Total Allocated Capacity (MW)													
CARM Total AC		59.9	59.9	60.4	61.0	63.6	63.6	63.7	63.6	63.5	62.3	59.8	59.9
TRICO Total AC		110.8	110.8	111.8	113.0	188.7	188.7	188.9	188.9	188.6	186.4	110.7	110.8
MEC Total AC		187.9	187.9	189.6	191.6	191.6	191.7	192.1	191.9	191.6	187.8	187.8	187.9
SSVEC Total AC		170.4	170.4	172.0	173.7	173.8	173.9	174.1	174.0	173.7	170.4	170.4	170.4
Total		529.0	529.0	533.8	539.3	617.7	617.9	618.8	618.4	617.4	606.9	528.7	529.0
Member Available Base Capacity After Power Sales, Losses (MW)													
CARM Available Base Capacity (8)	11.4%	41.2	41.2	41.7	42.3	42.4	42.4	42.5	42.4	42.3	41.1	41.1	41.2
TRICO Available Base Capacity (8)	21.1%	76.2	76.2	77.2	78.4	78.4	78.4	78.6	78.6	78.3	76.1	76.1	76.2
MEC Available Base Capacity (8)	35.8%	129.1	129.1	130.9	132.8	132.9	133.0	133.3	133.2	132.8	129.1	129.1	129.1
SSVEC Available Base Capacity (8)	31.7%	114.4	114.4	116.0	117.7	117.8	117.9	118.1	118.0	117.7	114.4	114.4	114.4
Subtotal Base	100.0%	360.9	360.9	365.8	371.2	371.5	371.7	372.5	372.2	371.1	360.7	360.7	360.9
Member Available Other Capacity After Losses, Reserves (MW)													
CARM Available Other Capacity (8)	11.4%	18.7	18.7	18.7	18.7	18.7	18.7	18.7	18.7	18.7	18.7	18.7	18.7
TRICO Available Other Capacity (8)	21.1%	34.6	34.6	34.6	34.6	34.6	34.6	34.6	34.6	34.6	34.6	34.6	34.6
MEC Available Other Capacity (8)	35.8%	58.8	58.8	58.7	58.8	58.7	58.7	58.8	58.7	58.8	58.7	58.7	58.8
SSVEC Available Other Capacity (8)	31.7%	56.0	56.0	56.0	56.0	56.0	56.0	56.0	56.0	56.0	56.0	56.0	56.0
Subtotal Available Other Cap		168.1	168.1	168.0	168.1	168.0	168.0	168.1	168.0	168.1	168.0	168.0	168.1
Member Total Available Capacity with Available S&G Capacity (MW)													
CARM Total Available Capacity		59.9	59.9	60.4	61.0	63.6	63.6	63.7	63.6	63.5	62.3	59.8	59.9
TRICO Total Available Capacity		110.8	110.8	111.8	113.0	188.7	188.7	188.9	188.9	188.6	186.4	110.7	110.8
MEC Total Available Capacity		187.9	187.9	189.6	191.6	191.6	191.7	192.1	191.9	191.6	187.8	187.8	187.9
SSVEC Total Available Capacity		170.4	170.4	172.0	173.7	173.8	173.9	174.1	174.0	173.7	170.4	170.4	170.4
Total		529.0	529.0	533.8	539.3	617.7	617.9	618.8	618.4	617.4	606.9	528.7	529.0

Notes: (1) Federal Hydro Estimated - AEPCO will establish Fed Hydro portion of Available Base Capacity monthly pursuant to the Federal Hydro Power Agreements.
(2) The 29 MW value added to LSH Reserves of 188 MW of Coal Unit capacity (includes spinning reserve capability) is required to restore SRSG Operating Reserves.
(3) The Class A Members have agreed that AEPCO will purchase transmission import capacity from SWTC or others as needed to hold generating reserves to 6.7%.
(4) The SWTC loss factors are subject to change from time to time as changes are implemented to such loss factors pursuant to SWTC's OATT Tariff.
(5) MEC Reserve fraction is rounded to ensure total reserves match totall reserves required of Class A members.
(6) Credit for Operating Reserve contribution from EuroFresh generation controlled by SSVEC pursuant to AEPCO-SSVEC agreement.
(7) Griffith PPA is available only in WECC Peak Hours; SouthPoint PPA is available only in Daytime Hours..
(8) Class A Member Available Base and Other Capacity fractions are rounded up and down as needed to match total AC.

