PUBLIC UTILITY COMMISSION
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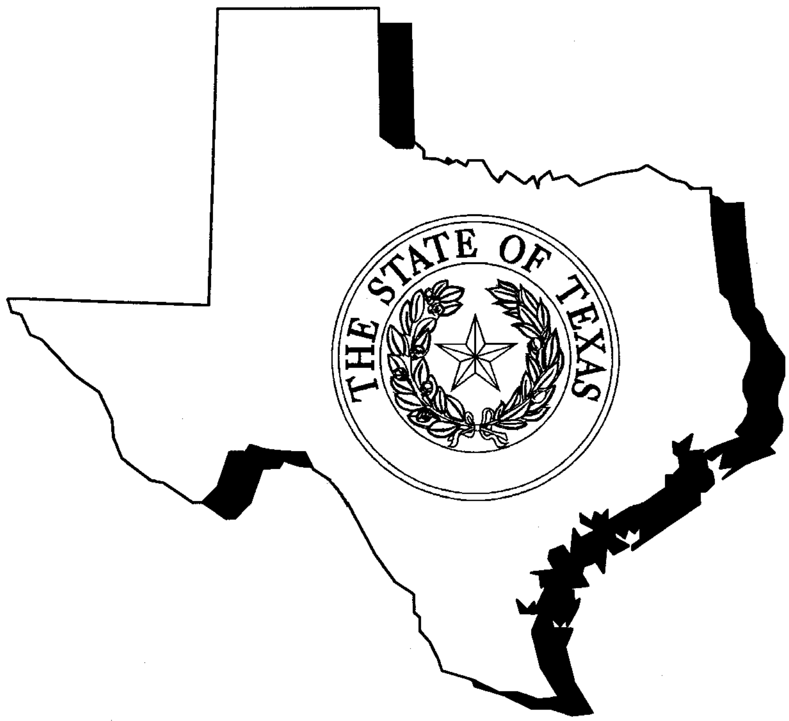

TRUE-UP PROCEEDING FORM
FOR ELECTRIC UTILITIES
FOR FILINGS PURSUANT TO §39.262
OF THE
PUBLIC UTILITY REGULATORY ACT

<u>GENERAL INSTRUCTIONS</u>

**TRUE-UP PROCEEDING FORM FOR ELECTRIC UTILITIES
PURSUANT TO §39.262
OF THE
PUBLIC UTILITY REGULATORY ACT**

General Instructions

1. This form is prescribed for the use of transmission and distribution utilities, affiliated retail energy providers, and affiliated power generation companies required to file the true-up proceeding pursuant to §39.262 of the Public Utility Regulatory Act (PURA). The objective of this report is to finalize and reconcile stranded costs with the amount of stranded costs estimated in the proceeding held under PURA §39.201. This report also provides a means to: recognize any difference in the price of power obtained through the capacity auctions and the power cost projections assumed in the ECOM model; account for the results of the annual reports; capture the true-up of price to beat revenues for customers who are paying the price to beat if market price is lower; review and make appropriate adjustments for regulatory assets per the provisions of PUC Subst. R. 25.263; and recover the final fuel balance.

2. Companies shall file this report with the Commission per the schedule set forth in PUC Subst. R. 25.263.

3. Companies shall file the true-up application with the Filing Clerk of the Commission's Central Records in accordance with Commission filing standards. The standards governing both hardcopy and electronic submissions are detailed in PUC Procedural Rules § 22.71 and § 22.72. A Microsoft Excel spreadsheet named "True-up Filing Schedules" has been provided with these instructions. The company shall file an electronic copy of this completed spreadsheet at the same time it files its printed true-up proceeding schedules. This spreadsheet shall be filed consistent with the Commission's electronic filing standards set out in §22.72(g) of the Procedural Rules. Each sheet of the Excel file is preformatted to calculate certain items based on company specific inputs. The schedules in the file entitled "True-up Filing Schedules" attempt to provide a complete listing of the basic schedules necessary for the true-up filing; however, if any schedules additional to those in the "True-up Filing Schedule" file are required for the utility's true-up filing, those schedules should be included.

