COMPOSITE OF AMENDED

RESTATED CERTIFICATE OF INCORPORATION

OF

AMERICAN ELECTRIC POWER COMPANY, INC.

Under Section 807 of the Business Corporation Law

**As filed with the Department of State
of the State of New York
on November 5, 1997
and
amended as filed
on February 4, 1999, September 15, 1999
and April 28, 2009**

COMPOSITE OF AMENDED
RESTATED CERTIFICATE OF INCORPORATION
OF
AMERICAN ELECTRIC POWER COMPANY, INC.
Under Section 807 of the Business Corporation Law

The undersigned, being respectively the Vice President and Assistant Secretary of American Electric Power Company, Inc., hereby certify that:

I. Name. The name of the corporation is AMERICAN ELECTRIC POWER COMPANY, INC. The name under which the corporation was formed is American Gas and Electric Company.

II. Date of Filing of Certificate of Incorporation. The certificate of consolidation forming the corporation was filed by the Department of State on February 18, 1925.

III. Original Certificate Superseded. The certificate of incorporation, as amended heretofore, is hereby restated without further amendment or change to read as herein set forth in full:

1. The name of the corporation shall be AMERICAN ELECTRIC POWER COMPANY, INC.

2. The purposes for which the corporation is formed are:

(a) To acquire, hold and dispose of the stock, bonds, notes, debentures and other securities and obligations (hereinafter called "securities") of any person, firm, association, or corporation, private, public or municipal, or of any body politic, including, without limitation, securities of electric and gas utility companies; and while the owner of such securities, to possess and exercise in respect thereof all the rights, powers and privileges of ownership thereof, including voting power;

(b) To aid in any manner permitted by law any person, firm, association or corporation in whose securities the corporation may be interested, directly or indirectly, and to do any other act or thing permitted by law for the preservation, protection, improvement or enhancement of the value of such securities or the property represented thereby or securing the same or owned, held or possessed by such person, firm, association or corporation;

(c) To acquire, construct, own, maintain, operate and dispose of real or personal property used or useful in the business of an electric utility company or gas utility company and such other real or personal property as may be permitted by law; and

(d) To do everything necessary, proper, advisable or convenient for the accomplishment of the foregoing purposes, and to do all other things incidental to them or connected with them that are not forbidden by law or by this certificate of incorporation.

3. The city and county in which the office of the corporation is to be located are the City and County of New York.

4.1. The aggregate number of shares which the corporation is authorized to issue is 600,000,000 shares of Common Stock of the par value of $6.50 each.

4.2. Each share of the Common Stock shall be equal in all respects to every other share of the Common Stock. Every holder of record of the Common Stock shall have one vote for each share of Common Stock held by him or her for the election of directors and upon all other matters.

4.3. The corporation may, at any time and from time to time, issue and dispose of any of the authorized and unissued shares of the Common Stock for such consideration as may be fixed by the Board of Directors, subject to any provisions of law then applicable, and subject to the provisions of any resolutions of the stockholders of the corporation relating to the issue and disposition of such shares.

4.4. Upon any issuance for money or other consideration of any stock of the corporation, or of any securities convertible into any stock of the corporation, of any class whatsoever which may be authorized from time to time, no holder of stock of any kind shall have any preemptive or other right to subscribe for, purchase or receive any proportionate or other share of the stock or securities so issued, but the Board of Directors may dispose of all or any portion of such stock or securities as and when it may determine free of any such rights, whether by offering the same to stockholders or by sale or other disposition as the Board of Directors may deem advisable; provided, however, that if the Board of Directors shall determine to issue and sell any shares of Common Stock (including, for the purposes of this paragraph, any security convertible into Common Stock, but excluding shares of Common Stock and securities convertible into Common Stock theretofore reacquired by the corporation after having been duly issued, and excluding shares of Common Stock and securities convertible into Common Stock issued to satisfy conversion or option rights theretofore granted by the corporation) solely for money and other than by:

(i) a public offering thereof, or

(ii) an offering thereof to or through underwriters or dealers who shall agree promptly to make a public offering thereof, or

(iii) any other offering thereof which shall have been authorized or approved by the affirmative vote, cast in person or by proxy, of the holders of record of a majority of the outstanding shares of Common Stock entitled to vote at the stockholders' meeting at which action shall have been taken with respect to such other offering,

such shares of Common Stock shall first be offered *pro rata* , except that the corporation shall not be obligated to offer or to issue any fractional interest in a full share of Common Stock, to the holders of record of the then outstanding shares of Common Stock (excluding outstanding shares of Common Stock held for the benefit of holders of scrip certificates or other instruments representing fractional interests in a full share of Common Stock) upon terms which, in the judgment of the Board of Directors of the corporation, shall be not less favorable (without deduction of such reasonable compensation for the sale, underwriting or purchase of such shares by underwriters or dealers as may lawfully be paid by the corporation) to the purchaser than the terms upon which such shares are offered to others than such holders of Common Stock; and provided that the time within which such preemptive rights shall be exercised may be limited to such time as to the Board of Directors may seem proper, not less, however, than fourteen (14) days after the mailing of notice that such preemptive rights are available and may be exercised.

5. Directors shall hold office after the expiration of their terms until their successors are elected and have qualified. Directors need not be stockholders.

6. To the fullest extent permitted by the New York Business Corporation Law as it exists on the date hereof or as it may hereafter be amended, no director of the corporation shall be liable to the corporation or its stockholders for damages for any breach of duty as a director. Any repeal or modification of the foregoing sentence by the stockholders of the corporation shall not adversely affect any right or protection of a director of the corporation existing at the time of such repeal or modification.

7.1.(A) In addition to any affirmative vote required by law or this certificate of incorporation (any other provision of this certificate of incorporation notwithstanding), and except as otherwise expressly provided in paragraph 7.2:

(1) any merger or consolidation of the corporation or any Subsidiary (as hereinafter defined) with (i) any Interested Stockholder (as hereinafter defined) or (ii) any other corporation (whether or not itself an Interested Stockholder) which is, or after such merger or consolidation would be, an Affiliate (as hereinafter defined) of an Interested Stockholder; or

(2) any sale, lease, license, exchange, mortgage, pledge, transfer or other disposition (in one transaction or a series of transactions) to or with any Interested Stockholder or any Affiliate of any Interested Stockholder of any assets of the corporation or any Subsidiary having an aggregate Fair Market Value (as hereinafter defined) of $100,000,000 or more; or

(3) the issuance or transfer by the corporation or any Subsidiary (in one transaction or a series of transactions) of any securities of the corporation or any Subsidiary to any Interested Stockholder or any Affiliate of any Interested Stockholder having an aggregate Fair Market Value of $100,000,000 or more, other than the issuance of securities upon the conversion of convertible securities of the corporation or any Subsidiary which were not acquired by such Interested Stockholder (or such Affiliate) from the corporation or a Subsidiary; or

(4) the adoption of any plan or proposal for the liquidation or dissolution of the corporation proposed by or on behalf of any Interested Stockholder or any Affiliate of any Interested Stockholder; or

(5) any reclassification of securities (including any reverse stock split), or recapitalization or reorganization of the corporation, or any merger or consolidation of the corporation with any of its Subsidiaries, or any self tender offer for or repurchase of securities of the corporation by the corporation or any Subsidiary or any other transaction

(whether of not with or into or otherwise involving any Interested Stockholder) which has the effect, directly or indirectly, of increasing the proportionate share of the outstanding shares of any class or series of equity or convertible securities of the corporation or any Subsidiary which is directly or indirectly owned by any Interested Stockholder or any Affiliate of any Interested Stockholder;

shall require the affirmative vote of the holders of at least (i) seventy-five per centum of the combined voting power of the then issued and outstanding capital stock of all classes and series of the corporation having voting powers (the "Voting Stock"), voting together as a single class, and (ii) a majority of the combined voting power of the then issued and outstanding Voting Stock beneficially owned by persons other than such Interested Stockholder, voting together as a single class, given at any annual meeting of stockholders or at any special meeting called for that purpose. Such affirmative vote shall be required notwithstanding the fact that no vote may be required, or that a lesser percentage may be specified, by law, by any other provision of this certificate of incorporation or in any agreement with any national securities exchange or otherwise.

(B) The term "Business Combination" as used herein shall mean any transaction which is referred to in any one or more of clauses (1) through (5) of sub-paragraph (A) of this paragraph 7.1.

7.2. The provisions of paragraph 7.1 shall not be applicable to any particular Business Combination, and such Business Combination shall require only such affirmative vote, if any, as is required by law, any other provision of this certificate of incorporation, and any agreement with any national securities exchange, if all of the conditions specified in either of the following sub-paragraphs (A) or (B) are met:

(A) The Business Combination shall have been approved by a majority of the Disinterested Directors (as hereinafter defined).

(B) All of the following conditions shall have been met:

(1) The aggregate amount of the cash and the Fair Market Value as of the date of the consummation of the Business Combination (the "Consummation Date") of consideration other than cash to be received per share by holders of Common Stock in such Business Combination shall be at least equal to the highest of the following (it being intended that the requirements of this clause (1) shall be required to be met with respect to every share of outstanding Common Stock, whether or not the Interested Stockholder has previously acquired any shares of Common Stock):

(i) (if applicable) the highest per share price (including any brokerage commissions, transfer taxes and soliciting dealers' fees) paid by the Interested Stockholder for any shares of Common Stock acquired by it (x) within the five-year period immediately prior to the first public announcement of the terms of the proposed Business Combination (the "Announcement Date") or (y) in the transaction in which it became an Interested Stockholder, whichever is higher;

(ii) the Fair Market Value per share of Common Stock on the Announcement Date or on the date on which the Interested Stockholder became an Interested Stockholder (such latter date is referred to herein as the "Determination Date"), whichever is higher; and

(iii) an amount which bears the same or greater percentage relationship to the Fair Market Value per share of Common Stock on the Announcement Date as the highest per share price determined in clause (B)(1)(i) above bears to the Fair Market Value per share of Common Stock on the date of the commencement of the acquisition of the Common Stock by such Interested Stockholder.

(2) The aggregate amount of cash and the Fair Market Value as of the Consummation Date of consideration other than cash to be received per share by holders of shares of any other class or series of outstanding Voting Stock shall be at least equal to the highest of the following (it being intended that the requirements of this clause (2) shall be required to be met with respect to every class or series of outstanding Voting Stock, whether or not the Interested Stockholder has previously acquired any shares of a particular class or series of Voting Stock):

(i) (if applicable) the highest per share price (including any brokerage commissions, transfer taxes and soliciting dealers' fees) paid by the Interested Stockholder for any shares of such class or series of Voting Stock acquired by it (x) within the five-year period immediately prior to the Announcement Date or (y) in the transaction in which it became an Interested Stockholder, whichever is higher;

(ii) the Fair Market Value per share of such class or series of Voting Stock on the Announcement Date or on the Determination Date, whichever is higher;

(iii) (if applicable) the highest preferential amount per share to which the holders of shares of such class or series of Voting Stock are entitled in the event of any liquidation, dissolution or winding up of the corporation, whether voluntary or involuntary; and

(iv) an amount which bears the same or greater percentage relationship to the Fair Market Value per share of such class or series of Voting Stock on the Announcement Date as the highest per share price determined in clause (B)(2)(i) above bears to the Fair Market Value per share of such Voting Stock on the date of the commencement of the acquisition of such Voting Stock by such Interested Stockholder.

(3) The consideration to be received by holders of a particular class or series of outstanding Voting Stock (including Common Stock) shall be in cash or in the same form as the Interested Stockholder has previously paid for shares of such class or series of Voting Stock. If the Interested Stockholder has paid for shares of any class or series of Voting Stock with varying forms of consideration, the form of consideration to be received by each holder of such class or series of Voting Stock shall be, at the option of such holder, either cash or the form used by the Interested Stockholder to acquire the largest number of shares of such class or series of Voting Stock previously acquired by it prior to the Announcement Date. The price determined in accordance with clauses (1) and (2) of this sub-paragraph (B) shall be subject to appropriate adjustment in the event of any stock dividend, stock split, combination of shares or similar event.

(4) After the Determination Date and prior to the Consummation Date:

(i) except as approved by a majority of the Disinterested Directors, there shall have been no failure to declare and pay at the regular dates therefor the full amount of any dividends (whether or not cumulative) payable on any class or series of stock of the corporation having a preference over the Common Stock as to dividends or upon liquidation; and

(ii) there shall have been (x) no reduction in the quarterly rate of dividends paid on the Common Stock (except as necessary to reflect any subdivision of the Common Stock), except as approved by a majority of the Disinterested Directors, and (y) an increase in such quarterly rate of dividends paid on such Common Stock as necessary to reflect any reclassification (including any reverse stock split), recapitalization, reorganization, self tender offer for or repurchase of securities of the corporation by the corporation or any Subsidiary or any similar transaction which has the effect of reducing the number of outstanding shares of the Common Stock, unless the failure so to increase such quarterly rate is approved by a majority of the Disinterested Directors; and

(iii) such Interested Stockholder shall not have become the beneficial owner of any additional shares of Voting Stock except as part of the transaction which results in such Interested Stockholder becoming an Interested Stockholder or upon conversion of convertible securities acquired by it prior to becoming an Interested Stockholder or as a result of a pro rata stock dividend or stock split; and

(iv) such Interested Stockholder shall not have received the benefit, directly or indirectly (except proportionately as a stockholder), of any loans, advances, guarantees, pledges or other financial assistance or tax credits or other tax advantages provided by the corporation or any Subsidiary, whether in anticipation of or in connection with such Business Combination or otherwise; and

(v) such Interested Stockholder shall not have caused any material change in the corporation's business or capital structure, including, without limitation, the issuance of shares of capital stock of the corporation to any third party.

(5) A proxy or information statement describing the proposed Business Combination and complying with the requirements of the Securities Exchange Act of 1934, as amended (the "Act"), and the rules and regulations thereunder (or any subsequent provisions replacing the Act, rules and regulations), shall be mailed by and at the expense of the Interested Stockholder to public stockholders of the corporation at least 30 days prior to the Consummation Date (whether or not such proxy or information statement is required to be mailed pursuant to the Act). The proxy or information statement shall contain at the front thereof in a prominent place (i) any recommendation as to the advisability (or inadvisability) of the Business Combination which a majority of the Disinterested Directors may choose to state, and (ii) if a majority of the Disinterested Directors so requests, the opinion of a reputable national investment banking firm as to the fairness (or not) of such Business Combination from the point of view of the remaining public stockholders of the corporation (such investment banking firm to be engaged solely on behalf of the remaining public stockholders, to be paid a reasonable fee for their services by the corporation upon receipt of such opinion, to be unaffiliated with such Interested Stockholder, and, to be selected by a majority of the Disinterested Directors).

(6) The holders of all outstanding shares of Voting Stock not beneficially owned by the Interested Stockholder prior to the consummation of any Business Combination shall be entitled to receive in such Business Combination cash or other consideration for their shares of such Voting Stock in compliance with clauses (1), (2) and (3) of sub-paragraph (B) of this paragraph 7.2 (provided, however, that the failure of any such holders who are exercising their statutory rights to dissent from such Business Combination and receive payment of the fair value of their shares to exchange their shares in such Business Combination shall not be deemed to have prevented the condition set forth in this clause (6) from being satisfied).

7.3. The following terms shall be deemed to have the meanings specified below:

(A) The term "person" shall mean any individual, firm, corporation, group (as such term is used in Regulation 13D-G of the rules and regulations under the Act, as in effect on January 1, 1988) or other entity.

(B) The term "Interested Stockholder" shall mean any person (other than the corporation, any Subsidiary or any pension, profit sharing, employee stock ownership, employee savings or other employee benefit plan, or any dividend reinvestment plan, of the corporation or any Subsidiary or any trustee of or fiduciary with respect to any such plan acting in such capacity) who or which:

(1) is the beneficial owner, directly or indirectly, of more than five per centum of the combined voting power of the then outstanding Voting Stock; or

(2) is an Affiliate of the corporation and at any time within the five-year period immediately prior to the date in question was the beneficial owner, directly or indirectly, of more than five per centum of the combined voting power of the then outstanding Voting Stock; or

(3) is an assignee of or has otherwise succeeded to any shares of Voting Stock which were at any time within the five-year period immediately prior to the date in question beneficially owned by an Interested Stockholder, if such assignment or succession shall have occurred in the course of a transaction or series of transactions not involving a public offering within the meaning of the Securities Act of 1933, as amended (or any subsequent provisions replacing such).

(C) A person shall be deemed a "beneficial owner" of any Voting Stock:

(1) which such person or any of its Affiliates or Associates (as hereinafter defined) beneficially owns, directly or indirectly; or

(2) which such person or any of its Affiliates or Associates has (i) the right to acquire (whether such right is exercisable immediately or only after the passage of time), pursuant to any agreement, arrangement or understanding or upon the exercise of conversion rights, exchange rights, warrants or options, or otherwise, or (ii) the right to vote pursuant to any agreement, arrangement or understanding; or

(3) which is beneficially owned, directly or indirectly, by any other person with which such person or any of its Affiliates or Associates has any agreement, arrangement or understanding for the purpose of acquiring, holding, voting or disposing of any shares of Voting Stock.

(D) For the purpose of determining whether a person is an Interested Stockholder pursuant to sub-paragraph (B) of this paragraph 7.3, the number of shares of Voting Stock deemed to be outstanding shall include shares deemed owned through application of sub-paragraph (C) of this paragraph 7.3, but shall not include any other shares of Voting Stock which may be issuable pursuant to any agreement, arrangement or understanding, or upon exercise of conversion rights, exchange rights, warrants or options, or otherwise.

(E) The term "Affiliate" of, or a person "affiliated" with, a specified person shall mean a person that directly, or indirectly through one or more intermediaries, controls, or is controlled by, or is under common control with, the person specified.

(F) The term "Associate" as used to indicate a relationship with any person shall mean (1) any corporation or organization (other than the corporation or a Subsidiary) of which such person is an officer or partner or is, directly or indirectly, the beneficial owner of ten per centum or more of any class or series of equity securities, (2) any trust or other estate in which such person has a substantial beneficial interest or as to which such person serves as trustee or in a similar fiduciary capacity, and (3) any relative or spouse of such person, or any relative of such spouse, who has the same home as such person.

(G) The term "Subsidiary" shall mean any corporation of which a majority of any class or series of equity security is owned, directly or indirectly, by the corporation or by a Subsidiary or by the corporation and one or more Subsidiaries; provided, however, that for the purposes of the definition of Interested Stockholder set forth in sub-paragraph (B) of this paragraph 7.3, the term "Subsidiary" shall mean only a corporation of which a majority of each class or series of equity security is owned, directly or indirectly, by the corporation.

(H) The term "Fair Market Value" shall mean: (1) in the case of stock, the highest closing sale price during the 30-day period immediately preceding the date in question of a share of such stock on the Composite Tape for New York Stock Exchange-Listed Stocks, or, if such stock is not quoted on the Composite Tape, on the New York Stock Exchange, or if such stock is not listed on such Exchange, on the principal United States securities exchange registered under the Act on which such stock is listed or, if such stock is not listed on any such exchange, the highest closing bid quotation with respect to a share of such stock during the 30-day period preceding the date in question on the National Association of Securities Dealers, Inc. Automated Quotations System or any similar system then in use, or if no such quotations are available, the fair market value on the date in question of a share of such stock as determined by a majority of the Disinterested Directors in good faith, in each case with respect to any class or series of such stock, appropriately adjusted for any dividend or distribution in shares of such stock or any subdivision or reclassification of outstanding shares of such stock into a greater number of shares of such stock or any combination or reclassification of outstanding shares of such stock into a smaller number of shares of such stock; and (2) in the case of property other than cash or stock, the fair market value of such property on the date in question as determined by a majority of the Disinterested Directors in good faith.

(I) In the event of any Business Combination in which the corporation is the survivor, the phrase "consideration other than cash to be received" as used in clauses (1) and (2) of sub-paragraph (B) of paragraph 7.2 shall include the shares of Common Stock and/or the shares of any other class or series of outstanding Voting Stock retained by the holders of such shares.

(J) The term "Disinterested Director" shall mean any member of the Board of Directors of the corporation who is unaffiliated with, and not a nominee of, the Interested Stockholder and who was a member of the Board of Directors prior to the Determination Date, and any successor of a Disinterested Director who is unaffiliated with, and not a nominee of, the Interested Stockholder and is recommended to succeed a Disinterested Director by a majority of the total number of Disinterested Directors then on the Board of Directors.

(K) References to "highest per share price" shall in each case with respect to any class or series of stock reflect an appropriate adjustment for any dividend or distribution in shares of such stock or any subdivision or reclassification of outstanding shares of such stock into a greater number of shares of such stock or any combination or reclassification of outstanding shares of such stock into a smaller number of shares of such stock.

7.4. A majority of the Board of Directors of the corporation shall have the power and duty to determine for the purpose of these paragraphs 7.1 through 7.6, on the basis of information known to them after reasonable inquiry, whether a person is an Interested Stockholder. Once the Board of Directors has made a determination, pursuant to the preceding sentence, that a person is an Interested Stockholder, a majority of the total number of directors of the corporation who would qualify as Disinterested Directors shall have the power and duty to interpret all of the terms and provisions of these paragraphs 7.1 through 7.6, and to determine on the basis of information known to them after reasonable inquiry all facts necessary to ascertain compliance therewith, including, without limitation, (A) the number of shares of Voting Stock beneficially owned by any person, (B) whether a person is an Affiliate or Associate of another, (C) whether the assets which are the subject of any Business Combination have, or the consideration to be received for the issuance or transfer of securities by the corporation or any Subsidiary in any Business Combination has, an aggregate Fair Market Value of $100,000,000 or more and (D) whether all of the applicable conditions set forth in sub-paragraph (B) of paragraph 7.2 have been met with respect to any Business Combination. Any determination pursuant to this paragraph 7.4 made in good faith shall be binding and conclusive on all parties.

7.5. Nothing contained in these paragraphs 7.1 through 7.6 shall be construed to relieve any Interested Stockholder from any fiduciary obligation imposed by law.

7.6. Notwithstanding any other provisions of this certificate of incorporation or the by-laws of the corporation (and notwithstanding the fact that a lesser percentage may be specified by law, this certificate of incorporation or the by-laws of the corporation), the affirmative vote of the holders of at least (A) seventy-five per centum of the combined voting power of the then issued and outstanding Voting Stock, voting together as a single class, and (B) a majority of the combined voting power of the then issued and outstanding Voting Stock beneficially owned by persons other than an Interested Stockholder, voting together as a single class, given at any annual meeting of stockholders or at any special meeting called for that purpose, shall be required to amend, alter, change or repeal, or adopt any provisions inconsistent with, these paragraphs 7.1 through 7.6; provided, however, that the foregoing provisions of this paragraph 7.6 shall not apply to, and such vote shall not be required for, any such amendment, alteration, change, repeal or adoption approved by a majority of the disinterested Directors, and any such amendment, alteration, change, repeal or adoption so approved shall require only such vote, if any, as is required by law, any other provision of this certificate of incorporation or the by-laws of the corporation.

8. The Secretary of State of the State of New York is hereby designated as the agent of the corporation upon whom any process in any action or proceeding against it may be served. The address to which the Secretary of State shall mail a copy of any process against the corporation served upon him is: c/o CT Corporation System, 111 Eighth, New York, NY 10011.

9. The name of the registered agent upon whom and the address of the registered agent at which process against the corporation may be served is: c/o CT Corporation System, 111 Eighth, New York, NY 10011.

AMERICAN ELECTRIC POWER COMPANY, INC.
(Formerly American Gas & Electric Company)

BY-LAWS

As Amended April 28, 2009

As of 04/28/09

AMERICAN ELECTRIC POWER COMPANY, INC.
(Formerly American Gas and Electric Company)

BY-LAWS

Section 1. The annual meeting of the stockholders of the Company shall be held on the fourth Wednesday of April in each year, or on such other date as determined by the Board of Directors, at an hour and place within or without the State of New York designated by the Board of Directors. (As amended January 28, 1998.)

Section 2. Special meetings of the stockholders of the Company may be held upon call of the Board of Directors or of the Executive Committee, or of stockholders holding one-fourth of the capital stock, at such time and at such place within or without the State of New York as may be stated in the call and notice. (As amended July 26, 1989.)

Section 3. Notice of time and place of every meeting of stockholders shall be mailed at least ten days previous thereto to each stockholder of record who shall have furnished a written address to the Secretary of the Company for the purpose. Such further notice shall be given as may be required by law. But meetings may be held without notice if all stockholders are present, or if notice is waived by those not present.

Section 4. Except as otherwise provided by law, the holders of a majority of the outstanding capital stock of the Company entitled to vote at any meeting of the stockholders of the Company must be present in person or by proxy at such meeting of the stockholders of the Company to constitute a quorum. If, however, such majority shall not be represented at any meeting of the stockholders of the Company regularly called, the holders of a majority of the shares present or represented and entitled to vote thereat shall have power to adjourn such meeting to another time without notice other than announcement of adjournment at the meeting, and there may be successive adjournments for like cause and in like manner until the requisite amount of shares entitled to vote at such meeting shall be represented. (As amended May 20, 1952.)

Section 5. As soon as may be after their election in each year, the Board of Directors or the Executive Committee shall appoint three inspectors of stockholders' votes and elections to serve until the final adjournment of the next annual stockholders' meeting. If they fail to make such appointment, or if their appointees, or any of them, fail to appear at any meeting of stockholders, the Chairman of the meeting may appoint inspectors, or an inspector, to act at that meeting.

Section 6. Meetings of the stockholders shall be presided over by the Chairman of the Board, or if he is not present, by the President, or, if neither the Chairman of the Board nor the President is present, by a Vice President, and in his absence, by a Chairman to be elected at the meeting. The Secretary of the Company shall act as Secretary of such meetings, if present. (As amended January 23, 1979.)

Section 7. The Board of Directors shall consist of such number of directors, not less than nine (9) nor more than seventeen (17), as shall be determined from time to time as herein provided. Directors shall be elected at each annual meeting of stockholders and each director so elected shall hold office until the next annual meeting of stockholders and until his successor is elected and qualified. The number of directors to be elected at any annual meeting of stockholders shall, except as otherwise provided herein, be the number fixed in the latest resolution of the Board of Directors adopted pursuant to the authority contained in the next succeeding sentence and not subsequently rescinded. The Board of Directors shall have power from time to time and at any time when the stockholders are not assembled as such in an annual or special meeting, by resolution adopted by a majority of the directors then in office, or such greater number required by law, to fix, within the limits prescribed by this Section 7, the number of directors of the Company. If the number of directors is increased, the additional directors may, to the extent permitted by law, be elected by a majority of the directors in office at the time of the increase, or, if not so elected prior to the next annual meeting of stockholders, such additional directors shall be elected at such annual meeting. If the number of directors is decreased, then to the extent that the decrease does not exceed the number of vacancies in the Board then existing, such resolution may provide that it shall become effective forthwith, and to the extent that the decrease exceeds such number of vacancies such resolution shall provide that it shall not become effective until the next election

of directors by the stockholders. If the Board of Directors shall fail to adopt a resolution which fixes initially the number of directors, the number of directors shall be twelve (12). If, after the number of directors shall have been fixed by such resolution, such resolution shall cease to be in effect other than by being superseded by another such resolution, or it shall become necessary that the number of directors be fixed by these By-Laws, the number of directors shall be that number specified in the latest of such resolutions, whether or not such resolution continues in effect. (As amended April 23, 1997.)

Section 8. Vacancies in the Board of Directors may be filled by the Board at any meeting.

Section 9. Meetings of the Board of Directors shall be held at times fixed by resolution of the Board, or upon the call of the Executive Committee, the Chairman of the Board, the President or the Presiding Director and the Secretary or officer performing his duties shall give reasonable notice of all meetings of directors; provided, that a meeting may be held without notice immediately after the annual election at the same place, and notice need not be given of regular meetings held at times fixed by resolution of the Board. Meetings may be held at any time without notice if all the directors are present, or if those not present waive notice either before or after the meeting. The number of directors necessary to constitute a quorum for the transaction of business shall be any number, which may be less than a majority of the Board but not less than one-third of its number, duly assembled at a meeting of such directors. Any one or more members of the Board or of any committee thereof may participate in a meeting of the Board or such committee by means of a conference telephone or similar communications equipment allowing all persons participating in the meeting to hear each other at the same time. Participation by such means constitutes presence in person at a meeting. (As amended December 10, 2003.)

Section 10. The Board of Directors, by resolution adopted by a majority of the entire Board, may designate among its members an Executive Committee and one or more other committees, each consisting of three (3) or more directors, and each of which, to the extent provided in such resolution, shall have all the authority of the Board. However, no such committee shall have authority as to any of the following matters:

(a) The submission to shareholders of any action as to which shareholders' authorization is required by law;

(b) The filling of vacancies in the Board of Directors or in any committee;

(c) The fixing of compensation of any director for serving on the Board or on any committee;

(d) The amendment or repeal of these By-Laws or the adoption of new By-Laws; or

(e) The amendment or repeal of any resolution of the Board which by its terms shall not be so amendable or repealable.

The Board of Directors shall have the power at any time to increase or decrease the number of members of any committee (provided that no such decrease shall reduce the number of members to less than three), to fill vacancies on it, to remove any member of it, and to change its functions or terminate its existence. Each committee may make such rules for the conduct of its business as it may deem necessary. A majority of the members of a committee shall constitute a quorum.

The Board of Directors shall also have the power to designate or appoint at any time and from time to time one or more individuals who have acquired as a former director or officer of the Company substantial experience with the Company's affairs as an Honorary Director, such individual or individuals to meet with the Board of Directors, or certain of the directors, at the invitation of the Chairman of the Board, from time to time for the purpose of rendering advice to the Board of Directors or such directors with respect to the Company's affairs for such compensation as shall be payable to directors of the Company who are not serving, at the time in question, as officers or employees of the Company or of American Electric Power Service Corporation; provided, however, that under no circumstances shall such individual or individuals be authorized or empowered to participate in the management or direction of the affairs of the Company or to perform the functions of a director or officer of the Company (as each such term is defined by the provisions of Rule 70 promulgated by the Securities and Exchange Commission under the provisions of Section 17(c) of the Public Utility Holding Company Act of 1935, as such definition shall be in effect at any time in question) or any similar function. (As amended April 26, 1978.)

Section 11. The Board of Directors, as soon as may be after the election each year, shall appoint one of their number Chairman of the Board and one of their number President of the Company, and shall appoint one or more Vice Presidents, a Secretary and a Treasurer, and from time to time shall appoint such other officers as they deem proper. The same person may be appointed to more than one office. (As amended January 23, 1979.)

Section 12. The term of office of all officers shall be one year, or until their respective successors are elected but any officer may be removed from office at any time by the Board of Directors, unless otherwise agreed by agreement in writing duly authorized by the Board of Directors. (As amended December 15, 2003.)

Section 13. The officers of the Company shall have such powers and duties as generally pertain to their offices, respectively, as well as such powers and duties as from time to time shall be conferred by the Board of Directors or the Executive Committee.

Section 14. The shares of stock of the Company shall be represented by a certificate or shall be uncertificated shares as provided for under New York law. Shares in the capital stock of the Company shall be transferred or assigned on the books of the Company only upon (i) surrender to the Company or its transfer agent of a certificate representing shares, duly endorsed or accompanied by proper evidence of succession, assignation, or authority to transfer, with such proof of the authenticity of the signature as the Company or its agents may reasonably require in the case of shares evidenced by a certificate or certificates or (ii) receipt of transfer instructions from the registered owner of uncertificated shares reasonably acceptable to the Company and its agents. (As amended December 12, 2007.)

Section 15. To the fullest extent permitted by law, the Company shall indemnify any person made, or threatened to be made, a party to any action or proceeding (formal or informal), whether civil, criminal, administrative or investigative and whether by or in the right of the Company or otherwise, by reason of the fact that such person, such person's testator or intestate, is or was a director, officer or employee of the Company, or of any subsidiary or affiliate of the Company, or served any other corporation, partnership, joint venture, trust, employee benefit plan or other enterprise in any capacity at the request of the Company, against all loss and expense including, without limiting the generality of the foregoing, judgments, fines (including excise taxes), amounts paid in settlement and attorneys' fees and disbursements actually and necessarily incurred as a result of such action or proceeding, or any appeal therefrom, and all legal fees and expenses incurred in successfully asserting a claim for indemnification pursuant to this Section 15; provided, however, that no indemnification may be made to or on behalf of any director, officer or employee if a judgment or other final adjudication adverse to the director, officer or employee establishes that such person's acts were committed in bad faith or were the result of active and deliberate dishonesty and were material to the cause of action so adjudicated, or that such person personally gained in fact a financial profit or other advantage to which such person was not legally entitled.

In any case in which a director, officer or employee of the Company (or a representative of the estate of such director, officer or employee) requests indemnification, upon such person's request the Board of Directors shall meet within sixty days thereof to determine whether such person is eligible for indemnification in accordance with the standard set forth above. Such a person claiming indemnification shall be entitled to indemnification upon a determination that no judgment or other final adjudication adverse to such person has established that such person's acts were committed in bad faith or were the result of active and deliberate dishonesty and were material to the cause of action so adjudicated, or that such person personally gained in fact a financial profit or other advantage to which such person was not legally entitled. Such determination shall be made:

(a) by the Board of Directors acting by a quorum consisting of directors who are not parties to the action or proceeding in respect of which indemnification is sought; or

(b) if such quorum is unobtainable or if directed by such quorum, then by either (i) the Board of Directors upon the opinion in writing of independent legal counsel that indemnification is proper in the circumstances because such person is eligible for indemnification in accordance with the standard set forth above, or (ii) by the stockholders upon a finding that such person is eligible for indemnification in accordance with the standard set forth above. Notwithstanding the foregoing, a determination of eligibility for indemnification may be made in any manner permitted by law.

To the fullest extent permitted by law, the Company shall promptly advance to any person made, or threatened to be made, a party to any action or proceeding (formal or informal), whether civil, criminal, administrative or investigative and whether by or in the right of the Company or otherwise, by reason of the fact that such person, such person's testator or intestate, is or was a director, officer or employee of the Company, or of any subsidiary or affiliate of the Company, or served any other corporation or any partnership, joint venture, trust, employee benefit plan or other enterprise in any capacity at the request of the Company, expenses incurred in defending such actions or proceedings, upon request of such person and receipt of an undertaking by or on behalf of such director, officer or employee to repay amounts advanced to the extent that it is ultimately determined that such person was not eligible for indemnification in accordance with the standard set forth above.

The foregoing provisions of this Section 15 shall be deemed to be a contract between the Company and each director, officer or employee of the Company, or its subsidiaries or affiliates, and any modification or repeal of this Section 15 or such provisions of the New York Business Corporation Law shall not diminish any rights or obligations existing prior to such modification or repeal with respect to any action or proceeding theretofore or thereafter brought; provided, however, that the right of indemnification provided in this Section 15 shall not be deemed exclusive of any other rights to which any director, officer or employee of the Company may now be or hereafter become entitled apart from this Section 15, under any applicable law including the New York Business Corporation Law. Irrespective of the provisions of this Section 15, the Board of Directors may, at any time or from time to time, approve indemnification of directors, officers, employees or agents to the full extent permitted by the New York Business Corporation Law at the time in effect, whether on account of past or future actions or transactions. Notwithstanding the foregoing, the Company shall enter into such additional contracts providing for indemnification and advancement of expenses with directors, officers or employees of the Company or its subsidiaries or affiliates as the Board of Directors shall authorize, provided that the terms of any such contract shall be consistent with the provisions of the New York Business Corporation Law.

As used in this Section 15, the term "employee" shall include, without limitation, any employee, including any professionally licensed employee, of the Company. Such term shall also include, without limitation, any employee, including any professionally licensed employee, of a subsidiary or affiliate of the Company who is acting on behalf of the Company.

The indemnification provided by this Section 15 shall be limited with respect to directors, officers and controlling persons to the extent provided in any undertaking entered into by the Company or its subsidiaries or affiliates, as required by the Securities and Exchange Commission pursuant to any rule or regulation of the Securities and Exchange Commission now or hereafter in effect.

If any action with respect to indemnification of directors or officers is taken by way of amendment to these By-Laws, resolution of the Board of Directors, or by agreement, then the Company shall give such notice to the stockholders as is required by law.

The Company may purchase and maintain insurance on behalf of any person described in this Section 15 against any liability which may be asserted against such person whether or not the Company would have the power to indemnify such person against such liability under the provisions of this Section 15 or otherwise.

If any provision of this Section 15 shall be found to be invalid or limited in application by reason of any law, regulation or proceeding, it shall not affect any other provision or the validity of the remaining provisions hereof.

The provisions of this Section 15 shall be applicable to claims, actions, suits or proceedings made, commenced or pending after the adoption hereof, whether arising from acts or omissions to act occurring before or after the adoption hereof. (As amended October 29, 1986.)

Section 16. These By-Laws may be amended or added to at any meeting of the Board of Directors by affirmative vote of a majority of all of the directors, if notice of the proposed change has been delivered or mailed to the directors five days before the meeting, or if all the directors are present, or if all not present assent in writing to such change; provided, however, that the provisions of Section 7 relating to the number of directors constituting the Board of Directors may be amended only by the affirmative vote, in person or by proxy, of the holders of a majority of the outstanding shares of capital stock entitled to vote at any meeting of the stockholders of the Company; and provided further that the provisions of Section 7 other than those relating to the number of directors constituting the Board of Directors, and the provisions of this Section 16 may be amended or added to only by the affirmative vote, in person or by proxy, of the holders of two-thirds of the outstanding shares of capital stock entitled to vote at any meeting of the stockholders of the Company; and provided further, in the event of any such amendment or addition pursuant to vote by the stockholders of the Company, that such amendment or addition, or a summary thereof, shall have been set forth or referred to in the notice of such meeting. (As renumbered and amended October 29, 1986.)