APPENDIX B to Exhibit A-5 to Rate Schedules A

PRM and CARM Monthly Allocated Capacity for 2015 thru 2020

All Values in MW Unless Indicated			Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Existing Resources														
Apache ST-2 Coal-fired			175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0
Apache ST-3 Coal-fired			175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0
Subtotal Base Units			350.0	350.0	350.0	350.0	350.0	350.0	350.0	350.0	350.0	350.0	350.0	350.0
Fed Hydro - SLCA IP PPA	(1)		1.6	1.6	1.4	6.9	7.0	7.3	8.2	7.8	6.8	1.4	1.4	1.6
Fed Hydro - Parker-Davis PPA	(1)		17.3	17.3	22.4	22.4	22.4	22.4	22.4	22.4	22.4	17.3	17.3	17.3
Sub Total Base Resources			368.9	368.9	373.8	379.3	379.4	379.7	380.6	380.2	379.2	368.7	368.7	368.9
Apache CC-1			82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0
Apache GT-2			20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0
Apache GT-3			65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0
Apache GT-4			38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0
Subtotal Other Resources			205.0	205.0	205.0	205.0	205.0	205.0	205.0	205.0	205.0	205.0	205.0	205.0
Subtotal Existing Resource Units			555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0
Subtotal Fed Hydro PPA	(1)		18.9	18.9	23.8	29.3	29.4	29.7	30.6	30.2	29.2	18.7	18.7	18.9
Total Existing Resources			573.9	573.9	578.8	584.3	584.4	584.7	585.6	585.2	584.2	573.7	573.7	573.9
Reserve Caculation														
2nd Hr Reserves Reqd for LSH Plus 29 MW	(2)		217.0	217.0	217.0	217.0	217.0	217.0	217.0	217.0	217.0	217.0	217.0	217.0
Less: WW-Mead-Davis Displacement			50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0
Less: AEPCO Wheeling Available			40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0
Less: SWTC Transmission Reserved			90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0
Less: Western/MEC Transmission Reserved			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Less: Transmission Import Capacity	(3)		180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0
Remaining Reserve Requrement (MW)			37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0
Reserve Requrement (% of Unit Cap)	(3)		6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%
Power Sales Resources MW														
Electrical District 2 Firm			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Salt River Project Firm			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Power Sales Resources			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Less Power Sales Losses	(4)	2.97%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Less Power Sales Reserves - MW			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SubTotal for Power Sales Resources			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Net Existing Resource Capacity														
Existing Resoucre Units after Pwr Sales			555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0
Less Member Losses after Reserves	(4)	2.31%	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0
Net Existing Resource Unit Capacity			543.0	543.0	543.0	543.0	543.0	543.0	543.0	543.0	543.0	543.0	543.0	543.0
Existing Fed Hydro Capacity			18.9	18.9	23.8	29.3	29.4	29.7	30.6	30.2	29.2	18.7	18.7	18.9
Total Existing Resource Capacity			561.9	561.9	566.8	572.3	572.4	572.7	573.6	573.2	572.2	561.7	561.7	561.9
Portion of Member Capacity Net of Losses														
CARM Existing Resource @ ACP		11.4%	64.100	64.1	64.6	65.2	65.3	65.3	65.4	65.3	65.2	64.0	64.0	64.1
TRICO Existing Resource @ ACP		21.1%	118.600	118.6	119.6	120.8	120.8	120.8	121.0	121.0	120.7	118.5	118.5	118.6