4. Concurrent with the filing of the True-up Proceeding schedules, the reporting transmission and distribution utility must also separately file with the Commission three (3) complete sets of workpapers used in the preparation of the testimony and schedules, subject to the provisions of these instructions dealing with voluminous workpapers. In addition, one (1) complete set of the same workpapers shall be delivered to the Office of Public Utility Counsel on the date of filing. To the extent workpapers and any other supporting schedules are in Microsoft Excel format, all such schedules shall be filed electronically in Excel format with formulas, cell references, etc. intact.

a. Workpaper referencing format: The workpaper reference shall always begin with the characters "WP/" followed by the schedule to which the workpaper refers. Specific workpapers shall then be referenced by ascending numbers. The resulting series of workpapers shall have a pyramid structure, with the top workpaper (the workpaper with the least complicated reference, for example WP/A-1) being the workpaper which directly reflects the amounts shown on a particular schedule. The next level down the pyramid would contain information that explains a portion of the top workpaper. Each successive level down the pyramid would explain something from the next higher level.

b. Workpaper content: All assumptions, calculations, sources and data supporting the amounts included in the schedules shall be included in the workpapers supporting each schedule.

c. Workpaper location: All workpapers not considered voluminous shall be organized and appear in the same order as the schedules they support. All non-voluminous workpapers shall be provided in both hard copy format as well as electronic format.

d. Voluminous workpapers: For any supporting workpaper that consists of 500 or more pages and that cannot be provided in electronic format, the utility may designate such information as voluminous. All voluminous material shall be made available in a designated location in Austin on the date of filing. The utility shall deliver a copy of all voluminous materials to both the Commission staff and the Office of Public Utility Counsel on the day of filing the True-up Proceeding Schedules.

5. The filing should contain company testimony on **each schedule relevant and applicable to the company's application** and also on the issues identified in General Instruction #10. An executive summary containing an overview of the application should also be included.

6. Companies using either the Stock Valuation or Partial Stock Valuation methods shall provide the following additional information in testimony, schedules or workpapers:

a. Audited historical (2001, 2002 and 2003) financial statements and projected (2004) financial statements (e.g. income, balance sheet, cash flows) for the affiliated power generation company.

b. A summary of each power sales agreement between the affiliated power generation company and any existing or former affiliated companies, which includes but is not limited to the type of sale (e.g. bilateral, ancillary services, capacity auction, other), the amount capacity and energy sold by sale type, capacity, energy and other prices by sale type, revenues by sale type, expenses by sale type, and a demonstration that the prices charged for each sale type reflect market conditions.

c. Support for the affiliated power generation company's capitalization and dividend policy including actual and targeted capital structure, dividend to book ratio, and payout ratio.

d. Documents provided to investors, investment advisors and/or credit rating agencies pertaining to future earnings and cash flow prospects of the affiliated power generation company.

e. A description of any compensation received for any options, rights of first refusal or other rights granted to a former affiliate to acquire the stock.

f. A description and a best estimate of the quantification of the effects of all commercially reasonable means taken by the affiliated power generation company that are consistent with protecting and enhancing the value of assets and common equity.

g. A list of all affiliate transactions between the transmission and distribution utility, affiliated retail electricity provider, and the affiliated power generation company including: a description of the services provided, the method of compensation and evidence that the prices charged for each sale type reflect market conditions.

h. A description of any restrictions imposed on the affiliated power generation company by a current or former affiliate, such as prohibitions on asset sales and limitations on the amount of debt financing, the use of hedging or similar procurement processes and how these prohibitions and limitations are consistent with the exercise of normal business practices.

i. A description of how the stock of the affiliated power generation company that is traded in a national exchange was marketed to the public.