Section 17. Each holder of common stock shall have one vote for every share of common stock entitled to vote which is registered in his or her name on the record date for the meeting. In cases where the number of nominees is less than or equal to the number of directors to be elected, each director to be elected by stockholders shall be elected by the vote of the majority of the votes cast at any meeting for the election of directors at which a quorum is present. For purposes of this Section 17, a majority of votes cast shall mean that the number of votes cast “for” a director’s election exceeds 50% of the total number of votes cast with respect to that director’s election. Votes cast shall include votes “for,” “against” or to withhold authority in each case and exclude abstentions with respect to that

director's election. In cases where the number of nominees exceeds the number of directors to be elected, each director to be elected by stockholders shall be elected by the vote of a plurality of the votes cast at any meeting for the election of directors at which a quorum is present.

If a nominee for director who is an incumbent director is not elected at a meeting of stockholders and no successor has been elected at the meeting, the director shall tender his or her resignation to the Board of Directors promptly after the certification of the election results by the inspector of elections. The Committee on Directors and Corporate Governance shall make a recommendation to the Board of Directors whether or not to accept the tendered resignation. The Board of Directors shall make the decision whether or not to accept the tendered resignation, taking into account the Committee on Directors and Corporate Governance's recommendation. The Board's decision about the tendered resignation, and the rationale behind the decision, shall be disclosed in a public announcement within 90 days after the date of the certification of the election results by the inspector of elections. The Committee on Directors and Corporate Governance in making its recommendation, and the Board of Directors in making the decision, may consider any factors or other information that they consider appropriate and relevant. The director who tenders his or her resignation shall not participate in the recommendation of the Committee on Directors and Corporate Governance or the decision of the Board of Directors about his or her resignation. If the incumbent director's resignation is not accepted by the Board of Directors, such director shall continue to serve until the next annual meeting and until his or her successor is duly elected, or his or her earlier resignation or removal. If a director's resignation is accepted by the Board of Directors pursuant to this By-Law, or if a nominee for director is not elected and the nominee is not an incumbent director, then the Board of Directors, in its sole discretion, may fill any resulting vacancy pursuant to the provisions of Sections 7 and 8 or may decrease the size of the Board of Directors pursuant to the provisions of Section 7. (As amended April 28, 2009.)

TRANSMISSION COORDINATION AGREEMENT

Between

**Public Service Company of Oklahoma,
Southwestern Electric Power Company,
West Texas Utilities Company,**

and

American Electric Power Service Corporation

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TRANSMISSION COORDINATION AGREEMENT

Between

Public Service Company of Oklahoma,
Southwestern Electric Power Company,
West Texas Utilities Company

and

American Electric Power Service Corporation

This TRANSMISSION COORDINATION AGREEMENT, hereinafter called "Agreement," is made and entered into as of the _____ day of _________, 2002, by and among West Texas Utilities Company ("WTU"), Public Service Company of Oklahoma ("PSO") and Southwestern Electric Power Company ("SWEPCO"), hereinafter separately referred to as "Company" and jointly as "Companies," and American Electric Power Service Corporation ("AEPSC").

WHEREAS, Companies are the owners and operators of interconnected generation, transmission and distribution facilities with which they are engaged in the business of transmitting and selling electric power to the general public, to other entities and to other electric utilities; and

WHEREAS, Companies achieve economic benefits for their customers through coordinated planning, operation and maintenance of their transmission facilities in the SPP;

NOW, THEREFORE, the Companies and AEPSC mutually agree as follows:

ARTICLE I

TERM OF AGREEMENT

1.1 Effective Date

This Agreement shall become effective as of the date American Electric Power Company, Inc. restructures its operating companies pursuant to Orders issued by the Federal Energy Regulatory Commission ("FERC" or "Commission") in Docket Nos. EC01-130-000 and ER01-2668-000, or such later date as is established by the FERC. This Agreement shall continue in force and effect for a term of one year from the effective date and continue from year to year thereafter until terminated by written notice given by any Company to the other Companies and to AEPSC. Such written notice shall become effective within 30 days of receipt.

1.2 Periodic Review

This Agreement will be reviewed periodically by the Coordinating Committee, as defined herein, to determine whether revisions are necessary to meet changing conditions. In the event that revisions are made by the Companies pursuant to Section 8.5, and after requisite approval or acceptance for filing by the appropriate regulatory authorities, the Coordinating Committee may thereafter, for the purpose of ready reference to a single document, prepare for distribution to the Companies an amended document reflecting all changes in and additions to this Agreement with notations thereon of the date amended.

ARTICLE II

DEFINITIONS

For purposes of this Agreement, the following definitions shall apply:

2.1 Agreement shall mean this Transmission Coordination Agreement including all attachments and schedules applying thereto and any amendments made hereafter.

2.2 Ancillary Services shall mean those services that are necessary to support the transmission of capacity and energy from resources to loads while maintaining reliable operation of the Companies' transmission facilities in accordance with Good Utility Practice, as that term is defined in the Open Access Transmission Tariff.

2.3 Company Demand shall mean the demand in megawatts of all retail and wholesale power customers in the SPP on whose behalf the Company, by statute, franchise, regulatory requirement, or contract, has undertaken an obligation to construct and operate its transmission system to meet the reliable electric needs of such customers, integrated over a period of one hour, plus the losses incidental to that service.

2.4 Company Peak Demand for a period shall be the highest Company Demand for any hour during the period.

2.5 Control Area shall mean an electric power system or combination of electric power systems to which a common automatic generation control scheme is applied for the purposes specified in the Open Access Transmission Tariff.

2.6 Coordinating Committee shall mean the organization established pursuant to Section 4.1 of this Agreement and whose duties are more fully set forth herein.

2.7 Designated Agent shall mean any entity that performs actions or functions on behalf of the Companies, an Eligible Customer (as that term is defined in the Open Access Transmission Tariff), or the Transmission Customer required under the Open Access Transmission Tariff.

2.8 Direct Assignment Facilities shall mean facilities or portions of facilities located in the SPP that are constructed by the Companies for the sole use or benefit of a particular Transmission Customer requesting service under the Open Access Transmission Tariff.

2.9 Generating Unit shall mean an electric generator, together with its prime mover and all auxiliary and appurtenant devices and equipment designed to be operated as a unit for the production of electric capacity and energy.

2.10 Hour shall mean a clock-hour.

2.11 Month shall mean a calendar month consisting of the applicable 24-Hour periods as measured by Central Standard Time.

2.12 Network Integration Transmission Service shall mean the transmission service provided in the SPP under Part III of the Open Access Transmission Tariff.

2.13 Open Access Transmission Tariff shall mean the Open Access Transmission Tariff or Tariffs filed on behalf of the Companies with the Federal Energy Regulatory Commission by AEPSC or a regional transmission entity **,** as such may be amended from time to time.

2.14 Point-to-Point Transmission Service shall mean the reservation and transmission of capacity and energy on either a firm or non-firm basis from the points of receipt to the points of delivery in the SPP under Part II of the Open Access Transmission Tariff.

2.15 PUCT shall mean the Public Utility Commission of Texas.

2.16 Scheduling, System Control and Dispatch Service shall mean the service required to schedule the movement of power through, out of, within, or into a Control Area, as specified in Schedule 1 of the Open Access Transmission Tariff.

2.17 SPP shall mean the Southwest Power Pool, or its successor in function.

2.18 Transmission Customer shall mean any Eligible Customer as defined in the Open Access Transmission Tariff (or its Designated Agent) that (i) executes a Service Agreement, or (ii) requests in writing that the Companies, or their agent, file with the Federal Energy Regulatory Commission a proposed unexecuted Service Agreement to receive service under the Open Access Transmission Tariff. This term is used in the Part I Common Service Provisions of the Open Access Transmission Tariff to include customers receiving service under Part II and Part III of the Open Access Transmission Tariff.

2.19 Transmission Service shall mean service provided in the SPP under Part II or Part III of the Open Access Transmission Tariff.

2.20 Transmission System shall mean the facilities owned, controlled or operated by the Companies that are used to provide transmission service in the SPP under Parts II and III of the Open Access Transmission Tariff.

2.21 Transmission System Operator shall mean that party that is charged with monitoring the reliability of the Companies' Transmission System.

ARTICLE III

OBJECTIVES

3.1 Purposes

The purposes of this Agreement are (a) to provide the contractual basis for the coordinated planning and operation of the Companies' transmission facilities in the SPP to achieve optimal economies, consistent with reliable electric service and regulatory and environmental requirements and (b) to provide the means by which the Companies will allocate among themselves the revenue that they receive for Part II and Part III and Ancillary Services provided in the SPP under the Open Access Transmission Tariff. Any revenue received by a Company(ies) from the provision of service under any other Part of the Open Access Transmission Tariff or any agreement, tariff or rate schedule other than the Open Access Transmission Tariff, will be kept by the Company(ies) that is (are) the party(ies) to such Part, agreement, tariff or rate schedule.

ARTICLE IV

COORDINATING COMMITTEE

4.1 Coordinating Committee

The Coordinating Committee is the organization established to oversee planning, construction, operation, and maintenance of the Transmission System. The Coordinating Committee members shall include at least one member representing each of the parties hereto who is not a member of the Operating Committee established under the Restated and Amended AEP-West Operating Agreement. The chairperson, who shall be appointed by the chief executive officer of the holder of the majority of the common stock of the Companies, shall appoint the member representative (s) of the Companies. Other than the chairperson, there shall be the same number of members representing each Company. The majority of the members on the Coordinating Committee shall be representatives of the Companies. Coordinating Committee decisions shall be by a majority vote of those present. However, any member not present may vote by proxy. The chairperson shall vote only in case of a tie. No employee of the Companies engaged in marketing, sales or brokering of electricity or an employee of any affiliate engaged or involved in the transmission, sale, or marketing of electricity or natural gas shall be appointed to, or serve on, the Coordinating Committee.

4.2 Responsibilities of the Coordinating Committee

The Coordinating Committee shall be responsible for overseeing:

(a) the Companies in the coordinated planning of their transmission facilities in the SPP, including studies for transmission planning purposes and their interaction with independent system operators and other regional bodies that are interested in transmission planning; and

(b) compliance with the terms of the Open Access Transmission Tariff and the rules and regulations of the Federal Energy Regulatory Commission relating thereto.

4.3 Delegation and Acceptance of Authority

The Companies hereby delegate to the Coordinating Committee, and the Coordinating Committee hereby accepts, responsibility and authority for the duties listed in this Article and elsewhere in this Agreement.

4.4 Reporting

The Coordinating Committee shall provide periodic summary reports of its activities under this Agreement to the transmission and reliability function employees of the Companies and shall keep such employees of the Companies informed of situations or problems that may materially affect the reliability of the Transmission System. Furthermore, the Coordinating Committee agrees to report to the transmission and reliability function employees of the Companies in such additional detail as is requested regarding specific issues or projects under its oversight.

ARTICLE V

PLANNING

5.1 Transmission Planning

The Companies agree that their respective transmission facilities in the SPP shall be planned and developed on the basis that their combined individual systems constitute a coordinated transmission system and that the objective of their planning shall be to maximize the economy, efficiency and reliability of the Transmission System as a whole. In this connection, the Coordinating Committee will from time to time, as it deems appropriate, direct studies for transmission planning purposes.

ARTICLE VI

TRANSMISSION

6.1 Delegation to the Transmission System Operator

The Companies shall delegate to the Transmission System Operator the responsibility and authority to act on behalf of the Companies for all of the requirements and purposes of the Open Access Transmission Tariff.

6.2 Transmission Facilities

Each Company shall make its transmission facilities in the SPP available to the Transmission System Operator.

6.3 Direct Assignment Facilities

Each Company shall make Direct Assignment Facilities available to the Transmission System Operator as may be required to provide service to a particular
Transmission Customer requesting service under the Open Access Transmission Tariff.

6.4 Transmission Service Revenues

(a) The Companies shall share transmission service revenues obtained from the use of the transmission facilities that comprise the Transmission System in accordance with Schedule A to this Agreement. Transmission service revenues are those revenues received for service provided under the Open Access Transmission Tariff. The Companies' annual transmission revenue requirements are shown on Schedule B to this Agreement and shall be revised whenever there is a change to the annual transmission revenue requirements in Attachment H to the Open Access Transmission Tariff or a change to the annual transmission revenue requirements underlying the rates set forth in Schedules 7 and 8 to the Open Access Transmission Tariff. Future revisions to the transmission revenue requirements ratios set forth in Schedule B will be made by the Companies' making an appropriate filing with the Commission, if required by law. Such changes shall become effective as of the date accepted or approved by the Commission, subject to refund if the Commission so orders.

(b) Revenues received for Ancillary Services shall be allocated among the Companies in accordance with the revenue ratios set forth in Schedule C. Future revisions to the revenue ratios set forth in Schedule C will be made by the Companies' making an appropriate filing with the Commission, if required by la w. Such changes shall become effective as of the date accepted or approved by the Commission, subject to refund if the Commission so orders.

(c) Revenues received for third-party use of Direct Assignment Facilities shall be distributed to the Company(ies) owning such facilities.

(d) The distribution to the Companies of revenues received for stranded costs received from third-party customers under the Open Access Transmission Tariff shall be determined on a case-by-case basis and shall be filed with the Commission, if required by law.

(e) The distribution to the Companies of revenues received for new transmission facilities received from third-party customers under the Open Access Transmission Tariff shall be determined on a case-by-case basis and shall be filed with the Commission, if required by law.

(f) Revenues received for Transmission System studies performed for the benefit of a Transmission Customer under Part II or Part III of the Open Access Transmission Tariff shall be allocated to each Company as applicable, in proportion to the ratio of each Company's number of transmission pole miles of the Transmission System, as such number of transmission pole miles is reported in each Company's Form 1 annual report, over the total number of transmission pole miles of the Transmission System.

6.5 Payment of Costs for Network Use

The Transmission System Operator shall bill each of the Companies for the amount due to the Transmission System Operator in each Month for their use of Network Integration Transmission Service and Ancillary Services under the Open Access Transmission Tariff on the basis set forth in the Open Access Transmission Tariff.

6.6 Payment of Costs for Point-to-Point Transmission Service

(a) The cost of Transmission Service on the Transmission System for third party off-system sales by a Company shall be borne by the selling Company(ies).

(b) The cost of Transmission Service provided by a third-party for off-system sales by a Company shall be borne by the selling Company(ies).

ARTICLE VII

ANCILLARY SERVICES

7.1 Ancillary Services

(a) Each Company shall make available Ancillary Services as required to provide service under the Open Access Transmission Tariff.

(b) Revenues received for Ancillary Services will be allocated between the Companies in accordance with Section 6.4(b) of this Agreement.

ARTICLE VIII

GENERAL

8.1 Regulatory Authorization

This Agreement is subject to certain regulatory approvals and the Companies shall diligently seek all necessary regulatory authorization for this Agreement.

8.2 Effect on Other Agreements

This Agreement shall not modify the obligations of any of the Companies under any agreement between such Company and others not parties to this Agreement in effect on the effective date of this Agreement.

8.3 Waivers

Any waiver at any time by a Company of its rights with respect to a default by any other Company under this Agreement shall not be deemed a waiver with respect to any subsequent default of similar or different nature.

8.4 Successors and Assigns; No Third Party Beneficiary

This Agreement shall inure to and be binding upon the successors and assigns of the respective Companies, but shall not be assignable by any of the Companies without the written consent of the other Companies, except upon foreclosure of a mortgage or deed of trust. Nothing expressed or mentioned or to which reference is made in this Agreement is intended or shall be construed to give any person or corporation other than the Companies any legal or equitable right, remedy or claim under or in respect of this Agreement or any provision herein contained, expressly or by reference, or any schedule hereto, this Agreement, any such schedule and any and all conditions and provisions hereof and thereof being intended to be and being for the sole exclusive benefit of the Companies, and for the benefit of no other person or corporation.

8.5 Amendment

It is contemplated by the Companies that it may be appropriate from time to time to change, amend, modify or supplement this Agreement or the schedules that are attached to this Agreement, to reflect changes in operating practices or costs of operations or for other reasons. This Agreement or such schedules may be changed, amended, modified or supplemented by an instrument in writing executed by all of the Companies subject to any required approval or acceptance for filing by the appropriate regulatory authorities.

8.6 Independent Contractors

By entering into this Agreement the Companies shall not become partners, and as to each other and to third persons, the Companies shall remain independent contractors in all matters relating to this Agreement.

8.7 Responsibility and Liability

The liability of the Companies shall be several, not joint or collective. Each Company shall be responsible only for its obligations, and shall be liable only for its
proportionate share of the costs and expenses as provided in this Agreement, and any liability resulting here from. Each Company will defend, indemnify, and save harmless the other Companies hereto from and against any and all liability, loss, costs, damages, and expenses, including reasonable attorney's fees, caused by or growing out of the gross negligence, willful misconduct, or breach of this Agreement by such indemnifying Company.

IN WITNESS WHEREOF, each Company has caused this Agreement to be executed and attested by its duly authorized officers.

WEST TEXAS UTILITIES COMPANY

Attest:

________________________ By:______________________________

Secretary AEP – Texas State President

PUBLIC SERVICE COMPANY OF OKLAHOMA

Attest:

________________________ By:______________________________

Secretary Vice President

SOUTHWESTERN ELECTRIC POWER COMPANY

Attest:

__________________________ By:_________________________________
Secretary Vice President

AMERICAN ELECTRIC POWER SERVICE CORPORATION

Attest:

__________________________ By:_________________________________
Secretary Senior Vice President

SCHEDULE A

ALLOCATION OF TRANSMISSION REVENUES

The revenue the Transmission System Operator receives pursuant to Section 6.4 of the Agreement for service provided in the SPP by the Companies under Parts II and III of the Open Access Transmission Tariff, other than revenues received pursuant to Sections 26 (Stranded Cost Recovery), 27 (Compensation for New Facilities and Redispatch Costs), and 34.4 (Redispatch Charge) thereof and for System and Facilities Studies made pursuant to Sections 19 (Additional Study Procedures for Firm Point-to-Point Transmission Service Requests) and 32 (Additional Study Procedures for Network Integration Transmission Service Requests), will be allocated among the Companies based on the ratios determined in accordance with Schedule B and Schedule C.

Revenues related to studies of the Transmission System performed for the benefit of Transmission Customers under Part II or Part III of the Open Access Transmission Tariff will be allocated among the Companies as applicable, in proportion to their respective number of transmission pole miles on the Transmission System. Direct Assignment Facilities revenues will be assigned to the Companies in proportion to the related costs that each of them incurred. Assignment of revenues received from a third party related to stranded cost or new transmission facilities shall be determined on a case-by-case basis.

SCHEDULE B

ANNUAL TRANSMISSION REVENUE REQUIREMENTS RATIOS

From time to time the Coordinating Committee will calculate for each of the Companies its Transmission Revenue Requirements Ratios set forth below. A Company's Transmission Revenue Requirements Ratio for revenue received under Part III of the Open Access Transmission Tariff shall be a fraction, the numerator of which is the Company's transmission revenue requirement that is used to calculate the Annual Transmission Revenue Requirements amount for the AEP West Zone – SPP set forth on Attachment H to the Open Access Transmission Tariff (herein called the Company Revenue Requirement) and the denominator of which is the sum of the Company Revenue Requirement for all of the Companies. A Company's Transmission Revenue Requirement Ratio for revenue received under Part II of the Open Access Transmission Tariff shall be a fraction, the numerator of which is the Company's transmission revenue requirement that is used to calculate the Annual Transmission Revenue Requirements underlying the rates set forth for the AEP West Zone – SPP on Schedules 7 and 8 to the Open Access Transmission Tariff and the denominator of which is the sum of the Company Revenue Requirements for all of the Companies.

Allocation Ratio for Revenue Received Under Part II and Part III of the Open
Access Transmission Tariff for service in the SPP.

	Revenue Requirement	Revenue Requirement Ratio
PSO	$ 37,353,669	42.12112%
SWEPCO	$ 51,123,364	57.64823%
WTU	$ 204,546	0.23065%
TOTAL	$ 88,681,579	100.00000%

SCHEDULE C

ALLOCATION OF ANCILLARY SERVICE REVENUES

The revenues the Transmission System Operator receives pursuant to Schedules 1 through 6 under the Open Access Transmission Tariff shall be allocated among the Companies as set forth below. Future revisions to the revenue ratios set forth in Schedule C will be made by the Companies' making an appropriate filing with the Commission, if required by law. Such changes shall become effective as of the date accepted or approved by the Commission, subject to refund if the Commission so orders.

(a) Revenues received from System Scheduling, System Control and Dispatch Service (AEP West Zone – SPP) under Schedule 1 of the Open Access Transmission Tariff will be allocated among PSO, SWEPCO and WTU based on the following ratio:

PSO	49.23%
SWEPCO	50.63%
WTU	0.14%

(b) Revenues received from System Reactive Supply and Voltage Control from Generation Sources Service (AEP West Zone – SPP) under Schedule 2 of the Open Access Transmission Tariff will be allocated between PSO and SWEPCO based on the following ratio:

PSO	39.53%
SWEPCO	60.47%

(c) Revenues received from System Regulation and Frequency Response Service (AEP West Zone – SPP) under Schedule 3 will be allocated between PSO and SWEPCO based on the following ratio:

PSO	40.00%
SWEPCO	60.00%

(d) Revenues received for and energy exchanged as part of System Energy Imbalance Service rendered under Schedule 4 will be allocated in the same manner as margin from off system sales and purchases as set forth in Service Schedule B to the Restated and Amended AEP-West Operating Agreement.

(e) Revenues received from System Operating Reserve - Spinning Reserve Service (AEP West Zone – SPP) under Schedule 5 and from System Operating Reserve – Supplemental Reserve Service (AEP West Zone – SPP) under Schedule 6 for load served in the PSO/SWEPCO Control Area will be allocated between PSO and SWEPCO based on the following ratio:

PSO	35.91%
SWEPCO	64.09%

AMERICAN ELECTRIC POWER SERVICE CORPORATION

CHANGE IN CONTROL AGREEMENT

As Revised Effective November 1, 2009

Whereas, American Electric Power Service Corporation, a New York corporation, including any of its subsidiary companies, divisions, organizations, or affiliated entities (collectively referred to as "AEPSC") considers it essential to its best interests and the best interests of the shareholders of the American Electric Power Company, Inc., a New York corporation, (hereinafter referred to as "Corporation") to foster the continued employment of key management personnel; and

Whereas, the uncertainty attendant to a Change In Control of the Corporation may result in the departure or distraction of management personnel to the detriment of AEPSC and the shareholders of the Corporation; and

Whereas, the Board of the Corporation has determined that steps should be taken to reinforce and encourage the continued attention and dedication of members of AEPSC's management to their assigned duties in the event of a Change In Control of the Corporation; and

Whereas, AEPSC therefore previously established the American Electric Power Service Corporation Change In Control Agreement (the "Agreement"), the current version of which is set forth in a document dated effective January 1, 2008; and

Whereas, the Human Resources Committee of the Board of the Corporation has decided to change the payments that should be provided to employees who are named as participating Executives (as defined in Article I(l) of the Agreement) on or after October 1, 2009;

Now, Therefore, AEPSC hereby amends the Agreement in its entirety.

ARTICLE I
DEFINITIONS

As used herein the following words and phrases shall have the following respective meanings unless the context clearly indicates otherwise.

(a) "Anniversary Date" means January 1 of each Calendar Year.

(b) "Annual Compensation" means the sum of the Executive's Annual Salary and the Executive's Target Annual Incentive.

(c) "Annual Salary" means the Executive's regular annual base salary immediately prior to the Executive's termination of employment, including compensation converted to other benefits under a flexible pay arrangement maintained by AEPSC or deferred pursuant to a written plan or agreement with AEPSC, but excluding sign-on bonuses, allowances and compensation paid or payable under any of AEPSC's long-term or short-term incentive plans or any similar payments, and any salary lump sum amount paid in lieu of or in addition to a base wage or salary increase.

(d) "Board" means the Board of Directors of American Electric Power Company, Inc.

(e) "Calendar Year" means the twelve (12) month period commencing each January 1 and ending each December 31.

(f) "Cause" shall mean

> (i) the willful and continued failure of the Executive to perform substantially the Executive's duties with AEPSC (other than any such failure as reasonably and consistently determined by the Board to have resulted from incapacity due to physical or mental illness), after a written demand for substantial performance is delivered to the Executive by the Board or an elected officer of AEPSC which specifically identifies the manner in which the Board or the elected officer believes that the Executive has not substantially performed the Executive's duties, or
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> (ii) the willful conduct or omission by the Executive, which the Board determines to be illegal or gross misconduct that is demonstrably injurious to AEPSC or the Corporation; or a breach of the Executive's fiduciary duty to AEPSC or the Corporation, as determined by the Board.

For purposes of this provision, no act or failure to act, on the part of the Executive, shall be considered "willful" unless it is done, or omitted to be done, by the Executive in bad faith or without reasonable belief that the Executive's action or omission was in the best interests of AEPSC or the Corporation. Any act, or failure to act, based upon authority given pursuant to a resolution duly adopted by the Board or upon the advice of counsel for AEPSC or the Corporation, shall be conclusively presumed to be done, or omitted to be done, by the Executive in good faith and in the best interests of AEPSC or the Corporation

(g) "Change In Control" of the Corporation shall be deemed to have occurred if and as of such date that (i) any "person" or "group" (as such terms are used in Section 13(d) and 14(d) of the Securities Exchange Act of 1934 ("Exchange Act")), other than AEPSC, any company owned, directly or indirectly, by the shareholders of the Corporation in substantially the same proportions as their ownership of stock of the Corporation or a trustee or other fiduciary holding securities under an employee benefit plan of the Corporation, becomes the "beneficial owner" (as defined in Rule 13d-3 under the Exchange Act), directly or indirectly, of more than one third of the then outstanding voting stock of the Corporation; or (ii) the consummation of a merger or consolidation of the Corporation with any other entity, other than a merger or consolidation which would result in the voting securities of the Corporation outstanding immediately prior thereto continuing to represent (either by remaining outstanding or by being converted into voting securities of the surviving entity) at least two-thirds of the total voting power represented by the voting securities of the Corporation or such surviving entity outstanding immediately after such merger or consolidation; or (iii) the consummation of the complete liquidation of the Corporation or the sale or disposition by the Corporation (in one transaction or a series of transactions) of all or substantially all of the Corporation's assets.

(h) "CIC Multiple" means a factor of (i) two and ninety-nine one-hundredths (2.99) with respect to the Chief Executive Officer of American Electric Power Service Corporation and such other Executives who are nominated for such factor by the Chief Executive Officer of American Electric Power Service Corporation and approved by the Human Resources Committee of the Board of the Corporation; or (ii) two (2.00) with respect to all other Executives.

(i) "Code" means the Internal Revenue Code of 1986, as amended from time to time.

(j) "Commencement Date" means January 1, 2008, which shall be the beginning date of the term of this Agreement.

(k) "Disability" means the Executive's total and permanent disability as defined in AEPSC's long-term disability plan covering the Executive immediately prior to the Change In Control.

(l) "Executive" means an employee of AEPSC or the Corporation who is designated by AEPSC and approved by the Human Resources Committee of the Board of the Corporation as an employee entitled to benefits, if any, under the terms of this Agreement. References in this agreement to the Executive shall be construed to include a Grandfathered Executive.

(m) "Good Reason" means

(1) an adverse change in the Executive's status, duties or responsibilities as an executive of AEPSC as in effect immediately prior to the Change In Control;

(2) failure of AEPSC to pay or provide the Executive in a timely fashion the salary or benefits to which the Executive is entitled under any employment agreement between AEPSC and the Executive in effect on the date of the Change In Control, or under any benefit plans or policies in which the Executive was participating at the time of the Change In Control;

(3) the reduction of the Executive's base salary as in effect on the date of the Change In Control;

(4) the taking of any action by AEPSC (including the elimination of a plan without providing substitutes therefor, the reduction of the Executive's awards thereunder or failure to continue the Executive's participation therein) that would substantially diminish the aggregate projected value of the Executive's awards or benefits under AEPSC's benefit plans or policies in which the Executive was participating at the time of the Change In Control; provided, however, that the diminishment of such awards or benefits that apply to other groups of employees of AEPSC in addition to Executives covered by this or a similar agreement shall be disregarded;

(5) a failure by AEPSC or the Corporation to obtain from any successor the assent to this Agreement contemplated by Article IV hereof; or

(6) the relocation, without the Executive's prior approval, of the office at which the Executive is to perform services on behalf of AEPSC to a location more than fifty (50) miles from its location immediately prior to the Change In Control.

Any circumstance described in this Article I(m) shall constitute Good Reason even if such circumstance would not constitute a breach by AEPSC of the terms of an employment agreement between AEPSC and the Executive in effect on the date of the Change In Control. However, such circumstance shall not constitute Good Reason unless (i) within ninety (90) days of the initial existence of such circumstance, the Executive shall have given AEPSC written notice of such circumstance, and (ii) AEPSC shall have failed to remedy such circumstance within thirty (30) days after its receipt of such notice. Such written notice to be provided by the Executive to AEPSC shall specify (A) the effective date for the Executive's proposed termination of employment (provided that such effective date may not precede the expiration of the period for AEPSC's opportunity to remedy), (B) reasonable detail of the facts and circumstances claimed to provide the basis for termination, and (C) the Executive's belief that such facts and circumstance would constitute Good Reason for purposes of this Agreement. The Executive's continued employment shall not constitute consent to, or a waiver of rights with respect to, any circumstances constituting Good Reason hereunder.

(n) "Grandfathered Executive" means an individual who became an Executive [as defined in Article I(l)] prior to October 1, 2009, and who continuously has remained such an Executive until becoming entitled to benefits set forth in this Agreement.

(o) "Qualifying Termination" shall mean following a Change In Control and during the term of this Agreement the Executive's employment is terminated for any reason excluding (i) the Executive's death, (ii) the Executive's Disability, (iii) the exhaustion of the Executive's benefits under the terms of an applicable AEPSC sick pay plan or long-term disability plan (other than by reason of the amendment or termination of such a plan), (iv) the Executive's Retirement, (v) by AEPSC for Cause or (vi) by the Executive without Good Reason. In addition, a Qualifying Termination shall be deemed to have occurred if, prior to a Change In Control, the Executive's employment was terminated during the term of this Agreement (A) by AEPSC without Cause, or (B) by the Executive based on events or circumstances that would constitute Good Reason if a Change in Control had occurred, in either case, (x) at the request of a person who has entered into an agreement with AEPSC or the Corporation, the consummation of which would constitute a Change In Control or (y) otherwise in connection with, as a result of or in anticipation of a Change In Control. The mere act of approving a Change In Control agreement shall not in and of itself be deemed to constitute an event or circumstance in anticipation of a Change In Control for purposes of this Article I(n).

(p) "Retirement" shall mean an Executive's voluntary termination of employment after attainment of age 55 with five or more years of service with AEPSC without Good Reason.

(q) "Target Annual Incentive" shall mean the award that the Executive would have received under the Senior Officer Annual Incentive Compensation Plan or such other annual incentive compensation plan applicable to such Executive for the year in which the Executive's termination occurs, if one hundred percent (100%) of the annual target award has been earned. Executives not participating in an annual incentive compensation plan that has predefined target levels will be treated as though they were participants in an annual incentive plan with such targets and will be assigned the same annual target percent as their participating peers in a comparable salary grade.

ARTICLE II
TERM OF AGREEMENT

2.1 The initial term of this Agreement shall be for the period beginning on the Commencement Date and ending on the December 31 immediately following the Commencement Date. The term of this Agreement shall automatically be extended for an additional Calendar Year on the first Anniversary Date immediately following the initial term of this Agreement without further action by AEPSC, and shall be automatically extended for an additional Calendar Year on each succeeding Anniversary Date, unless AEPSC shall have served notice upon the Executive at least thirty (30) days prior to such Anniversary Date of AEPSC's intention that this Agreement shall not be extended, provided, however, that if a Change In Control of the Corporation shall occur during the term of this Agreement, this Agreement shall terminate two years after the date the Change In Control is completed.

2.2 If an employee is designated as an Executive after the Commencement Date or after an Anniversary Date, the initial term of this Agreement shall be for the period beginning on the date the employee is designated as an Executive and ending on the December 31 immediately following.

2.3 Notwithstanding Section 2.1, the term of this Agreement shall end upon any termination of the Executive's employment that is other than a Qualifying Termination in connection with a Change In Control of the Corporation. For example, this Agreement shall terminate if the Executive's position is eliminated and the Executive's employment is terminated, other than in connection with a Change In Control of the Corporation, (i) due to a downsizing, consolidation or restructuring of AEPSC or of any other subsidiary of the Corporation or (ii) due to the sale, disposition or divestiture of all or a portion of AEPSC or of any other subsidiary of the Corporation.

ARTICLE III
COMPENSATION UPON A QUALIFYING TERMINATION IN CONNECTION WITH A CHANGE IN CONTROL

3.1 Except as otherwise provided in Section 3.3, upon a Qualifying Termination, the Executive shall be under no further obligation to perform services for AEPSC and shall be entitled to receive the following payments and benefits:

(a) As soon as practicable following the Executive's date of termination, AEPSC shall make a lump sum cash payment to the Executive in an amount equal to the sum of (1) the Executive's Annual Salary through the date of termination to the extent not theretofore paid, (2) the product of (x) the current plan year's Target Annual Incentive and (y) a fraction, the numerator of which is the number of days in such calendar year through the date of termination, and the denominator of which is 365, except that annual incentive plans which do not have predetermined annual target awards for participants shall have their pro-rated incentive compensation award for the current plan year paid as soon as practicable, and (3) any accrued vacation pay that otherwise would be available upon the Executive's termination of employment with AEPSC, in each case to the extent not theretofore paid and in full satisfaction of the rights of the Executive thereto; provided, however, in the case of a Qualifying Termination in the circumstances specified in Article I (o)(B), payment of the amount described in subsection (2) of this Section 3.1(a) shall not be made until immediately after the Change in Control event or circumstance; and

(b) Within sixty (60) days of the Executive's return of the signed release form, AEPSC shall make a lump sum cash payment to the Executive in an amount equal to the CIC Multiple times the Executive's Annual Compensation. If the Qualifying Termination is specified in Article I(o) (A) or (B), no such lump sum payment shall be made unless and until the Change in Control related to the Qualifying Termination shall have occurred.

3.2 The Executive shall be entitled to such outplacement services and other non-cash severance or separation benefits as may then be available under the terms of a plan or agreement to groups of employees of AEPSC in addition to Executives who are covered under the terms of this or a similar agreement. See also section 3.3(b). To the extent any benefits described in this Article III, Section 3.2 cannot be provided pursuant to the appropriate plan or program maintained by AEPSC, AEPSC shall provide such benefits outside such plan or program at no additional cost to the Executive.

3.3 Notwithstanding the foregoing;

(a) The severance payments and benefits provided under Sections 3.1(b), 3.2 and, if applicable, 3.4 hereof shall be conditioned upon the Executive executing a release at the time the Executive's employment is terminated, in the form established by the Corporation or by AEPSC, releasing the Corporation, AEPSC and their shareholders, partners, officers, directors, employees and agents from any and all claims and from any and all causes of action of kind or character, including but not limited to all claims or causes of action arising out of Executive's employment with the Corporation or AEPSC or the termination of such employment.

(b) The severance payments and benefits provided under Sections 3.1, 3.2 and, if applicable, 3.4 hereof shall be subject to, and conditioned upon, the waiver of any other cash severance payment or other benefits provided by AEPSC pursuant to any other severance agreement between AEPSC and the Executive. No amount shall be payable under this Agreement to, or on behalf of the Executive, if the Executive elects benefits under any other cash severance plan or program, or any other special pay arrangement with respect to the termination of the Executive's employment.

(c) The Executive agrees that at all times following termination, the Executive will not, without the prior written consent of AEPSC or the Corporation, disclose to any person, firm or corporation any "confidential information," of AEPSC or the Corporation which is now known to the Executive or which hereafter may become known to the Executive as a result of the Executive's employment or association with AEPSC or the Corporation, unless such disclosure is required under the terms of a valid and effective subpoena or order issued by a court or governmental body; provided, however, that the foregoing shall not apply to confidential information which becomes publicly disseminated by means other than a breach of this provision. It is recognized that damages in the event of breach of this Section 3.3(c) by the Executive would be difficult, if not impossible, to ascertain, and it is therefore agreed that AEPSC and the Corporation, in addition to and without limiting any other remedy or right that AEPSC or the Corporation may have, shall have the right to an injunction or other equitable relief in any court of competent jurisdiction, enjoining any such breach, and the Executive hereby waives any and all defenses the Executive may have on the ground of lack of jurisdiction or competence of the court to grant such an injunction or other equitable relief. The existence of this right shall not preclude AEPSC or the Corporation from pursuing any other rights or remedies at law or in equity which AEPSC or the Corporation may have.

“Confidential information” shall mean any confidential, propriety and or trade secret information, including, but not limited to, concepts, ideas, information and materials relating to AEPSC or the Corporation, client records, client lists, economic and financial analysis, financial data, customer contracts, marketing plans, notes, memoranda, lists, books, correspondence, manuals, reports or research, whether developed by AEPSC or the Corporation or developed by the Executive acting alone or jointly with AEPSC or the Corporation while the Executive was employed by AEPSC.

3.4 Notwithstanding anything to the contrary in this Agreement, but subject to the requirements of Section 3.3, in the event that any payment or distribution by AEPSC to or for the benefit of any Grandfathered Executive, whether paid or payable or distributed or distributable pursuant to the terms of this Agreement or otherwise (a "Payment"), would be subject to the excise tax imposed by Section 4999 of the Internal Revenue Code of 1986, as amended (the “Code”) (or any successor provision thereto) by reason of being “contingent on a change in ownership or control” of the Corporation, within the meaning of Section 280G of the Code (or any successor provision thereto) or any interest or penalties with respect to such excise tax other than any such amount as may become payable by the Grandfathered Executive by reason of Code Section 409A (such excise tax, together with any such interest or penalties, are hereinafter collectively referred to as the "Excise Tax"), and the aggregate total of such Payments (the “Total Payments”) is determined to be an “excess parachute payment” pursuant to Code Section 280G with the effect that the Grandfathered Executive is liable for the payment of the Excise Tax.