MEC Existing Resource @ ACP		35.8%	201.200	201.2	202.9	204.9	204.9	205.0	205.4	205.2	204.9	201.1	201.1	201.2
SSVEC Existing Resource @ ACP		31.7%	178.100	178.1	179.7	181.4	181.5	181.6	181.8	181.7	181.4	178.1	178.1	178.1
Member Reserve Shares (MW)														
CARM Reserves			4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2
TRICO Reserves			7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8
MEC Reserves	(5)		13.3	13.3	13.3	13.3	13.3	13.3	13.3	13.3	13.3	13.3	13.3	13.3
SSVEC Reserves			11.7	11.7	11.7	11.7	11.7	11.7	11.7	11.7	11.7	11.7	11.7	11.7
Less: EuroFresh Reserve Credit	(6)		(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)
Net SSVEC from Existing Resources			7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7
Total Reserves Req'd of Class A Members			37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0
S&G PPA Resources														
Griffith Purchased Power			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
South Point Purchased Power			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total S&G PPA Resources			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total After Network Losses			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CARM Available S&G Capacity		0.0%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
TRICO Available S&G Capcity		0.0%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Member Total Allocated Capacity (MW)														
CARM Total AC			59.9	59.9	60.4	61.0	61.1	61.1	61.2	61.1	61.0	59.8	59.8	59.9
TRICO Total AC			110.8	110.8	111.8	113.0	113.0	113.0	113.2	113.2	112.9	110.7	110.7	110.8
MEC Total AC			187.9	187.9	189.6	191.6	191.6	191.7	192.1	191.9	191.6	187.8	187.8	187.9
SSVEC Total AC			170.4	170.4	172.0	173.7	173.8	173.9	174.1	174.0	173.7	170.4	170.4	170.4
Total			529.0	529.0	533.8	539.3	539.5	539.7	540.6	540.2	539.2	528.7	528.7	529.0
Member Available Base Capacity After Power Sales, Losses (MW)														
CARM Available Base Capacity	(7)	11.4%	41.2	41.2	41.7	42.3	42.4	42.4	42.5	42.4	42.3	41.1	41.1	41.2
TRICO Available Base Capacity	(7)	21.1%	76.2	76.2	77.2	78.4	78.4	78.4	78.6	78.6	78.3	76.1	76.1	76.2
MEC Available Base Capacity	(7)	35.8%	129.1	129.1	130.9	132.8	132.9	133.0	133.3	133.2	132.8	129.1	129.1	129.1
SSVEC Available Base Capacity	(7)	31.7%	114.4	114.4	116.0	117.7	117.8	117.9	118.1	118.0	117.7	114.4	114.4	114.4
Subtotal Base		**100.0%**	360.9	360.9	365.8	371.2	371.5	371.7	372.5	372.2	371.1	360.7	360.7	360.9
Member Available Other Capacity After Losses, Reserves (MW)														
CARM Available Other Capacity	(7)	11.4%	18.7	18.7	18.7	18.7	18.7	18.7	18.7	18.7	18.7	18.7	18.7	18.7
TRICO Available Other Capacity	(7)	21.1%	34.6	34.6	34.6	34.6	34.6	34.6	34.6	34.6	34.6	34.6	34.6	34.6
MEC Available Other Capacity	(7)	35.8%	58.8	58.8	58.7	58.8	58.7	58.7	58.8	58.7	58.8	58.7	58.7	58.8
SSVEC Available Other Capacity	(7)	31.7%	56.0	56.0	56.0	56.0	56.0	56.0	56.0	56.0	56.0	56.0	56.0	56.0
Subtotal Available Other Cap			168.1	168.1	168.0	168.1	168.0	168.0	168.1	168.0	168.1	168.0	168.0	168.1
Member Total Available Capacity with Available S&G Capacity (MW)														
CARM Total Available Capacity			59.9	59.9	60.4	61.0	61.1	61.1	61.2	61.1	61.0	59.8	59.8	59.9
TRICO Total Available Capacity			110.8	110.8	111.8	113.0	113.0	113.0	113.2	113.2	112.9	110.7	110.7	110.8
MEC Total Available Capacity			187.9	187.9	189.6	191.6	191.6	191.7	192.1	191.9	191.6	187.8	187.8	187.9
SSVEC Total Available Capacity			170.4	170.4	172.0	173.7	173.8	173.9	174.1	174.0	173.7	170.4	170.4	170.4
Total			529.0	529.0	533.8	539.3	539.5	539.7	540.6	540.2	539.2	528.7	528.7	529.0