7. Companies using either the “Sale of Asset” or “Asset Exchange” methods shall provide in testimony, schedules, or workpapers the following additional information as may be applicable:

a. A schedule of each and every asset sold or exchanged including, but not limited to, all assets associated with the production of electricity, including generation plants, electrical interconnections of the generation plant to the transmission system, fuel contracts, fuel transportation contracts, water contracts, lands, surface or subsurface water rights, emissions-related allowances, gas storage facilities, gas pipelines and gas pipeline interconnections.

b. All documents provided directly to potential buyers including but not limited to: 1) Information Memoranda, prototype purchase sale agreements, management presentation documents, bid instructions for each round of bidding, notices of selection or elimination, and other correspondence (redacted, if necessary, to prevent identification of unsuccessful bidders); 2) an index of voluminous data; 3) an index (including the number of pages) of documents in the data room available to bidders; 4) instructions (in relation to #3) for obtaining access to the electronic data room or all documents in data room on CD; and 5) all bidders’ Q&A (provided in either written or electronic form).

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c. A general overview of the sale or exchange process, including a discussion of how the process is consistent with generally accepted practice regarding asset sales.

d. A copy of the request for proposal (RFP) or other document used to solicit competitive offers, including but not limited to:

i. Minimum opening bid or other mandatory terms and conditions

ii. Information provided to prospective bidders about the assets (e.g. book value, fuel contracts, projected operating costs, location on the ERCOT grid)

iii. Bidder qualifications.

iv. A description of the bidding process.

v. A list of the major milestones (e.g. time for submitting questions, bidders conference, time for submitting responses, announce shortlist, negotiations, final award, and closing date).

vi. A description of any encumbrances associated with an asset to be sold (e.g. identify parties having the rights of first refusal, long-term contracts, environmental and other liabilities, approval process for jointly-owned facilities).

vii. Identification of all mitigation measures designed to enhance the value of the asset.

e. A complete list of bids and associated terms and conditions that were compared in each round of bidding to select successful bidders. The only bidder names that must be matched to a specific final bid and terms are the *winning* bidders.

f. A description of the evaluation process, which includes a list all criteria for determining the best offer, identifies any bids that were rejected and the reasons for rejection, identifies all persons responsible for evaluation and decision-making, summarizes the sale terms and conditions, provides justification demonstrating that the timing of each asset sale would protect and enhance the sale price.

g. A description and a best estimate of the quantification of the effects of all commercially reasonable means taken by the affiliated power generation company to protect and enhance the value of the assets that were sold.

h. A copy of all submissions to the Commission related to an asset sale or asset exchange.

8. Companies proposing a Capacity Auction True-Up will provide the following additional information:

a. An electronic copy of the ECOM Model approved by the Commission in the UCOS case.

b. Workpapers supporting the actual busbar sales in 2002 and 2003 by generating unit.

c. The capacity rating and net energy generation by generating unit in 1999, 2000 and 2001.

d. Actual fuel costs by generating unit in 1999, 2000, 2001, 2002 and 2003.

e. Quantification of any nonrecurring fuel costs and any other fuel costs included in subpart (d) that do not meet the definition of "Eligible Fuel Expense" as defined in Substantive Rule §25.236(a).

9. Companies claiming stranded costs shall also provide detailed information on the amount of generation-related accumulated deferred federal income taxes, excess accumulated deferred income taxes, and investment tax credits as of 12/31/01 along with supporting workpapers (see Schedule IX).

10. The testimony accompanying this filing should support each and every schedule and workpaper, as applicable, and shall address, at a minimum, the following issues:

a. Compliance of the particular market valuation methodology used with the specific requirements set forth in PURA §39.262(h).

b. Compliance with PURA §39.252(d).

c. Support for any new regulatory assets to be included in this proceeding that were not previously determined to be prudent by the Commission in a prior rate case.

11. **Electronic files.** To the maximum extent possible, the testimony, schedules, and workpapers of the filing shall be provided to in an electronic format (e.g., diskette, CD ROM, or via electronic mail) on the date of filing. Any numerical data provided electronically shall be in Microsoft Excel on computer diskette or CD ROM.