(a) If the Total Payments do not exceed 105% of the amount as would trigger the Grandfathered Executive having any “parachute payment” as described in Code Section 280G(b)(2), then, after taking into account any reduction in the Total Payments provided by reason of Code Section 280G in such other plans, arrangements or agreements, the cash payments provided in Section 3.2 of this Agreement shall first be reduced, and the noncash payments and benefits shall thereafter be reduced, to the extent necessary so that no portion of the Total Payments is subject to the Excise Tax; provided, however, that the Grandfathered Executive may elect (at any time prior to the payment of any Total Payment under this Agreement) to have the noncash payments and benefits reduced (or eliminated) prior to any reduction of the cash payments under this Agreement.

(b) If the Total Payments exceed 105% of the amount as would trigger the Grandfathered Executive having any “parachute payment” as described in Code Section 280G(b)(2), then, AEPSC shall pay to the Grandfathered Executive an additional payment (a "Gross-up Payment") in an amount such that after payment by the Grandfathered Executive of all taxes (including any interest or penalties imposed with respect to such taxes, but excluding any such taxes, interest or penalties as may be imposed on the Grandfathered Executive pursuant to Code Section 409A), including any Excise Tax imposed on any Gross-up Payment, the Grandfathered Executive retains an amount of the Gross-up Payment equal to the Excise Tax imposed upon the Payments.

(c) All determinations required to be made under this Section 3.4, including the assumptions to be utilized in arriving at such determinations and whether an Excise Tax is payable by the Grandfathered Executive and the amount of such Excise Tax, shall be made by a nationally recognized tax preparation, financial counseling or public accounting firm (the “Tax Firm”) that is experienced in 280G calculations and that is selected by AEPSC prior to the Change in Control. The Tax Firm shall be directed by AEPSC to submit its preliminary determination and detailed supporting calculations to both AEPSC and the Grandfathered Executive within 15 calendar days after the date of the Grandfathered Executive’s termination of employment, if applicable, and any other such time or times as may be requested by AEPSC or the Grandfathered Executive. If the Tax Firm determines that Excise Tax would be payable by the Grandfathered Executive if not for the applicability of Section 3.4(a), AEPSC shall reduce the payments as described in said Section 3.4(a) in a manner consistent with determinations made by the Tax Firm. If the Tax Firm determines that a Gross-up Payment to the Grandfathered Executive is triggered pursuant to Section 3.4(b), AEPSC shall make the Gross-Up Payment attributable thereto. If the Tax Firm determines that no Excise Tax is payable by the Grandfathered Executive, it shall, at the same time as it makes such determination, furnish the Grandfathered Executive with an opinion that she has substantial authority not to report any Excise Tax on her federal, state, local income or other tax return. All fees and expenses of the Tax Firm shall be paid by AEPSC in connection with the calculations required by this section.

(d) The federal, state and local income or other tax returns filed by the Grandfathered Executive (or any filing made by a consolidated tax group, which includes AEPSC) shall be prepared and filed on a consistent basis with the determination of the Tax Firm with respect to the Excise Tax payable by the Grandfathered Executive. The Grandfathered Executive shall make proper payment of the amount of any Excise Tax, and at the request of AEPSC, provide to AEPSC true and correct copies (with any amendments) of her federal income tax return as filed with the Internal Revenue and such other documents reasonably requested by AEPSC, evidencing such payment.

(e) The Grandfathered Executive shall notify AEPSC immediately in writing of any claim by the Internal Revenue Service that, if successful, would require AEPSC to make a Gross-up Payment (or a Gross-up Payment in excess of that, if any, initially determined under Section 3.4(b)) within five days of the receipt of such claim. AEPSC shall notify the Grandfathered Executive in writing at least five days prior to the due date of any response required with respect to such claim, or such shorter time period following AEPSC's receipt of the notice, if it plans to contest the claim. If AEPSC decides to contest such claim, the Grandfathered Executive shall cooperate fully with AEPSC in such action; provided, however, AEPSC shall bear and pay directly or indirectly all costs and expenses (including additional interest and penalties) incurred in connection with such action and shall indemnify and hold the Grandfathered Executive harmless, on an after-tax basis, for any Excise Tax or income tax, including interest and penalties with respect thereto, imposed as a result of AEPSC's action. If the Grandfathered Executive receives a refund of any amount paid by AEPSC with respect to such claim, the Grandfathered Executive shall promptly pay to AEPSC (i) such refund and (ii) the amount of any Gross-up Payment associated with such refund that is not included in the amount of such refund (such as taxes other than federal taxes included in the Gross-up Payment). If AEPSC fails to timely notify the Grandfathered Executive whether it will contest such claim or AEPSC determines not to contest such claim, then AEPSC shall immediately pay to the Grandfathered Executive the portion of such claim, if any, which it has not previously paid to the Grandfathered Executive as well as the amount of any Gross-up Payment (calculated pursuant to Section 3.4) associated with such payment but that has not otherwise been paid to the Grandfathered Executive.

(f) Unless otherwise required by this Agreement to be paid earlier, any Gross-up Payment required under this Section 3.4 shall be paid no later than the end of the Grandfathered Executive’s taxable year next following the Grandfathered Executive’s taxable year in which the related taxes are remitted to the applicable taxing authority.

3.5 The obligations of AEPSC to pay the benefits described in Sections 3.1, 3.2, and if applicable, 3.4, shall, subject to Section 3.3, be absolute and unconditional and shall not be affected by any circumstances, including, without limitation, any set-off, counterclaim, recoupment, defense or other right which AEPSC may have against the Executive; provided, however, AEPSC shall comply with and enforce obligations of AEPSC or the Executive under law determined by AEPSC to be applicable, including any withholding in order to comply with a court order. In no event shall the Executive be obligated to seek other employment or take any other action by way of mitigation of the amounts payable to the Executive under any of the provisions of this Agreement, nor shall the amount of any payment hereunder be reduced by any compensation earned by the Executive as a result of employment by another employer.

3.6 Executive alone shall be liable for the payment of any and all tax cost, incremental or otherwise, incurred by the Executive in connection with the provision of any benefits described in this Agreement. No provision of this Agreement shall be interpreted to provide for the gross-up or other mitigation of any amount payable or benefit provided to the Executive under the terms of this Agreement as a result of such taxes, except to the extent specifically set forth in Section 3.4.

3.7 Notwithstanding any provision of this Agreement to the contrary, if the Executive is a “specified employee” (as determined with respect AEPSC for purposes of Code Section 409A), the Executive shall not be entitled to any payments upon separation of service prior to the earliest of (1) the date that is six months after the date of separation from service for any reason other than death, (2) the date of the Executive’s death, or (3) such earlier time that would not cause the Executive to incur any excise tax under Code Section 409A.

ARTICLE IV
SUCCESSOR TO CORPORATION

4.1 This Agreement shall bind any successor of AEPSC or the Corporation, its assets or its businesses (whether direct or indirect, by purchase, merger, consolidation or otherwise) in the same manner and to the same extent that AEPSC or the Corporation would be obligated under this Agreement if no succession had taken place.

4.2 In the case of any transaction in which a successor would not by the foregoing provision or by operation of law be bound by this Agreement, AEPSC and the Corporation shall require such successor expressly and unconditionally to assume and agree to perform AEPSC’s and the Corporation’s obligations under this Agreement, in the same manner and to the same extent that AEPSC and the Corporation would be required to perform if no such succession had taken place. The term “Corporation,” as used in this Agreement, shall mean the Corporation as hereinbefore defined and any successor or assignee to its business or assets which by reason hereof becomes bound by this Agreement.

ARTICLE V
MISCELLANEOUS

5.1 Any notices and all other communications provided for herein shall be in writing and shall be deemed to have been duly given when delivered or mailed, by certified or registered mail, return receipt requested, postage prepaid addressed to AEPSC at its principal office and to the Executive at the Executive’s residence or at such other addresses as AEPSC or the Executive shall designate in writing.

5.2 Except to the extent otherwise provided in Article II (Term of Agreement), no provision of this Agreement may be modified, waived or discharged except in writing specifically referring to such provision and signed by either AEPSC or the Executive against whom enforcement of such modification, waiver or discharge is sought. No waiver by either AEPSC or the Executive of the breach of any condition or provision of this Agreement shall be deemed a waiver of any other condition or provision at the same or any other time.

5.3 The validity, interpretation, construction and performance of this Agreement shall be governed by the laws of the State of Ohio.

5.4 The invalidity or unenforceability of any provision of this Agreement shall not affect the validity or enforceability of any other provision of this Agreement, which shall remain in full force and effect.

5.5 This Agreement does not constitute a contract of employment or impose on the Executive, AEPSC or the Corporation any obligation to retain the Executive as an employee, to change the status of the Executive’s employment, or to change AEPSC’s policies regarding the termination of employment.

5.6 If the Executive institutes any legal action in seeking to obtain or enforce or is required to defend in any legal action the validity or enforceability of, any right or benefit provided by this Agreement, AEPSC will pay for all actual and reasonable legal fees and expenses incurred (as incurred) by the Executive, regardless of the outcome of such action; provided, however, that if such action instituted by the Executive is found by a court of competent jurisdiction to be frivolous, the Executive shall not be entitled to legal fees and expenses and shall be liable to AEPSC for amounts already paid for this purpose.

5.7 If the Executive makes a written request alleging a right to receive benefits under this Agreement or alleging a right to receive an adjustment in benefits being paid under the Agreement, AEPSC shall treat it as a claim for benefit. All claims for benefit under the Agreement shall be sent to the Human Resources Department of AEPSC and must be received within 30 days after the Executive's termination of employment. If AEPSC determines that the Executive who has claimed a right to receive benefits, or different benefits, under the Agreement is not entitled to receive all or any part of the benefits claimed, it will inform the Executive in writing of its determination and the reasons therefor in terms calculated to be understood by the Executive. The notice will be sent within 90 days of the claim unless AEPSC determines additional time, not exceeding 90 days, is needed. The notice shall make specific reference to the pertinent Agreement provisions on which the denial is based, and describe any additional material or information, if any, necessary for the Executive to perfect the claim and the reason any such additional material or information is necessary. Such notice shall, in addition, inform the Executive what procedure the Executive should follow to take advantage of the review procedures set forth below in the event the Executive desires to contest the denial of the claim. The Executive may within 90 days thereafter submit in writing to AEPSC a notice that the Executive contests the denial of the claim by AEPSC and desires a further review. AEPSC shall within 60 days thereafter review the claim and authorize the Executive to appear personally and review pertinent documents and submit issues and comments relating to the claim to the persons responsible for making the determination on behalf of AEPSC. AEPSC will render its final decision with specific reasons therefor in writing and will transmit it to the Executive within 60 days of the written request for review, unless AEPSC determines additional time, not exceeding 60 days, is needed, and so notifies the Executive. If AEPSC fails to respond to a claim filed in accordance with the foregoing within 60 days or any such extended period, AEPSC shall be deemed to have denied the claim.

AEPSC has caused this Change In Control Agreement to be signed on behalf of all participating employers effective as of the 1 st day of November, 2009.

American Electric Power Service Corporation

By /s/ Michael G. Morris
Michael G. Morris
Chairman, President & CEO

**AMERICAN ELECTRIC POWER SYSTEM
STOCK OWNERSHIP REQUIREMENT PLAN**

(As Amended and Restated Effective January 1, 2010)

ARTICLE I

PURPOSE AND EFFECTIVE DATE

1.1 The Human Resources Committee ("HRC") of the Board of Directors of American Electric Power Company, Inc. believes that it is critical to AEP's long-term success to effectively align the long-term financial interests of senior executives with those of AEP's shareholders and that an effective alignment is best accomplished by substantial, long-term stock ownership. The American Electric Power System Stock Ownership Requirement Plan (the "Plan") was established by American Electric Power Service Corporation (the "Company") and such subsidiaries of the Parent Corporation that have Eligible Employees to facilitate the achievement and maintenance of Minimum Stock Ownership Requirements assigned to Eligible Employees.

1.2 Except as otherwise specified herein, the effective date of this Amended and Restated American Electric Power System Stock Ownership Requirement Plan is January 1, 2010. This document amends and restates the Plan as most recently amended and restated by a document that was executed on December 31, 2008, to fix the Determination Date (as defined in Section 5.3) with respect to Annual Incentive Compensation for periods that begin on or after January 1, 2010.

ARTICLE II

DEFINITIONS

2.1 "Account" means the separate memo account established and maintained by the Committee (or the recordkeeper employed by the Company) to record the number of Shares and Share Equivalents that have been designated in accordance with the terms of this Plan to satisfy all Minimum Stock Ownership Requirements assigned to a Participant.

2.2 "AEP" means the Parent Corporation and its direct and indirect subsidiaries.

2.3 "Annual Incentive Compensation" means incentive compensation payable pursuant to the terms of an annual incentive compensation plan approved by the Committee for inclusion in the Plan, provided that such annual incentive compensation shall be determined without regard to any salary or wage reductions made pursuant to sections 125 or 402(e)(3) of the Code or participant contributions pursuant to a pay reduction agreement under the American Electric Power System Supplemental Retirement Savings Plan, as amended or the American Electric Power System Incentive Compensation Deferral Plan. Annual Incentive Compensation will not include an employee's base pay, non-annual bonuses (such as but not limited to project bonuses and sign-on bonuses), severance pay, or relocation payments.

2.4 "Applicable Tax Payments" means the following types of taxes that AEP may withhold and pay that are applicable to the amount then credited to the Career Share Account:

(a) Federal Insurance Contributions Act (FICA) tax imposed under Code Sections 3101, 3121(a) and 3121(v)(2) (the "FICA Amount");

(b) Income tax at source on wages imposed under Code Section 3401 or the corresponding withholding provisions of applicable state, local and foreign tax laws as a result of the payment of the FICA Amount; and

(c) The additional income tax at source on wages attributable to pyramiding Code Section 3401 wages and taxes;

provided, however, that the total Applicable Tax Payments may not exceed such limits as may be applicable to comply with the requirements of Code Section 409A.

2.5 "Career Share Account" means a separate memo account that is a subset of the Account that is maintained to identify the Career Share Units used to satisfy a Participant's Minimum Stock Ownership Requirements.

2.6 "Career Share Units" or "Career Shares" means the Share Equivalents tracked in a Participant's Career Share Account in order to determine whether and when the Participant has satisfied his or her Minimum Stock Ownership Requirements. Phantom stock units that become earned and vested under the Long-Term Incentive Plan represent an example of an award that may become Career Shares under the terms of this Plan. Career Shares also have been referred to as "Phantom Stock Units" in Company communications.

2.7 "Claims Reviewer" means the person or committee designated by the Company (or by a duly authorized person) as responsible for the review of claims for benefits under the Plan in accordance with Section 8.1. Until changed, the Claims Reviewer shall be the Company's employee who is the head of the Executive Benefits area of the Human Resources department.

2.8 "Code" means the Internal Revenue Code of 1986 as amended from time to time.

2.9 "Committee" means the committee designated by the Company (or by a duly authorized person) as responsible for the administration of the Plan. Until changed, the Committee shall consist of the employees of the Company holding the following positions: chief executive officer of the Company; head of the Human Resources department (currently, Vice President Human Resources); the employee to whom the head of the Human

Resources department reports (currently, Senior Vice President – Shared Services) and the chief financial officer of the Company. The Committee may authorize any person or persons to act on its behalf with full authority in regard to any of its duties and hereunder other than those set forth in Section 9.2.

2.10 "Common Stock" means the common stock, $6.50 par value, of the Parent Corporation.

2.11 "Company" means American Electric Power Service Corporation.

2.12 "Eligible Employee" means any employee of AEP who is hired into or promoted to a position that is eligible to be assigned a Minimum Stock Ownership Requirement, and only so long as a Minimum Stock Ownership Requirement applies. At the date of execution of this document, a Minimum Stock Ownership Requirement is assigned to those employees employed at exempt salary grade 36 or higher. An individual who is not directly compensated by AEP or who is not treated by AEP as an active employee shall not be considered an Eligible Employee.

2.13 First Date Available" or "FDA" means the last day of the month coincident with or next following the date that is six (6) months after the date of the Participant's or Former Participant's Termination.

2.14 "Incentive Compensation Deferral Plan" means the American Electric Power System Incentive Compensation Deferral Plan, as amended from time to time.

2.15 "Long Term Incentive Plan" or "LTIP" means the American Electric Power System Long-Term Incentive Plan, as amended from time to time, including any successor plan or plans. The LTIP that is in effect as of the date this Plan is executed is entitled the "Amended and Restated American Electric Power System Long-Term Incentive Plan – Approved by Shareholders April 26, 2005 (as amended through December 12, 2007)"

2.16 "Market Value" means the closing price of a Share, as published in *The Wall Street Journal* report of the New York Stock Exchange – Composite Transactions on the date in question or, if the Share shall not have been traded on such date or if the New York Stock Exchange is closed on such date, then the first day prior thereto on which the Common Stock was so traded.

2.17 "Minimum Stock Ownership Requirement" or "MSOR" means the targeted aggregate number of Shares and Share Equivalents specified under the terms of this Plan as applicable to the Participant. Participants may be assigned multiple minimum stock ownership requirements. Any MSOR assigned to a Participant shall no longer be applicable to such Participant after the date of the Participant's Termination.

2.18 "MSOR Window Period" means the period that begins as of the date a particular MSOR is effective with respect to an Eligible Employee (or Participant, with regard to any increase in his or her MSOR) and ends on the five (5) year anniversary of that date.

2.19 "Next Date Available" or "NDA" means the June 30 of the calendar year immediately following the calendar year in which falls the Participant's Termination.

2.20 "Parent Corporation" means American Electric Power Company, Inc., a New York corporation, and any successor thereto.

2.21 "Participant" is defined in Article IV.

2.22 "Performance-Based Compensation" has the meaning set forth in Section 409A(a)(4)(B)(iii) of the Code.

2.23 "Performance Shares" means performance shares or performance share units (or other similar types of equity incentive compensation) awarded under the American Electric Power System Performance Share Incentive Plan or the Long-Term Incentive Plan. Reference in this Plan to the "12/10/2003 Performance Share Awards" shall be deemed to refer to the Performance Shares that were issued with a grant date of December 10, 2003 and subject to a performance period from December 10, 2003 through December 31, 2004.

2.24 "Phantom Stock Units" are also referred to as "Career Shares." See definition of "Career Share Units," above.

2.25 "Plan Year" means the twelve-month period commencing each January 1 and ending the following December 31.

2.26 "Share" means a share of common stock of the Parent Corporation, and includes, but is not limited to, such shares as may be purchased directly by or for the Participant or through the American Electric Power Company, Inc. Dividend Reinvestment and Direct Stock Purchase Plan or issued in connection with the Participant's performance of services for AEP, such as pursuant to the American Electric Power System Long-Term Incentive Plan.

2.27 "Share Equivalent" is determined by reference to the amount credited to the Participant's Career Share Account under this Plan and to the Participant's AEP Stock Fund accounts maintained in connection with the American Electric Power System Retirement Savings Plan, the American Electric Power System Supplemental Retirement Savings Plan, and the American Electric Power System Incentive Compensation Deferral Plan. No certificates shall have been issued with respect to such Share Equivalents.

(a) To the extent that the amount credited under these arrangements are not otherwise reported under the terms of the applicable plan as a number of shares of Common Stock, the number of Share Equivalents attributable to such amount shall be determined by dividing the dollar amount so credited by the Market Value of a Share determined as of the applicable valuation date; provided that effective beginning May 1, 2008, the number of Share Equivalents attributable to such amount shall be determined by

(i) multiplying the dollar amount credited to such AEP Stock Fund under the Plan by the Dilution Percentage with respect to that fund as of the applicable valuation date; then

(ii) dividing the product in (i) by the Market Value of a Share determined as of the applicable valuation date.

(b) For purposes of this Section, the "Dilution Percentage" applicable to a plan's AEP Stock Fund shall be determined by

(i) dividing the aggregate Market Value of the Shares held by the fund (or, with respect to the phantom AEP Stock Fund that is maintained with respect to the American Electric Power System Supplemental Retirement Savings Plan and the American Electric Power System Incentive Compensation Deferral Plan, by the actual fund to which such phantom fund is tied – currently, the AEP Stock Fund under the American Electric Power System Retirement Savings Plan); by

(ii) the value of all of the assets held in that fund (or such fund to which a phantom fund is tied) as of the applicable valuation date.

2.28 "Termination" means termination of employment with the Company and its subsidiaries and affiliates for any reason; provided that effective with respect to Participants whose employment terminates on or after January 1, 2005, determinations as to the circumstances that will be considered a Termination (including a disability and leave of absence) shall be made in a manner consistent with the written policies adopted by the HRC from time to time to the extent such policies are consistent with the requirements imposed under Code 409A(a)(2)(A)(i).

2.29 "Vested" or "Earned and Vested" means, for purposes of this Plan, that the Shares or Share Equivalents credited to the Participant have become both objectively determinable and no longer subject to a substantial risk of forfeiture.

2.30 "2006 Distribution Election Period" means the period or periods designated by the Committee during which Participants (or Former Participants) are given the opportunity to select among the distribution options set forth in Article VII, provided that any such period shall end no later than December 31, 2006.

2.31 "Key Employee means a Participant who is classified as a "specified employee" at the time of Termination in accordance with the policies adopted by the Committee in order to comply with the requirements of Section 409A(a)(2)(B)(i) of the Code and the guidance issued thereunder,

ARTICLE III

ADMINISTRATION

3.1 The Plan shall be administered by the Committee. The Committee shall have full discretionary power and authority (i) to administer and interpret the terms and conditions of the Plan and (ii) to establish reasonable procedures with which Participants, Former Participant and beneficiaries must comply to exercise any right or privilege established hereunder. The rights and duties of the Participants and all other persons and entities claiming an interest under the Plan shall be subject to, and bound by, actions taken by or in connection with the exercise of the powers and authority granted under this Article.

3.2 The Committee may employ agents, attorneys, accountants, or other persons and allocate or delegate to them powers, rights, and duties all as the Committee may consider necessary or advisable to properly carry out the administration of the Plan.

3.3 The Company shall maintain, or cause to be maintained, records showing the individual balances in each Participant's Account, including each Participant's Career Share Account. Statements setting forth the value of the amount credited to the Participant's Account shall be made available to each Participant no less often than once per year. The maintenance of the Account records and the distribution of statements may be delegated to a recordkeeper by either the Company or the Committee.

ARTICLE IV

PARTICIPATION

An Eligible Employee shall become a Participant as of the date that the Eligible Employee is first assigned a Minimum Stock Ownership Requirement.

ARTICLE V

SATISFACTION OF MINIMUM STOCK OWNERSHIP REQUIREMENT

5.1 Accounts. The Committee shall establish and maintain an Account for each Participant that will record the number of Shares and Share Equivalents that have been designated in accordance with the terms of this Plan to satisfy the Minimum Stock Ownership Requirement applicable to such Participant.

5.2 Share Commitment Designated by Participant.

(a) A Participant may from time to time designate that certain Shares or Share Equivalents that are owned by the Participant or otherwise credited to the Participant be credited to the Account of such Participant. A Participant shall be permitted to so designate any Shares or Share Equivalents only to the extent the following requirements have been satisfied:

(i) The Shares or Share Equivalents have been earned by the Participant, if applicable;

(ii) The Shares or Share Equivalents are then Vested;

(iii) The Shares or Share Equivalents are not automatically allocated to the Participant's Career Share Account pursuant to Section 5.3, below; and

(iv) The Shares or Share Equivalents are not encumbered, pledged or hypothecated in any way.

(b) Any designation made by a Participant under this Section shall be made in writing and in a form that is satisfactory to the Committee.

5.3 Accrual of Career Shares .

(a) *Determination Date.* For purposes of this Section 5.3, the term "Determination Date" means

(i) the date that is six months prior to the end of the performance period, with respect to an award of Performance Shares that qualifies as Performance-Based Compensation and that is based on services performed over a period of at least 12 months; or

(ii) except as otherwise specified in subsection (iii), the June 30 that falls within the calendar year to which Annual Incentive Compensation relates (or the date six months prior to the end of the performance period, with respect to Annual Incentive Compensation that is not based on a calendar year), provided that such Annual Incentive Compensation qualifies as Performance-Based Compensation that is based on services performed over a period of at least 12 months; or

(iii) to the extent that the awarded Performance Shares or the Annual Incentive Compensation are not Performance-Based Compensation that is based on services performed over a period of at least 12 months, or as to any Annual Incentive Compensation that is based on services performed over a period that begins on or after January 1, 2010, the later of (A) the December 31 immediately prior to the year in which the services on which the Performance Shares or Annual Incentive Compensation is based are to be performed, or (B) the date the Participant first became an Eligible Employee.

(b) *Participant Has Not Satisfied MSOR.*

(i) If a Participant has not satisfied all applicable Minimum Stock Ownership Requirements on or before a Determination Date applicable to Performance Shares that have been awarded to such Participant, the Participant's Career Share Account shall be credited with the number of Shares or Share Equivalents that become Earned and Vested (reduced, however, to the extent of any Applicable Tax Payments) for the Participant as a result of the award of such Performance Shares. Notwithstanding the foregoing provisions of this paragraph (i), effective for Determination Dates occurring on or after May 1, 2008, the number of Shares or Share Equivalents so credited to the Participant's Career Share Account shall be limited to that number needed to satisfy the Participant's MSOR, and the balance, if any, of such Earned and Vested Performance Shares shall be administered without regard to the provisions of this Plan. For this purpose, the number of Shares or Share Equivalents needed to satisfy the Participant's MSOR shall be determined by reference to the highest MSOR that is applicable to such Participant as of the Determination Date with respect to such Performance Shares:

(A) after taking into account

(1) Shares or Share Equivalents that are credited to the Participant's Account pursuant to the Participant's designation under Section 5.2 no later than such Determination Date;

(2) the Share Equivalents that are credited to the Participant's Career Share Account as of such Determination Date; and

(3) the Share Equivalents attributable to reinvested dividends through the date such Performance Shares become Earned and Vested, but only to the extent such reinvested dividends are attributable to the Share Equivalents that were credited to the Participant's Career Share Account as of such Determination Date; but

(B) Disregarding the Share Equivalents that may be credited to such Participant's Career Share Account pursuant to this subsection 5.3(b)(i) [with regard to Performance Shares] or subsection 5.3(b)(ii), below [with regard to Annual Incentive Compensation], that either

(1) has a Determination Date that is after the Determination Date for such Performance Shares; or

(2) has not become Earned and Vested as of the date such Performance Shares become Earned and Vested.

(ii) If a Participant has not satisfied all applicable Minimum Stock Ownership Requirements on or before a Determination Date that both is applicable to Annual Incentive Compensation and falls after the last day of the final year of the Participant's MSOR Window Period, the Participant's Career Share Account shall be credited with the number of Shares or Share Equivalents, as appropriate, attributable to 25% (50%, effective beginning January 1, 2006) of the Annual Incentive Compensation that becomes Earned and Vested for the Participant as a result of the approval of such Annual Incentive Compensation. Notwithstanding the foregoing provisions of this paragraph (ii), effective for Determination Dates occurring on or after May 1, 2008, the number of Shares or Share Equivalents so credited to the Participant's Career Share Account shall be limited to the lesser of 50% of the Annual Incentive Compensation that becomes Earned and Vested for the Participant or the number needed to satisfy the Participant's MSOR, and the balance, if any, of such Earned and Vested Annual Incentive Compensation shall be administered without regard to the provisions of this Plan. For this purpose, the number of Shares or Share Equivalents needed to satisfy the Participant's MSOR shall be determined by reference to the highest MSOR that is applicable to such Participant as of the Determination Date with respect to such Annual

Incentive Compensation,

(A) after taking into account,

(1) The Shares or Share Equivalents that are credited to the Participant's Account pursuant to the Participant's designation under Section 5.2 no later than such Determination Date;

(2) the Share Equivalents that are credited to the Participant's Career Share Account as of such Determination Date;

(3) the Share Equivalents attributable to reinvested dividends through the date such Annual Incentive Compensation becomes Earned and Vested, but only to the extent such reinvested dividends are attributable to the Share Equivalents that were credited to the Participant's Career Share Account as of such Determination Date; but

(B) Disregarding the Share Equivalents that may be credited to such Participant's Career Share Account pursuant to subsection 5.3(b)(i), above [with regard to Performance Shares], or this subsection 5.3(b)(ii) [with regard to Annual Incentive Compensation], that either

(1) has a Determination Date that is after the Determination Date for such Annul Incentive Compensation; or

(2) has not become Earned and Vested as of the date such Annual Incentive Compensation becomes Earned and Vested.

(iii) The Share Equivalents that are disregarded pursuant to subparagraph 5.3(b)(i)(B) or subparagraph 5.3(b)(ii)(B) may include those attributable to Performance Shares or Annual Incentive Compensation that had become Earned and Vested and thereupon credited to such Participant's Career Share Account, and as a result, such Career Share Account may be credited with Share Equivalents in excess of the number actually needed to satisfy the highest MSOR that is applicable to such Participant as of the applicable Determination Date.

(iv) If the same Determination Date applies to more than one award of Performance Shares, Annual Incentive Compensation or both for a particular Participant, and such awards also become Earned and Vested as of the same date, the following priority shall be used in determining which award (or portion thereof) shall be credited to the Participant's Career Share Account:

(A) First, Share Equivalents attributable to Performance Shares shall be credited before those attributable to Annual Incentive Compensation; then

(B) Share Equivalents attributable to awards of the same type shall be credited in the same order in which they were initially granted.

(v) A Participant's Career Share Account shall be credited to the extent otherwise described in this Section 5.3(b) even if the Participant shall have satisfied all applicable MSOR or shall have ceased to remain an Eligible Employee during the period between the Determination Date and the date the Performance Shares or Annual Incentive Compensation are Earned and Vested. However, if a Participant shall have no MSOR as of an applicable Determination Date by reason of the Participant's having ceased to remain an Eligible Employee, the payment or deferral of the amounts that become payable to the Participant relative to Annual Incentive Compensation or as a result of an award of Performance Shares to which such Determination Date applies shall be determined in accordance with other plans and programs as may apply, including, for example, the Incentive Compensation Deferral Plan.

(c) *Participant Has Satisfied MSOR.* If a Participant has satisfied his or her MSOR on or before the applicable Determination Date, the payment or deferral of the amounts that become payable to the Participant relative to Annual Incentive Compensation or as a result of an award of Performance Shares shall be determined in accordance with other plans and programs as may apply, including, for example, the Incentive Compensation Deferral Plan.

5.4 Holding Requirement For Exercised Stock Options. If a Participant has not satisfied the applicable MSOR on or before the close of the related MSOR Window Period, then, the Participant shall be required to retain until Termination all Shares acquired through stock options exercised by the Participant between the date immediately following the close of such MSOR Window Period until the date the Participant has satisfied such MSOR; provided, however, the Participant shall be permitted to cause the sale of such Shares as would allow the Participant to cover the costs and applicable taxes directly associated with such exercises. However, the retention requirement set forth in this Section 5.4 shall not apply once and so long as the Participant has no MSOR by reason of the Participant's having ceased to remain an Eligible Employee.

ARTICLE VI

CAREER SHARE ACCOUNT
DIVIDENDS AND ADJUSTMENTS

6.1 Reinvestment of Dividends. Effective on each dividend payment date with respect to the Common Stock, the Career Share Account of a Participant shall be credited with an additional number of whole and fractional Share Equivalents, computed to three decimal places, equal to the product of the dividend per share then payable, multiplied by the number of Share Equivalents then credited to such Career Share Account, divided by the Market Value on the dividend payment date.

6.2 Adjustments. The number of Share Equivalents credited to a Participant's Career Share Account shall be appropriately adjusted for any change in the Common Stock by reason of any merger, reclassification, consolidation, recapitalization, stock dividend, stock split or any similar change affecting the Common Stock.

ARTICLE VII

CAREER SHARE ACCOUNT
DISTRIBUTIONS

7.1 Upon a Participant's Termination for any reason, the Company shall cause the Participant to be paid the full amount credited to his or her Career Share Account in accordance with the following rules:

(a) *Medium of Payment.* Effective beginning June 1, 2008, Payments shall be made in cash; provided that effective prior to June 1, 2008, payments had been permitted in cash, shares of Common Stock, or a combination of both as elected by the Participant on a form that is acceptable to the Company and submitted within a reasonable period of time before the distribution was scheduled to commence. Cash payments of Career Shares shall be calculated on the basis of the average of the Fair Market Value of the Common Stock for the last 20 trading days prior to the applicable distribution date (i.e., the Participant's date of Termination, deferred distribution date, respective installment payment dates or the date of the Participant's death, as the case may be).

(b) *Timing and Form of Distribution.* Except as otherwise provided in Section 7.2, the following rules shall apply with regard to the timing and form of the distributions to be made from the Participant's Career Share Account:

(1) *Form of Distribution* . The Company shall cause the Participant to be paid the full amount credited to his or her Active Career Share Account in accordance with his or her effective election in one of the following forms:

(A) A single lump sum distribution

(i) as of the First Date Available; or

(ii) as of the Next Date Available; or

(iii) as of the fifth anniversary of the First Date Available; or

(iv) as of the fifth anniversary of the Next Date Available; or

(B) In five (5) annual installments commencing

(i) as of the First Date Available; or

(ii) as of the Next Date Available; or

(iii) as of the fifth anniversary of the First Date Available; or

(iv) as of the fifth anniversary of the Next Date Available; or

(C) In ten (10) annual installments commencing.

(i) as of the First Date Available; or

(ii) as of the Next Date Available.

(2) *Effective Election* . For this purpose, a Participant's election with respect to the distribution of his or her Career Share Account shall not be effective unless all of the following requirements are satisfied.

(A) The election is submitted to the Company in writing in a form determined by the Committee to be acceptable;

(B) The election is submitted timely. For purposes of this paragraph, a distribution election will be considered "timely" only if it is submitted prior to the Participant's Termination and it satisfies the requirements of (i), (ii) or (iii), below, as may be applicable:

(i) Submitted no later than the first Determination Date after June 30, 2006 with respect to a Participant who had neither a 12/10/2003 Performance Share Award nor any amount credited to his Career Share Account as of June 30, 2006; or

(ii) Submitted during a 2006 Distribution Election Period that is applicable to the Participant, but only with regard to the distribution election form last submitted by such Participant before the expiration of that period; or

(iii) If the Participant is submitting the election to change the timing or form of distribution that is then in effect with respect to the Participant's Career Share Account other than an effective distribution election submitted as part of the 2006 Distribution Election Period, such election must be submitted at least one year prior to the date of the Participant's Termination.

(C) If the Participant is submitting the election pursuant to paragraph (b)(2)(B)(iii) to change the timing or form of distribution that is then in effect with respect to the Participant's Career Share Account (i.e., the Participant is not submitting an election with his initial applicable Determination Date [(B)(i)] nor during the applicable 2006 Distribution Election Period [(B)(ii)], the newly selected option must result in the further deferral of the first scheduled payment by at least 5 years. For purposes of compliance with the rule set forth in Section 409A(a) of the Code (and the regulations issued thereunder), each distribution option described in Section 7.1(b)(1) shall be treated as a single payment as of the first scheduled payment date.

(D) If the Participant is submitting the election pursuant to paragraph (b)(2)(B)(ii) to change the timing or form of distribution that is then in effect with respect to the Participant's Career Share Account, the newly selected option may not defer payments that the Participant would have received in 2006 if not for the new distribution election nor cause payments to be made in 2006 if not for the new distribution election.

(3) For purposes of this Section 7.1(b), if a Participant's effective distribution election form was submitted using the options that had been made available under the Plan as in effect prior to January 1, 2005 [i.e., as either (A) a single lump-sum payment, or in annual installment payments over not less than two nor more than ten years; (B) commencing within 60 days after the date of the Participant's Termination or the first, second, third, fourth or fifth anniversary of the Participant's Termination], then:

(A) If the Participant's Termination occurs prior to the expiration of the 2006 Distribution Election Period last applicable to the Participant, the Participant's effective distribution election form shall be given full effect. Solely for purposes of this paragraph (3)(A), a participant's distribution election form shall be considered effective notwithstanding the requirement of Section 7.1(b)(2)(B)(iii) (which requires that a form be submitted at least one year prior to the date of the Participant's Termination), provided that such form had become effective prior to the Participant's Termination in accordance with the terms applicable to such election form at the time it was submitted by the Participant; and

(B) If the Participant's Termination occurs after the expiration of the last applicable 2006 Distribution Election Period, the Participant shall be considered to have elected the corresponding option as set forth in Schedule A attached to this Plan.

(4) If the provisions of Section 7.1(b)(3) are not applicable to a Participant and the Participant fails to submit an effective distribution election with regard to his Career Share Account that satisfies the requirements of Section 7.1(b)(2)(B)(i) (by his initial applicable Determination Date) or Section 7.1(b)(2)(B)(ii) (during an applicable 2006 Distribution Election Period), as applicable, by such Determination Date or the last day of the 2006 Distribution Election Period, respectively, such Participant shall be considered to have elected a distribution of his or her Career Share Account in a single lump sum as of the First Date Available.

(5) If an annual installment option is selected, the amount to be distributed in any one-year shall be determined by dividing the Participant's Career Share Account Balance by the number of years remaining in the elected distribution period.

7.2 Events Affecting Timing or Amount of Distributions .

(a) *"Election" To Accelerate Payment of Career Shares Attributable to 12/10/2003 Performance Share Award.* Notwithstanding any provision of Section 7.1 to the contrary, if a Participant had not satisfied his or her MSOR on or before June 30, 2004 (the Determination Date applicable to the 12/10/2003 Performance Share Awards), but as of June 30, 2006 either (i) does satisfy his or her applicable MSOR(s) or (ii) has no applicable MSOR because the participant is longer an Eligible Employee, the Participant will be deemed to have elected as of June 30, 2006 a lump sum payment with respect to the Share or Share Equivalents that would have been credited to the Participant's Career Share Account as a result of the 12/10/2003 Performance Share Award. Such payment shall be made as of the date that the 12/10/2003 Performance Share Awards otherwise would have become payable if the Participant were not a participant in this Plan.