Notes: (1) Federal Hydro Estimated - AEPCO will establish Fed Hydro portion of Available Base Capacity monthly pursuant to the Federal Hydro Power Agreements.
(2) The 29 MW value added to LSH Reserves of 188 MW of Coal Unit capacity (includes spinning reserve capability) is required to restore SRSG Operating Reserves.
(3) The Class A Members have agreed that AEPCO will purchase transmission import capacity from SWTC or others as needed to hold generating reserves to 6.7%.
(4) The SWTC loss factors are subject to change from time to time as changes are implemented to such loss factors pursuant to SWTC's OATT Tariff.
(5) MEC Reserve fraction is rounded to ensure total reserves match totall reserves required of Class A members.
(6) Credit for Operating Reserve contribution from EuroFresh generation controlled by SSVEC pursuant to AEPCO-SSVEC agreement.
(7) *Class A Member Available Base and Other Capacity fractions are rounded up and down as needed to match total AC.*

APPENDIX B to Exhibit A-5 to Rate Schedules A

PRM and CARM Monthly Allocated Capacity for 2021 thru 2035

All Values in MW Unless Indicated			Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Existing Resources														
Apache ST-2 Coal-fired			175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0
Apache ST-3 Coal-fired			175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0
Subtotal Base Units			350.0	350.0	350.0	350.0	350.0	350.0	350.0	350.0	350.0	350.0	350.0	350.0
Fed Hydro - SLCA IP PPA	(1)		1.6	1.6	1.4	6.9	7.0	7.3	8.2	7.8	6.8	1.4	1.4	1.6
Fed Hydro - Parker-Davis PPA	(1)		17.3	17.3	22.4	22.4	22.4	22.4	22.4	22.4	22.4	17.3	17.3	17.3
Sub Total Base Resources			368.9	368.9	373.8	379.3	379.4	379.7	380.6	380.2	379.2	368.7	368.7	368.9
Apache CC-1			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Apache GT-2			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Apache GT-3			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Apache GT-4			38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0
Subtotal Other Resources			38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0
Subtotal Existing Resource Units			388.0	388.0	388.0	388.0	388.0	388.0	388.0	388.0	388.0	388.0	388.0	388.0
Subtotal Fed Hydro PPA	(1)		18.9	18.9	23.8	29.3	29.4	29.7	30.6	30.2	29.2	18.7	18.7	18.9
Total Existing Resources			406.9	406.9	411.8	417.3	417.4	417.7	418.6	418.2	417.2	406.7	406.7	406.9
Reserve Caculation														
2nd Hr Reserves Reqd for LSH Plus 29 MW	(2)		217.0	217.0	217.0	217.0	217.0	217.0	217.0	217.0	217.0	217.0	217.0	217.0
Less: WW-Mead-Davis Displacement			50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0
Less: AEPCO Wheeling Available			40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0
Less: SWTC Transmission Reserved			100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
Less: Western/MEC Transmission Reserved			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Less: Transmission Import Capacity	(3)		190.0	190.0	190.0	190.0	190.0	190.0	190.0	190.0	190.0	190.0	190.0	190.0
Remaining Reserve Requrement (MW)			27.0	27.0	27.0	27.0	27.0	27.0	27.0	27.0	27.0	27.0	27.0	27.0
Reserve Requrement (% of Unit Cap)	(3)		7.0%	7.0%	7.0%	7.0%	7.0%	7.0%	7.0%	7.0%	7.0%	7.0%	7.0%	7.0%
Power Sales Resources MW														
Electrical District 2 Firm			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Salt River Project Firm			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Power Sales Resources			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Less Power Sales Losses	(4)	2.97%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Less Power Sales Reserves - MW			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SubTotal for Power Sales Resources			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Net Existing Resource Capacity														
Existing Resoucre Units after Pwr Sales			388.0	388.0	388.0	388.0	388.0	388.0	388.0	388.0	388.0	388.0	388.0	388.0
Less Member Losses after Reserves	(4)	2.31%	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3