12. **Confidentiality.** If the utility claims that requested information is confidential, a statement to that effect shall be included in the filing package in the schedule where the information is requested. The utility shall include a signed statement by its attorney that presents, for each schedule for which the utility claims that the requested information is confidential, the claimed reasons that the information should be treated as confidential. Further, the statement should indicate that the attorney has reviewed the information sufficiently to state in good faith that the information is confidential.

Until a protective order is issued, the utility shall provide the Commission or a party granted intervenor status the information claimed to be confidential if the party agrees to be bound by the draft protective order included at the end of these General Instructions as if it had been issued. Use of the draft protective order as a confidentiality agreement pending issuance of a protective order does not preclude issuance of a protective order that differs from the draft protective order contained in these instructions.

13. Companies without stranded costs and which are only required to file for the true-up of price-to-beat revenues and/or the final fuel reconciliation should complete only those relevant schedules of this filing package.

14. In addition to each portion of the filing that is attested to and sponsored by individual witnesses, each True-up Proceeding Filing shall contain a general attestation, by an officer or manager, under whose direction relevant portions of the filing are prepared, of each of the transmission and distribution utility, affiliated retail energy provider, and affiliated power generation company that is required to file this report.

15. If it is necessary to revise any schedule after the initial filing of the True-up, a new electronic version and four (4) printed copies of the report and any explanatory testimony shall be provided. The electronic version and all printed copies shall be labeled "revised" and include the date of revision. Additionally, a summary table should be included listing each revised schedule and an explanation of the change. Copies of all revisions and explanatory testimony should be provided electronically to the Commission Staff, the Office of Public Utility Counsel, and all intervenors.

CONFIDENTIALITY

This section shall include a signed statement by the utility's attorney that presents, for each schedule for which the utility claims that the requested information is confidential, the claimed reasons that the information should be treated as confidential and that states that the attorney has reviewed the information sufficiently to state in good faith that the information is confidential.

This section shall also contain a draft protective order for parties' use prior to the issuance of a protective order.

Schedule Instructions

Schedule I: Determination of True-up Amount

No inputs are required on this schedule.

This schedule will automatically determine the utility's true-up amount and true-up amount remaining to be collected/refunded, based on items calculated on other schedules.

Schedule I-A: Determination of Mitigation to be Refunded

No inputs are required on this schedule.

Line 1 shall reflect any market value in excess of book value. Amount is automatically displayed as a positive amount from calculations from other schedules.

Line 2 automatically reflects the mitigation amount due to redirected depreciation as determined on Schedule III-E.

Line 3 automatically reflects the excess earnings depreciation mitigation amount net of any amounts refunded in 2002 through 2004 as determined on Schedule III-F.
Line 4 automatically reflects the net mitigation of redirected depreciation and excess earnings after taking into account any refund of excess earnings mitigation in 2002 through 2004.

Line 5 automatically reflects mitigation to be refunded, which is the lessor of the net mitigation from Line 4 or the market value in excess of book value from Line 1. This results in the total refund being capped at the total amount of mitigation.

Schedule II: Comparison of Book Value to Market Value

No inputs are required on this schedule.

This schedule will automatically compare the utility's book value to market value, based on items calculated on other schedules. If Line 4 is positive, stranded costs that exist will be shown on Line 5. If Line 4 is negative, the market value in excess of book value will be shown on Line 6.

Schedule III: Summary of Net Book Value of Generation Assets to Include in True-up Determination

No inputs are required on this schedule.

This schedule will automatically determine the utility's net book value of generation assets to include in the true-up, based on items calculated on other schedules. The workpapers should include a schedule that matches the total net book value of generation assets with the total market value of those generation assets.