(b) *Special Considerations.* Notwithstanding any provision of this Article to the contrary,

(1) Limited Cashout - if the Participant's Career Share Account is $10,000 or less on the Participant's First Date Available (or, if the Participant is not a Key Employee, on the last day of the month coincident with or next following the date that is one (1) month after the date of the Participant's Termination) (called the "Cashout Date"), the Committee may require that the full value of the Participant's Career Share Account be distributed as of the Cashout Date in a single, lump sum distribution regardless of the form elected by such Participant, provided that such payment is consistent with the limited cash-out right described in Treasury Regulation Section 1.409A-3(j)(4)(v) or other guidance of the Code in that the payment results in the termination and liquidation of the entirety of the Participant's interest under each nonqualified deferred compensation plan (including all agreements, methods, programs, or other arrangements with respect to which deferrals of compensation are treated as having been deferred under a single nonqualified deferred compensation plan under Treasury Regulation 1.409A-1(c)(2) or other guidance of the Code) that is associated with this Plan; and the total payment with respect to any such single nonqualified deferred compensation plan is not greater than the applicable dollar amount under Code Section 402(g)(1)(B). Provided, however,

(2) Avoid Violations - payment to a Participant will be delayed at any time that the Company reasonably anticipates that the making of such payment will violate Federal securities laws or other applicable law; provided however, that any payments so delayed shall be paid at the earliest date at which the Company reasonably anticipates that the making of such payment will not cause such violation.

ARTICLE VIII

BENEFICIARIES

8.1 Each Participant may designate a beneficiary or beneficiaries who shall receive the balance of the Participant's Career Share Account if the Participant dies prior to the complete distribution of the Participant's Career Share Account. Any designation, or change or rescission of a beneficiary designation shall be made by the Participant's completion, signature and submission to the Committee of the appropriate beneficiary form prescribed by the Committee. A beneficiary form shall take effect as of the date the form is signed provided that the Committee receives it before taking any action or making any payment to another beneficiary named in accordance with this Plan and any procedures implemented by the Committee. If any payment is made or other action is taken before a beneficiary form is received by the Committee, any changes made on a form received thereafter will not be given any effect. If a Participant fails to designate a beneficiary, or if all beneficiaries named by the Participant do not survive the Participant, the Participant's Career Share Account will be paid to the Participant's estate. Unless clearly specified otherwise in an applicable court order presented to the Committee prior to the Participant's death, the designation of a Participant's spouse as a beneficiary shall be considered automatically revoked as to that spouse upon the legal termination of the Participant's marriage to that spouse.

8.2 Distribution to a Participant's beneficiary shall be in the form of a single lump-sum payment within 60 days after the Committee makes a final determination as to the beneficiary or beneficiaries entitled to receive such distribution.

ARTICLE IX

CLAIMS PROCEDURE

9.1 The following procedures shall apply with respect to claims for benefits under the Plan.

(a) Any Participant or beneficiary who believes he or she is entitled to receive a distribution under the Plan which he or she did not receive or that amounts credited to his or her Account are inaccurate, may file a written claim signed by the Participant, beneficiary or authorized representative with the Claims Reviewer, specifying the basis for the claim. The Claims Reviewer shall provide a claimant with written or electronic notification of its determination on the claim within ninety days after such claim was filed; provided, however, if the Claims Reviewer determines special circumstances require an extension of time for processing the claim, the claimant shall receive within the initial ninety-day period a written notice of the extension for a period of up to ninety days from the end of the initial ninety day period. The extension notice shall indicate the special circumstances requiring the extension and the date by which the Plan expects to render the benefit determination.

(b) If the Claims Reviewer renders an adverse benefit determination under Section 8.1(a), the notification to the claimant shall set forth, in a manner calculated to be understood by the claimant:

(1) The specific reasons for the denial of the claim;

(2) Specific reference to the provisions of the Plan upon which the denial of the claim was based;

(3) A description of any additional material or information necessary for the claimant to perfect the claim and an explanation of why such material or information is necessary, and

(4) An explanation of the review procedure specified in Section 9.2, and the time limits applicable to such procedures, including a statement of the claimant's right to bring a civil action under section 502(a) of the Employee Retirement Income Security Act of 1974, as amended, following an adverse benefit determination on review.

9.2 The following procedures shall apply with respect to the review on appeal of an adverse determination on a claim for benefits under the Plan.

(a) Within sixty days after the receipt by the claimant of an adverse benefit determination, the claimant may appeal such denial by filing with the Committee a written request for a review of the claim. If such an appeal is filed within the sixty day period, the Committee, or a duly appointed representative of the Committee, shall conduct a full and fair review of such claim that takes into account all comments, documents, records and other information submitted by the claimant relating to the claim, without regard to whether such information was submitted or considered in the initial benefit determination. The claimant shall be entitled to submit written comments, documents, records and other information relating to the claim for benefits and shall be provided, upon request and free of charge, reasonable access to, and copies of all documents, records and other information relevant to the claimant's claim for benefits. If the claimant requests a hearing on the claim and the Committee concludes such a hearing is advisable and schedules such a hearing, the claimant shall have the opportunity to present the claimant's case in person or by an authorized representative at such hearing.

(b) The claimant shall be notified of the Committee's benefit determination on review within sixty days after receipt of the claimant's request for review, unless the Committee determines that special circumstances require an extension of time for processing the review. If the Committee determines that such an extension is required, written notice of the extension shall be furnished to the claimant within the initial sixty-day period. Any such extension shall not exceed a period of sixty days from the end of the initial period. The extension notice shall indicate the special circumstances requiring the extension and the date by which the Committee expects to render the benefit determination.

(c) The Committee shall provide a claimant with written or electronic notification of the Plan's benefit determination on review. The determination of the Committee shall be final and binding on all interested parties. Any adverse benefit determination on review shall set forth, in a manner calculated to be understood by the claimant:

(1) The specific reason(s) for the adverse determination;

(2) Reference to the specific provisions of the Plan on which the determination was based;

(3) A statement that the claimant is entitled to receive, upon request and free of charge, reasonable access to, and copies of, all documents, records and other information relevant to the claimant's claim for benefits; and

(4) A statement of the claimant's right to bring an action under Section 502(a) of ERISA.

ARTICLE X

MISCELLANEOUS PROVISIONS

10.1 Each Participant agrees that as a condition of participation in the Plan, the Company may withhold applicable federal, state and local taxes, Social Security taxes and Medicare taxes from any deferral and distribution hereunder to the extent that such taxes are then payable.

10.2 In the event the Committee, in its sole discretion, shall find that a Participant or beneficiary is unable to care for his or her affairs because of illness or accident, the Committee may direct that any payment due the Participant or the beneficiary be paid to the duly appointed personal representative of the Participant or beneficiary, and any such payment so made shall be a complete discharge of the liabilities of the Plan and the Company with respect to such Participant or beneficiary.

10.3 The Company intends to continue the Plan indefinitely but reserves the right, in its sole discretion, to modify the Plan from time to time, or to terminate the Plan entirely or to direct the permanent discontinuance or temporary suspension of deferral contributions under the Plan; provided that no such modification, termination, discontinuance or suspension shall reduce the benefits accrued for the benefit of any Participant or beneficiary under the Plan as of the date of such modification, termination, discontinuance or suspension.

10.4 Nothing in the Plan shall interfere with or limit in any way the right of AEP to terminate any Participant's employment at any time, or confer upon a Participant any right to continue in the employ of AEP.

10.5 The Company intends the following with respect to this Plan: (1) Section 451(a) of the Code would apply to the Participant's recognition of gross income as a result of participation herein; (2) the Participants will not recognize gross income as a result of participation in the Plan unless and until and then only to the extent that distributions are received; (3) the Company will not receive a deduction for amount credited to any Account unless and until and then only to the extent that amounts are actually distributed; (4) the provisions of Parts 2, 3, and 4 of Subtitle B of Title I of ERISA shall not be applicable; and (5) the design and administration of the Plan are intended to comply with the requirements of Section 409A of the Code, to the extent such section is effective and applicable to amounts deferred hereunder. However, no Eligible Employee, Participant, beneficiary or any other person shall have any recourse against the Corporation, the Company, the Committee or any of their affiliates, employees, agents, successors, assigns or other representatives if any of those conditions are determined not to be satisfied.

10.6 The Plan shall be construed and administered according to the applicable provisions of ERISA and the laws of the State of Ohio.

10.7 Neither a Participant nor any other person shall have any right to sell, assign, transfer, pledge, mortgage or otherwise encumber, transfer, alienate or convey in advance of actual receipt, the amounts, if any, payable under this Plan. Such amounts payable, or any part thereof, and all rights to such amounts payable are not assignable and are not transferable. No part of the amounts payable shall, prior to actual payment, be subject to seizure, attachment, garnishment or sequestration for the payment of any debts, judgments, alimony or separate maintenance owed by a Participant or any other person. Additionally, no part of any amounts payable shall, prior to actual payment, be transferable by operation of law in the event of a Participant's or any other person's bankruptcy or insolvency or be transferable to a spouse as a result of a property settlement or otherwise, except that if necessary to comply with a "qualified domestic relations order," as defined in ERISA Section 206(d), pursuant to which a court has determined that a spouse or former spouse of a Participant has an interest in the Participant's benefits under the Plan, the Committee shall distribute the spouse's or former spouse's interest in the Participant's benefits under the Plan to such spouse or former spouse in accordance with the Participant's election under this Plan as to the time and form of payment.

American Electric Power Service Corporation has caused this amendment and restatement of the American Electric Power System Stock Ownership Requirement Plan to be signed as of this ___ day of December, 2009.

AMERICAN ELECTRIC POWER SERVICE CORPORATION

By /s/ Genevieve A. Tuchow
Genevieve A. Tuchow
Vice President, Human Resources

EXHIBIT 12

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIAIRIES
Computation of Consolidated Ratios of Earnings to Fixed Charges
(in millions except ratio data)

	Year Ended December 31,				
	2005	**2006**	**2007**	**2008**	**2009**
EARNINGS					
Income Before Income Tax Expense and Equity Earnings	$ 1,463	$ 1,483	$ 1,663	$ 2,015	$ 1,938
Fixed Charges (as below)	913	999	1,146	1,240	1,237
Preferred Security Dividend Requirements of Consolidated Subsidiaries	(10)	(4)	(4)	(4)	(4)
Total Earnings	$ 2,366	$ 2,478	$ 2,805	$ 3,251	$ 3,171
FIXED CHARGES					
Interest Expense	$ 694	$ 729	$ 838	$ 957	$ 973
Credit for Allowance for Borrowed Funds Used During Construction	36	82	79	75	67
Estimated Interest Element in Lease Rentals	173	184	225	204	193
Preferred Security Dividend Requirements of Consolidated Subsidiaries	10	4	4	4	4
Total Fixed Charges	$ 913	$ 999	$ 1,146	$ 1,240	$ 1,237
Ratio of Earnings to Fixed Charges	2.59	2.48	2.44	2.62	2.56

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American Electric Power Company, Inc. and Subsidiary Companies
Appalachian Power Company and Subsidiaries
Columbus Southern Power Company and Subsidiaries
Indiana Michigan Power Company and Subsidiaries
Ohio Power Company Consolidated
Public Service Company of Oklahoma
Southwestern Electric Power Company Consolidated

Audited Financial Statements and
Management's Financial Discussion and Analysis

AEP: America's Energy Partner®

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
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GLOSSARY OF TERMS

When the following terms and abbreviations appear in the text of this report, they have the meanings indicated below.

Term	Meaning
AEGCo	AEP Generating Company, an AEP electric utility subsidiary.
AEP or Parent	American Electric Power Company, Inc.
AEP Consolidated	AEP and its majority owned consolidated subsidiaries and consolidated affiliates.
AEP Credit	AEP Credit, Inc., a subsidiary of AEP which factors accounts receivable and accrued utility revenues for affiliated electric utility companies.
AEP East companies	APCo, CSPCo, I&M, KPCo and OPCo.
AEP Foundation	AEP charitable organization created in 2005 for charitable contributions in the communities in which AEP's subsidiaries operate.
AEP Power Pool	Members are APCo, CSPCo, I&M, KPCo and OPCo. The Pool shares the generation, cost of generation and resultant wholesale off-system sales of the member companies.
AEP System or the System	American Electric Power System, an integrated electric utility system, owned and operated by AEP's electric utility subsidiaries.
AEP West companies	PSO, SWEPCo, TCC and TNC.
AEPEP	AEP Energy Partners, Inc., a subsidiary of AEP dedicated to wholesale marketing and trading, asset management and commercial and industrial sales in the deregulated Texas market.
AEPES	AEP Energy Services, Inc., a subsidiary of AEP Resources, Inc.
AEPSC	American Electric Power Service Corporation, a service subsidiary providing management and professional services to AEP and its subsidiaries.
AFUDC	Allowance for Funds Used During Construction.
AOCI	Accumulated Other Comprehensive Income.
APCo	Appalachian Power Company, an AEP electric utility subsidiary.
APSC	Arkansas Public Service Commission.
CAA	Clean Air Act.
CO_2	Carbon Dioxide and other greenhouse gases.
Cook Plant	Donald C. Cook Nuclear Plant, a two-unit, 2,191 MW nuclear plant owned by I&M.
CSPCo	Columbus Southern Power Company, an AEP electric utility subsidiary.
CSW	Central and South West Corporation, a subsidiary of AEP (Effective January 21, 2003, the legal name of Central and South West Corporation was changed to AEP Utilities, Inc.).
CSW Operating Agreement	Agreement, dated January 1, 1997, as amended, by and among PSO and SWEPCo governing generating capacity allocation. AEPSC acts as the agent.
CTC	Competition Transition Charge.
CWIP	Construction Work in Progress.

DETM	Duke Energy Trading and Marketing L.L.C., a risk management counterparty.
DHLC	Dolet Hills Lignite Company, LLC, a wholly-owned lignite mining subsidiary of SWEPCo that is a consolidated variable interest entity.
E&R	Environmental compliance and transmission and distribution system reliability.
EIS	Energy Insurance Services, Inc., a nonaffiliated captive insurance company.
ERCOT	Electric Reliability Council of Texas.
ERISA	Employee Retirement Income Security Act of 1974, as amended.
ESP	Electric Security Plans, filed with the PUCO, pursuant to the Ohio Amendments.
ETA	Electric Transmission America, LLC an equity interest joint venture with MidAmerican Energy Holdings Company formed to own and operate electric transmission facilities in North America outside of ERCOT.
ETT	Electric Transmission Texas, LLC, an equity interest joint venture between AEP Utilities, Inc. and MidAmerican Energy Holdings Company Texas Transco, LLC formed to own and operate electric transmission facilities in ERCOT.
FAC	Fuel Adjustment Clause.
FASB	Financial Accounting Standards Board.
Federal EPA	United States Environmental Protection Agency.
FERC	Federal Energy Regulatory Commission.
FGD	Flue Gas Desulfurization or Scrubbers.
FTR	Financial Transmission Right, a financial instrument that entitles the holder to receive compensation for certain congestion-related transmission charges that arise when the power grid is congested resulting in differences in locational prices.
GAAP	Accounting Principles Generally Accepted in the United States of America.
IGCC	Integrated Gasification Combined Cycle, technology that turns coal into a cleaner-burning gas.
Interconnection Agreement	Agreement, dated July 6, 1951, as amended, by and among APCo, CSPCo, I&M, KPCo and OPCo, defining the sharing of costs and benefits associated with their respective generating plants.
IRS	Internal Revenue Service.
IURC	Indiana Utility Regulatory Commission.
I&M	Indiana Michigan Power Company, an AEP electric utility subsidiary.
JMG	JMG Funding LP.
KGPCo	Kingsport Power Company, an AEP electric distribution subsidiary.
KPCo	Kentucky Power Company, an AEP electric utility subsidiary.
KPSC	Kentucky Public Service Commission.
kV	Kilovolt.
KWH	Kilowatthour.
LPSC	Louisiana Public Service Commission.
MISO	Midwest Independent Transmission System Operator.
MLR	Member load ratio, the method used to allocate AEP Power Pool transactions to its members.
MMBtu	Million British Thermal Units.
MPSC	Michigan Public Service Commission.
MTM	Mark-to-Market.
MW	Megawatt.
MWH	Megawatthour.
NO_x	Nitrogen oxide.
Nonutility Money Pool	AEP’s Nonutility Money Pool.
NSR	New Source Review.
OCC	Corporation Commission of the State of Oklahoma.
OPCo	Ohio Power Company, an AEP electric utility subsidiary.
OPEB	Other Postretirement Benefit Plans.
OTC	Over the counter.
OVEC	Ohio Valley Electric Corporation, which is 43.47% owned by AEP.
PJM	Pennsylvania – New Jersey – Maryland regional transmission organization.
PM	Particulate Matter.
PSO	Public Service Company of Oklahoma, an AEP electric utility subsidiary.
PUCO	Public Utilities Commission of Ohio.
PUCT	Public Utility Commission of Texas.

Registrant Subsidiaries	AEP subsidiaries which are SEC registrants; APCo, CSPCo, I&M, OPCo, PSO and SWEPCo.
REP	Texas Retail Electric Provider.
Risk Management Contracts	Trading and nontrading derivatives, including those derivatives designated as cash flow and fair value hedges.
Rockport Plant	A generating plant, consisting of two 1,300 MW coal-fired generating units near Rockport, Indiana, owned by AEGCo and I&M.
RTO	Regional Transmission Organization.
S&P	Standard and Poor’s.
Sabine	Sabine Mining Company, a lignite mining company that is a consolidated variable interest entity.
SFAS	Statement of Financial Accounting Standards issued by the Financial Accounting Standards Board.
SIA	System Integration Agreement.
SNF	Spent Nuclear Fuel.
SO_2	Sulfur Dioxide.
SPP	Southwest Power Pool.
Stall Unit	J. Lamar Stall Unit at Arsenal Hill Plant.
Sweeny	Sweeny Cogeneration Limited Partnership, owner and operator of a four unit, 480 MW gas-fired generation facility, owned 50% by AEP.
SWEPCo	Southwestern Electric Power Company, an AEP electric utility subsidiary.
TA	Transmission Agreement dated April 1, 1984 by and among APCo, CSPCo, I&M, KPCo and OPCo, which allocates costs and benefits in connection with the operation of transmission assets.
TCC	AEP Texas Central Company, an AEP electric utility subsidiary.
TEM	SUEZ Energy Marketing NA, Inc. (formerly known as Tractebel Energy Marketing, Inc.).
Texas Restructuring Legislation	Legislation enacted in 1999 to restructure the electric utility industry in Texas.
TNC	AEP Texas North Company, an AEP electric utility subsidiary.
True-up Proceeding	A filing made under the Texas Restructuring Legislation to finalize the amount of stranded costs and other true-up items and the recovery of such amounts.
Turk Plant	John W. Turk, Jr. Plant.
Utility Money Pool	AEP System’s Utility Money Pool.
Virginia SCC	Virginia State Corporation Commission.
WPCo	Wheeling Power Company, an AEP electric distribution subsidiary.
WVPSC	Public Service Commission of West Virginia.

FORWARD-LOOKING INFORMATION

This report made by AEP and its Registrant Subsidiaries contains forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934. Although AEP and each of its Registrant Subsidiaries believe that their expectations are based on reasonable assumptions, any such statements may be influenced by factors that could cause actual outcomes and results to be materially different from those projected. Among the factors that could cause actual results to differ materially from those in the forward-looking statements are:

- The economic climate and growth in, or contraction within, our service territory and changes in market demand and demographic patterns.
- Inflationary or deflationary interest rate trends.
- Volatility in the financial markets, particularly developments affecting the availability of capital on reasonable terms and developments impairing our ability to finance new capital projects and refinance existing debt at attractive rates.
- The availability and cost of funds to finance working capital and capital needs, particularly during periods when the time lag between incurring costs and recovery is long and the costs are material.
- Electric load and customer growth.
- Weather conditions, including storms, and our ability to recover significant storm restoration costs through applicable rate mechanisms.
- Available sources and costs of, and transportation for, fuels and the creditworthiness and performance of fuel suppliers and transporters.
- Availability of necessary generating capacity and the performance of our generating plants.
- Our ability to recover I&M's Donald C. Cook Nuclear Plant Unit 1 restoration costs through warranty, insurance and the regulatory process.
- Our ability to recover regulatory assets and stranded costs in connection with deregulation.
- Our ability to recover increases in fuel and other energy costs through regulated or competitive electric rates.
- Our ability to build or acquire generating capacity, including the Turk Plant, and transmission line facilities (including our ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs (including the costs of projects that are cancelled) through applicable rate cases or competitive rates.
- New legislation, litigation and government regulation, including requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances or additional regulation of flyash and similar combustion products that could impact the continued operation and cost recovery of our plants.
- Timing and resolution of pending and future rate cases, negotiations and other regulatory decisions (including rate or other recovery of new investments in generation, distribution and transmission service and environmental compliance).
- Resolution of litigation (including our dispute with Bank of America).
- Our ability to constrain operation and maintenance costs.
- Our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy-related commodities.
- Changes in the creditworthiness of the counterparties with whom we have contractual arrangements, including participants in the energy trading market.
- Actions of rating agencies, including changes in the ratings of debt.
- Volatility and changes in markets for electricity, natural gas, coal, nuclear fuel and other energy-related commodities.
- Changes in utility regulation, including the implementation of ESPs and related regulation in Ohio and the allocation of costs within regional transmission organizations, including PJM and SPP.
- Accounting pronouncements periodically issued by accounting standard-setting bodies.
- The impact of volatility in the capital markets on the value of the investments held by our pension, other postretirement benefit plans and nuclear decommissioning trust and the impact on future funding requirements.
- Prices and demand for power that we generate and sell at wholesale.
- Changes in technology, particularly with respect to new, developing or alternative sources of generation.
- Other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events.

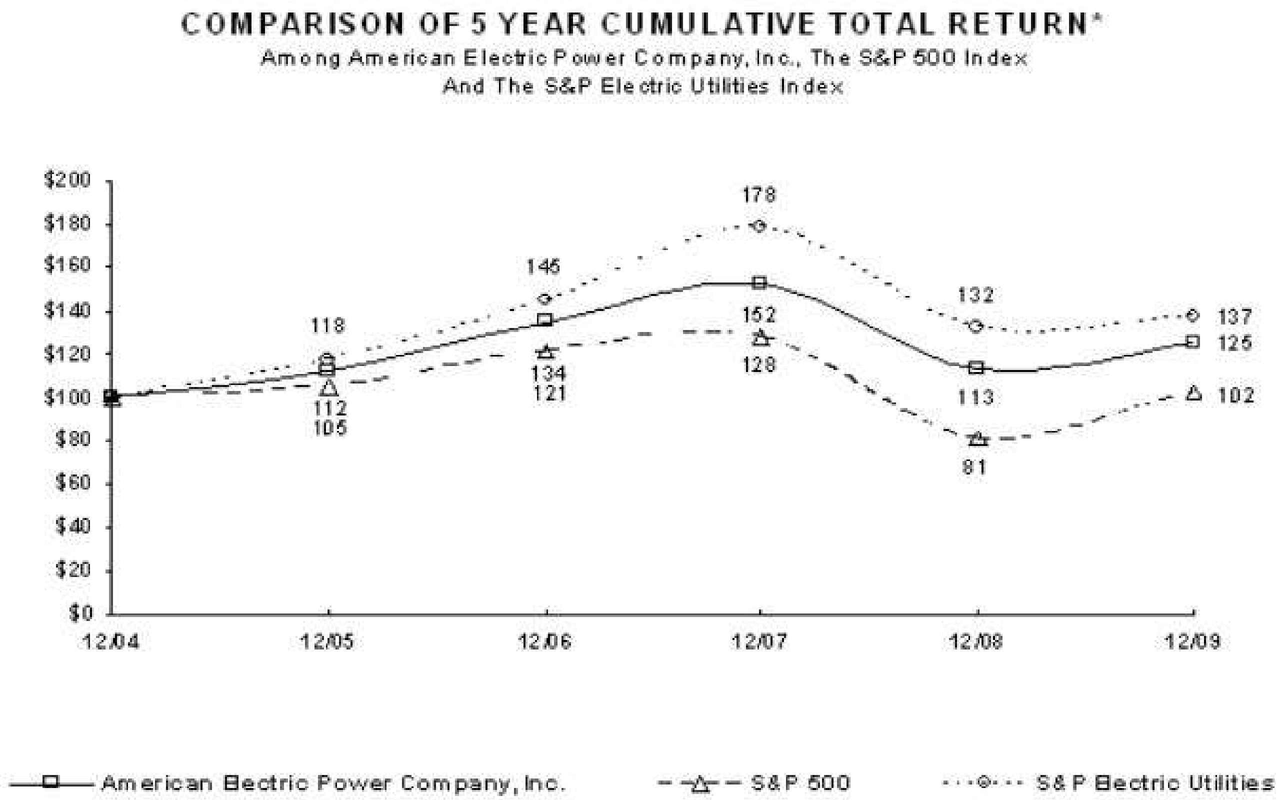
AEP and its Registrant Subsidiaries expressly disclaim any obligation to update any forward-looking information.

AEP COMMON STOCK AND DIVIDEND INFORMATION

The AEP common stock quarterly high and low sales prices, quarter-end closing price and the cash dividends paid per share are shown in the following table:

Quarter Ended	High	Low	Quarter-End Closing Price	Dividend
December 31, 2009	$ 36.51	$ 29.59	$ 34.79	$ 0.41
September 30, 2009	32.36	28.07	30.99	0.41
June 30, 2009	29.16	24.75	28.89	0.41
March 31, 2009	34.34	24.00	25.26	0.41
December 31, 2008	$ 37.28	$ 25.54	$ 33.28	$ 0.41
September 30, 2008	41.60	34.86	37.03	0.41
June 30, 2008	45.95	39.46	40.23	0.41
March 31, 2008	49.11	39.35	41.63	0.41

AEP common stock is traded principally on the New York Stock Exchange. At December 31, 2009, AEP had approximately 96,000 registered shareholders.



*$100 invested on 12/31/04 in stock or index, including reinvestment of dividends.
Fiscal year ending December 31.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
SELECTED CONSOLIDATED FINANCIAL DATA

	2009	2008	2007	2006	2005
			(in millions)		
STATEMENTS OF INCOME DATA					
Total Revenues	$ 13,489	$ 14,440	$ 13,380	$ 12,622	$ 12,111
Operating Income	$ 2,771	$ 2,787	$ 2,319	$ 1,966	$ 1,927
Income Before Discontinued Operations, Extraordinary Loss and Cumulative Effect of Accounting Change	$ 1,370	$ 1,376	$ 1,153	$ 1,001	$ 1,043
Discontinued Operations, Net of Tax	-	12	24	10	27
Income Before Extraordinary Loss and Cumulative Effect of Accounting Change	1,370	1,388	1,177	1,011	1,070
Extraordinary Loss, Net of Tax	(5)	-	(79)	-	(225)(a)
Cumulative Effect of Accounting Change, Net of Tax	-	-	-	-	(17)
Net Income	1,365	1,388	1,098	1,011	828
Less: Net Income Attributable to Noncontrolling Interests	5	5	6	6	7
NET INCOME ATTRIBUTABLE TO AEP SHAREHOLDERS	1,360	1,383	1,092	1,005	821
Less: Preferred Stock Dividend Requirements of Subsidiaries	3	3	3	3	7
EARNINGS ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 1,357	$ 1,380	$ 1,089	$ 1,002	$ 814
BALANCE SHEETS DATA					
Property, Plant and Equipment	$ 51,684	$ 49,710	$ 46,145	$ 42,021	$ 39,121
Accumulated Depreciation and Amortization	17,340	16,723	16,275	15,240	14,837
Net Property, Plant and Equipment	$ 34,344	$ 32,987	$ 29,870	$ 26,781	$ 24,284
Total Assets	$ 48,348	$ 45,155	$ 40,319	$ 37,877	$ 35,662
AEP Common Shareholders' Equity	$ 13,140	$ 10,693	$ 10,079	$ 9,412	$ 9,088
Noncontrolling Interests	$ -	$ 17	$ 18	$ 18	$ 14
Cumulative Preferred Stock Not Subject to Mandatory Redemption	$ 61	$ 61	$ 61	$ 61	$ 61
Long-term Debt (b)	$ 17,498	$ 15,983	$ 14,994	$ 13,698	$ 12,226
Obligations Under Capital Leases (b)	$ 317	$ 325	$ 371	$ 291	$ 251
AEP COMMON STOCK DATA					
Basic Earnings (Loss) per Share Attributable to AEP Common Shareholders:					
Income Before Discontinued Operations, Extraordinary Loss and Cumulative Effect of Accounting Change	$ 2.97	$ 3.40	$ 2.87	$ 2.52	$ 2.64
Discontinued Operations, Net of Tax	-	0.03	0.06	0.02	0.07
Income Before Extraordinary Loss and Cumulative Effect of Accounting Change	2.97	3.43	2.93	2.54	2.71
Extraordinary Loss, Net of Tax	(0.01)	-	(0.20)	-	(0.58)
Cumulative Effect of Accounting Change, Net of Tax	-	-	-	-	(0.04)

Basic Earnings per Share Attributable to AEP Common Shareholders	$ 2.96	$ 3.43	$ 2.73	$ 2.54	$ 2.09
Weighted Average Number of Basic Shares Outstanding (in millions)	459	402	399	394	390
Market Price Range:					
High	$ 36.51	$ 49.11	$ 51.24	$ 43.13	$ 40.80
Low	$ 24.00	$ 25.54	$ 41.67	$ 32.27	$ 32.25
Year-end Market Price	$ 34.79	$ 33.28	$ 46.56	$ 42.58	$ 37.09
Cash Dividends Paid per AEP Common Share	$ 1.64	$ 1.64	$ 1.58	$ 1.50	$ 1.42
Dividend Payout Ratio	55.41%	47.8%	57.9%	59.1%	67.9%
Book Value per AEP Common Share	$ 27.49	$ 26.35	$ 25.17	$ 23.73	$ 23.08

(a) Extraordinary Loss, Net of Tax for 2005 reflects TCC’s stranded cost.
(b) Includes portion due within one year.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
MANAGEMENT'S FINANCIAL DISCUSSION AND ANALYSIS OF RESULTS OF OPERATIONS

American Electric Power Company, Inc. (AEP) is one of the largest investor-owned electric public utility holding companies in the United States. Our electric utility operating companies provide generation, transmission and distribution services to more than five million retail customers in Arkansas, Indiana, Kentucky, Louisiana, Michigan, Ohio, Oklahoma, Tennessee, Texas, Virginia and West Virginia.

We operate an extensive portfolio of assets including:

- Almost 39,000 megawatts of generating capacity, one of the largest complements of generation in the U.S., the majority of which provides a significant cost advantage in most of our market areas.
- Approximately 39,000 miles of transmission lines, including 2,116 miles of 765kV lines, the backbone of the electric interconnection grid in the Eastern U.S.
- 215,800 miles of distribution lines that deliver electricity to 5.2 million customers.
- Substantial commodity transportation assets (more than 9,000 railcars, approximately 3,000 barges, 64 towboats, 29 harbor boats and a coal handling terminal with 18 million tons of annual capacity).

EXECUTIVE OVERVIEW

Economic Conditions

In 2009, our operations were impacted by difficult economic conditions. While our 2009 residential and commercial KWH sales were down moderately in comparison to 2008, our industrial KWH sales declined substantially in 2009 by 16%. Approximately half of the decrease was due to cutbacks or closures by 10 of our large metals producing customers. We also experienced varying decreases in KWH sales to customers in the transportation, plastics, rubber and paper manufacturing industries. We forecast a recovery in industrial sales volumes of approximately 5% in 2010 as compared to 2009.

Margins from off-system sales decreased due to reductions in sales volumes and weak market prices for power, reflecting reduced overall demand for electricity. Off-system sales volumes decreased by 50% in 2009. We forecast a recovery in off-system sales volumes of approximately 60% in 2010 as compared to 2009.

Regulatory Activity

Significant 2009 Approved Rate Increases

Arkansas – The APSC approved a base rate increase that provides for an $18 million annual increase in revenues effective December 2009 and a decrease in annual depreciation rates of $12 million. The order also includes a separate rider of approximately $11 million annually for the recovery of carrying costs, depreciation and operation and maintenance expenses on the Stall Unit once it is placed in service as expected in mid-2010.

Indiana – The IURC approved a base rate increase that provides for an annual increase in revenues of $42 million effective March 2009, including a $19 million base rate increase and $23 million in additional tracker revenues for certain incurred costs, subject to true-up.

Ohio – The PUCO issued an order that modified and approved CSPCo's and OPCo's ESP filings that authorized capped rate increases during the three-year ESP period and also authorized a FAC. The order provided for a $94 million and $103 million increase in CSPCo's and OPCo's 2009 revenues. Projected revenue increases for CSPCo and OPCo under the capped rate provision of the ESP order are listed below:

	Projected Revenue Increases 2010	2011
	(in millions)	
CSPCo	$ 109	$ 116
OPCo	125	153

Changes in customer usage may have an impact on actual revenue increases under the capped rate provision of the ESP order. In addition to the revenue increases, net income was positively affected by material noncash FAC deferrals in 2009 and will continue through 2011, including a carrying charge at CSPCo's and OPCo's weighted average cost of capital. These deferrals will be collected through a non-bypassable surcharge from 2012 through 2018. Several notices of appeal are pending at the Supreme Court of Ohio.

Oklahoma – The OCC approved PSO's Capital Reliability Rider (CRR) filing to recover up to $30 million under the CRR on an annual basis beginning in January 2010 until PSO's next base rate order. The order approving the CRR requires PSO to file a base rate case no later than July 2010.

Virginia – The Virginia SCC issued an order which provides for a $130 million annual fuel revenue increase effective August 2009 to recover deferred and projected fuel costs. The Virginia SCC also approved APCo's Transmission Rate Adjustment Clause effective December 2009 which will increase annual revenue by $22 million to provide for eligible transmission service costs billed by PJM.

West Virginia – For APCo's and WPCo's Expanded Net Energy Cost (ENEC) filing, the WVPSC issued an order granting a $355 million increase effective October 2009 over a four-year phase-in period plus a fixed annual carrying cost rate of 4% to recover fuel, purchased power and other deferred and projected energy costs.

Pending Rate Cases

Kentucky – In December 2009, KPCo filed a base rate case with the KPSC to increase base revenues by $124 million annually based on an 11.75% return on common equity. New rates are expected to become effective in July 2010.

Texas – In August 2009, SWEPCo filed a rate case with the PUCT to increase its base rates by approximately $75 million annually including a return on equity of 11.5%. The filing includes financing cost riders of $32 million related to construction of the Stall Unit and Turk Plant, a vegetation management rider of $16 million and other requested increases of $27 million. The March 2010 hearings were suspended for the parties to pursue settlement discussions.

Virginia – In July 2009, APCo filed a generation and distribution base rate increase with the Virginia SCC of $154 million annually based on a 13.35% return on common equity. The new rates, subject to refund, became effective in December 2009. To date, intervenors have filed testimony which management estimates could result in revenue increases ranging from $63 million to $94 million. In February 2010, in response to customer concerns regarding higher electric bills, APCo, in working with service area legislators, proactively developed proposed legislation to suspend the collection of interim rates. The Governor of Virginia approved this legislation.

Regulatory Strategy and Announced 2010 Base Rate Cases

We intend to seek increases in base rates where our returns on equity are not considered reasonable. We also intend to actively pursue the recovery of significant 2009 storm restoration costs and new investments in generation, transmission and distribution service and environmental compliance. We will continue to pursue cost recovery mechanisms in 2010 that will ensure ratepayers and shareholders are treated fairly.

To date, we have filed or given notice of the following base rate cases:

Michigan – In January 2010, I&M filed for a $63 million increase in annual base rates based on an 11.75% return on common equity. I&M can request interim rates, subject to refund, after six months. A final order from the MPSC is required within one year.

West Virginia – APCo provided notice to the WVPSC that it intends to file a base rate case, now planned for March 2010.

Global Warming

Climate change is a global issue and the United States should assume a leadership role in developing a new international approach that will address growing emissions from all nations. In 2009, the U.S. House of Representatives passed a comprehensive energy and climate change bill. The Senate Environmental and Public Works Committee passed legislation out of committee. The Federal EPA also issued a final mandatory greenhouse gas reporting rule covering a broad range of facilities. Mandated CO_2 emission reductions will have significant capital and operating cost impacts on the AEP System. It will also impact decisions concerning the retirement of some of our smaller coal generating units.

Mountaineer Carbon Capture and Storage Project

APCo and ALSTOM Power, Inc., an unrelated third party, jointly constructed a CO_2 capture validation facility, which was placed into service in September 2009. APCo also constructed and owns the necessary facilities to store the CO_2. In October 2009, APCo started injecting CO_2 into the underground storage facilities.

In December 2009, APCo received approval for federal grant funding of $334 million for a new commercial scale project at the Mountaineer Plant to capture and store carbon for 235 MW of the plant's existing 1,300 MW of capacity by 2015. The cost of this proposed project is currently estimated to be $668 million, excluding Asset Retirement Obligations. We are currently seeking partners in this project to share the projected remaining costs.

Cook Plant Unit 1 Fire and Shutdown

In September 2008, I&M shut down Cook Plant Unit 1 (Unit 1) due to turbine vibrations, caused by blade failure, which resulted in a fire on the electric generator. Management believes that I&M should recover a significant portion of repair and replacement costs through the turbine vendor's warranty, insurance and the regulatory process. Upon receipt of accidental outage insurance proceeds, I&M mitigated the incremental fuel cost of replacement power to ratepayers. I&M repaired Unit 1 and it resumed operations in December 2009 at reduced power. The Unit 1 rotors were repaired and reinstalled due to the extensive lead time required to manufacture and install new turbine rotors. As a result, the replacement of the repaired turbine rotors and other equipment is scheduled for the Unit 1 planned outage in the fall of 2011.

Turk Plant

SWEPCo is currently constructing the Turk Plant, a new base load 600 MW pulverized coal ultra-supercritical generating unit in Arkansas. SWEPCo owns 73% of the Turk Plant and will operate the completed facility. The APSC, LPSC and PUCT approved SWEPCo's application to build the Turk Plant.

In June 2009, the Arkansas Court of Appeals issued a unanimous decision that would reverse the APSC's grant of its permission for construction of the Turk Plant to serve Arkansas retail customers. In October 2009, the Arkansas Supreme Court granted the petitions filed by SWEPCo and the APSC to review the Arkansas Court of Appeals decision.