Net Existing Resource Unit Capacity			379.7	379.7	379.7	379.7	379.7	379.7	379.7	379.7	379.7	379.7	379.7	379.7
Existing Fed Hydro Capacity			18.9	18.9	23.8	29.3	29.4	29.7	30.6	30.2	29.2	18.7	18.7	18.9
Total Existing Resource Capacity			398.6	398.6	403.5	409.0	409.1	409.4	410.3	409.9	408.9	398.4	398.4	398.6
Portion of Member Capacity Net of Losses														
CARM Existing Resource @ ACP		11.4%	45.4	45.4	46.0	46.6	46.6	46.7	46.8	46.7	46.6	45.4	45.4	45.4
TRICO Existing Resource @ ACP		21.1%	84.1	84.1	85.1	86.3	86.3	86.4	86.6	86.5	86.3	84.1	84.1	84.1
MEC Existing Resource @ ACP		35.8%	142.7	142.7	144.4	146.4	146.4	146.6	146.9	146.7	146.4	142.6	142.6	142.7
SSVEC Existing Resource @ ACP		31.7%	126.4	126.3	127.9	129.6	129.7	129.8	130.1	129.9	129.6	126.3	126.3	126.3
Member Reserve Shares (MW)														
CARM Reserves			3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1
TRICO Reserves			5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7
MEC Reserves	(5)		9.6	9.6	9.6	9.6	9.6	9.6	9.6	9.6	9.6	9.6	9.6	9.6
SSVEC Reserves			8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6
Less: EuroFresh Reserve Credit	(6)		(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)
Net SSVEC from Existing Resources			4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6
Total Reserves Req'd of Class A Members			27.0	27.0	27.0	27.0	27.0	27.0	27.0	27.0	27.0	27.0	27.0	27.0
S&G PPA Resources														
Griffith Purchased Power			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
South Point Purchased Power			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total S&G PPA Resources			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total After Network Losses			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CARM Available S&G Capacity		3.2%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
TRICO Available S&G Capcity		96.8%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Member Total Allocated Capacity (MW)														
CARM *Total* AC			42.3	42.3	42.9	43.5	43.5	43.6	43.7	43.6	43.5	42.3	42.3	42.3
TRICO Total AC			78.4	78.4	79.4	80.6	80.6	80.7	80.9	80.8	80.6	78.4	78.4	78.4
MEC Total AC			133.1	133.1	134.8	136.8	136.8	137.0	137.3	137.1	136.8	133.0	133.0	133.1
SSVEC Total AC			121.8	121.7	123.3	125.0	125.1	125.2	125.5	125.3	125.0	121.7	121.7	121.7
Total			375.6	375.5	380.4	385.9	386.0	386.5	387.4	386.8	385.9	375.4	375.4	375.5
Member Available Base Capacity After Power Sales, Losses (MW)														
CARM Available Base Capacity	(7)	11.4%	41.1	41.1	41.7	42.3	42.3	42.4	42.5	42.4	42.3	41.1	41.1	41.1
TRICO Available Base Capacity	(7)	21.1%	76.1	76.1	77.1	78.3	78.3	78.4	78.6	78.5	78.3	76.1	76.1	76.1
MEC Available Base Capacity	(7)	35.8%	129.2	129.2	130.9	132.9	132.9	133.1	133.4	133.2	132.9	129.1	129.1	129.2
SSVEC Available Base Capacity	(7)	31.7%	114.4	114.3	115.9	117.6	117.7	117.8	118.1	117.9	117.6	114.3	114.3	114.3
Subtotal Base		100.0%	360.8	360.7	365.6	371.1	371.2	371.7	372.6	372.0	371.1	360.6	360.6	360.7
Member Available Other Capacity After Losses, Reserves (MW)														
CARM Available Other Capacity	(7)	11.4%	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2
TRICO Available Other Capacity	(7)	21.1%	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3
MEC Available Other Capacity	(7)	35.8%	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9
SSVEC Available Other Capacity	(7)	31.7%	7.4	7.4	7.4	7.4	7.4	7.4	7.4	7.4	7.4	7.4	7.4	7.4
Subtotal Available Other Cap			14.8	14.8	14.8	14.8	14.8	14.8	14.8	14.8	14.8	14.8	14.8	14.8
Member Total Available Capacity with Available S&G Capacity (MW)														
CARM Total Available Capacity			42.3	42.3	42.9	43.5	43.5	43.6	43.7	43.6	43.5	42.3	42.3	42.3
TRICO Total Available Capacity			78.4	78.4	79.4	80.6	80.6	80.7	80.9	80.8	80.6	78.4	78.4	78.4
MEC Total Available Capacity			133.1	133.1	134.8	136.8	136.8	137.0	137.3	137.1	136.8	133.0	133.0	133.1
SSVEC Total Available Capacity			121.8	121.7	123.3	125.0	125.1	125.2	125.5	125.3	125.0	121.7	121.7	121.7
Total			375.6	375.5	380.4	385.9	386.0	386.5	387.4	386.8	385.9	375.4	375.4	375.5