Schedule III-A: Net Book Value (Before Mitigation) of Generation Assets on Books as of 12/31/01

Line 1 column (a) reflects generation related electric plant in service by FERC Chart of Accounts (FCA) that is on the regulated books at 12/31/01. This amount must equal the amount reflected on the regulated balance sheet for the integrated utility or power generation company at 12/31/01. Plant in service will not include investment that is otherwise included in the affiliated TDU's Transmission Cost of Service (TCOS) and in the cost of service used to set the Tariff for Retail Delivery Service. Supporting workpapers will be provided to show that investments booked to FERC Accounts other than 310 through 346 are generation-related and to explain any differences between this filing and the generation-related amounts determined in the affiliated TDU's Unbundled Cost of Service (UCOS) filing pursuant to PURA §39.201.

Line 1 column (b) reflects generation related accumulated depreciation by FERC Chart of Account that is on the regulated books at 12/31/01. This amount should exclude any accumulated depreciation due to redirected depreciation or excess earnings depreciation. Accumulated depreciation will not include accumulated depreciation that is otherwise included in the affiliated TDU's TCOS filing and in the cost of service used to set the Tariff for Retail Delivery Service. Supporting workpapers will be provided to show that accumulated depreciation booked to FERC Accounts other than 310 through 346 is generation-related and to explain any differences between this filing and the generation-related amounts determined in the affiliated TDU's UCOS filing pursuant to PURA §39.201.

Line 2 reflects the net of Line 1(a) and Line 1(b), which results in Net Electric Plant in Service before the effects of mitigation.

Line 3 reflects any generation related Construction Work in Progress on the regulated books at 12/31/01.

Line 4 reflects any generation related Plant Held for Future Use on the regulated books at 12/31/01.

Line 5 reflects any nuclear fuel and nuclear fuel stock inventory on the books at 12/31/01.

Line 6 reflects any other generation-related assets at 12/31/01 not included above. Workpapers should fully describe and explain each type of other asset included.

Line 7 reflects net book value of generation assets before mitigation as of 12/31/01.

Integrated Utility or Generation Company balance sheets on a regulated basis as of 12/31/01 should be included as part of the workpapers. Workpapers should be provided for each fixed capital account in this summary (aggregate) schedule.

Schedule III-B: Environmental Expenditures Not Included in Book Value as of 12/31/01 but Incurred Through 5/01/03

Line 1 reflects all environmental expenditures that qualify under Section 39.263.

Line 2 reflects the amount of the qualified environmental expenditures that are included in the net book value of generation assets as of 12/31/01 (before mitigation).

Line 3 calculates the amount of environmental expenditures not included in book value as of 12/31/01 but incurred before 5/01/03.

A detailed schedule documenting the amounts and types of expenditures should be included as part of the workpapers

Schedule III-C: Deferred Debits as a Result of Discontinuing Application of SFAS No. 71

This schedule should include deferred debits that were recorded as a result of discontinuing application of SFAS No. 71. The deferred debits should be listed by category. Journal entries and supporting calculations should be included as part of the workpapers.

Schedule III-D: Summary of Above-Market Purchased Power Costs

No inputs are required on this schedule.

Based on items calculated on other schedules, this schedule will automatically determine the above-market purchased power costs.

Schedule III-D-1: Summary of Amount Utility Would Pay Third Party to Take Contract

No inputs are required on this schedule.

Based on items calculated on other schedules, this schedule automatically calculates the above market purchased power cost for each contract if the offer is structured as the amount the utility would pay third parties to take the purchased power contracts.

Schedule III-D-1-a, III-D-1-b, III-D-1-c: Amount Utility Would Pay Third-Party to Take Contract—Detail

This schedule should be prepared for each contract**. Three schedules have been provided, but additional schedules should be created if necessary.**

Line 1 should reflect the electric utility's Power Contract MW obligation.

Line 2 should reflect the MW obligation and above-market costs (i.e., lowest costs to the electric utility paying to relieve itself of the obligation) associated with each of the highest three offers for power under each existing purchased power contract.

Line 3 automatically adds up the MW obligations and above market costs associated with each offer.