In November 2008, SWEPCo received its required air permit approval from the Arkansas Department of Environmental Quality (ADEQ) and commenced construction at the site. The Turk Plant cannot be placed in service without its air permit. Certain parties filed an appeal of the air permit approval with the Arkansas Pollution Control and Ecology Commission (APCEC). In January 2010, the APCEC upheld the air permit. In February 2010, the parties who unsuccessfully appealed the air permit to the APCEC filed a notice of appeal of the APCEC's decision with the Circuit Court of Hempstead County, Arkansas. The same parties filed a petition with the Federal EPA to review the air permit. In December 2009, the Federal EPA rejected the parties' petition on every issue except one, where the Federal EPA asked the ADEQ to supplement the air permit record on one aspect of its Best Available Control Technology analysis.

If for any reason SWEPCo is unable to complete the Turk Plant construction and place the Turk Plant in service, it would reduce net income, cash flows and possibly impact financial condition.

Transmission Initiatives

We continue our pursuit of transmission opportunities throughout the U.S. In 2009, we announced that our recently formed transmission company, AEP Transmission Company, LLC, will pursue new transmission investments within our retail service territories. We plan to invest approximately $120 million in these transmission opportunities in 2010. Through a joint venture, we have existing and planned transmission projects in ERCOT. We continue to pursue other transmission opportunities outside of our retail service territories through joint ventures with other partners.

gridSMART SM

We are currently introducing and implementing our gridSMART SM project in portions of our retail service territories. gridSMART SM is a combination of advanced technologies and consumer programs intended to improve electricity distribution efficiency, reduce power demand thereby reducing power plant emissions and help consumers manage their electricity use and costs. In 2009, CSPCo received approval for federal grant funding of $75 million from the U.S. Department of Energy for the Ohio gridSMART SM demonstration program. These funds will provide capital to reduce the ultimate cost to customers. Subject to appropriate cost recovery, we intend to implement gridSMART SM in other sections of our retail service territories.

RESULTS OF OPERATIONS

SEGMENTS

Our primary business is our electric utility operations. Within our Utility Operations segment, we centrally dispatch generation assets and manage our overall utility operations on an integrated basis because of the substantial impact of cost-based rates and regulatory oversight. While our Utility Operations segment remains our primary business segment, other segments include our AEP River Operations segment with significant barging activities and our Generation and Marketing segment, which includes our nonregulated generating, marketing and risk management activities primarily in the ERCOT market area. Intersegment sales and transfers are generally based on underlying contractual arrangements and agreements.

Our reportable segments and their related business activities are as follows:

Utility Operations
- Generation of electricity for sale to U.S. retail and wholesale customers.
- Electricity transmission and distribution in the U.S.

AEP River Operations
- Commercial barging operations that annually transport approximately 33 million tons of coal and dry bulk commodities primarily on the Ohio, Illinois and lower Mississippi Rivers. Approximately 49% of the barging is for transportation of agricultural products, 27% for coal, 8% for steel and 16% for other commodities.

Generation and Marketing
- Wind farms and marketing and risk management activities primarily in ERCOT.

The table below presents our consolidated Income Before Discontinued Operations and Extraordinary Loss by segment for the years ended December 31, 2009, 2008 and 2007.

	Years Ended December 31,		
	2009	2008	2007
		(in millions)	
Utility Operations	$ 1,329	$ 1,123	$ 1,040
AEP River Operations	47	55	61
Generation and Marketing	41	65	67
All Other (a)	(47)	133	(15)
Income Before Discontinued Operations and Extraordinary Loss	$ 1,370	$ 1,376	$ 1,153

(a) All Other includes:
- Parent's guarantee revenue received from affiliates, investment income, interest income and interest expense and other nonallocated costs.
- Tax and interest expense adjustments related to our UK operations which were sold in 2004 and 2002.
- Forward natural gas contracts that were not sold with our natural gas pipeline and storage operations in 2004 and 2005. These contracts are financial derivatives which will gradually settle and completely expire in 2011.
- The 2008 cash settlement of a purchase power and sale agreement with TEM related to the Plaquemine Cogeneration Facility. The cash settlement of $255 million ($164 million, net of tax) is included in Net Income.

AEP CONSOLIDATED

2009 Compared to 2008

Income Before Discontinued Operations and Extraordinary Loss in 2009 decreased $6 million compared to 2008 primarily due to income in 2008 from the cash settlement of a purchase power and sale agreement with TEM offset by an increase in income from our Utility Operations segment. The increase in Utility Operations segment net income primarily relates to rate increases in our Indiana, Ohio, Oklahoma and Virginia service territories partially offset by lower industrial sales as well as lower off-system sales margins due to lower sales volumes and lower market prices.

Average basic shares outstanding increased to 459 million in 2009 from 402 million in 2008 primarily due to the issuance of 69 million shares of AEP common stock. Actual shares outstanding were 478 million as of December 31, 2009.

2008 Compared to 2007

Income Before Discontinued Operations and Extraordinary Loss in 2008 increased $223 million compared to 2007 primarily due to income from the cash settlement received in 2008 related to a purchase power and sale agreement with TEM, the 2008 deferral of Oklahoma ice storm expenses incurred in 2007 and base rate increases in our Ohio, Texas and Virginia service territories. These increases over 2007 were partially offset by higher interest expense and fuel expense and a provision for refund recorded to reflect the impact of an order issued in November 2008 by the FERC regarding the affiliate allocation of off-system sales margins under the SIA and the CSW Operating Agreement.

Average basic shares outstanding increased to 402 million in 2008 from 399 million in 2007 primarily due to the issuance of shares under our incentive compensation and dividend reinvestment plans. Actual shares outstanding were 406 million as of December 31, 2008. In 2008, we contributed 1,250,000 shares of common stock held in treasury to the AEP Foundation.

Our results of operations are discussed below by operating segment.

UTILITY OPERATIONS

Our Utility Operations segment includes primarily regulated revenues with direct and variable offsetting expenses and net reported commodity trading operations. We believe that a discussion of the results from our Utility Operations segment on a gross margin basis is most appropriate in order to further understand the key drivers of the segment. Gross margin represents utility operating revenues less the related direct cost of fuel, including consumption of chemicals and emissions allowances, and purchased power.

	Years Ended December 31, 2009	2008	2007
		(in millions)	
Revenues	$ 12,803	$ 13,566	$ 12,655
Fuel and Purchased Power	4,420	5,622	4,838
Gross Margin	8,383	7,944	7,817
Depreciation and Amortization	1,561	1,450	1,483
Other Operating Expenses	4,162	4,114	4,129
Operating Income	2,660	2,380	2,205
Other Income, Net	138	173	105
Interest Expense	916	915	784
Income Tax Expense	553	515	486
Income Before Discontinued Operations and Extraordinary Loss	$ 1,329	$ 1,123	$ 1,040

Summary of KWH Energy Sales for Utility Operations
For the Years Ended December 31, 2009, 2008 and 2007

Energy/Delivery Summary	2009	2008	2007
		(in millions of KWH)	
Retail:			
Residential	58,232	58,892	59,182
Commercial	49,925	50,382	50,611
Industrial	54,428	64,508	63,555
Miscellaneous	3,048	3,114	3,186
Total Retail (a)	165,633	176,896	176,534
Wholesale	29,679	43,085	42,917
Total KWHs	195,312	219,981	219,451

(a) Includes energy delivered to customers served by AEP's Texas Wires Companies.

Cooling degree days and heating degree days are metrics commonly used in the utility industry as a measure of the impact of weather on net income. In general, degree day changes in our eastern region have a larger effect on net income than changes in our western region due to the relative size of the two regions and the number of customers within each region.

Summary of Heating and Cooling Degree Days for Utility Operations
For the Years Ended December 31, 2009, 2008 and 2007

	2009	2008	2007
		(in degree days)	
Eastern Region			

Actual – Heating (a)	3,097	3,134	3,014
Normal – Heating (b)	3,040	3,018	3,042
Actual – Cooling (c)	816	949	1,266
Normal – Cooling (b)	1,011	986	978
Western Region			
Actual – Heating (a)	970	992	1,026
Normal – Heating (b)	984	1,010	1,028
Actual – Cooling (d)	2,439	2,252	2,318
Normal – Cooling (b)	2,344	2,320	2,326

(a) Eastern Region and Western Region heating degree days are calculated on a 55 degree temperature base.
(b) Normal Heating/Cooling represents the thirty-year average of degree days.
(c) Eastern Region cooling degree days are calculated on a 65 degree temperature base.
(d) Western Region cooling degree days are calculated on a 65 degree temperature base for PSO/SWEPCo and a 70 degree temperature base for TCC/TNC.

2009 Compared to 2008

Reconciliation of Year Ended December 31, 2008 to Year Ended December 31, 2009
Income from Utility Operations Before Discontinued Operations and Extraordinary Loss
(in millions)

Year Ended December 31, 2008		$ 1,123
Changes in Gross Margin:		
Retail Margins	549	
Off-system Sales	(333)	
Transmission Revenues	25	
Other Revenues	198	
Total Change in Gross Margin		439
Total Expenses and Other:		
Other Operation and Maintenance	(46)	
Depreciation and Amortization	(111)	
Taxes Other Than Income Taxes	(2)	
Interest and Investment Income	(38)	
Carrying Costs Income	(36)	
Allowance for Equity Funds Used During Construction	37	
Interest Expense	(1)	
Equity Earnings of Unconsolidated Subsidiaries	2	
Total Expenses and Other		(195)
Income Tax Expense		(38)
Year Ended December 31, 2009		$ 1,329

The major components of the increase in Gross Margin, defined as revenues less the related direct cost of fuel, including consumption of chemicals and emissions allowances, and purchased power were as follows:

- Retail Margins increased $549 million primarily due to the following:
  - A $187 million increase related to the PUCO's approval of our Ohio ESPs, a $170 million increase related to base rates and recovery of E&R costs in Virginia and construction financing costs in West Virginia, a $75 million increase in base rates in Oklahoma, a $42 million net rate increase for I&M and $50 million of rate increases in our other jurisdictions.
  - A $201 million increase in fuel margins in Ohio primarily due to the deferral of fuel costs by CSPCo and OPCo in 2009. The PUCO's March 2009 approval of CSPCo's and OPCo's ESPs allows for the deferral of fuel and related

costs during the ESP period.

- A $102 million increase due to the December 2008 provision for refund of off-system sales margins as ordered by the FERC related to the SIA.
- A $68 million increase due to lower PJM and other costs as the result of lower generation sales.

These increases were partially offset by:

- A $214 million decrease in margins from industrial sales due to reduced operating levels and suspended operations by certain large industrial customers in our service territories.
- A $78 million decrease in fuel margins due to higher fuel and purchased power costs related to the Cook Plant Unit 1 shutdown. This decrease in fuel margins was offset by a corresponding increase in Other Revenues as discussed below.
- A $52 million decrease in usage primarily due to a 14% decrease in cooling degree days in our eastern region.
- A $29 million decrease related to favorable coal contract amendments in 2008.

- Margins from Off-system Sales decreased $333 million primarily due to lower physical sales volumes and lower margins in our eastern service territory reflecting lower market prices, partially offset by higher trading and marketing margins.
- Transmission Revenues increased $25 million primarily due to increased rates in the ERCOT and SPP regions.
- Other Revenues increased $198 million primarily due to the Cook Plant accidental outage insurance proceeds of $185 million. I&M reduced customer bills by approximately $78 million for the cost of replacement power during the outage period. This increase in revenues was offset by a corresponding decrease in Retail Margins as discussed above.

Total Expenses and Other and Income Tax Expense changed between years as follows:

- Other Operation and Maintenance expenses increased $46 million primarily due to the following:
  - The 2008 deferral of $74 million of previously expensed Oklahoma ice storm costs resulting from an OCC order approving recovery of January and December 2007 ice storm expenses.
  - A $64 million increase in administrative and general expenses primarily for employee benefits.
  - A $48 million increase in storm restoration expenses due to the December 2009 winter storm in Tennessee, Virginia and West Virginia. We plan to seek recovery of these expenses.
  - A $32 million increase in demand side management, energy efficiency and vegetation management programs.
  - A $29 million increase in recoverable transmission service expenses.
  - A $14 million increase due to the completion of reliability deferrals in Virginia in December 2008 and the decrease of environmental deferrals in Virginia in 2009.

  These increases were partially offset by:
  - A $67 million decrease in distribution and customer account expenses.
  - A $51 million decrease in transmission expenses related to cost recovery rider amortization in Ohio and rate adjustment clause deferrals in Virginia.
  - A $43 million decrease in other operating expenses including lower charitable contributions.
  - A $39 million decrease in RTO fees, forestry and other transmission expenses.
  - A $15 million decrease in plant outage and other plant operating and maintenance expenses, including lower removal costs.
- Depreciation and Amortization increased $111 million primarily due to higher depreciable property balances as the result of environmental improvements placed in service at OPCo and various other property additions and higher depreciation rates for OPCo related to shortened depreciable lives for certain generating facilities.
- Interest and Investment Income decreased $38 million primarily due to lower interest income related to federal income tax refunds filed with the IRS and the recognition of other-than-temporary losses related to equity investments held by our protected cell of EIS in 2009.
- Carrying Costs Income decreased $36 million primarily due to the completion of reliability deferrals in Virginia in December 2008 and the decrease of environmental deferrals in Virginia in 2009.
- Allowance for Equity Funds Used During Construction increased $37 million as a result of construction at SWEPCo's Turk Plant and Stall Unit and the reapplication of "Regulated Operations" accounting guidance for the generation portion of SWEPCo's Texas retail jurisdiction effective April 2009.
- Interest Expense increased $1 million primarily due to a $52 million increase in interest expense related to increased long-term debt borrowings partially offset by interest expense of $47 million recorded in 2008 related to the 2008 SIA adjustment for off-system sales margins in accordance with the FERC's 2008 order.
- Income Tax Expense increased $38 million primarily due to an increase in pretax book income offset by the regulatory accounting treatment of state income taxes and other book/tax differences which are accounted for on a flow-through basis.

2008 Compared to 2007

Reconciliation of Year Ended December 31, 2007 to Year Ended December 31, 2008
Income from Utility Operations Before Discontinued Operations and Extraordinary Loss
(in millions)

Year Ended December 31, 2007		$ 1,040
Changes in Gross Margin:		
Retail Margins	159	
Off-system Sales	(90)	
Transmission Revenues	33	
Other Revenues	25	
Total Change in Gross Margin		127
Total Expenses and Other:		
Other Operation and Maintenance	35	
Gain on Dispositions of Assets, Net	(19)	
Depreciation and Amortization	33	
Taxes Other Than Income Taxes	(1)	
Interest and Investment Income	21	
Carrying Costs Income	32	
Allowance for Equity Funds Used During Construction	12	
Interest Expense	(131)	
Equity Earnings of Unconsolidated Subsidiaries	3	
Total Expenses and Other		(15)
Income Tax Expense		(29)
Year Ended December 31, 2008		$ 1,123

The major components of the increase in Gross Margin, defined as revenues less the related direct cost of fuel, including consumption of chemicals and emissions allowances, and purchased power were as follows:

- Retail Margins increased $159 million primarily due to the following:
  - A $206 million increase related to net rate increases implemented in our Ohio jurisdictions, a $53 million increase related to recovery of E&R costs in Virginia and construction financing costs in West Virginia, a $25 million net increase in rates in Oklahoma, a $21 million increase in base rates in Texas and an $18 million increase in base rates in Virginia.
  - A $99 million net increase due to adjustments recorded in 2007 related to the 2007 Virginia base rate case which included a second quarter 2007 provision for revenue refund.
  - A $50 million increase related to increased usage by Ormet, an industrial customer in Ohio.
  - A $40 million net increase due to favorable coal contract amendments in 2008.
  - A $17 million increase due to a 2007 provision related to a SWEPCo Texas fuel reconciliation proceeding.
  - An $8 million increase in sales to municipal and cooperative customers, primarily in CSPCo's service territory.

  These increases were partially offset by:
  - A $186 million increase in fuel expense in Ohio. CSPCo and OPCo did not have active fuel clauses in 2008 and 2007.
  - A $102 million decrease due to the December 2008 provision for refund of off-system sales margins as ordered by the FERC related to the SIA.
  - A $65 million decrease in usage primarily due to a 26% decrease in cooling degree days in our eastern region and a 10% decrease in cooling degree days in our western region.
  - A $40 million net decrease in retail sales primarily due to lower industrial sales in Indiana, Ohio and Virginia as a result of the economic slowdown in the second half of 2008.
- Margins from Off-system Sales decreased $90 million primarily due to the following:
  - A $45 million decrease due to higher trading margins realized in 2007 and the favorable effects of a fuel reconciliation in our western service territory in 2007. This decrease was partially offset by higher physical off-system sales in our eastern territory as the result of higher realized prices and higher PJM capacity revenues.
  - A $46 million decrease primarily due to an increase in sharing of off-system sales margins with customers resulting from a full year of sharing in Virginia in 2008 compared to one quarter of sharing in 2007.

- Transmission Revenues increased $33 million primarily due to increased rates.
- Other Revenues increased $25 million primarily due to increased third-party engineering and construction work, an increase in pole attachment revenue and an unfavorable provision for TCC for the refund of bonded rates recorded in 2007.

Total Expenses and Other and Income Tax Expense changed between years as follows:

- Other Operation and Maintenance expenses decreased $35 million primarily due to the following:
  - An $84 million decrease due to distribution expense recorded in 2007 for ice storm costs incurred in January and December 2007 and a $74 million decrease related to the deferral of these costs in the first quarter of 2008.
  - A $77 million decrease related to the recording of NSR settlement costs in September 2007.
  - A $9 million decrease related to the establishment of a regulatory asset in the third quarter of 2008 for Virginia's share of previously expensed NSR settlement costs.

  These decreases were partially offset by:
  - A $60 million increase in recoverable PJM expenses in Ohio.
  - A $38 million increase in tree trimming, reliability and other transmission and distribution expenses.
  - A $28 million increase in generation plant operations and maintenance expense.
  - A $28 million increase in recoverable customer account expenses related to the Universal Service Fund for Ohio customers who qualify for payment assistance.
  - A $22 million increase due to storm costs incurred in 2008 by SWEPCo and I&M.
  - A $13 million increase in maintenance expense at the Cook Plant.
  - A $12 million increase due to the amortization of deferred 2007 Oklahoma ice storm costs in 2008.
  - A $10 million increase related to the write-off of the unrecoverable pre-construction costs for PSO's cancelled Red Rock Generating Facility in the first quarter of 2008.
- Gain on Dispositions of Assets, Net decreased $19 million primarily due to the expiration of the earnings sharing agreement with Centrica from the sale of our Texas REPs in 2002. In 2007, we received the final earnings sharing payment of $20 million.
- Depreciation and Amortization expense decreased $33 million primarily due to lower commission-approved depreciation rates in Indiana, Michigan, Oklahoma and Texas and lower Ohio regulatory asset amortization, partially offset by higher depreciable property balances and prior year adjustments related to the Virginia base rate case.
- Interest and Investment Income increased $21 million primarily due to the favorable effect of claims for refund filed with the IRS.
- Carrying Costs Income increased $32 million primarily due to increased cost deferrals in Virginia and Oklahoma.
- Allowance for Equity Funds Used During Construction increased $12 million primarily due to various generation projects under construction.
- Interest Expense increased $131 million primarily due to additional debt issued and higher interest rates on variable rate debt and interest expense of $47 million on off-system sales margins in accordance with the FERC's order related to the SIA.
- Income Tax Expense increased $29 million due to an increase in pretax income.

AEP RIVER OPERATIONS

2009 Compared to 2008

Income Before Discontinued Operations and Extraordinary Loss from our AEP River Operations segment decreased from $55 million in 2008 to $47 million in 2009 primarily due to lower revenues as a result of a weak import market.

2008 Compared to 2007

Income Before Discontinued Operations and Extraordinary Loss from our AEP River Operations segment decreased from $61 million in 2007 to $55 million in 2008 primarily due to rising diesel fuel prices, travel restrictions caused by significant flooding on various internal waterways throughout 2008, the impact of Hurricanes Ike and Gustav and other adverse operating conditions. Additionally, decreases in import demand and grain export demand resulted in lower freight demand as a result of a slowing U.S. economy.

GENERATION AND MARKETING

2009 Compared to 2008

Income Before Discontinued Operations and Extraordinary Loss from our Generation and Marketing segment decreased from

$65 million in 2008 to $41 million in 2009 primarily due to lower gross margins at the Oklaunion Generating Station as a result of lower power prices in ERCOT and decreased generation from our wind farms.

2008 Compared to 2007

Income Before Discontinued Operations and Extraordinary Loss from our Generation and Marketing segment decreased from $67 million in 2007 to $65 million in 2008 primarily due to the sale in 2007 of our equity investment in Sweeny and related contracts which resulted in $37 million of after-tax income offset by higher gross margins from marketing activities and improved plant performance and hedging activities from our share of the Oklaunion Generating Station.

ALL OTHER

2009 Compared to 2008

Income Before Discontinued Operations and Extraordinary Loss from All Other decreased from income of $133 million in 2008 to a loss of $47 million in 2009. In 2008, we had after-tax income of $164 million from a litigation settlement of a purchase power and sale agreement with TEM.

2008 Compared to 2007

Income Before Discontinued Operations and Extraordinary Loss from All Other increased from a loss of $15 million in 2007 to income of $133 million in 2008. In 2008, we had after-tax income of $164 million from a litigation settlement of a purchase power and sale agreement with TEM.

AEP SYSTEM INCOME TAXES

2009 Compared to 2008

Income Tax Expense decreased $67 million between 2008 and 2009 primarily due to a decrease in pretax book income and the regulatory accounting treatment of state income taxes and other book/tax differences which are accounted for on a flow-through basis.

2008 Compared to 2007

Income Tax Expense increased $126 million between 2007 and 2008 primarily due to an increase in pretax book income.

FINANCIAL CONDITION

We measure our financial condition by the strength of our balance sheet and the liquidity provided by our cash flows. During 2009, we maintained our strong financial condition as reflected by our issuances of $1.64 billion (net proceeds) of AEP common stock in April and $2.3 billion of long-term debt primarily to pay our 2008 draws on the credit facilities, fund our construction program and refinance debt maturities. These issuances help to support our investment grade ratings and maintain financial flexibility.

DEBT AND EQUITY CAPITALIZATION

	December 31,			
	2009		2008	
	($ in millions)			
Long-term Debt, including amounts due within one year	$ 17,498	56.8%	$ 15,983	55.6%
Short-term Debt	126	0.4	1,976	6.9
Total Debt	17,624	57.2	17,959	62.5
Preferred Stock of Subsidiaries	61	0.2	61	0.2
AEP Common Equity	13,140	42.6	10,693	37.2
Noncontrolling Interests	-	-	17	0.1
Total Debt and Equity Capitalization	$ 30,825	100.0%	$ 28,730	100.0%

Our ratio of debt to total capital improved from 62.5% to 57.2% in 2009 due to the issuance of common shares and the application of the proceeds to reduce debt. Our 2009 financing activities and prudent management of capital expenditures during the current economic conditions will reduce our expected 2010 capital market requirements and continue to strengthen our balance sheet.

Approximately $1.6 billion of our $17 billion of outstanding long-term debt will mature in 2010, excluding payments due for securitization bonds which we recover directly from ratepayers. In September 2009, OPCo issued $500 million of 5.375% senior unsecured notes which will be used to pay at maturity some of its outstanding debt due in 2010. We believe that our projected cash flows from operating activities are sufficient to support our ongoing operations. Our debt matures in 2010 as follows:

		(in millions)
First Quarter	$	498
Second Quarter		703
Third Quarter		12
Fourth Quarter		375

LIQUIDITY

Liquidity, or access to cash, is an important factor in determining our financial stability. We believe we have adequate liquidity under our existing credit facilities. At December 31, 2009, we had $3.6 billion in aggregate credit facility commitments to support our operations. Additional liquidity is available from cash from operations and a sale of receivables agreement. We are committed to maintaining adequate liquidity. We generally use short-term borrowings to fund working capital needs, property acquisitions and construction until long-term funding is arranged. Sources of long-term funding include issuance of long-term debt, sale-leaseback or leasing agreements or common stock.

Credit Facilities

We manage our liquidity by maintaining adequate external financing commitments. At December 31, 2009, our available liquidity was approximately $3.4 billion as illustrated in the table below:

		Amount	Maturity
		(in millions)	
Commercial Paper Backup:			
Revolving Credit Facility	$	1,500	March 2011
Revolving Credit Facility		1,454	April 2012
Revolving Credit Facility		627	April 2011
Total		3,581	
Cash and Cash Equivalents		490	
Total Liquidity Sources		4,071	
Less: AEP Commercial Paper Outstanding		119	
Letters of Credit Issued		568	
Net Available Liquidity	$	3,384	

We have credit facilities totaling $3.6 billion, of which two $1.5 billion credit facilities support our commercial paper program. The two $1.5 billion credit facilities allow for the issuance of up to $750 million as letters of credit under each credit facility. We also have a $627 million credit facility which can be utilized for letters of credit or draws.

We use our commercial paper program to meet the short-term borrowing needs of our subsidiaries. The program is used to fund both a Utility Money Pool, which funds the utility subsidiaries, and a Nonutility Money Pool, which funds the majority of the nonutility subsidiaries. In addition, the program also funds, as direct borrowers, the short-term debt requirements of other subsidiaries that are not participants in either money pool for regulatory or operational reasons. In 2009, we repaid the $2 billion borrowed in 2008 under the credit facilities. The maximum amount of commercial paper outstanding during 2009 was $614 million. The weighted-average interest rate for our commercial paper during 2009 was 0.61%.

Sale of Receivables

In 2009, we renewed our sale of receivables agreement through July 2010. The sale of receivables agreement provides a commitment of $750 million from banks and commercial paper conduits to purchase receivables. We intend to extend or replace the sale of receivables agreement at maturity.

Debt Covenants and Borrowing Limitations

Our revolving credit agreements contain certain covenants and require us to maintain our percentage of debt to total capitalization at a level that does not exceed 67.5%. The method for calculating our outstanding debt and other capital is contractually defined in our revolving credit agreements. At December 31, 2009, this contractually-defined percentage was

53.9%. Nonperformance of these covenants could result in an event of default under these credit agreements. At December 31, 2009, we complied with all of the covenants contained in these credit agreements. In addition, the acceleration of our payment obligations or the obligations of certain of our major subsidiaries prior to maturity under any other agreement or instrument relating to debt outstanding in excess of $50 million would cause an event of default under these credit agreements and in a majority of our non-exchange traded commodity contracts, which would permit the lenders and counterparties to declare the outstanding amounts payable. However, a default under our non-exchange traded commodity contracts does not cause an event of default under our revolving credit agreements.

The revolving credit facilities do not permit the lenders to refuse a draw on any facility if a material adverse change occurs.

Utility Money Pool borrowings and external borrowings may not exceed amounts authorized by regulatory orders. At December 31, 2009, we had not exceeded those authorized limits.

Dividend Policy and Restrictions

We have declared common stock dividends payable in cash in each quarter since July 1910, representing 399 consecutive quarters. The Board of Directors declared a quarterly dividend of $0.41 per share in January 2010. Future dividends may vary depending upon our profit levels, operating cash flows and capital requirements, as well as financial and other business conditions existing at the time. We have the option to defer interest payments on the AEP Junior Subordinated Debentures for one or more periods of up to 10 consecutive years per period. During any period in which we defer interest payments, we may not declare or pay any dividends or distributions on, or redeem, repurchase or acquire, our common stock. We believe that these restrictions will not have a material effect on our cash flows, financial condition or limit any dividend payments in the foreseeable future.

Credit Ratings

Our credit ratings as of December 31, 2009 were as follows:

	Moody's	S&P	Fitch
AEP Short Term Debt	P-2	A-2	F-2
AEP Senior Unsecured Debt	Baa2	BBB	BBB

In 2009, Moody's:

- Placed AEP on negative outlook.
- Downgraded TNC to Baa2 and placed it on stable outlook.
- Changed the rating outlook for APCo from negative to stable.
- Downgraded SWEPCo to Baa3 and placed it on stable outlook.
- Downgraded OPCo to Baa1 and placed it on stable outlook.

In 2009, Fitch:

- Changed its rating outlook for SWEPCo and TCC from stable to negative.
- Downgraded APCo's senior unsecured rating to BBB and placed it on stable outlook.

If we receive a downgrade in our credit ratings by one of the rating agencies listed above, our borrowing costs could increase and access to borrowed funds could be negatively affected.

CASH FLOW

Managing our cash flows is a major factor in maintaining our liquidity strength.

	Years Ended December 31,		
	2009	2008	2007
	(in millions)		
Cash and Cash Equivalents at Beginning of Period	$ 411	$ 178	$ 301
Net Cash Flows from Operating Activities	2,475	2,581	2,394
Net Cash Flows Used for Investing Activities	(2,916)	(4,027)	(3,921)
Net Cash Flows from Financing Activities	520	1,679	1,404
Net Increase (Decrease) in Cash and Cash Equivalents	79	233	(123)

Cash and Cash Equivalents at End of Period	$ 490	$ 411	$ 178

Cash from operations, combined with a bank-sponsored receivables purchase agreement and short-term borrowings, provides working capital and allows us to meet other short-term cash needs.

Operating Activities

	Years Ended December 31,		
	2009	**2008**	**2007**
		(in millions)	
Net Income	$ 1,365	$ 1,388	$ 1,098
Less: Discontinued Operations, Net of Tax	-	(12)	(24)
Income Before Discontinued Operations	1,365	1,376	1,074
Depreciation and Amortization	1,597	1,483	1,513
Other	(487)	(278)	(193)
Net Cash Flows from Operating Activities	$ 2,475	$ 2,581	$ 2,394

Net Cash Flows from Operating Activities were $2.5 billion in 2009 consisting primarily of Income Before Discontinued Operations of $1.4 billion and $1.6 billion of noncash Depreciation and Amortization. Other changes represent items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. Significant changes in other items include the negative impact on cash of an increase in coal inventory reflecting decreased customer demand for electricity, an increase in under-recovered fuel primarily in Ohio and West Virginia and an increase in accrued tax benefits resulting from a net income tax operating loss in 2009. Deferred Income Taxes increased primarily due to the American Recovery and Reinvestment Act of 2009 extending bonus depreciation provisions, a change in tax accounting method and an increase in tax versus book temporary differences from operations.

Net Cash Flows from Operating Activities were $2.6 billion in 2008 consisting primarily of Income Before Discontinued Operations of $1.4 billion and $1.5 billion of noncash Depreciation and Amortization. Other changes represent items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. Net Cash Flows from Operating Activities increased in 2008 due to the TEM settlement. Under-recovered fuel costs and fuel, materials and supplies inventories increased working capital requirements due to the higher cost of coal and natural gas. Deferred Income Taxes increased primarily due to the enactment of the Economic Stimulus Act which enhanced expensing provisions for certain assets placed in service in 2008 and provided for a 50% bonus depreciation provision for certain assets placed in service in 2008.

Net Cash Flows from Operating Activities were $2.4 billion in 2007 consisting primarily of Income Before Discontinued Operations of $1.1 billion and $1.5 billion of noncash Depreciation and Amortization. Other changes represent items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. Significant changes in other items resulted in lower cash from operations due to increased accounts receivable of $113 million for new contracts in the generation and marketing segment and increased utility segment receivables and the CTC refunds in Texas.

Investing Activities

	Years Ended December 31,		
	2009	**2008**	**2007**
		(in millions)	
Construction Expenditures	$ (2,792)	$ (3,800)	$ (3,556)
Acquisitions of Assets	(104)	(160)	(512)
Proceeds from Sales of Assets	278	90	222
Other	(298)	(157)	(75)
Net Cash Flows Used for Investing Activities	$ (2,916)	$ (4,027)	$ (3,921)

Net Cash Flows Used for Investing Activities were $2.9 billion in 2009 primarily due to Construction Expenditures for our new generation, environmental and distribution investment plan. Proceeds from Sales of Assets in 2009 includes $104 million relating to the sale of a portion of Turk Plant to joint owners as planned and $95 million for sales of Texas transmission assets to ETT.

Net Cash Flows Used for Investing Activities were $4 billion in 2008 primarily due to Construction Expenditures for distribution, environmental and new generation investment.

Net Cash Flows Used for Investing Activities were $3.9 billion in 2007 primarily due to Construction Expenditures for our environmental, distribution and new generation investment plan and purchases of gas-fired generating units.

Financing Activities

	Years Ended December 31,		
	2009	**2008**	**2007**
	(in millions)		
Issuance of Common Stock, Net	$ 1,728	$ 159	$ 144
Issuance/Retirement of Debt, Net	(360)	2,266	1,902
Dividends Paid on Common Stock	(758)	(666)	(636)
Other	(90)	(80)	(6)
Net Cash Flows from Financing Activities	$ 520	$ 1,679	$ 1,404

Net Cash Flows from Financing Activities in 2009 were $520 million. Issuance of Common Stock, Net of $1.7 billion is comprised of our issuance of 69 million shares of common stock with net proceeds of $1.64 billion and additional shares through our dividend reinvestment, employee savings and incentive programs. Our net debt retirements were $360 million. The net retirements included the repayment of $2 billion outstanding under our credit facilities and retirement of $816 million of long-term debt and issuances of $1.9 billion of senior unsecured and debt notes and $431 million of pollution control bonds. We paid common stock dividends of $758 million.

Net Cash Flows from Financing Activities were $1.7 billion in 2008 primarily due to the borrowing under our credit facility to provide liquidity during the 2008 credit market. We paid common stock dividends of $666 million.

Net Cash Flows from Financing Activities were $1.4 billion in 2007 primarily from issuance of debt to fund our construction program. We paid common stock dividends of $636 million.

The following financing activities occurred during 2009:

AEP Common Stock:

- In April 2009, we issued 69 million shares of common stock with net proceeds of $1.64 billion.
- During 2009, we issued 3 million shares of common stock under our incentive compensation, employee savings and dividend reinvestment plans and received net proceeds of $88 million.

Debt:

- During 2009, we issued approximately $2.3 billion of long-term debt, including $1.7 billion of senior notes at interest rates ranging from 5.15% to 8.13%, $431 million of pollution control revenue bonds ($104 million at variable rates and $327 million at fixed interest rates ranging from 3.875% to 6.3%) and $196 million of notes at interest rates ranging from 5.44% to 8.03%. The proceeds from these issuances were used to fund long-term debt maturities and our construction programs.
- During 2009, we entered into $400 million of interest rate derivatives and settled $421 million of such transactions. The settlements resulted in net cash receipts of $20 million. As of December 31, 2009, we had in place interest rate derivatives designated as cash flow hedges with a notional amount of $79 million in order to hedge risk exposure of variable interest rate debt.
- At December 31, 2009, we had credit facilities totaling $3 billion to support our commercial paper program and short-term borrowing. As of December 31, 2009, we had $119 million of commercial paper outstanding. For the corporate borrowing program, the maximum amount of commercial paper outstanding during the year was $614 million in June 2009 and the weighted average interest rate of commercial paper outstanding during the year was 0.61%.

In 2010:

- In January 2010, TCC retired $86 million of its outstanding Securitization Bonds.
- We expect to refinance approximately $1.2 billion of the $1.6 billion of long-term debt that will mature in 2010.

BUDGETED CONSTRUCTION EXPENDITURES

We forecast approximately $2.2 billion of construction expenditures for 2010. Estimated construction expenditures are subject to periodic review and modification and may vary based on the ongoing effects of regulatory constraints, environmental regulations, business opportunities, market volatility, economic trends, weather, legal reviews and the ability to access capital. These construction expenditures will be funded through cash flows from operations and financing activities.

OFF-BALANCE SHEET ARRANGEMENTS

Under a limited set of circumstances, we enter into off-balance sheet arrangements for various reasons including accelerating cash collections, reducing operational expenses and spreading risk of loss to third parties. Our current guidelines restrict the use of off-balance sheet financing entities or structures to traditional operating lease arrangements and sales of customer accounts receivable that we enter in the normal course of business. The following identifies significant off-balance sheet arrangements:

AEP Credit

AEP Credit has a sale of receivables agreement with bank conduits. Under the sale of receivables agreement, AEP Credit sells an interest in a portion of the receivables it acquires from affiliated utilities to the bank conduits and receives cash. We have no ownership interest in the conduits and, in accordance with GAAP, are not required to consolidate these entities. AEP Credit continues to service the receivables. This off-balance sheet transaction was entered to allow AEP Credit to repay its outstanding debt obligations, continue to purchase our operating companies' receivables and accelerate cash collections.

AEP Credit's sale of receivables agreement expires in July 2010. We intend to extend or replace the sale of receivables agreement. The sale of receivables agreement provides commitments of $750 million to purchase receivables from AEP Credit. At December 31, 2009, AEP Credit had $631 million of receivable sales outstanding. For the remaining receivables left unsold to the bank conduits, AEP Credit maintains an interest in the receivables and this interest is pledged as collateral for the collection of receivables sold. The fair value of the retained interest is based on book value due to the short-term nature of the accounts receivables less an allowance for anticipated uncollectible accounts. See "SFAS 166 "Accounting for Transfers of Financial Assets" (SFAS 166)" section of Note 2.

Rockport Plant Unit 2

AEGCo and I&M entered into a sale and leaseback transaction in 1989 with Wilmington Trust Company (Owner Trustee), an unrelated unconsolidated trustee for Rockport Plant Unit 2 (the Plant). The Owner Trustee was capitalized with equity from six owner participants with no relationship to AEP or any of its subsidiaries and debt from a syndicate of banks and certain institutional investors. The future minimum lease payments for each company are $960 million as of December 31, 2009.

The gain from the sale was deferred and is being amortized over the term of the lease, which expires in 2022. The Owner Trustee owns the Plant and leases it to AEGCo and I&M. Our subsidiaries account for the lease as an operating lease with the future payment obligations included in Note 13. The lease term is for 33 years with potential renewal options. At the end of the lease term, AEGCo and I&M have the option to renew the lease or the Owner Trustee can sell the Plant. We, as well as our subsidiaries, have no ownership interest in the Owner Trustee and do not guarantee its debt.