Notes: (1) Federal Hydro Estimated - AEPCO will establish Fed Hydro portion of Available Base Capacity monthly pursuant to the Federal Hydro Power Agreements.

(2) The 29 MW value added to LSH Reserves of 188 MW of Coal Unit capacity (includes spinning reserve capability) is required to restore SRSG Operating Reserves.

(3) The Class A Members have agreed that AEPCO will purchase transmission import capacity from SWTC or others as needed to hold generating reserves to 6.7%.

(4) The SWTC loss factors are subject to change from time to time as changes are implemented to such loss factors pursuant to SWTC's OATT Tariff.

(5) MEC Reserve fraction is rounded to ensure total reserves match totall reserves required of Class A members.

(6) Credit for Operating Reserve contribution from EuroFresh generation controlled by SSVEC pursuant to AEPCO-SSVEC agreement.

(7) Class A Member Available Base and Other Capacity fractions are rounded up and down as needed to match total AC.

Exhibit A-6: Sample Bill				
CARM		ACP %		
DATE:				February 10, 2011
January, 2011				
				Total $
Fixed Charge				
O&M Charge				
		kwh	$/kwh	Total $
Base Billing Energy				
Base Energy Fuel Adjustor				
Other Billing Energy				
Supplemental Billing Energy				
Supplemental Billing Energy Fuel Adjustor				
S&G PPA Billing Energy				
S&G PPA Energy Fuel Adjustor				
Other Billing Energy				
Other Energy Fuel Adjustor				
Minimum Base Capacity Charge				
Minimum Other Capacity Charge				
	DOAF			
Demand Overrun Adjustment	%			
Overrun Energy Charge				
	mkW	12MORA		
Power Factor Adjustor				
ACC Gross Operating Revenue Assessment				

Exhibit A-6: Sample Data for Bill CARM	Monthly MWH
Supplemental Billing Energy	
Supplemental Transfers delivered	
Off-peak	
On-Peak	
S&G Billing Energy	
S&G Transfers delivered	
Off-peak	
On-Peak	
Base Billing Energy	
Base Economy Purchases	
Off-peak	
On-Peak	
Base Transfer delivered	
Off-peak	
On-Peak	
Base Economy Sales credits	
Off-peak	
On-Peak	
Base Mismatch Energy	
Other Billing Energy	
Off-peak	
On-Peak	
Supplemental Transfer Billing Energy received	
Off-peak	
On-Peak	
S&G PPA Transfer Billing Energy received	
Off-peak	
On-Peak	
Base Transfer Billing Energy received	
Off-peak	
On-Peak	
Total Other Energy	
Off-peak	
On-Peak	