Railcars

In June 2003, we entered into an agreement with BTM Capital Corporation, as lessor, to lease 875 coal-transporting aluminum railcars. The initial lease term was five years with three consecutive five-year renewal periods for a maximum lease term of twenty years. We intend to maintain the lease for the full lease term of twenty years via the renewal options. The lease is accounted for as an operating lease. The future minimum lease obligation is $40 million for the remaining railcars as of December 31, 2009. Under a return-and-sale option, the lessor is guaranteed that the sale proceeds will equal at least a specified lessee obligation amount which declines with each five year renewal. At December 31, 2009, the maximum potential loss was approximately $25 million ($17 million, net of tax) assuming the fair market value of the equipment is zero at the end of the current five-year lease term. However, we believe that the fair market value would produce a sufficient sales price to avoid any loss. We have other railcar lease arrangements that do not utilize this type of financing structure.

SUMMARY OBLIGATION INFORMATION

Our contractual cash obligations include amounts reported on the Consolidated Balance Sheets and other obligations disclosed in our footnotes. The following table summarizes our contractual cash obligations at December 31, 2009:

Payments Due by Period
(in millions)

Contractual Cash Obligations	Less Than 1 year	2-3 years	4-5 years	After 5 years	Total
Short-term Debt (a)	$ 126	$ -	$ -	$ -	$ 126

Interest on Fixed Rate Portion of Long-term Debt (b)	976	1,809	1,632	9,994	14,411
Fixed Rate Portion of Long-term Debt (c)	1,341	1,380	2,120	11,713	16,554
Variable Rate Portion of Long-term Debt (d)	400	85	100	425	1,010
Capital Lease Obligations (e)	85	116	58	147	406
Noncancelable Operating Leases (e)	334	646	462	1,538	2,980
Fuel Purchase Contracts (f)	3,087	4,370	2,484	7,873	17,814
Energy and Capacity Purchase Contracts (g)	82	144	195	1,161	1,582
Construction Contracts for Capital Assets (h)	464	958	930	-	2,352
Total	$ 6,895	$ 9,508	$ 7,981	$ 32,851	$ 57,235

(a) Represents principal only excluding interest.
(b) Interest payments are estimated based on final maturity dates of debt securities outstanding at December 31, 2009 and do not reflect anticipated future refinancing, early redemptions or debt issuances.
(c) See "Long-term Debt" section of Note 14. Represents principal only excluding interest.
(d) See "Long-term Debt" section of Note 14. Represents principal only excluding interest. Variable rate debt had interest rates that ranged between 0.20% and 0.82% at December 31, 2009.
(e) See Note 13.
(f) Represents contractual obligations to purchase coal, natural gas and other consumables as fuel for electric generation along with related transportation of the fuel.
(g) Represents contractual obligations for energy and capacity purchase contracts.
(h) Represents only capital assets that are contractual obligations. Actual payments are dependent upon and may vary significantly based upon the decision to build, regulatory approval schedules, timing and escalation of project costs.

Our $110 million liability related to uncertainty in Income Taxes is not included above because we cannot reasonably estimate the cash flows by period.

Our pension funding requirements are not included in the above table. As of December 31, 2009, we expect to make contributions to our pension plans totaling $160 million in 2010. Estimated contributions of $286 million in 2011 and $296 million in 2012 may vary significantly based on market returns, changes in actuarial assumptions and other factors.

In addition to the amounts disclosed in the contractual cash obligations table above, we make additional commitments in the normal course of business. These commitments include standby letters of credit, guarantees for the payment of obligation performance bonds and other commitments. At December 31, 2009, our commitments outstanding under these agreements are summarized in the table below:

Amount of Commitment Expiration Per Period
(in millions)

Other Commercial Commitments	**Less Than 1 year**	**2-3 years**	**4-5 years**	**After 5 years**	**Total**
Standby Letters of Credit (a)	$ 568	$ -	$ -	$ -	$ 568
Guarantees of the Performance of Outside Parties (b)	-	-	-	65	65
Guarantees of Our Performance (c)	507	1,086	-	31	1,624
Total Commercial Commitments	$ 1,075	$ 1,086	$ -	$ 96	$ 2,257

(a) We enter into standby letters of credit (LOCs) with third parties. These LOCs cover items such as gas and electricity risk management contracts, construction contracts, insurance programs, security deposits, debt service reserves and variable rate Pollution Control Bonds. AEP, on behalf of our subsidiaries, and/or the subsidiaries issued all of these LOCs in the ordinary course of business. There is no collateral held in relation to any guarantees in excess of our ownership percentages. In the event any LOC is drawn, there is no recourse to third parties. The maximum future payments of these LOCs are $568 million with maturities ranging from January 2010 to December 2010. See "Letters of Credit" section of Note 6.
(b) See "Guarantees of Third-Party Obligations" section of Note 6.
(c) We issued performance guarantees and indemnifications for energy trading and various sale agreements.

THE AMERICAN RECOVERY AND REINVESTMENT ACT OF 2009

The American Recovery and Reinvestment Act of 2009 provided for several new grant programs and expanded tax credits and an extension of the 50% bonus depreciation provision enacted in the Economic Stimulus Act of 2008. The enacted provisions did not have a material impact on net income or financial condition. However, the bonus depreciation contributed to the 2009 federal, state and local net income tax operating loss, which will result in a future cash flow benefit.

In 2009, APCo received approval for $334 million in federal grant funding from the United States Department of Energy (DOE) for a new commercial scale project at the Mountaineer Plant to capture and store carbon. CSPCo received approval for $75 million in federal grant funding from the DOE for the gridSMART [SM] demonstration program. These grants will provide capital to reduce the ultimate cost to our customers. Management is still negotiating terms of these grants with the DOE.

TRANSMISSION INITIATIVES

AEP Transmission Company, LLC (Utility Operations segment)

In 2006, we formed the AEP Transmission Company, LLC (AEP Transco). In 2009, AEP Transco formed seven wholly-owned transmission companies. AEP Transco is the holding company for the seven new transmission companies. These seven companies consist of:

- AEP Appalachian Transmission Company, Inc. (covering Virginia and Tennessee)
- AEP West Virginia Transmission Company, Inc.
- AEP Indiana Michigan Transmission Company, Inc.
- AEP Kentucky Transmission Company, Inc.
- AEP Ohio Transmission Company, Inc.
- AEP Oklahoma Transmission Company, Inc.
- AEP Southwestern Transmission Company, Inc. (covering Arkansas and Louisiana)

In December 2009, AEP, on behalf of these seven companies, filed formula rate requests with the FERC for transmission services under the PJM Open Access Transmission Tariff (OATT) and SPP OATT , as applicable, and to implement a transmission cost of service formula rate.

Starting in 2010, AEP Transco, through its seven subsidiaries, will make appropriate state regulatory filings and begin developing and owning new transmission assets that are physically connected to AEP's existing system. AEPSC and various AEP subsidiaries will provide services to AEP Transco. AEP Transco will not have any employees.

Joint Venture Initiatives (Utility Operations segment)

AEP is currently participating in the following joint venture initiatives:

Project Name	Location	Projected Completion Date	Owners (Ownership %)	Total Estimated Project Costs at Completion	AEP's Equity Method Investment at December 31, 2009	Approved Return on Equity
				(in thousands)		
ETT	Texas (ERCOT)	2017	MEHC Texas Transco, LLC (50%) AEP (50%)	$ 3,097,000 (a)	$ 53,496	9.96%
PATH (b)	Ohio/West Virginia	2014 (c)	Allegheny Energy (50%) AEP (50%)	1,800,000 (d)	15,763	14.3%
Tallgrass	Oklahoma	2013	OGE Energy (50%) ETA (50%) (e)	500,000	624	12.8%
Prairie Wind	Kansas	2013	Westar Energy (50%) ETA (50%) (e)	400,000	650	12.8%
Pioneer	Indiana	2015	Duke Energy (50%) AEP (50%)	1,000,000	-	12.54%

(a) In addition to ETT's current total estimated project costs of $3.1 billion, ETT plans to invest in additional transmission projects in ERCOT over the next several years. Future projects will be evaluated on a case-by-case basis. See "ETT 2007 Formation Appeal" section of Note 4.

(b) In September 2007, AEP Transmission Holding Company, LLC and AET PATH Company, LLC, a subsidiary of Allegheny Energy, Inc., formed a joint venture by creating Potomac-Appalachian Transmission Highline, LLC (PATH) and its subsidiaries. The PATH subsidiaries will operate as transmission utilities owning certain electric transmission assets within PJM.

(c) In December 2009, PJM released preliminary findings that the projected completion date may be pushed back based on voltage and service needs. A final report is expected in June 2010.

(d) PATH consists of the "Ohio Series" and the "West Virginia Series," both owned equally by subsidiaries of Allegheny Energy Inc. and AEP, and the "Allegheny Series" which is wholly-owned by a subsidiary of Allegheny Energy Inc. The total project is estimated to cost approximately $1.8 billion. AEP's estimated share of the project cost is approximately $600 million.

(e) Electric Transmission America, LLC (ETA) is a 50/50 joint venture with MidAmerican Energy Holdings Company (MEHC) America Transco, LLC and AEP Transmission Holding Company, LLC. ETA will be utilized as a vehicle to invest in selected transmission projects located in North America, outside of ERCOT. AEP Transmission Holding Company, LLC owns 25% of Tallgrass and Prairie Wind through its ownership interest in ETA.

SIGNIFICANT FACTORS

REGULATORY ISSUES

Ohio Electric Security Plan Filings

During 2009, the PUCO issued an order that modified and approved CSPCo's and OPCo's ESPs that established rates through 2011. The order also limits rate increases for CSPCo to 7% in 2009, 6% in 2010 and 6% in 2011 and for OPCo to 8% in 2009, 7% in 2010 and 8% in 2011. The order provides a FAC for the three-year period of the ESP. Several notices of appeal are outstanding at the Supreme Court of Ohio and an order is expected from the PUCO related to the SEET methodology. See "Ohio Electric Security Plan Filings" section of Note 4.

Cook Plant Unit 1 Fire and Shutdown

In September 2008, I&M shut down Cook Plant Unit 1 (Unit 1) due to turbine vibrations, caused by blade failure, which resulted in a fire on the electric generator. Management believes that I&M should recover a significant portion of repair and replacement costs through the turbine vendor's warranty, insurance and the regulatory process. Upon receipt of accidental insurance proceeds, I&M mitigated the incremental fuel cost of replacement power to ratepayers. I&M repaired Unit 1 and it resumed operations in December 2009 at reduced power. The Unit 1 rotors were repaired and reinstalled due to the extensive lead time required to manufacture and install new turbine rotors. As a result, the replacement of the repaired turbine rotors and other equipment is scheduled for the Unit 1 planned outage in the fall of 2011. See "Cook Plant Unit 1 Fire and Shutdown" section of Note 6.

Texas Restructuring Appeals

Pursuant to PUCT restructuring orders, TCC securitized net recoverable stranded generation costs of $2.5 billion and is recovering the principal and interest on the securitization bonds through the end of 2020. TCC also refunded net other true-up regulatory liabilities of $375 million during the period October 2006 through June 2008 via a CTC credit rate rider. After a ruling from the Texas District Court and the Texas Court of Appeals, TCC, the PUCT and intervenors filed petitions for review with the Texas Supreme Court. See "Texas Restructuring Appeals" section of Note 4.

Turk Plant

SWEPCo is currently constructing the Turk Plant, a new base load 600 MW pulverized coal ultra-supercritical generating unit in Arkansas, which is expected to be in-service in 2012. SWEPCo owns 73% of the Turk Plant and will operate the completed facility. The Turk Plant is currently estimated to cost $1.6 billion, excluding AFUDC, with SWEPCo's share estimated to cost $1.2 billion, excluding AFUDC. Notices of appeal are outstanding at the Arkansas Supreme Court and the Circuit Court of Hempstead County, Arkansas. Complaints are also outstanding at the LPSC and the Federal District Court for the Western District of Arkansas. See "Turk Plant" section of Note 4.

LITIGATION

In the ordinary course of business, we are involved in employment, commercial, environmental and regulatory litigation. Since it is difficult to predict the outcome of these proceedings, we cannot state what their eventual outcome will be, or what the timing of the amount of any loss, fine or penalty may be. We assess the probability of loss for each contingency and accrue a liability for cases that have a probable likelihood of loss if the loss can be estimated. For details on our regulatory proceedings and pending litigation see Note 4 – Rate Matters and Note 6 – Commitments, Guarantees and Contingencies. Adverse results in these proceedings have the potential to materially affect our net income.

Environmental Litigation

The Federal EPA, a number of states and certain special interest groups filed complaints alleging that APCo, CSPCo, I&M and OPCo modified certain units at their coal-fired generating plants in violation of the NSR requirements of the CAA. In 2007, we settled this litigation by a consent decree with the Federal EPA, the United States Department of Justice, the states and the special interest groups. Under the consent decree, we agreed to annual SO_2 and NO_x emission caps for sixteen coal-fired power plants located in Indiana, Kentucky, Ohio, Virginia and West Virginia. We agreed to install FGD equipment at Big Sandy and at Muskingum River Plants no later than the end of 2015 and selective catalytic reduction and FGD emissions control equipment at Rockport Plant no later than the end of 2017 and 2019 for Unit 1 and Unit 2, respectively.

ENVIRONMENTAL ISSUES

We are implementing a substantial capital investment program and incurring additional operational costs to comply with environmental control requirements. The most significant source is the CAA's requirements to reduce emissions of SO_2, NO_x and PM from fossil fuel-fired power plants.

We are engaged in litigation about environmental issues, have been notified of potential responsibility for the clean-up of contaminated sites and incur costs for disposal of SNF and future decommissioning of our nuclear units. We are also engaged in the development of possible future requirements to reduce CO_2 emissions to address concerns about global climate change.

Clean Air Act Requirements

The CAA establishes a comprehensive program to protect and improve the nation's air quality and control sources of air emissions. The states implement and administer many of these programs and could impose additional or more stringent requirements.

The Federal EPA issued the Clean Air Interstate Rule (CAIR) requiring specific reductions in SO_2 and NO_x emissions from power plants. In 2008, the D.C. Circuit Court of Appeals issued a decision remanding CAIR to the Federal EPA. CAIR remains in effect while a new rulemaking is conducted. Nearly all of the states in which our power plants are located are covered by CAIR.

The Federal EPA issued a Clean Air Mercury Rule (CAMR) setting mercury standards for new coal-fired power plants and requiring all states to issue new state implementation plans (SIPs) including mercury requirements for existing coal-fired power plants. The D.C. Circuit Court of Appeals ruled that the Federal EPA's action delisting fossil fuel-fired power plants did not conform to the procedures specified in the CAA, and vacated and remanded the federal rules for both new and existing coal-fired power plants to the Federal EPA.

The Federal EPA issued a Clean Air Visibility Rule (CAVR), detailing how the CAA's best available retrofit technology requirements will be applied to facilities built between 1962 and 1977 that emit more than 250 tons per year of certain pollutants in specific industrial categories, including power plants.

Estimated Air Quality Environmental Investments

The CAIR, CAVR and the consent decree signed to settle the NSR litigation require us to make significant additional investments, some of which are estimable. Our estimates are subject to significant uncertainties and will be affected by any changes in the outcome of several interrelated variables and assumptions, including: the timing of implementation; required levels of reductions; methods for allocation of allowances; and our selected compliance alternatives and their costs. In short, we cannot estimate our compliance costs with certainty and the actual costs to comply could differ significantly from the estimates discussed below.

The CAIR, CAVR and commitments in the consent decree will require installation of additional controls on our power plants through 2019. We plan to install additional scrubbers on 7,300 MW for SO_2 control. From 2010 to 2019, we estimate total environmental investment to meet these requirements of $5.5 billion including investment in scrubbers and other SO_2

equipment of approximately $4.6 billion. These estimates are highly uncertain due to the variability associated with: (1) the states' implementation of these regulatory programs, including the potential for SIPs or federal implementation plans that impose standards more stringent than CAIR; (2) additional rulemaking activities in response to the court decisions remanding the CAIR and CAMR; (3) the actual performance of the pollution control technologies installed on our units; (4) changes in costs for new pollution controls; (5) new generating technology developments; and (6) other factors. Associated operational and maintenance expenses will also increase during those years. We cannot estimate these additional operational and maintenance costs due to the uncertainties described above, but they are expected to be significant.

We will seek recovery of expenditures for pollution control technologies, replacement or additional generation and associated operating costs from customers through our regulated rates (in regulated jurisdictions). We should be able to recover these expenditures through market prices in deregulated jurisdictions. If not, those costs could adversely affect future net income, cash flows and possibly financial condition.

Global Warming

The topics of whether the earth is warming, how much and how fast, what role human activity plays, and what to do about it are very controversial and actively debated. The public policy makers and influencers in Washington and in the 11 states we serve have conflicting views. We are focused on taking, in the short term, actions that we see as prudent, such as improving energy efficiency, investing in developing cost-effective and less carbon-intensive technologies, and evaluating our assets across a range of plausible scenarios and outcomes. We are also active participants in a variety of public policy discussions at state and federal levels, to assure that proposed new requirements are feasible and the economies of the states we serve are not placed at a competitive disadvantage.

We believe that this is a global issue and that the United States should assume a leadership role in developing a new international approach that will address growing emissions of CO_2 and other greenhouse gases (generally referred to as CO_2 in this discussion) from all nations, including developing countries. We support a reasonable approach to CO_2 emission reductions, that recognizes a reliable and affordable electric supply is vital to economic stability, and that allows sufficient time for technology development. We proposed that national and international policy for reasonable CO_2 controls should involve the following principles:

- Comprehensiveness
- Cost-effectiveness
- Realistic emission reduction objectives
- Reliable monitoring and verification mechanisms
- Incentives to develop and deploy CO_2 reduction technologies
- Removal of regulatory or economic barriers to CO_2 emission reductions
- Recognition for early actions/investments in CO_2 reduction/mitigation
- Inclusion of adjustment provisions if largest emitters in developing world do not take action

For additional information on global warming see Part I of the Annual Report under the headings entitled "Business – General – Environmental and Other Matters – Global Warming."

In June 2009, the U.S. House of Representatives passed the American Clean Energy and Security Act (ACES). ACES is a comprehensive energy and climate change bill that includes a number of provisions that would directly affect our business including energy efficiency and renewable electricity standards, funding for carbon capture and sequestration validation projects, CO_2 emission standards for new fossil fuel-fired electric generating plants and an economy-wide cap and trade program for large sources of CO_2 emissions that would reduce emissions by 17% in 2020 and just over 80% by 2050 from 2005 levels. The Senate Environmental and Public Works Committee passed legislation out of committee in September 2009 but it failed to advance to the Senate floor. Until legislation is final, we are unable to predict its impact on net income, cash flows and financial condition.

While comprehensive economy-wide regulation of CO_2 emissions might be achieved through new legislation, several states and interest groups petitioned the Federal EPA to establish CO_2 emission standards under the existing requirements of the CAA. In September 2009, the Federal EPA issued a final mandatory CO_2 reporting rule covering a broad range of facilities emitting in excess of 25,000 tons of CO_2 emissions per year. The Federal EPA issued a final endangerment finding for CO_2 emissions from new motor vehicles in December 2009, and is expected to issue final rules in March 2010. The Federal EPA has also issued a proposed scheme to streamline and phase in regulation of stationary source CO_2 emissions through the NSR's prevention of significant deterioration and CAA's Title V permitting programs. The Federal EPA stated its intent to finalize the permitting rule in conjunction with or following the final motor vehicle rule, and is reconsidering whether to include CO_2 emissions in a number of stationary source standards, including standards that apply to new and modified electric utility units. If substantial CO_2 emission reductions are required, there will be significant increases in capital expenditures and operating costs which would impact the ultimate retirement of older, less-efficient, coal-fired units. To the extent we install additional controls on our generating plants to limit CO_2 emissions and receive regulatory approvals to increase our rates, cost recovery could have a positive effect on future earnings. Prudently incurred capital investments made by our subsidiaries in rate-regulated jurisdictions to comply with legal requirements and benefit customers are generally included in rate base for recovery and earn a return on investment. We would expect these principles to apply to investments made to address new environmental requirements. However, requests for rate increases reflecting these costs can affect us adversely because our regulators could limit the amount or timing of increased costs that we would recover through higher rates. In addition, to the extent our costs are relatively higher than our competitors' costs, such as operators of nuclear generation, it could reduce our off-system sales or cause us to lose customers in jurisdictions that permit customers to choose their supplier of generation service.

Several states have adopted programs that directly regulate CO_2 emissions from power plants, but none of these programs are currently in effect in states where we have generating facilities. Certain of our states have passed legislation establishing renewable energy, alternative energy and/or energy efficiency requirements (including Ohio, Michigan, Texas and Virginia). We are taking steps to comply with these requirements. In order to meet these requirements and as a key part of our corporate sustainability effort, we pledged to increase our wind power by an additional 2,000 MW from 2007 levels by 2011. By the end of 2009, we secured through power purchase agreements an additional 1,013 MW of wind power. To the extent demand for renewable energy from wind power increases, it could have a positive effect on future earnings from our transmission activities. For example, a project in Texas would build new transmission lines to transport electricity from planned wind energy generation in west Texas to more densely populated areas in eastern Texas.

We have taken measurable, voluntary actions to reduce and offset our CO_2 emissions. We participate in a number of voluntary programs to monitor, mitigate and reduce CO_2 emissions, including the Federal EPA's Climate Leaders program, the United States Department of Energy's CO_2 reporting program and the Chicago Climate Exchange. Through the end of 2008, we reduced our emissions by a cumulative 51 million metric tons from adjusted baseline levels in 1998 through 2001 as a result of these voluntary actions. Our total CO_2 emissions in 2008 were 155 million metric tons. We estimate that our 2009 emissions were approximately 140 million metric tons. Since 2004, our cumulative reductions will be in excess of 70 million metric tons.

Certain groups have filed lawsuits alleging that emissions of CO_2 are a "public nuisance" and seeking injunctive relief and/or damages from small groups of coal-fired electricity generators, petroleum refiners and marketers, coal companies and others. We have been named in pending lawsuits, which we are vigorously defending. It is not possible to predict the outcome of these lawsuits or their impact on our operations or financial condition. See "Carbon Dioxide Public Nuisance Claims" and "Alaskan Villages' Claims" sections of Note 6.

Future federal and state legislation or regulations that mandate limits on the emission of CO_2 would result in significant increases in capital expenditures and operating costs, which, in turn, could lead to increased liquidity needs and higher financing costs. Excessive costs to comply with future legislation or regulations might force our utility subsidiaries to close some coal-fired facilities and could lead to possible impairment of assets. As a result, mandatory limits could have a material adverse impact on our net income, cash flows and financial condition.

Global warming creates the potential for physical and financial risk. The materiality of the risks depends on whether any physical changes occur quickly or over several decades and the extent and nature of those changes. Physical risks from climate change could include changes in weather conditions. Our customers' energy needs currently vary with weather conditions, primarily temperature and humidity. For residential customers, heating and cooling today represent their largest energy use. To the extent weather patterns change significantly, customers' energy use could increase or decrease depending on the duration and magnitude of any changes. Increased energy use due to weather changes could require us to invest in more generating assets, transmission and other infrastructure to serve increased load, driving the overall cost of electricity up. Decreased energy use due to weather changes could affect our financial condition through lower sales and decreased revenues. Extreme weather conditions in general require more system backup, adding to costs, and can contribute to increased system stresses, including service interruptions and increased storm restoration costs. We may not recover all costs related to mitigating these physical and financial risks. Weather conditions outside of our service territory could also have an impact on our revenues, either directly through changes in the patterns of our off-system power purchases and sales or indirectly through demographic changes as people adapt to changing weather. We buy and sell electricity depending upon system needs and market opportunities. Extreme weather conditions that create high energy demand could raise electricity prices, which could increase the cost of energy we provide to our customers and could provide opportunity for increased wholesale sales.

To the extent climate change impacts a region's economic health, it could also impact our revenues. Our financial performance is tied to the health of the regional economies we serve. The price of energy, as a factor in a region's cost of living as well as an important input into the cost of goods, has an impact on the economic health of our communities. The cost of additional regulatory requirements would normally be borne by consumers through higher prices for energy and purchased goods.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES, NEW ACCOUNTING PRONOUNCEMENTS

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

The preparation of financial statements in accordance with GAAP requires us to make estimates and assumptions that affect reported amounts and related disclosures, including amounts related to legal matters and contingencies. We consider an accounting estimate to be critical if:

- It requires assumptions to be made that were uncertain at the time the estimate was made; and
- Changes in the estimate or different estimates that could have been selected could have a material effect on our consolidated net income or financial condition.

We discuss the development and selection of critical accounting estimates as presented below with the Audit Committee of AEP’s Board of Directors and the Audit Committee reviews the disclosure relating to them.

We believe that the current assumptions and other considerations used to estimate amounts reflected in our consolidated financial statements are appropriate. However, actual results can differ significantly from those estimates.

The sections that follow present information about our critical accounting estimates, as well as the effects of hypothetical changes in the material assumptions used to develop each estimate.

Regulatory Accounting

Nature of Estimates Required

Our consolidated financial statements reflect the actions of regulators that can result in the recognition of revenues and expenses in different time periods than enterprises that are not rate-regulated.

We recognize regulatory assets (deferred expenses to be recovered in the future) and regulatory liabilities (deferred future revenue reductions or refunds) for the economic effects of regulation. Specifically, we match the timing of our expense recognition with the recovery of such expense in regulated revenues. Likewise, we match income with the regulated revenues from our customers in the same accounting period. We also record regulatory liabilities for refunds, or probable refunds, to customers that have not been made.

Assumptions and Approach Used

When incurred costs are probable of recovery through regulated rates, we record them as regulatory assets on the balance sheet. We review the probability of recovery at each balance sheet date and whenever new events occur. Examples of new events include changes in the regulatory environment, issuance of a regulatory commission order or passage of new legislation. The assumptions and judgments used by regulatory authorities continue to have an impact on the recovery of costs, rate of return earned on invested capital and timing and amount of assets to be recovered through regulated rates. If recovery of a regulatory asset is no longer probable, we write off that regulatory asset as a charge against earnings. A write-off of regulatory assets may also reduce future cash flows since there will be no recovery through regulated rates.

Effect if Different Assumptions Used

A change in the above assumptions may result in a material impact on our net income. Refer to Note 5 for further detail related to regulatory assets and liabilities.

Revenue Recognition – Unbilled Revenues

Nature of Estimates Required

We record revenues when energy is delivered to the customer. The determination of sales to individual customers is based on the reading of their meters, which we perform on a systematic basis throughout the month. At the end of each month, amounts of energy delivered to customers since the date of the last meter reading are estimated and the corresponding unbilled revenue accrual is recorded. This estimate is reversed in the following month and actual revenue is recorded based on meter readings. In accordance with the applicable state commission regulatory treatment in Arkansas, Louisiana, Oklahoma and Texas, PSO and SWEPCo do not record the fuel portion of unbilled revenue.

The changes in unbilled electric utility revenues included in Revenue on our Consolidated Statements of Income were $55 million, $72 million and $47 million for the years ended December 31, 2009, 2008 and 2007, respectively. The increases in unbilled electric revenues are primarily due to rate increases and changes in weather. Accrued unbilled revenues for the Utility Operations segment were $503 million and $448 million as of December 31, 2009 and 2008, respectively.

Assumptions and Approach Used

For each operating company, we compute the monthly estimate for unbilled revenues as net generation less the current month's billed KWH plus the prior month's unbilled KWH. However, due to meter reading issues, meter drift and other anomalies, a separate monthly calculation limits the unbilled estimate within a range of values. This limiter calculation is derived from an allocation of billed KWH to the current month and previous month, on a cycle-by-cycle basis, and dividing the current month aggregated result by the billed KWH. The limits are statistically set at one standard deviation from this percentage to determine the upper and lower limits of the range. The unbilled estimate is compared to the limiter calculation and adjusted for variances exceeding the upper and lower limits.

Effect if Different Assumptions Used

Significant fluctuations in energy demand for the unbilled period, weather, line losses or changes in the composition of customer classes could impact the accuracy of the unbilled revenue estimate. A 1% change in the limiter calculation when it is outside the range would increase or decrease unbilled revenues by 1% of the accrued unbilled revenues on the Consolidated Balance Sheets.

Accounting for Derivative Instruments

Nature of Estimates Required

We consider fair value techniques, valuation adjustments related to credit and liquidity and judgments related to the probability of forecasted transactions occurring within the specified time period to be critical accounting estimates. These estimates are considered significant because they are highly susceptible to change from period to period and are dependent on many subjective factors.

Assumptions and Approach Used

We measure the fair values of derivative instruments and hedge instruments accounted for using MTM accounting based on exchange prices and broker quotes. If a quoted market price is not available, we estimate the fair value based on the best market information available including valuation models that estimate future energy prices based on existing market and broker quotes, supply and demand market data and other assumptions. Fair value estimates, based upon the best market information available, involve uncertainties and matters of significant judgment. These uncertainties include projections of macroeconomic trends and future commodity prices, including supply and demand levels and future price volatility.

We reduce fair values by estimated valuation adjustments for items such as discounting, liquidity and credit quality. We calculate liquidity adjustments by utilizing bid/ask spreads to estimate the potential fair value impact of liquidating open positions over a reasonable period of time. We base credit adjustments on estimated defaults by counterparties that are calculated using historical default probabilities for companies with similar credit ratings. We evaluate the probability of the occurrence of the forecasted transaction within the specified time period as provided in the original documentation related to hedge accounting.

Effect if Different Assumptions Used

There is inherent risk in valuation modeling given the complexity and volatility of energy markets. Therefore, it is possible that results in future periods may be materially different as contracts settle.

The probability that hedged forecasted transactions will not occur by the end of the specified time period could change operating results by requiring amounts currently classified in Accumulated Other Comprehensive Income (Loss) to be classified into operating income.

For additional information regarding derivatives, hedging and fair value measurements, see Notes 10 and 11. See "Fair Value Measurements of Assets and Liabilities" section of Note 1 for fair value calculation policy.

Long-Lived Assets

Nature of Estimates Required

In accordance with the requirements of "Property, Plant and Equipment" accounting guidance, we evaluate long-lived assets for impairment whenever events or changes in circumstances indicate that the carrying amount of any such assets may not be recoverable or the assets meet the held for sale criteria. We utilize a group composite method of depreciation to estimate the useful lives of long-lived assets. The evaluations of long-lived held and used assets may result from abandonments, significant decreases in the market price of an asset, a significant adverse change in the extent or manner in which an asset is being used or in its physical condition, a significant adverse change in legal factors or in the business climate that could affect the value of an asset, as well as other economic or operations analyses. If the carrying amount is not recoverable, we record an impairment to the extent that the fair value of the asset is less than its book value. For assets held for sale, an impairment is recognized if the expected net sales price is less than its book value. For regulated assets, an impairment charge could be offset by the establishment of a regulatory asset, if rate recovery is probable. For nonregulated assets, any impairment charge is recorded against earnings.

Assumptions and Approach Used

The fair value of an asset is the amount at which that asset could be bought or sold in a current transaction between willing parties other than in a forced or liquidation sale. Quoted market prices in active markets are the best evidence of fair value and are used as the basis for the measurement, if available. In the absence of quoted prices for identical or similar assets in active markets, we estimate fair value using various internal and external valuation methods including cash flow projections or other market indicators of fair value such as bids received, comparable sales or independent appraisals. We perform depreciation studies to determine composite depreciation rates and related lives which are subject to periodic review by state regulatory commissions. The fair value of the asset could be different using different estimates and assumptions in these valuation techniques.

Effect if Different Assumptions Used

In connection with the evaluation of long-lived assets in accordance with the requirements of "Property, Plant and Equipment" accounting guidance, the fair value of the asset can vary if different estimates and assumptions would have been used in our applied valuation techniques. The estimate for depreciation rates takes into account the past history of interim capital replacements and the amount of salvage expected. In cases of impairment, we made our best estimate of fair value using valuation methods based on the most current information at that time. Fluctuations in realized sales proceeds versus the estimated fair value of the asset are generally due to a variety of factors including, but not limited to, differences in subsequent market conditions, the level of bidder interest, timing and terms of the transactions and our analysis of the benefits of the transaction.

Pension and Other Postretirement Benefits

We maintain qualified, defined benefit pension plans (Qualified Plans), which cover a substantial majority of nonunion and certain union employees, and unfunded, nonqualified supplemental plans (Nonqualified Plans) to provide benefits in excess of amounts permitted under the provisions of the tax law to be paid to participants in the Qualified Plans (collectively the Pension Plans). We merged the Qualified Plans at December 31, 2008. Additionally, we entered into individual retirement agreements with certain current and retired executives that provide additional retirement benefits as a part of the Nonqualified Plans. We also sponsor other postretirement benefit plans to provide medical and life insurance benefits for retired employees (Postretirement Plans). The Pension Plans and Postretirement Plans are collectively the Plans.

For a discussion of investment strategy, investment limitations, target asset allocations and the classification of investments within the fair value hierarchy, see "Investments Held in Trust for Future Liabilities" and "Fair Value Measurements of Assets and Liabilities" sections of Note 1. See Note 8 for information regarding costs and assumptions for employee retirement and postretirement benefits.

The following table shows the net periodic cost of the Plans:

	Years Ended December 31,		
Net Periodic Benefit Cost	**2009**	**2008**	**2007**

	(in millions)		
Pension Plans	$ 96	$ 51	$ 50
Postretirement Plans	141	80	81

The net periodic benefit cost is calculated based upon a number of actuarial assumptions, including expected long-term rates of return on the Plans' assets. In developing the expected long-term rate of return assumption for 2010, we evaluated input from actuaries and investment consultants, including their reviews of asset class return expectations as well as long-term inflation assumptions. We also considered historical returns of the investment markets as well as our ten-year average return, for the period ended December 2009, of approximately 3.7% for the Pension Plans and approximately 2.3% for the Postretirement Plans. We anticipate that the investment managers we employ for the Plans will invest the assets to generate future returns averaging 8% for the Pension Plan and Postretirement Plans.

The expected long-term rate of return on the Plans' assets is based on our targeted asset allocation and our expected investment returns for each investment category. Our assumptions are summarized in the following table:

	Pension Plans		**Other Postretirement Benefit Plans**	
	2010 Target Asset Allocation	**Assumed/ Expected Long-term Rate of Return**	**2010 Target Asset Allocation**	**Assumed/ Expected Long-term Rate of Return**
Equity	50%	9.50%	66%	9.75%
Real Estate	5%	7.25%	-%	-%
Debt Securities	39%	6.00%	33%	6.00%
Other Investments	5%	10.00%	-%	-%
Cash and Cash Equivalents	1%	3.00%	1%	3.00%
Total	100%		100%	

We regularly review the actual asset allocation and periodically rebalance the investments to our targeted allocation. We believe that 8% for the Pension Plans and Postretirement Plans are reasonable long-term rates of return on the Plans' assets despite the recent market volatility. The Pension Plans' assets had an actual gain (loss) of 17.1% and (24.1)% for the years ended December 31, 2009 and 2008, respectively. The Postretirement Plans' assets had an actual gain (loss) of 23.7% and (24.7)% for the years ended December 31, 2009 and 2008, respectively. We will continue to evaluate the actuarial assumptions, including the expected rate of return, at least annually, and will adjust the assumptions as necessary.

We base our determination of pension expense or income on a market-related valuation of assets, which reduces year-to-year volatility. This market-related valuation recognizes investment gains or losses over a five-year period from the year in which they occur. Investment gains or losses for this purpose are the difference between the expected return calculated using the market-related value of assets and the actual return based on the market-related value of assets. Since the market-related value of assets recognizes gains or losses over a five-year period, the future value of assets will be impacted as previously deferred gains or losses are recorded. As of December 31, 2009, we had cumulative losses of approximately $600 million that remain to be recognized in the calculation of the market-related value of assets. These unrecognized net actuarial losses will result in increases in the future pension costs depending on several factors, including whether such losses at each measurement date exceed the corridor in accordance with "Compensation – Retirement Benefits" accounting guidance.

The method used to determine the discount rate that we utilize for determining future obligations is a duration-based method in which a hypothetical portfolio of high quality corporate bonds similar to those included in the Moody's Aa bond index was constructed but with a duration matching the benefit plan liability. The composite yield on the hypothetical bond portfolio was used as the discount rate for the plan. The discount rate at December 31, 2009 under this method was 5.6% for the Qualified Plan, 5.5% for the Nonqualified Plans and 5.85% for the Postretirement Plans. Due to the effect of the unrecognized actuarial losses and based on an expected rate of return on the Pension Plans' assets of 8%, a discount rate of 5.6% and 5.5% and various other assumptions, we estimate that the pension costs for all pension plans will approximate $163 million, $166 million and $186 million in 2010, 2011 and 2012, respectively. Based on an expected rate of return on the OPEB plans' assets of 8%, a discount rate of 5.85% and various other assumptions, we estimate Postretirement Plan costs will approximate $112 million, $94 million and $77 million in 2010, 2011 and 2012, respectively. Future actual cost will depend on future investment performance, changes in future discount rates and various other factors related to the populations participating in the Plans. The actuarial assumptions used may differ materially from actual results. The effects of a 50 basis point change to selective actuarial assumptions are included in the "Effect if Different Assumptions Used" section below.

The value of the Pension Plans' assets increased to $3.4 billion at December 31, 2009 from $3.2 billion at December 31, 2008 primarily due to investment gains. The Qualified Plans paid $240 million in benefits to plan participants during 2009 (nonqualified plans paid $8 million in benefits). The value of our Postretirement Plans' assets increased to $1.3 billion at December 31, 2009 from $1 billion at December 31, 2008 primarily due to investment gains and contributions. The Postretirement Plans paid $120 million in benefits to plan participants during 2009.

Nature of Estimates Required

We sponsor pension and other retirement and postretirement benefit plans in various forms covering all employees who meet eligibility requirements. We account for these benefits under "Compensation" and "Plan Accounting" accounting guidance. The measurement of our pension and postretirement benefit obligations, costs and liabilities is dependent on a variety of assumptions.

Assumptions and Approach Used

The critical assumptions used in developing the required estimates include the following key factors:

- Discount rate
- Rate of compensation increase
- Cash balance crediting rate
- Health care cost trend rate
- Expected return on plan assets

Other assumptions, such as retirement, mortality and turnover, are evaluated periodically and updated to reflect actual experience.

Effect if Different Assumptions Used

The actuarial assumptions used may differ materially from actual results due to changing market and economic conditions, higher or lower withdrawal rates, longer or shorter life spans of participants or higher or lower lump sum versus annuity payout elections by plan participants. These differences may result in a significant impact to the amount of pension and postretirement benefit expense recorded. If a 50 basis point change were to occur for the following assumptions, the approximate effect on the financial statements would be as follows:

	Pension Plans		Other Postretirement Benefit Plans	
	+0.5%	**-0.5%**	**+0.5%**	**-0.5%**
	(in millions)			
Effect on December 31, 2009 Benefit Obligations				
Discount Rate	$ (231)	$ 253	$ (119)	$ 133
Compensation Increase Rate	15	(14)	3	(3)
Cash Balance Crediting Rate	45	(39)	N/A	N/A
Health Care Cost Trend Rate	N/A	N/A	96	(87)
Effect on 2009 Periodic Cost				
Discount Rate	(20)	22	(11)	11
Compensation Increase Rate	4	(4)	-	(1)
Cash Balance Crediting Rate	10	(9)	N/A	N/A
Health Care Cost Trend Rate	N/A	N/A	15	(14)
Expected Return on Plan Assets	(20)	20	(5)	5

N/A = Not Applicable

Nuclear Trust Funds

Nuclear decommissioning and spent nuclear fuel trust funds represent funds that regulatory commissions allow us to collect through rates to fund future decommissioning and spent nuclear fuel disposal liabilities. By rules or orders, the IURC, the MPSC and the FERC established investment limitations and general risk management guidelines.

We maintain trust funds for each regulatory jurisdiction. These funds are managed by external investment managers who must comply with the guidelines and rules of the applicable regulatory authorities. The trust assets are invested to optimize the net of tax earnings of the trust giving consideration to liquidity, risk, diversification and other prudent investment objectives. We record securities held in these trust funds as Spent Nuclear Fuel and Decommissioning Trusts on our Consolidated Balance Sheets. We record these securities at fair value. We utilize our trustee's external pricing service in our estimate of the fair value of the underlying investments held in these trusts. Our investment managers review and validate the prices utilized by the trustee to determine fair value. We perform our own valuation testing to verify the fair values of the securities. We receive audit reports of our trustee's operating controls and valuation processes. See "Investments Held in Trust for Future Liabilities" section of Note 1 and "Fair Value Measurements of Trust Assets for Decommissioning and SNF Disposal" section of Note 11.

NEW ACCOUNTING PRONOUNCEMENTS

Adoption of New Accounting Pronouncements in 2009

The FASB issued SFAS 160 "Noncontrolling Interest in Consolidated Financial Statements" (SFAS 160), modifying reporting for noncontrolling interest (minority interest) in consolidated financial statements. The statement requires noncontrolling interest be reported in equity and establishes a new framework for recognizing net income or loss and comprehensive income by the controlling interest. We retrospectively adopted the presentation and disclosure requirements of SFAS 160.

New Accounting Pronouncements Adopted During the First Quarter of 2010

We prospectively adopted SFAS 166 "Accounting for Transfers of Financial Assets" (SFAS 166) effective January 1, 2010. The adoption of this standard resulted in AEP Credit's transfer of receivables being accounted for as financings with the receivable and debt recorded on our balance sheet.

We prospectively adopted SFAS 167 "Amendments to FASB Interpretation No. 46(R)" (SFAS 167) effective January 1, 2010. We no longer consolidate DHLC effective with the adoption of this standard.

See Note 2 for further discussion of accounting pronouncements.

Future Accounting Changes

The FASB's standard-setting process is ongoing and until new standards have been finalized and issued, we cannot determine the impact on the reporting of our operations and financial position that may result from any such future changes. The FASB is currently working on several projects including revenue recognition, contingencies, financial instruments, emission allowances, fair value measurements, leases, insurance, hedge accounting, consolidation policy and discontinued operations. We also expect to see more FASB projects as a result of its desire to converge International Accounting Standards with GAAP. The ultimate pronouncements resulting from these and future projects could have an impact on our future net income and financial position.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET AND CREDIT RISK

Market Risks

Our Utility Operations segment is exposed to certain market risks as a major power producer and marketer of wholesale electricity, coal and emission allowances. These risks include commodity price risk, interest rate risk and credit risk. In addition, we may be exposed to foreign currency exchange risk because occasionally we procure various services and materials used in our energy business from foreign suppliers. These risks represent the risk of loss that may impact us due to changes in the underlying market prices or rates.

Our Generation and Marketing segment, operating primarily within ERCOT, transacts in wholesale energy trading and marketing contracts. This segment is exposed to certain market risks as a marketer of wholesale electricity. These risks include commodity price risk, interest rate risk and credit risk. These risks represent the risk of loss that may impact us due to changes in the underlying market prices or rates.

All Other includes natural gas operations which holds forward natural gas contracts that were not sold with the natural gas pipeline and storage assets. These contracts are financial derivatives, which will gradually settle and completely expire in 2011. Our risk objective is to keep these positions generally risk neutral through maturity.

We employ risk management contracts including physical forward purchase and sale contracts and financial forward purchase and sale contracts. We engage in risk management of electricity, coal, natural gas and emission allowances and to a lesser degree other commodities associated with our energy business. As a result, we are subject to price risk. The amount of risk taken is determined by the commercial operations group in accordance with the market risk policy approved by the Finance Committee of our Board of Directors. Our market risk oversight staff independently monitors our risk policies, procedures and risk levels and provides members of the Commercial Operations Risk Committee (CORC) various daily, weekly and/or monthly reports regarding compliance with policies, limits and procedures. The CORC consists of our Executive Vice President - Generation, Chief Financial Officer, Senior Vice President of Commercial Operations and Chief Risk Officer. When commercial activities exceed predetermined limits, we modify the positions to reduce the risk to be within the limits unless specifically approved by the CORC.

MTM Risk Management Contract Net Assets (Liabilities)
Year Ended December 31, 2009
(in millions)

	Utility Operations	Generation and Marketing	All Other	Total
Total MTM Risk Management Contract Net Assets (Liabilities) at December 31, 2008	$ 175	$ 104	$ (7)	$ 272
(Gain) Loss from Contracts Realized/Settled During the Period and Entered in a Prior Period	(99)	(7)	5	(101)
Fair Value of New Contracts at Inception When Entered During the Period (a)	14	63	-	77
Changes in Fair Value Due to Market Fluctuations During the Period (b)	5	(13)	(1)	(9)
Changes in Fair Value Allocated to Regulated Jurisdictions (c)	39	-	-	39
Total MTM Risk Management Contract Net Assets (Liabilities) at December 31, 2009	$ 134	$ 147	$ (3)	278
Cash Flow Hedge Contracts				(9)
Collateral Deposits				86
Total MTM Derivative Contract Net Assets at December 31, 2009				$ 355

(a) Reflects fair value on long-term structured contracts which are typically with customers that seek fixed pricing to limit their risk against fluctuating energy prices. The contract prices are valued against market curves associated with the delivery location and delivery term. A significant portion of the total volumetric position has been economically hedged.
(b) Market fluctuations are attributable to various factors such as supply/demand, weather, etc.
(c) “Change in Fair Value Allocated to Regulated Jurisdictions” relates to the net gains (losses) of those contracts that are not reflected on the Consolidated Statements of Income. These net gains (losses) are recorded as regulatory liabilities/assets.

See Note 10 – Derivatives and Hedging and Note 11 – Fair Value Measurements for additional information related to our risk management contracts. The following tables and discussion provide information on our credit risk and market volatility risk.

Credit Risk

We limit credit risk in our wholesale marketing and trading activities by assessing creditworthiness of potential counterparties before entering into transactions with them and continuing to evaluate their creditworthiness after transactions have been originated. We use Moody's Investors Service, Standard & Poor's and current market-based qualitative and quantitative data to assess the financial health of counterparties on an ongoing basis. If an external rating is not available, an internal rating is generated utilizing a quantitative tool developed by Moody's to estimate probability of default that corresponds to an implied external agency credit rating. Based on our analysis, we set appropriate risk parameters for each internally-graded counterparty. We may also require cash deposits, letters of credit and parental/affiliate guarantees as security from counterparties in order to mitigate credit risk.

We have risk management contracts with numerous counterparties. Since open risk management contracts are valued based on changes in market prices of the related commodities, our exposures change daily. At December 31, 2009, our credit exposure net of collateral to sub investment grade counterparties was approximately 12.2%, expressed in terms of net MTM assets, net receivables and the net open positions for contracts not subject to MTM (representing economic risk even though there may not be risk of accounting loss). As of December 31, 2009, the following table approximates our counterparty credit quality and exposure based on netting across commodities, instruments and legal entities where applicable:

Counterparty Credit Quality	Exposure Before Credit Collateral	Credit Collateral	Net Exposure	Number of Counterparties >10% of Net Exposure	Net Exposure of Counterparties >10%
	(in millions, except number of counterparties)				
Investment Grade	$ 653	$ 44	$ 609	2	$ 186
Split Rating	3	-	3	1	3
Noninvestment Grade	2	1	1	3	1
No External Ratings:					
Internal Investment Grade	82	2	80	3	48
Internal Noninvestment Grade	106	11	95	3	79
Total as of December 31, 2009	$ 846	$ 58	$ 788	12	$ 317
Total as of December 31, 2008	$ 793	$ 29	$ 764	9	$ 284

Value at Risk (VaR) Associated with Risk Management Contracts

We use a risk measurement model, which calculates VaR to measure our commodity price risk in the risk management portfolio. The VaR is based on the variance-covariance method using historical prices to estimate volatilities and correlations and assumes a 95% confidence level and a one-day holding period. Based on this VaR analysis, at December 31, 2009, a near term typical change in commodity prices is not expected to have a material effect on our net income, cash flows or financial condition.

The following table shows the end, high, average and low market risk as measured by VaR for the years ended:

VaR Model

December 31, 2009 (in millions)				December 31, 2008 (in millions)			
End	High	Average	Low	End	High	Average	Low
$1	$2	$1	$-	$-	$3	$1	$-

We back-test our VaR results against performance due to actual price moves. Based on the assumed 95% confidence interval, the performance due to actual price moves would be expected to exceed the VaR at least once every 20 trading days. Our backtesting results show that our actual performance exceeded VaR far fewer than once every 20 trading days. As a result, we believe our VaR calculation is conservative.

As our VaR calculation captures recent price moves, we also perform regular stress testing of the portfolio to understand our exposure to extreme price moves. We employ a historical-based method whereby the current portfolio is subjected to actual, observed price moves from the last four years in order to ascertain which historical price moves translated into the largest potential MTM loss. We then research the underlying positions, price moves and market events that created the most significant exposure and report the findings to the Risk Executive Committee or the CORC as appropriate.

Interest Rate Risk

We utilize an Earnings at Risk (EaR) model to measure interest rate market risk exposure. EaR statistically quantifies the extent to which AEP's interest expense could vary over the next twelve months and gives a probabilistic estimate of different levels of interest expense. The resulting EaR is interpreted as the dollar amount by which actual interest expense for the next twelve months could exceed expected interest expense with a one-in-twenty chance of occurrence. The primary drivers of EaR are from the existing floating rate debt (including short-term debt) as well as long-term debt issuances in the next twelve months. As calculated on debt outstanding as of December 31, 2009 and 2008, the estimated EaR on our debt portfolio for the following twelve months was $4 million and $86 million, respectively.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of American Electric Power Company, Inc.:

We have audited the accompanying consolidated balance sheets of American Electric Power Company, Inc. and subsidiary companies (the "Company") as of December 31, 2009 and 2008, and the related consolidated statements of income, changes in equity and comprehensive income (loss), and of cash flows for each of the three years in the period ended December 31, 2009. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of American Electric Power Company, Inc. and subsidiary companies as of December 31, 2009 and 2008, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2009, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 2 to the consolidated financial statements, the accompanying consolidated financial statements were retrospectively adjusted to reflect the adoption of FASB Statement No. 160, *Noncontrolling Interests in Consolidated Financial Statements* .

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2009, based on the criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 26, 2010 expressed an unqualified opinion on the Company's internal control over financial reporting.

/s/ Deloitte & Touche LLP

Columbus, Ohio
February 26, 2010

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of American Electric Power Company, Inc.:

We have audited the internal control over financial reporting of American Electric Power Company, Inc. and subsidiary companies (the "Company") as of December 31, 2009, based on criteria established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying *Management's Report on Internal Control Over Financial Reporting* . Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2009, based on the criteria established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements as of and for the year ended December 31, 2009 of the Company and our report dated February 26, 2010 expressed an unqualified opinion on those financial statements and included an explanatory paragraph concerning the Company's adoption of a new accounting pronouncement.

/s/ Deloitte & Touche LLP

Columbus, Ohio
February 26, 2010

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

The management of American Electric Power Company, Inc. and subsidiary companies (AEP) is responsible for establishing and maintaining adequate internal control over financial reporting as such term is defined in Rule 13a- 15 (f) and 15d-15(f) under the Securities Exchange Act of 1934, as amended. AEP's internal control system was designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Management assessed the effectiveness of AEP's internal control over financial reporting as of December 31, 2009. In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in Internal Control – Integrated Framework. Based on management's assessment, AEP's internal control over financial reporting was effective as of December 31, 2009.

AEP's independent registered public accounting firm has issued an attestation report on AEP's internal control over financial reporting. The Report of Independent Registered Public Accounting Firm appears on the previous page.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF INCOME
For the Years Ended December 31, 2009, 2008 and 2007
(in millions, except per-share and share amounts)

REVENUES	2009	2008	2007
Utility Operations	$ 12,733	$ 13,326	$ 12,101
Other Revenues	756	1,114	1,279
TOTAL REVENUES	13,489	14,440	13,380
EXPENSES			
Fuel and Other Consumables Used for Electric Generation	3,478	4,474	3,829
Purchased Electricity for Resale	1,053	1,281	1,138
Other Operation	2,620	2,856	2,664
Maintenance	1,205	1,053	1,162
Gain on Settlement of TEM Litigation	-	(255)	-
Depreciation and Amortization	1,597	1,483	1,513
Taxes Other Than Income Taxes	765	761	755
TOTAL EXPENSES	10,718	11,653	11,061
OPERATING INCOME	2,771	2,787	2,319
Other Income (Expense):			
Interest and Investment Income	11	57	51
Carrying Costs Income	47	83	51
Allowance for Equity Funds Used During Construction	82	45	33
Gain on Disposition of Equity Investments	-	-	47
Interest Expense	(973)	(957)	(838)
INCOME BEFORE INCOME TAX EXPENSE AND EQUITY EARNINGS	1,938	2,015	1,663
Income Tax Expense	575	642	516
Equity Earnings of Unconsolidated Subsidiaries	7	3	6
INCOME BEFORE DISCONTINUED OPERATIONS AND EXTRAORDINARY LOSS	1,370	1,376	1,153
DISCONTINUED OPERATIONS, NET OF TAX	-	12	24
INCOME BEFORE EXTRAORDINARY LOSS	1,370	1,388	1,177
EXTRAORDINARY LOSS, NET OF TAX	(5)	-	(79)
NET INCOME	1,365	1,388	1,098
Less: Net Income Attributable to Noncontrolling Interests	5	5	6
NET INCOME ATTRIBUTABLE TO AEP SHAREHOLDERS	1,360	1,383	1,092
Less: Preferred Stock Dividend Requirements of Subsidiaries	3	3	3
EARNINGS ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 1,357	$ 1,380	$ 1,089
WEIGHTED AVERAGE NUMBER OF BASIC AEP COMMON SHARES OUTSTANDING	458,677,534	402,083,847	398,784,745

BASIC EARNINGS (LOSS) PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS			
Income Before Discontinued Operations and Extraordinary Loss	$ 2.97	$ 3.40	$ 2.87
Discontinued Operations, Net of Tax	-	0.03	0.06
Income Before Extraordinary Loss	2.97	3.43	2.93
Extraordinary Loss, Net of Tax	(0.01)	-	(0.20)
TOTAL BASIC EARNINGS PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 2.96	$ 3.43	$ 2.73
WEIGHTED AVERAGE NUMBER OF DILUTED AEP COMMON SHARES OUTSTANDING	458,982,292	403,640,708	400,198,799
DILUTED EARNINGS (LOSS) PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS			
Income Before Discontinued Operations and Extraordinary Loss	$ 2.97	$ 3.39	$ 2.86
Discontinued Operations, Net of Tax	-	0.03	0.06
Income Before Extraordinary Loss	2.97	3.42	2.92
Extraordinary Loss, Net of Tax	(0.01)	-	(0.20)
TOTAL DILUTED EARNINGS PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 2.96	$ 3.42	$ 2.72
CASH DIVIDENDS PAID PER SHARE	$ 1.64	$ 1.64	$ 1.58

See Notes to Consolidated Financial Statements.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY AND COMPREHENSIVE INCOME (LOSS)
For the Years Ended December 31, 2009, 2008 and 2007
(in millions)

	AEP Common Shareholders						
	Common Stock						
	Shares	Amount	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interests	Total
TOTAL EQUITY – DECEMBER 31, 2006	418	$ 2,718	$ 4,221	$ 2,696	$ (223)	$ 18	$ 9,430
Adoption of Guidance for Uncertainty in Income Taxes, Net of Tax				(17)			(17)
Issuance of Common Stock	4	25	119				144
Common Stock Dividends				(630)		(6)	(636)
Preferred Stock Dividend Requirements of Subsidiaries				(3)			(3)
Other Changes in Equity			12				12
SUBTOTAL – EQUITY							8,930
COMPREHENSIVE INCOME							
Other Comprehensive Income (Loss), Net of Taxes:							
Cash Flow Hedges, Net of Tax of $10					(20)		(20)
Securities Available for Sale, Net of Tax of $1					(1)		(1)
Reapplication of Regulated Operations Accounting Guidance for Pensions, Net of Tax of $6					11		11
Pension and OPEB Funded Status, Net of Tax of $42					79		79
NET INCOME				1,092		6	1,098
TOTAL COMPREHENSIVE INCOME							1,167
TOTAL EQUITY – DECEMBER 31, 2007	422	2,743	4,352	3,138	(154)	18	10,097
Adoption of Guidance for Split-Dollar Life Insurance Accounting, Net of Tax of $6				(10)			(10)
Adoption of Guidance for Fair Value Accounting, Net of Tax of $0				(1)			(1)
Issuance of Common Stock	4	28	131				159
Reissuance of Treasury Shares			40				40
Common Stock Dividends				(660)		(6)	(666)
Preferred Stock Dividend Requirements of Subsidiaries				(3)			(3)
Other Changes in Equity			4				4
SUBTOTAL – EQUITY							9,620
COMPREHENSIVE INCOME							
Other Comprehensive Income (Loss), Net of Taxes:							
Cash Flow Hedges, Net of Tax of $2					4		4
Securities Available for Sale, Net of Tax of $9					(16)		(16)
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $7					12		12
Pension and OPEB Funded Status, Net of Tax of $161					(298)		(298)
NET INCOME				1,383		5	1,388

TOTAL COMPREHENSIVE INCOME							1,090
TOTAL EQUITY – DECEMBER 31, 2008	426	2,771	4,527	3,847	(452)	17	10,710
Issuance of Common Stock	72	468	1,311				1,779
Common Stock Dividends				(753)		(5)	(758)
Preferred Stock Dividend Requirements of Subsidiaries				(3)			(3)
Purchase of JMG			37			(18)	19
Other Changes in Equity			(51)			1	(50)
SUBTOTAL – EQUITY							11,697
COMPREHENSIVE INCOME							
Other Comprehensive Income, Net of Taxes:							
Cash Flow Hedges, Net of Tax of $4					7		7
Securities Available for Sale, Net of Tax of $6					11		11
Reapplication of Regulated Operations Accounting Guidance for Pensions, Net of Tax of $8					15		15
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $13					23		23
Pension and OPEB Funded Status, Net of Tax of $12					22		22
NET INCOME				1,360		5	1,365
TOTAL COMPREHENSIVE INCOME							1,443
TOTAL EQUITY – DECEMBER 31, 2009	498	$ 3,239	$ 5,824	$ 4,451	$ (374)	$ -	$13,140

See Notes to Consolidated Financial Statements

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
ASSETS
December 31, 2009 and 2008
(in millions)

	2009	2008
CURRENT ASSETS		
Cash and Cash Equivalents	$ 490	$ 411
Other Temporary Investments	363	327
Accounts Receivable:		
Customers	492	569
Accrued Unbilled Revenues	503	449
Miscellaneous	92	90
Allowance for Uncollectible Accounts	(37)	(42)
Total Accounts Receivable	1,050	1,066
Fuel	1,075	634
Materials and Supplies	586	539
Risk Management Assets	260	256
Accrued Tax Benefits	547	46
Regulatory Asset for Under-Recovered Fuel Costs	85	284
Margin Deposits	89	86
Prepayments and Other Current Assets	211	126
TOTAL CURRENT ASSETS	4,756	3,775
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Production	23,045	21,242
Transmission	8,315	7,938
Distribution	13,549	12,816
Other Property, Plant and Equipment (including coal mining and nuclear fuel)	3,744	3,741
Construction Work in Progress	3,031	3,973
Total Property, Plant and Equipment	51,684	49,710
Accumulated Depreciation and Amortization	17,340	16,723
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	34,344	32,987
OTHER NONCURRENT ASSETS		
Regulatory Assets	4,595	3,783
Securitized Transition Assets	1,896	2,040
Spent Nuclear Fuel and Decommissioning Trusts	1,392	1,260
Goodwill	76	76
Long-term Risk Management Assets	343	355
Deferred Charges and Other Noncurrent Assets	946	879
TOTAL OTHER NONCURRENT ASSETS	9,248	8,393
TOTAL ASSETS	$ 48,348	$ 45,155

See Notes to Consolidated Financial Statements.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
LIABILITIES AND EQUITY
December 31, 2009 and 2008

	2009	2008
CURRENT LIABILITIES	(in millions)	
Accounts Payable	$ 1,158	$ 1,297
Short-term Debt	126	1,976
Long-term Debt Due Within One Year	1,741	447
Risk Management Liabilities	120	134
Customer Deposits	256	254
Accrued Taxes	632	634
Accrued Interest	287	270
Regulatory Liability for Over-Recovered Fuel Costs	76	66
Other Current Liabilities	931	1,219
TOTAL CURRENT LIABILITIES	5,327	6,297
NONCURRENT LIABILITIES		
Long-term Debt	15,757	15,536
Long-term Risk Management Liabilities	128	170
Deferred Income Taxes	6,420	5,128
Regulatory Liabilities and Deferred Investment Tax Credits	2,909	2,789
Asset Retirement Obligations	1,254	1,154
Employee Benefits and Pension Obligations	2,189	2,184
Deferred Credits and Other Noncurrent Liabilities	1,163	1,126
TOTAL NONCURRENT LIABILITIES	29,820	28,087
TOTAL LIABILITIES	35,147	34,384
Cumulative Preferred Stock Not Subject to Mandatory Redemption	61	61
Rate Matters (Note 4)		
Commitments and Contingencies (Note 6)		
EQUITY		
Common Stock – Par Value – $6.50 Per Share:		

	2009	2008
Shares Authorized	600,000,000	600,000,000
Shares Issued	498,333,265	426,321,248

	2009	2008
(20,278,858 shares and 20,249,992 shares were held in treasury at December 31, 2009 and 2008, respectively)	3,239	2,771
Paid-in Capital	5,824	4,527
Retained Earnings	4,451	3,847
Accumulated Other Comprehensive Income (Loss)	(374)	(452)
TOTAL AEP COMMON SHAREHOLDERS' EQUITY	13,140	10,693
Noncontrolling Interests	-	17
TOTAL EQUITY	13,140	10,710
TOTAL LIABILITIES AND EQUITY	$ 48,348	$ 45,155

See Notes to Consolidated Financial Statements.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2009, 2008 and 2007
(in millions)

	2009	2008	2007
OPERATING ACTIVITIES			
Net Income	$ 1,365	$ 1,388	$ 1,098
Less: Discontinued Operations, Net of Tax	-	(12)	(24)
Income Before Discontinued Operations	1,365	1,376	1,074
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:			
Depreciation and Amortization	1,597	1,483	1,513
Deferred Income Taxes	1,244	498	76
Provision for SIA Refund	-	149	-
Extraordinary Loss, Net of Tax	5	-	79
Carrying Costs Income	(47)	(83)	(51)
Allowance for Equity Funds Used During Construction	(82)	(45)	(33)
Mark-to-Market of Risk Management Contracts	(59)	(140)	3
Amortization of Nuclear Fuel	63	88	65
Pension and Postemployment Benefits	83	42	41
Property Taxes	(17)	(13)	(26)
Fuel Over/Under-Recovery, Net	(474)	(272)	(117)
Gains on Sales of Assets, Net	(15)	(17)	(88)
Change in Noncurrent Liability for NSR Settlement	-	-	58
Change in Other Noncurrent Assets	(137)	(244)	(142)
Change in Other Noncurrent Liabilities	161	(34)	66
Changes in Certain Components of Working Capital:			
Accounts Receivable, Net	41	71	(113)
Fuel, Materials and Supplies	(475)	(183)	16
Margin Deposits	(3)	(40)	50
Accounts Payable	8	(94)	(21)
Customer Deposits	2	(48)	49
Accrued Taxes, Net	(470)	4	(90)
Accrued Interest	17	30	11
Other Current Assets	(70)	(29)	(11)
Other Current Liabilities	(262)	82	(15)
Net Cash Flows from Operating Activities	2,475	2,581	2,394
INVESTING ACTIVITIES			
Construction Expenditures	(2,792)	(3,800)	(3,556)
Change in Other Temporary Investments, Net	16	45	(114)
Purchases of Investment Securities	(853)	(1,922)	(11,086)
Sales of Investment Securities	748	1,917	11,213
Acquisitions of Nuclear Fuel	(169)	(192)	(74)
Acquisitions of Assets	(104)	(160)	(512)
Proceeds from Sales of Assets	278	90	222
Other Investing Activities	(40)	(5)	(14)
Net Cash Flows Used for Investing Activities	(2,916)	(4,027)	(3,921)
FINANCING ACTIVITIES			
Issuance of Common Stock, Net	1,728	159	144
Issuance of Long-term Debt	2,306	2,774	2,546
Borrowings from Revolving Credit Facilities	127	2,055	85
Change in Short-term Debt, Net	119	(660)	659
Retirement of Long-term Debt	(816)	(1,824)	(1,286)
Repayments to Revolving Credit Facilities	(2,096)	(79)	(102)
Proceeds from Nuclear Fuel Sale/Leaseback	-	-	85

Principal Payments for Capital Lease Obligations	(82)	(97)	(67)
Dividends Paid on Common Stock	(758)	(666)	(636)
Dividends Paid on Cumulative Preferred Stock	(3)	(3)	(3)
Other Financing Activities	(5)	20	(21)
Net Cash Flows from Financing Activities	520	1,679	1,404
Net Increase (Decrease) in Cash and Cash Equivalents	79	233	(123)
Cash and Cash Equivalents at Beginning of Period	411	178	301
Cash and Cash Equivalents at End of Period	$ 490	$ 411	$ 178

See Notes to Consolidated Financial Statements.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
INDEX TO NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. ORGANIZATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

ORGANIZATION

The principal business conducted by seven of our electric utility operating companies is the generation, transmission and distribution of electric power. TCC exited the generation business and along with KGPCo and WPCo, provide only transmission and distribution services. TNC engages in the transmission and distribution of electric power and is a part owner in the Oklaunion Plant operated by PSO. TNC leases their entire portion of the output of the plant through 2027 to a nonutility affiliate. AEGCo is a regulated electricity generation business whose function is to provide power to our regulated electric utility operating companies. These companies are subject to regulation by the FERC under the Federal Power Act and the Energy Policy Act of 2005. These companies maintain accounts in accordance with the FERC and other regulatory guidelines. These companies are subject to further regulation with regard to rates and other matters by state regulatory commissions.

We also engage in wholesale electricity, natural gas and other commodity marketing and risk management activities in the United States. In addition, our operations include nonregulated wind farms and barging operations and we provide various energy-related services.

SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Rates and Service Regulation

Our public utility subsidiaries' rates are regulated by the FERC and state regulatory commissions in our eleven state operating territories. The FERC also regulates our affiliated transactions, including AEPSC intercompany service billings which are generally at cost, under the 2005 Public Utility Holding Company Act and the Federal Power Act. The FERC also has jurisdiction over the issuances and acquisitions of securities of our public utility subsidiaries, the acquisition or sale of certain utility assets and mergers with another electric utility or holding company. For non-power goods and services, the FERC requires that a nonregulated affiliate can bill an affiliated public utility company no more than market while a public utility must bill the higher of cost or market to a nonregulated affiliate. The state regulatory commissions in Virginia and West Virginia also regulate certain intercompany transactions under their affiliate statutes.

The FERC regulates wholesale power markets and wholesale power transactions. Our wholesale power transactions are generally market-based. They are cost-based regulated when we negotiate and file a cost-based contract with the FERC or the FERC determines that we have "market power" in the region where the transaction occurs. We have entered into wholesale power supply contracts with various municipalities and cooperatives that are FERC-regulated, cost-based contracts. These contracts are generally formula rate mechanisms, which are trued up to actual costs annually. Our wholesale power transactions in the SPP region are cost-based due to PSO and SWEPCo having market power in the SPP region.

The state regulatory commissions regulate all of the distribution operations and rates of our retail public utilities on a cost basis. They also regulate the retail generation/power supply operations and rates except in Ohio and the ERCOT region of Texas. The ESP rates in Ohio continue the process of increasing generation/power supply rates over time to approach market rates. In the ERCOT region of Texas, the generation/supply business is under customer choice and market pricing and is conducted by REPs. Through its nonregulated subsidiaries, AEP enters into short and long-term wholesale transactions to buy or sell capacity, energy and ancillary services in the ERCOT market. In addition, these nonregulated subsidiaries control certain wind and coal-fired generation assets, the power from which is marketed and sold in ERCOT. Effective November 2009, AEP had no active REPs in ERCOT. SWEPCo operates in the SPP area which includes a portion of Texas. In 2009, the Texas legislature amended its restructuring legislation for the generation portion of SWEPCo's Texas retail jurisdiction to delay indefinitely restructuring requirements. As a result, SWEPCo reapplied accounting guidance for "Regulated Operations" to its Texas generation operations. In 2007, Virginia legislation ended a transition to market-based rates and returned APCo's retail generation/supply business to cost-based regulation.

The FERC also regulates our wholesale transmission operations and rates. The FERC claims jurisdiction over retail transmission rates when retail rates are unbundled in connection with restructuring. CSPCo's and OPCo's retail transmission rates in Ohio, APCo's retail transmission rates in Virginia, I&M's retail transmission rates in Michigan and TCC's and TNC's retail transmission rates in Texas are unbundled. CSPCo's and OPCo's retail transmission rates in Ohio and APCo's retail transmission rates in Virginia are based on the FERC's Open Access Transmission Tariff (OATT) rates that are cost-based. Although I&M's retail transmission rates in Michigan and TCC's and TNC's retail transmission rates in Texas are unbundled, retail transmission rates are regulated, on a cost basis, by the state regulatory commissions. Bundled retail transmission rates are regulated, on a cost basis, by the state commissions.

In addition, the FERC regulates the SIA, the Interconnection Agreement, the CSW Operating Agreement, the System Transmission Integration Agreement, the Transmission Agreement, the Transmission Coordination Agreement and the AEP System Interim Allowance Agreement, all of which allocate shared system costs and revenues to the utility subsidiaries that are parties to each agreement.

Both the FERC and state regulatory commissions are permitted to review and audit the books and records of any company within a public utility holding company system.

Principles of Consolidation

Our consolidated financial statements include our wholly-owned and majority-owned subsidiaries and variable interest entities (VIEs) of which we are the primary beneficiary. Intercompany items are eliminated in consolidation. We use the equity method of accounting for equity investments where we exercise significant influence but do not hold a controlling financial interest. Such investments are recorded as Deferred Charges and Other Noncurrent Assets on our Consolidated Balance Sheets; equity earnings are included in Equity Earnings of Unconsolidated Subsidiaries on our Consolidated Statements of Income. For years, we have had ownership interests in generating units that are jointly-owned with nonaffiliated companies. Our proportionate share of the operating costs associated with such facilities is included on our Consolidated Statements of Income and our proportionate share of the assets and liabilities are reflected on our Consolidated Balance Sheets.

Variable Interest Entities

The accounting guidance for "Variable Interest Entities" is a consolidation model that considers risk absorption of a variable interest entity (VIE), also referred to as variability. Entities are required to consolidate a VIE when it is determined that they are the primary beneficiary of that VIE, as defined by the accounting guidance for "Variable Interest Entities." In determining whether we are the primary beneficiary of a VIE, we consider factors such as equity at risk, the amount of the VIE's variability we absorb, guarantees of indebtedness, voting rights including kick-out rights, power to direct the VIE and other factors. We believe that significant assumptions and judgments were applied consistently. Also, see "SFAS 167 'Amendments to FASB Interpretation No. 46(R)' " section of Note 2 for discussion of impact of new accounting guidance effective January 1, 2010.

We are currently the primary beneficiary of Sabine, DHLC, DCC Fuel LLC (DCC Fuel) and a protected cell of EIS. We were the primary beneficiary of JMG through December 15, 2009 when the lease was cancelled and all assets and liabilities of JMG were transferred to OPCo. We hold a significant variable interest in Potomac-Appalachian Transmission Highline, LLC West Virginia Series (West Virginia Series). In addition, we have not provided material financial or other support to Sabine, DHLC, DCC Fuel or our protected cell of EIS that was not previously contractually required. Refer to the discussion of JMG below for details regarding payments that were not contractually required and for the subsequent transfer of JMG's assets and liabilities to OPCo.

Sabine is a mining operator providing mining services to SWEPCo. SWEPCo has no equity investment in Sabine but is Sabine's only customer. SWEPCo guarantees the debt obligations and lease obligations of Sabine. Under the terms of the note agreements, substantially all assets are pledged and all rights under the lignite mining agreement are assigned to SWEPCo. The creditors of Sabine have no recourse to any AEP entity other than SWEPCo. Under the provisions of the mining agreement, SWEPCo is required to pay, as a part of the cost of lignite delivered, an amount equal to mining costs plus a management fee. Based on these facts, management has concluded that SWEPCo is the primary beneficiary and is required to consolidate Sabine. SWEPCo's total billings from Sabine for the years ended December 31, 2009 and 2008 were $99 million and $110 million, respectively. See the tables below for the classification of Sabine's assets and liabilities on our Consolidated Balance Sheets.

DHLC is a wholly-owned subsidiary of SWEPCo. DHLC is a mining operator that sells 50% of the lignite produced to SWEPCo and 50% to Cleco Corporation, a nonaffiliated company. SWEPCo and Cleco Corporation share half of the executive board seats, with equal voting rights and each entity guarantees a 50% share of DHLC's debt. SWEPCo and Cleco Corporation equally approve DHLC's annual budget. The creditors of DHLC have no recourse to any AEP entity other than SWEPCo. As SWEPCo is the sole equity owner of DHLC it receives 100% of the management fee. Based on the structure and equity ownership, management has concluded that SWEPCo is the primary beneficiary and is currently required to consolidate DHLC. In December 2009, SWEPCo provided additional capital to DHLC in the amount of $5 million. SWEPCo's total billings from DHLC for the years ended December 31, 2009 and 2008 were $43 million and $44 million, respectively. See the tables below for the classification of DHLC assets and liabilities on our Consolidated Balance Sheets. Also, see "SFAS 167 'Amendments to FASB Interpretation No. 46(R)' " section of Note 2 for discussion of impact of new accounting guidance effective January 1, 2010.

OPCo had a lease agreement with JMG to finance OPCo's FGD system installed on OPCo's Gavin Plant. The PUCO approved the original lease agreement between OPCo and JMG. JMG owned and leased the FGD to OPCo. JMG was considered a single-lessee leasing arrangement with only one asset. OPCo's lease payments were the only form of repayment associated with JMG's debt obligations even though OPCo did not guarantee JMG's debt. The creditors of JMG had no recourse to any AEP entity other than OPCo for the lease payment. Based on the structure of the entity, management had concluded OPCo was the primary beneficiary and was required to consolidate JMG. In April 2009, OPCo paid JMG $58 million which was used to retire certain long-term debt of JMG. While this payment was not contractually required, OPCo made this payment in anticipation of purchasing the outstanding equity of JMG. In July 2009, OPCo purchased all of the outstanding equity ownership of JMG for $28 million resulting in an elimination of OPCo's Noncontrolling Interest related to JMG and an increase in equity of $37 million. In August and September 2009, JMG reacquired $218 million of auction rate debt, funded by OPCo capital contributions to JMG. These reacquisitions were not contractually required. In December 2009, the lease was cancelled and all the assets and liabilities of JMG were transferred to OPCo. OPCo's total billings under the lease term from JMG for the years ended December 31, 2009 and 2008 were $66 million and $57 million, respectively. See the tables below for the classification of JMG's assets and liabilities on our Consolidated Balance Sheets.

EIS has multiple protected cells in which our subsidiaries participate in one protected cell for approximately ten lines of insurance. Neither AEP nor its subsidiaries have an equity investment of EIS. The AEP system is essentially this EIS cell's only participant, but allows certain third parties access to this insurance. Our subsidiaries and any allowed third parties share in the insurance coverage, premiums and risk of loss from claims. Based on the structure of the protected cell and EIS, management has concluded that we are the primary beneficiary of the protected cell and are required to consolidate its assets and liabilities. Our insurance premium payments to the protected cell for the years ended December 31, 2009 and 2008 were $30 million and $28 million, respectively. See the tables below for the classification of the protected cell's assets and liabilities on our Consolidated Balance Sheets. Note the amount reported as equity is the protected cell's policy holders' surplus.