Exhibit A-6: Sample Bill

INVOICE				
To: ARM				
Address				
City, AZ				
'ATTN:				
	Energy Cost Responsibility			
CARM Member 1	**Demand Ratio Share**			
DATE:				**February 10, 2011**
January, 2011				
		DRS	**CARM $**	**Total $**
Fixed Charge				
O&M Charge				
		ECR	**CARM $**	**Total $**
Base Billing Energy				
Base Energy Fuel Adjustor				
Other Billing Energy				
Supplemental Billing Energy				
Supplemental Billing Energy Fuel Adjustor				
S&G PPA Billing Energy				
S&G PPA Energy Fuel Adjustor				
Other Billing Energy				
Other Energy Fuel Adjustor				
Minimum Base Capacity Charge				
	DOAF			
Minimum Other Capacity Charge	**%**			
Demand Overrun Adjustment				
	mkW	**12MORA**		
Overrun Energy Charge				
Power Factor Adjustor				
ACC Gross Operating Revenue Assessment				

Exhibit A-6: Sample Data for Bill	
ARM MEMBER 1 15% of CARM	Monthly
	MWH
Supplemental Billing Energy	
Supplemental Transfer delivered	
Off-peak	
On-Peak	
S&G Billing Energy	
S&G Transfer delivered	
Off-peak	
On-Peak	
Base Billing Energy	
Base Economy Purchases	
Off-peak	
On-Peak	
Base Transfer delivered	
Off-peak	
On-Peak	
Base Economy Sales credits	
Off-peak	
On-Peak	
Base Mismatch Energy	
Other Billing Energy	
Off-peak	
On-Peak	
Supplemental Transfer Billing Energy received	
Off-peak	
On-Peak	
S&G PPA Transfer Billing Energy received	
Off-peak	
On-Peak	
Base Transfer Billing Energy received	
Off-peak	
On-Peak	
Total Other Energy	
Off-peak	
On-Peak	

EXHIBIT C

DUNCAN VALLEY ELECTRIC COOPERATIVE, INC.
PO Box 440 | 222 North Highway 75
Duncan AZ 85534 | Duncan AZ 85534
Owned By Those We Serve - Incorporated - June 1947
Phone: (520) 359-2503 www.dvec.org Fax: (520) 359-2370

May 11, 2010

Chairman Kristin K. Mayes
Commissioner Gary Pierce
Commissioner Paul Newman
Commissioner Sandra D. Kennedy
Commissioner Bob Stump
Arizona Corporation Commission
1200 W. Washington
Phoenix, Arizona 85007

RE: NINTH AMENDMENT TO THE WHOLESALE POWER CONTRACT BETWEEN DUNCAN VALLEY ELECTRIC COOPERATIVE, INC. AND ARIZONA ELECTRIC POWER COOPERATIVE, INC.

Dear Commissioners:

I am the President of Board of Directors of Duncan Valley Electric Cooperative, Inc. (DVEC) which has recently approved and executed the Ninth Amendment to the Wholesale Power Contract (the "Amendment") between DVEC and Arizona Electric Power Cooperative, Inc. (AEPCO). This Amendment and similar revisions to the contractual relationships among AEPCO and its other Class A members have been arrived at after very careful and extensive deliberation and discussion by all of AEPCO's Member Cooperatives.

The purpose of my letter is to confirm to you DVEC's complete support of the Amendment to our Wholesale Power Contract and our authorization to AEPCO to file the Amendment for your approval. We appreciate your attention to this matter and request that the Commission approve it.

Sincerely,

Johnnie Frie

Johnnie Frie
President of Board of Directors
Duncan Valley Electric Cooperative

GRAHAM COUNTY ELECTRIC COOPERATIVE, INC.
GRAHAM COUNTY UTILITIES, INC.
P.O. Drawer B
Pima, Arizona 85543

Serving The Beautiful Gila Valley
In Southeastern Arizona

Telephone (928) 485-2451
Fax (928) 485-9491

May 11, 2010

Chairman Kristin K. Mayes
Commissioner Gary Pierce
Commissioner Paul Newman
Commissioner Sandra D. Kennedy
Commissioner Bob Stump
Arizona Corporation Commission
1200 W. Washington
Phoenix, Arizona 85007

RE: SEVENTH AMENDMENT TO THE WHOLESALE POWER CONTRACT BETWEEN GRAHAM COUNTY ELECTRIC COOPERATIVE, INC. AND ARIZONA ELECTRIC POWER COOPERATIVE, INC.

Dear Commissioners:

I am the President of Board of Directors of Graham County Electric Cooperative, Inc. (GCEC) which has recently approved and executed the Seventh Amendment to the Wholesale Power Contract (the "Amendment") between GCEC and Arizona Electric Power Cooperative, Inc. (AEPCO). This Amendment and similar revisions to the contractual relationships among AEPCO and its other Class A members have been arrived at after very careful and extensive deliberation and discussion by all of AEPCO's Member Cooperatives.

The purpose of my letter is to confirm to you GCEC's complete support of the Amendment to our Wholesale Power Contract and our authorization to AEPCO to file the Amendment for your approval. We appreciate your attention to this matter and request that the Commission approve it.

Sincerely,

Gene Robert Larson

Gene Robert Larson, President, Board of Directors
Graham County Electric Cooperative

EXHIBIT D

Arizona Electric Power Cooperative, Inc.
Summary of Revised Proposed Rates
TRICO PRM Case
Docket No. E-01773A-09-0472

	Proposed Rates Amended Filing - 4/20/2010 TRICO as ARM				Revised Proposed Rates TRICO as PRM			
All-Requirements Members:								
Fixed Charge		862,343	/Month (1)		$	232,978	/Month (1)	
O&M Charge		1,229,653	/Month (1)		$	436,144	/Month (1)	
Energy Rates:								
Base Resources	$	0.03236	/kWh		$	0.03157	/kWh	
Other Resources	$	0.06746	/kWh		$	0.06069	/kWh	
Energy Rate	$	0.03722	/kWh	(Average)	$	0.03276	/kWh	(Average)
Partial-Requirements Members:								
Mohave Electric Cooperative:								
Fixed Charge	$	709,721	/Month		$	709,721	/Month	
O&M Charge	$	1,323,724	/Month		$	1,323,724	/Month	
Energy Rates:								
Base Resources	$	0.03216	/kWh		$	0.03216	/kWh	
Other Existing Resources	$	0.06879	/kWh		$	0.06879	/kWh	
Energy Rate	$	0.03595	/kWh	(Average)	$	0.03595	/kWh	(Average)
Sulphur Springs Valley Electric Cooperative:								
Fixed Charge	$	628,440	/Month		$	628,440	/Month	
O&M Charge	$	1,172,125	/Month		$	1,172,125	/Month	
Energy Rates:								
Base Resources	$	0.03230	/kWh		$	0.03230	/kWh	
Other Existing Resources	$	0.06676	/kWh		$	0.06676	/kWh	
Energy Rate	$	0.03672	/kWh	(Average)	$	0.03672	/kWh	(Average)
Trico Electric Cooperative:								
Fixed Charge	(Rates as stated above for				$	629,365	/Month	
O&M Charge	All-Requirements Members)				$	793,509	/Month	
Energy Rates:								
Base Resources					$	0.03240	/kWh	
Other Existing Resources					$	0.06612	/kWh	
Energy Rate					$	0.03885	/kWh	(Average)

(1) The Fixed Charge and the O&M Charge will be apportioned among the ARMs and allocated to each ARM based upon each ARM's monthly Demand Share Ratio. The Demand Share Ratio will be calculated each month as the percentage of each ARM's 12-month rolling average demand to the total of the ARMs' 12-month rolling average demand.