In September 2009, I&M entered into a nuclear fuel sale and leaseback transaction with DCC Fuel. DCC Fuel was formed for the purpose of acquiring, owning and leasing nuclear fuel to I&M. DCC Fuel purchased the nuclear fuel from I&M with funds received from the issuance of notes to financial institutions. DCC Fuel is a single-lessee leasing arrangement with only one asset and is capitalized with all debt. Payments on the lease will be made semi-annually on April 1 and October 1, beginning in April 2010. As of December 31, 2009, no payments have been made by I&M to DCC Fuel. The lease was recorded as a capital lease on I&M's balance sheet as title to the nuclear fuel transfers to I&M at the end of the 48 month lease term. Based on the structure, management has concluded that I&M is the primary beneficiary and is required to consolidate DCC Fuel. The capital lease is eliminated upon consolidation. See the tables below for the classification of DCC Fuel's assets and liabilities on our Consolidated Balance Sheets.

The balances below represent the assets and liabilities of the VIEs that are consolidated. These balances include intercompany transactions that are eliminated upon consolidation.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
VARIABLE INTEREST ENTITIES
December 31, 2009
(in millions)

	SWEPCo Sabine	SWEPCo DHLC	OPCo JMG	I&M DCC Fuel	Protected Cell of EIS
ASSETS					
Current Assets	$ 51	$ 8	$ -	$ 47	$ 130
Net Property, Plant and Equipment	149	44	-	89	-
Other Noncurrent Assets	35	11	-	57	2
Total Assets	$ 235	$ 63	$ -	$ 193	$ 132
LIABILITIES AND EQUITY					
Current Liabilities	$ 36	$ 17	$ -	$ 39	$ 36
Noncurrent Liabilities	199	38	-	154	74
Equity	-	8	-	-	22

Total Liabilities and Equity	$ 235	$ 63	$ -	$ 193	$ 132

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
VARIABLE INTEREST ENTITIES
December 31, 2008
(in millions)

	SWEPCo Sabine	SWEPCo DHLC	OPCo JMG	I&M DCC Fuel	Protected Cell of EIS
ASSETS					
Current Assets	$ 33	$ 22	$ 11	$ -	$ 107
Net Property, Plant and Equipment	117	33	423	-	-
Other Noncurrent Assets	24	11	1	-	2
Total Assets	$ 174	$ 66	$ 435	$ -	$ 109
LIABILITIES AND EQUITY					
Current Liabilities	$ 32	$ 18	$ 161	$ -	$ 30
Noncurrent Liabilities	142	44	257	-	60
Equity	-	4	17	-	19
Total Liabilities and Equity	$ 174	$ 66	$ 435	$ -	$ 109

In September 2007, we and Allegheny Energy Inc. (AYE) formed a joint venture by creating Potomac-Appalachian Transmission Highline, LLC (PATH). PATH is a series limited liability company and was created to construct a high-voltage transmission line project in the PJM region. PATH consists of the "Ohio Series," the "West Virginia Series (PATH-WV)," both owned equally by AYE and AEP and the "Allegheny Series" which is 100% owned by AYE. Provisions exist within the PATH-WV agreement that make it a VIE. The "Ohio Series" does not include the same provisions that make PATH-WV a VIE. Neither the "Ohio Series" or "Allegheny Series" are considered VIEs. We are not required to consolidate PATH-WV as we are not the primary beneficiary, although we hold a significant variable interest in PATH-WV. Our equity investment in PATH-WV is included in Deferred Charges and Other Noncurrent Assets on our Consolidated Balance Sheets. We and AYE share the returns and losses equally in PATH-WV. Our subsidiaries and AYE's subsidiaries provide services to the PATH companies through service agreements. At the current time, PATH-WV has no debt outstanding. However, when debt is issued, the debt to equity ratio in each series should be consistent with other regulated utilities. The entities recover costs through regulated rates.

Given the structure of the entity, we may be required to provide future financial support to PATH-WV in the form of a capital call. This would be considered an increase to our investment in the entity. Our maximum exposure to loss is to the extent of our investment. The likelihood of such a loss is remote since the FERC approved PATH-WV's request for regulatory recovery of cost and a return on the equity invested.

Our investment in PATH-WV was:

	December 31,			
	2009		2008	
	As Reported on the Consolidated Balance Sheet	Maximum Exposure	As Reported on the Consolidated Balance Sheet	Maximum Exposure
	(in millions)			
Capital Contribution from Parent	$ 13	$ 13	$ 4	$ 4
Retained Earnings	3	3	2	2
Total Investment in PATH-WV	$ 16	$ 16	$ 6	$ 6

Accounting for the Effects of Cost-Based Regulation

As the owner of rate-regulated electric public utility companies, our consolidated financial statements reflect the actions of regulators that result in the recognition of certain revenues and expenses in different time periods than enterprises that are not rate-regulated. In accordance with accounting guidance for "Regulated Operations," we record regulatory assets (deferred expenses) and regulatory liabilities (future revenue reductions or refunds) to reflect the economic effects of regulation by matching expenses with their recovery through regulated revenues and income with its passage to customers through the reduction of regulated revenues. Due to the passage of legislation requiring restructuring and a transition to customer choice and market-based rates, we discontinued the application of "Regulated Operations" accounting treatment for the generation portion of our business in Ohio for CSPCo and OPCo and in Texas for TNC. In 2009, the Texas legislature amended its restructuring legislation for the generation portion of SWEPCo's Texas retail jurisdiction to delay indefinitely restructuring requirements. As a result, SWEPCo reapplied accounting guidance for "Regulated Operations" to its Texas generation operations. In 2007, the Virginia legislature also amended its restructuring legislation to provide for the re-regulation of generation and supply business and rates on a cost basis, which resulted in the re-application of accounting guidance for "Regulated Operations" for APCo's Virginia generation operations.

Accounting guidance for "Discontinuation of Rate-Regulated Operations" requires the recognition of an impairment of stranded net regulatory assets and stranded plant costs if they are not recoverable in regulated rates. In addition, an enterprise is required to eliminate from its balance sheet the effects of any actions of regulators that had been recognized as regulatory assets and regulatory liabilities. Such impairments and adjustments are classified as an extraordinary item. Consistent with accounting guidance for "Discontinuation of Rate-Regulated Operations," APCo and SWEPCo recorded extraordinary reductions in earnings and shareholder's equity from the reapplication of "Regulated Operations" accounting guidance in 2007 and 2009, respectively.

Use of Estimates

The preparation of these financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the amounts reported in the financial statements and accompanying notes. These estimates include, but are not limited to, inventory valuation, allowance for doubtful accounts, goodwill, intangible and long-lived asset impairment, unbilled electricity revenue, valuation of long-term energy contracts, the effects of regulation, long-lived asset recovery, the effects of contingencies and certain assumptions made in accounting for pension and postretirement benefits. The estimates and assumptions used are based upon management's evaluation of the relevant facts and circumstances as of the date of the financial statements. Actual results could ultimately differ from those estimates.

Cash and Cash Equivalents

Cash and Cash Equivalents include temporary cash investments with original maturities of three months or less.

Other Temporary Investments

Other Temporary Investments include marketable securities that we intend to hold for less than one year, investments by our protected cell of EIS and funds held by trustees primarily for the payment of debt.

We classify our investments in marketable securities as available-for-sale or held-to-maturity in accordance with the provisions of "Investments – Debt and Equity Securities" accounting guidance. We do not have any investments classified as trading.

Available-for-sale securities reflected in Other Temporary Investments are carried at fair value with the unrealized gain or loss, net of tax, reported in AOCI. Held-to-maturity securities reflected in Other Temporary Investments are carried at amortized cost. The cost of securities sold is based on the specific identification or weighted average cost method. The fair value of most investment securities is determined by currently available market prices. Where quoted market prices are not available, we use the market price of similar types of securities that are traded in the market to estimate fair value.

In evaluating potential impairment of securities with unrealized losses, we considered, among other criteria, the current fair value compared to cost, the length of time the security's fair value has been below cost, our intent and ability to retain the investment for a period of time sufficient to allow for any anticipated recovery in value and current economic conditions. See "Fair Value Measurements of Other Temporary Investments" in Note 11.

Inventory

Fossil fuel inventories are generally carried at average cost. Materials and supplies inventories are carried at average cost.

Accounts Receivable

Customer accounts receivable primarily include receivables from wholesale and retail energy customers, receivables from energy contract counterparties related to our risk management activities and customer receivables primarily related to other revenue-generating activities.

We recognize revenue from electric power sales when we deliver power to our customers. To the extent that deliveries have occurred but a bill has not been issued, we accrue and recognize, as Accrued Unbilled Revenues on our Consolidated Balance Sheets, an estimate of the revenues for energy delivered since the last billing.

AEP Credit factors accounts receivable, excluding receivables from risk management activities, for certain subsidiaries. The subsidiaries include CSPCo, I&M, KGPCo, KPCo, OPCo, PSO, SWEPCo and a portion of APCo. Since APCo does not have regulatory authority to sell accounts receivable in its West Virginia regulatory jurisdiction, only a portion of APCo's accounts receivable are sold to AEP Credit. AEP Credit has a sale of receivables agreement with bank conduits. Under the sale of receivables agreement, AEP Credit sells an interest in the receivables it acquires to the bank conduits and receives cash. This transaction constitutes a sale of receivables in accordance with the accounting guidance effective during 2009 for "Transfers and Servicing," allowing the receivables to be removed from the company's balance sheet (see "Sale of Receivables – AEP Credit" section of Note 14). Also, see "SFAS 166 'Accounting for Transfers of Financial Assets' " section of Note 2 for discussion of impact of new accounting guidance effective January 1, 2010.

Emission Allowances

We record emission allowances at cost, including the annual SO_2 and NO_x emission allowance entitlements received at no cost from the Federal EPA. We follow the inventory model for these allowances. We record allowances expected to be consumed within one year in Materials and Supplies and allowances with expected consumption beyond one year in Deferred Charges and Other Noncurrent Assets on our Consolidated Balance Sheets. We record the consumption of allowances in the production of energy in Fuel and Other Consumables Used for Electric Generation on our Consolidated Statements of Income at an average cost. We record allowances held for speculation in Prepayments and Other Current Assets on our Consolidated Balance Sheets. We report the purchases and sales of allowances in the Operating Activities section of the Statements of Cash Flows. We record the net margin on sales of emission allowances in Utility Operations Revenue on our Consolidated Statements of Income because of its integral nature to the production process of energy and our revenue optimization strategy for our utility operations. The net margin on sales of emission allowances affects the determination of deferred fuel or deferred emission allowance costs and the amortization of regulatory assets for certain jurisdictions.

Property, Plant and Equipment and Equity Investments

Electric utility property, plant and equipment are stated at original purchase cost. Property, plant and equipment of nonregulated operations and equity investments (included in Deferred Charges and Other Noncurrent Assets) are stated at fair value at acquisition (or as adjusted for any applicable impairments) plus the original cost of property acquired or constructed since the acquisition, less disposals. Additions, major replacements and betterments are added to the plant accounts. For the Utility Operations segment, normal and routine retirements from the plant accounts, net of salvage, are charged to accumulated depreciation for both cost-based rate-regulated and most nonregulated operations under the group composite method of depreciation. The group composite method of depreciation assumes that on average, asset components are retired at the end of their useful lives and thus there is no gain or loss. The equipment in each primary electric plant account is identified as a separate group. Under the group composite method of depreciation, continuous interim routine replacements of items such as boiler tubes, pumps, motors, etc. result in the original cost, less salvage, being charged to accumulated depreciation. For the nonregulated generation assets, a gain or loss would be recorded if the retirement is not considered an interim routine replacement. The depreciation rates that are established for the generating plants take into account the past history of interim capital replacements and the amount of salvage received. These rates and the related lives are subject to periodic review. Gains and losses are recorded for any retirements in the AEP River Operations and Generation and Marketing segments. Removal costs are charged to regulatory liabilities for cost-based rate-regulated operations and charged to expense for nonregulated operations. The costs of labor, materials and overhead incurred to operate and maintain our plants are included in operating expenses.

Long-lived assets are required to be tested for impairment when it is determined that the carrying value of the assets may no longer be recoverable or when the assets meet the held for sale criteria under the accounting guidance for "Impairment or Disposal of Long-Lived Assets." Equity investments are required to be tested for impairment when it is determined there may be an other than temporary loss in value.

The fair value of an asset or investment is the amount at which that asset or investment could be bought or sold in a current transaction between willing parties, as opposed to a forced or liquidation sale. Quoted market prices in active markets are the best evidence of fair value and are used as the basis for the measurement, if available. In the absence of quoted prices for identical or similar assets or investments in active markets, fair value is estimated using various internal and external valuation methods including cash flow analysis and appraisals.

Allowance for Funds Used During Construction (AFUDC) and Interest Capitalization

AFUDC represents the estimated cost of borrowed and equity funds used to finance construction projects that is capitalized and recovered through depreciation over the service life of regulated electric utility plant. For nonregulated operations, including generating assets in Ohio and Texas, interest is capitalized during construction in accordance with the accounting guidance for "Capitalization of Interest."

Valuation of Nonderivative Financial Instruments

The book values of Cash and Cash Equivalents, Accounts Receivable, Short-term Debt and Accounts Payable approximate fair value because of the short-term maturity of these instruments. The book value of the pre-April 1983 spent nuclear fuel disposal liability approximates the best estimate of its fair value.

Fair Value Measurements of Assets and Liabilities

The accounting guidance for "Fair Value Measurements and Disclosures" establishes a fair value hierarchy that prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 measurement) and the lowest priority to unobservable inputs (Level 3 measurement). Where observable inputs are available for substantially the full term of the asset or liability, the instrument is categorized in Level 2. When quoted market prices are not available, pricing may be completed using comparable securities, dealer values, operating data and general market conditions to determine fair value. Valuation models utilize various inputs that include quoted prices for similar assets or liabilities in active markets, quoted prices for identical or similar assets or liabilities in inactive markets, market corroborated inputs (i.e. inputs derived principally from, or correlated to, observable market data) and other observable inputs for the asset or liability.

For our commercial activities, exchange traded derivatives, namely futures contracts, are generally fair valued based on unadjusted quoted prices in active markets and are classified as Level 1. Level 2 inputs primarily consist of OTC broker quotes in moderately active or less active markets, as well as exchange traded contracts where there is insufficient market liquidity to warrant inclusion in Level 1. We verify our price curves using these broker quotes and classify these fair values within Level 2 when substantially all of the fair value can be corroborated. We typically obtain multiple broker quotes, which are non-binding in nature, but are based on recent trades in the marketplace. When multiple broker quotes are obtained, we average the quoted bid and ask prices. In certain circumstances, we may discard a broker quote if it is a clear outlier. We use a historical correlation analysis between the broker quoted location and the illiquid locations and if the points are highly correlated we include these locations within Level 2 as well. Certain OTC and bilaterally executed derivative instruments are executed in less active markets with a lower availability of pricing information. Long-dated and illiquid complex or structured transactions and FTRs can introduce the need for internally developed modeling inputs based upon extrapolations and assumptions of observable market data to estimate fair value. When such inputs have a significant impact on the measurement of fair value, the instrument is categorized as Level 3.

We utilize our trustee's external pricing service in our estimate of the fair value of the underlying investments held in the benefit plan and nuclear trusts. Our investment managers review and validate the prices utilized by the trustee to determine fair value. We perform our own valuation testing to verify the fair values of the securities. We receive audit reports of our trustee's operating controls and valuation processes. The trustee uses multiple pricing vendors for the assets held in the plans. Equities are classified as Level 1 holdings if they are actively traded on exchanges. Fixed income securities do not trade on an exchange and do not have an official closing price. Pricing vendors calculate bond valuations using financial models and matrices. Fixed income securities are typically classified as Level 2 holdings because their valuation inputs are based on observable market data. Observable inputs used for valuing fixed income securities are benchmark yields, reported trades, broker/dealer quotes, issuer spreads, two-sided markets, benchmark securities, bids, offers, reference data, and economic events. Other securities with model-derived valuation inputs that are observable are also classified as Level 2 investments. Investments with unobservable valuation inputs are classified as Level 3 investments. Benefit plan assets included in Level 3 are real estate and private equity investments that are valued using methods requiring judgment including appraisals.

Deferred Fuel Costs

The cost of fuel and related emission allowances and emission control chemicals/consumables is charged to Fuel and Other Consumables Used for Electric Generation expense when the fuel is burned or the allowance or consumable is utilized. The cost of fuel also includes the cost of nuclear fuel burned which is computed primarily on the units-of-production method. In regulated jurisdictions with an active FAC, fuel cost over-recoveries (the excess of fuel revenues billed to customers over applicable fuel costs incurred) are generally deferred as current regulatory liabilities and under-recoveries (the excess of applicable fuel costs incurred over fuel revenues billed to customers) are generally deferred as current regulatory assets. These deferrals are amortized when refunded or when billed to customers in later months with the state regulatory commissions' review and approval. The amount of an over-recovery or under-recovery can also be affected by actions of the state regulatory commissions. On a routine basis, state regulatory commissions review and/or audit our fuel procurement policies and practices, the fuel cost calculations and FAC deferrals. When a fuel cost disallowance becomes probable, we adjust our FAC deferrals and record provisions for estimated refunds to recognize these probable outcomes. Fuel cost over-recovery and under-recovery balances are classified as noncurrent when there is a phase-in plan or the FAC has been suspended.

Changes in fuel costs, including purchased power in Kentucky for KPCo, in Indiana (beginning in July 2007) and Michigan for I&M, in Texas, Louisiana and Arkansas for SWEPCo, in Oklahoma for PSO and in Virginia and West Virginia (prior to 2009) for APCo are reflected in rates in a timely manner through the FAC. Beginning in 2009, changes in fuel costs, including purchased power in Ohio for CSPCo and OPCo and in West Virginia for APCo are reflected in rates through FAC phase-in plans. All of the profits from off-system sales are shared with customers through the FAC in West Virginia for APCo. A portion of profits from off-system sales are shared with customers through the FAC and other rate mechanisms in Oklahoma for PSO, Texas, Louisiana and Arkansas for SWEPCo, Kentucky for KPCo, Virginia (beginning in September 2007) for APCo and in Indiana (beginning in July 2007) and some areas of Michigan for I&M. Where the FAC or off-system sales sharing mechanism is capped, frozen or non-existent (prior to July 2007 for I&M in Indiana, prior to 2009 for CSPCo and OPCo in Ohio and currently in Texas for AEP Energy Partners, Inc.), changes in fuel costs or sharing of off-system sales impacted earnings.

Revenue Recognition

Regulatory Accounting

Our consolidated financial statements reflect the actions of regulators that can result in the recognition of revenues and expenses in different time periods than enterprises that are not rate-regulated. Regulatory assets (deferred expenses) and regulatory liabilities (deferred revenue reductions or refunds) are recorded to reflect the economic effects of regulation in the same accounting period by matching expenses with their recovery through regulated revenues and by matching income with its passage to customers in cost-based regulated rates.

When regulatory assets are probable of recovery through regulated rates, we record them as assets on our Consolidated Balance Sheets. We test for probability of recovery at each balance sheet date or whenever new events occur. Examples of new events include the issuance of a regulatory commission order or passage of new legislation. If it is determined that recovery of a regulatory asset is no longer probable, we write off that regulatory asset as a charge against income.

Traditional Electricity Supply and Delivery Activities

Revenues are recognized from retail and wholesale electricity sales and electricity transmission and distribution delivery services. We recognize the revenues on our Consolidated Statements of Income upon delivery of the energy to the customer and include unbilled as well as billed amounts. In accordance with the applicable state commission regulatory treatment, PSO and SWEPCo do not record the fuel portion of unbilled revenue.

Most of the power produced at the generation plants of the AEP East companies is sold to PJM, the RTO operating in the east service territory. We purchase power from PJM to supply our customers. Generally, these power sales and purchases are reported on a net basis as revenues on our Consolidated Statements of Income. However, in 2009, there were times when we were a purchaser of power from PJM to serve retail load. These purchases were recorded gross as Purchased Electricity for Resale on our Consolidated Statements of Income. Other RTOs in which we operate do not function in the same manner as PJM. They function as balancing organizations and not as exchanges.

Physical energy purchases, including those from RTOs, that are identified as non-trading, but excluding PJM purchases described in the preceding paragraph, are accounted for on a gross basis in Purchased Electricity for Resale on our Consolidated Statements of Income.

In general, we record expenses when purchased electricity is received and when expenses are incurred, with the exception of certain power purchase contracts that are derivatives and accounted for using MTM accounting where generation/supply rates are not cost-based regulated. In jurisdictions where the generation/supply business is subject to cost-based regulation, the unrealized MTM amounts are deferred as regulatory assets (for losses) and regulatory liabilities (for gains).

For power purchased under derivative contracts in our west zone where we are short capacity, we defer all unrealized gains and losses as regulatory liabilities for net gains or regulatory assets for net losses that result from measuring these contracts at fair value during the period before settlement. If the contract results in the physical delivery of power from a RTO or any other counterparty, we reverse the previously recorded unrealized gains and losses from MTM valuations and record the settled amounts gross as Purchased Electricity for Resale. If the contract does not result in physical delivery, we reverse the previously recorded unrealized gains and losses from MTM valuations and record the settled amounts as Revenues on our Consolidated Statements of Income on a net basis (see Note 10).

Energy Marketing and Risk Management Activities

We engage in wholesale electricity, natural gas, coal and emission allowances marketing and risk management activities focused on wholesale markets where we own assets and adjacent markets. Our activities include the purchase and sale of energy under forward contracts at fixed and variable prices and the buying and selling of financial energy contracts, which include exchange traded futures and options, as well as over-the-counter options and swaps. We engage in certain energy marketing and risk management transactions with RTOs.

We recognize revenues and expenses from wholesale marketing and risk management transactions that are not derivatives upon delivery of the commodity. We use MTM accounting for wholesale marketing and risk management transactions that are derivatives unless the derivative is designated in a qualifying cash flow hedge relationship or a normal purchase or sale. We include the unrealized and realized gains and losses on wholesale marketing and risk management transactions that are accounted for using MTM in Revenues on our Consolidated Statements of Income on a net basis. In jurisdictions subject to cost-based regulation, we defer the unrealized MTM amounts and some realized gains and losses as regulatory assets (for losses) and regulatory liabilities (for gains). We include unrealized MTM gains and losses resulting from derivative contracts on our Consolidated Balance Sheets as Risk Management Assets or Liabilities as appropriate.

Certain qualifying wholesale marketing and risk management derivative transactions are designated as hedges of variability in future cash flows as a result of forecasted transactions (cash flow hedge). We initially record the effective portion of the cash flow hedge's gain or loss as a component of AOCI. When the forecasted transaction is realized and affects net income, we subsequently reclassify the gain or loss on the hedge from AOCI into revenues or expenses within the same financial statement line item as the forecasted transaction on our Consolidated Statements of Income. Excluding those jurisdictions subject to cost-based regulation, we recognize the ineffective portion of the gain or loss in revenues or expense immediately on our Consolidated Statements of Income, depending on the specific nature of the associated hedged risk. In regulated jurisdictions, we defer the ineffective portion as regulatory assets (for losses) and regulatory liabilities (for gains) (see "Accounting for Cash Flow Hedging Strategies" section of Note 10).

Barging Activities

AEP River Operations' revenue is recognized based on percentage of voyage completion. The proportion of freight transportation revenue to be recognized is determined by applying a percentage to the contractual charges for such services. The percentage is determined by dividing the number of miles from the loading point to the position of the barge as of the end of the accounting period by the total miles to the destination specified in the customer's freight contract. The position of the barge at accounting period end is determined by our computerized barge tracking system.

Levelization of Nuclear Refueling Outage Costs

In order to match costs with nuclear refueling cycles, I&M defers incremental operation and maintenance costs associated with periodic refueling outages at its Cook Plant and amortizes the costs over the period beginning with the month following the start of each unit's refueling outage and lasting until the end of the month in which the same unit's next scheduled refueling outage begins. I&M adjusts the amortization amount as necessary to ensure full amortization of all deferred costs by the end of the refueling cycle.

Maintenance

We expense maintenance costs as incurred. If it becomes probable that we will recover specifically-incurred costs through future rates, we establish a regulatory asset to match the expensing of those maintenance costs with their recovery in cost-based regulated revenues. We defer distribution tree trimming costs for PSO above the level included in base rates and amortize those deferrals commensurate with recovery through a rate rider in Oklahoma.

Income Taxes and Investment Tax Credits

We use the liability method of accounting for income taxes. Under the liability method, we provide deferred income taxes for all temporary differences between the book and tax basis of assets and liabilities which will result in a future tax consequence.

When the flow-through method of accounting for temporary differences is reflected in regulated revenues (that is, when deferred taxes are not included in the cost of service for determining regulated rates for electricity), we record deferred income taxes and establish related regulatory assets and liabilities to match the regulated revenues and tax expense.

We account for investment tax credits under the flow-through method except where regulatory commissions reflect investment tax credits in the rate-making process on a deferral basis. We amortize deferred investment tax credits over the life of the plant investment.

We account for uncertain tax positions in accordance with the accounting guidance for "Income Taxes." We classify interest expense or income related to uncertain tax positions as interest expense or income as appropriate and classify penalties as Other Operation.

Excise Taxes

We act as an agent for some state and local governments and collect from customers certain excise taxes levied by those state or local governments on our customers. We do not recognize these taxes as revenue or expense.

Debt and Preferred Stock

We defer gains and losses from the reacquisition of debt used to finance regulated electric utility plants and amortize the deferral over the remaining term of the reacquired debt in accordance with their rate-making treatment unless the debt is refinanced. If we refinance the reacquired debt associated with the regulated business, the reacquisition costs attributable to the portions of the business subject to cost-based regulatory accounting are generally deferred and amortized over the term of the replacement debt consistent with its recovery in rates. Some jurisdictions require that these costs be expensed upon reacquisition. We report gains and losses on the reacquisition of debt for operations not subject to cost-based rate regulation in Interest Expense on our Consolidated Statements of Income.

We defer debt discount or premium and debt issuance expenses and amortize generally utilizing the straight-line method over the term of the related debt. The straight-line method approximates the effective interest method and is consistent with the treatment in rates for regulated operations. We include the amortization expense in Interest Expense on our Consolidated Statements of Income.

Where reflected in rates, we include redemption premiums paid to reacquire preferred stock of utility subsidiaries in paid-in capital and amortize the premiums to retained earnings commensurate with recovery in rates. We credit the excess of par value over costs of preferred stock reacquired to paid-in capital and reclassify the excess to retained earnings upon the redemption of the entire preferred stock series.

Goodwill and Intangible Assets

When we acquire businesses, we record the fair value of all assets and liabilities, including intangible assets. To the extent that consideration exceeds the fair value of identified assets, we record goodwill. We do not amortize goodwill and intangible assets with indefinite lives. We test acquired goodwill and other intangible assets with indefinite lives for impairment at least annually at their estimated fair value. We test goodwill at the reporting unit level and other intangibles at the asset level. Fair value is the amount at which an asset or liability could be bought or sold in a current transaction between willing parties, that is, other than in a forced or liquidation sale. Quoted market prices in active markets are the best evidence of fair value and are used as the basis for the measurement, if available. In the absence of quoted prices for identical or similar assets in active markets, we estimate fair value using various internal and external valuation methods. We amortize intangible assets with finite lives over their respective estimated lives, currently ranging from 10 to 15 years, to their estimated residual values. We also review the lives of the amortizable intangibles with finite lives on an annual basis.

Investments Held in Trust for Future Liabilities

We have several trust funds with significant investments intended to provide for future payments of pension and OPEB benefits, nuclear decommissioning and spent nuclear fuel disposal. All of our trust funds' investments are diversified and managed in compliance with all laws and regulations. Our investment strategy for trust funds is to use a diversified portfolio of investments to achieve an acceptable rate of return while managing the interest rate sensitivity of the assets relative to the associated liabilities. To minimize investment risk, the trust funds are broadly diversified among classes of assets, investment strategies and investment managers. We regularly review the actual asset allocation and periodically rebalance the investments to targeted allocation when appropriate. Investment policies and guidelines allow investment managers in approved strategies to use financial derivatives to obtain or manage market exposures and to hedge assets and liabilities. The investments are reported at fair value under the "Fair Value Measurements and Disclosures" accounting guidance.

Benefit Plans

All benefit plan assets are invested in accordance with each plan's investment policy. The investment policy outlines the investment objectives, strategies and target asset allocations by plan.

The investment philosophies for our benefit plans support the allocation of assets to minimize risks and optimizing net returns. Strategies used include:

- Maintaining a long-term investment horizon.
- Diversifying assets to help control volatility of returns at acceptable level.
- Managing fees, transaction costs and tax liabilities to maximize investment earnings.
- Using active management of investments where appropriate risk/return opportunities exist.
- Keeping portfolio structure style-neutral to limit volatility compared to applicable benchmarks.
- Using alternative asset classes such as real estate and private equity to maximize return and provide additional portfolio diversification.

The target asset allocation and allocation ranges are as follows:

Pension Plan Assets	Minimum	Target	Maximum
Domestic Equity	30.0%	35.0%	40.0%
International and Global Equity	10.0%	15.0%	20.0%
Fixed Income	35.0%	39.0%	45.0%
Real Estate	4.0%	5.0%	6.0%
Other Investments	1.0%	5.0%	7.0%
Cash	0.5%	1.0%	3.0%

OPEB Plans Assets	Minimum	Target	Maximum
Equity	61.0%	66.0%	71.0%
Fixed Income	29.0%	33.0%	37.0%
Cash	1.0%	1.0%	4.0%

The investment policy for each benefit plan contains various investment limitations. The investment policies establish concentration limits for securities. Investment policies prohibit the benefit trust funds from purchasing securities issued by AEP (with the exception of proportionate and immaterial holdings of AEP securities in passive index strategies). However, our investment policies do not preclude the benefit trust funds from receiving contributions in the form of AEP securities, provided that the AEP securities acquired by each plan may not exceed the limitations imposed by law. Each investment manager's portfolio is compared to a diversified benchmark index.

For equity investments, the limits are as follows:

- No security in excess of 5% of all equities.
- Cash equivalents must be less than 10% of an investment manager's equity portfolio.
- Individual stock must be less than 10% of each manager's equity portfolio.
- No investment in excess of 5% of an outstanding class of any company.
- No securities may be bought or sold on margin or other use of leverage.

For fixed income investments, the concentration limits must not exceed:

- 3% in one issuer
- 20% in non-US dollar denominated
- 5% private placements
- 5% convertible securities
- 60% for bonds rated AA+ or lower
- 50% for bonds rated A+ or lower
- 10% for bonds rated BBB- or lower

For obligations of non-government issuers the following limitations apply:

- AAA rated debt: a single issuer should account for no more than 5% of the portfolio.
- AA+, AA, AA- rated debt: a single issuer should account for no more than 3% of the portfolio.
- Debt rated A+ or lower: a single issuer should account for no more than 2% of the portfolio.

- No more than 10% of the portfolio may be invested in high yield and emerging market debt combined at any time.

A portion of the pension assets is invested in real estate funds to provide diversification, add return, and hedge against inflation. Real estate properties are illiquid, difficult to value, and not actively traded. The pension plan uses external real estate investment managers to invest in commingled funds that hold real estate properties. To mitigate investment risk in the real estate portfolio, commingled real estate funds are used to ensure that holdings are diversified by region, property type, and risk classification. Real estate holdings include core, value-added, and development risk classifications and some investments in Real Estate Investment Trusts (REITs), which are publicly traded real estate securities classified as Level 1.

A portion of the pension assets is invested in private equity. Private equity investments add return and provide diversification and typically require a long-term time horizon to evaluate investment performance. Private equity is classified as an alternative investment because it is illiquid, difficult to value, and not actively traded. The pension plan uses limited partnerships and commingled funds to invest across the private equity investment spectrum. Our private equity holdings are with six general partners who help monitor the investments and provide investment selection expertise. The holdings are currently comprised of venture capital, buyout, and hybrid debt and equity investment instruments. Commingled private equity funds are used to enhance the holdings' diversity.

We participate in a securities lending program with BNY Mellon to provide incremental income on idle assets and to provide income to offset custody fees and other administrative expenses. We lend securities to borrowers approved by BNY Mellon in exchange for cash collateral. All loans are collateralized by at least 102% of the loaned asset's market value and the cash collateral is invested. The difference between the rebate owed to the borrower and the cash collateral rate of return determines the earnings on the loaned security. The securities lending program's objective is providing modest incremental income with a limited increase in risk.

We hold trust owned life insurance (TOLI) underwritten by The Prudential Insurance Company in the OPEB plan trusts. The strategy for holding life insurance contracts in the taxable VEBA trust is to minimize taxes paid on the asset growth in the trust. Earnings on plan assets are tax-deferred within the TOLI contract and can be tax-free if held until claims are paid. Life insurance proceeds remain in the trust and are used to fund future retiree medical benefit liabilities. With consideration to other investments held in the trust, the cash value of the TOLI contracts is invested in two diversified funds. A portion is invested in a commingled fund with underlying investments in stocks that are actively traded on major international equity exchanges. The other portion of the TOLI cash value is invested in a diversified, commingled fixed income fund with underlying investments in government bonds, corporate bonds and asset-backed securities.

Cash and cash equivalents are held in each trust to provide liquidity and meet short-term cash needs. Cash equivalent funds are used to provide diversification and preserve principal. The underlying holdings in the cash funds are investment grade money market instruments including commercial paper, certificates of deposit, treasury bills and other types of investment grade short-term debt securities. The cash funds are valued each business day and provide daily liquidity.

Nuclear Trust Funds

Nuclear decommissioning and spent nuclear fuel trust funds represent funds that regulatory commissions allow us to collect through rates to fund future decommissioning and spent nuclear fuel disposal liabilities. By rules or orders, the IURC, the MPSC and the FERC established investment limitations and general risk management guidelines. In general, limitations include:

- Acceptable investments (rated investment grade or above when purchased).
- Maximum percentage invested in a specific type of investment.
- Prohibition of investment in obligations of AEP or its affiliates.
- Withdrawals permitted only for payment of decommissioning costs and trust expenses.

We maintain trust records for each regulatory jurisdiction. These funds are managed by external investment managers who must comply with the guidelines and rules of the applicable regulatory authorities. The trust assets are invested to optimize the net of tax earnings of the trust giving consideration to liquidity, risk, diversification and other prudent investment objectives.

We record securities held in these trust funds as Spent Nuclear Fuel and Decommissioning Trusts on our Consolidated Balance Sheets. We record these securities at fair value. We classify securities in the trust funds as available-for-sale due to their long-term purpose. When a security's fair value is less than its cost basis, we recognize an impairment as we do not make specific investment decisions regarding the assets held in these trusts. Impairments reduce the cost basis of the securities which will affect any future unrealized gain or realized gain or loss due to the adjusted cost of investment. We record unrealized gains and other-than-temporary impairments from securities in these trust funds as adjustments to the regulatory liability account for the nuclear decommissioning trust funds and to regulatory assets or liabilities for the spent nuclear fuel disposal trust funds in accordance with their treatment in rates. See the “Nuclear Contingencies” section of Note 6 for additional discussion of nuclear matters. See “Fair Value Measurements of Trust Assets for Decommissioning and SNF Disposal” section of Note 11 for disclosure of the fair value of assets within the trusts.

Comprehensive Income (Loss)

Comprehensive income (loss) is defined as the change in equity (net assets) of a business enterprise during a period from transactions and other events and circumstances from nonowner sources. It includes all changes in equity during a period except those resulting from investments by owners and distributions to owners. Comprehensive income (loss) has two components: net income (loss) and other comprehensive income (loss).

Components of Accumulated Other Comprehensive Income (Loss)(AOCI)

AOCI is included on our Consolidated Balance Sheets in our equity section. The following table provides the components that constitute the balance sheet amount in AOCI:

	December 31,	
Components	**2009**	**2008**
	(in millions)	
Securities Available for Sale, Net of Tax	$ 12	$ 1
Cash Flow Hedges, Net of Tax	(15)	(22)
Amortization of Pension and OPEB Deferred Costs, Net of Tax	35	12
Pension and OPEB Funded Status, Net of Tax	(406)	(443)
Total	$ (374)	$ (452)

Stock-Based Compensation Plans

At December 31, 2009, we had stock options, performance units, restricted shares and restricted stock units outstanding to employees under The Amended and Restated American Electric Power System Long-Term Incentive Plan (LTIP). This plan was last approved by shareholders in 2005.

We maintain career share accounts under the Stock Ownership Requirement Plan to facilitate executives in meeting minimum stock ownership requirements assigned to executives by the HR Committee of the Board of Directors. Career shares are derived from vested performance units granted to employees under the LTIP. Career shares are equal in value to shares of AEP common stock and do not become payable to executives until after their service ends. Dividends paid on career shares are reinvested as additional career shares.

We also compensate our non-employee directors, in part, with stock units under The Stock Unit Accumulation Plan for non-employee directors. These stock units become payable in cash to directors after their service ends.

In addition, we maintain a variety of tax qualified and nonqualified deferred compensation plans for employees and non-employee directors that include, among other options, an investment in or an investment return equivalent to that of AEP common stock.

In January 2006, we adopted accounting guidance for “Share-Based Payment” which requires the measurement and recognition of compensation expense for all share-based payment awards made to employees and directors, including stock options, based on estimated fair values.

We recognize compensation expense for all share-based awards with service only vesting conditions granted on or after January 2006 using the straight-line single-option method. In 2009, 2008 and 2007, we granted awards with performance conditions which are expensed on the accelerated multiple-option approach. Stock-based compensation expense recognized on our Consolidated Statements of Income for the years ended December 31, 2009, 2008 and 2007 is based on awards ultimately expected to vest. Therefore, stock-based compensation expense has been reduced to reflect estimated forfeitures. Accounting guidance for “Share-Based Payment” requires forfeitures to be estimated at the time of grant and revised, if necessary, in subsequent periods if actual forfeitures differ from those estimates.

For the years ended December 31, 2009, 2008 and 2007, compensation cost is included in Net Income for the performance share units, phantom stock units, restricted shares, restricted stock units and the director’s stock units. See Note 15 for additional discussion.