Line 4 automatically calculates the weighted average cost of the highest three offers based on each offer's market cost and corresponding MW obligations. No input is required for this line.

Line 5 calculates the total above market cost for the contract based on the Line 4 weighted average costs and the unsold portion, if any, of the utility's power contracts obligation from Line 1.

Details of the purchased power contacts should be included as part of the workpapers.
All offers should be included as part of the workpapers.

<u>Schedule III-D-2: Summary of Amount Third-Party Would Pay Utility for Power under Contract</u>

No inputs are required on this schedule.

Based on items calculated on other schedules, this schedule automatically calculates the above market purchased power cost for each contract if the offer is structured as the amount the third party pays to take power under the purchased power contracts.

<u>Schedule III-D-2-a, III-D-2-b, III-D-2-c: Amount Third-Party Would Pay Utility for Power under Contract—Detail</u>

This schedule should be prepared for each contract. **Three schedules have been provided, but additional schedules should be created if necessary.**

Line 1 should reflect the electric utility's Power Contract MW obligation.

Line 2 should include the amount for wholesale demand and energy costs that a utility is obligated to pay under the existing purchased power contract. This amount should be the net present value of the obligation. The discount rate used in the net present value calculation should be the utility’s cost of capital approved in its unbundled cost-of-service proceeding. Details of the purchased power contacts should be included as part of the workpapers.

Line 3 reflects the MW purchase commitment and market value for each of the highest three offers for Line 1 demand and energy. All offers should be included as part of the workpapers.

Line 4 automatically displays sums of the MW purchase obligation and market value for each offer.

Line 5 is the weighted average of the three highest offers of Line 3 weighted by market value and MW purchase commitment. No input is required for this line.

Line 6 is the total market value of the contract based on the weighted value on Line 5 and any unsold MW from the utility's MW purchase obligation in Line 1. No input is required for this line.

Line 7 reflects the above market purchased power costs to include in the net book value of generation assets. No input is required for this line.

Schedule III-E: Redirected Depreciation—Net of Reversed Amounts

Line 1 reflects by year the utility's redirected depreciation for 1998 through 2001 pursuant to PURA Section 39.256.

Line 2 reflects by year the amount of redirected depreciation for 1998 through 2001 that has been reversed pursuant to commission order.

Line 3 automatically reflects the total redirected depreciation that has not been reversed. No input is required.

Supporting workpapers should be included. The information provided should include the docket numbers and relevant final-order excerpts from the proceedings that authorized the reversal of the redirected depreciation, and the dates on which the depreciation was reversed.

Schedule III-F: Excess Earnings Depreciation Mitigation—Net of Refunded Amounts

This schedule determines the amount of excess earnings depreciation that can be applied to reduce the net book value of generation assets.

Line 1 reflects by year the utility's excess earnings depreciation calculated pursuant to the annual report required under Section 39.257(b) for 1999 through 2001 and any excess earnings depreciation permitted pursuant to a transition plan in 1998. The amount shown should include adjustments made after December 31, 2001 (including adjustments due to annual report review). The amount shown should be the total excess earnings determined by the commission even if the commission has subsequently ordered the refund of excess earnings depreciation and precluded future excess earnings depreciation.

Line 2 automatically reflects the total excess earnings depreciation possible pursuant to the annual report. No input is required.

Line 3 through Line 5 reflects by year the amount of excess earnings depreciation in Line 2 that has been refunded (including return) to customers. 2002 and 2003 should reflect actual refunded amounts. 2004 should reflect an estimate of the refunded amounts through the projected date of the true-up final order.

Line 6 automatically reflects the total excess earnings depreciation that has been refunded. No input is required.

Line 7 is the difference between the amount of excess earnings depreciation possible and the amount of excess earnings depreciation refunded to customers. This difference is the amount of mitigation that has not been refunded and can be used to reduce net book value for the true-up.

The company’s final Annual Reports for 1998 through 2001 should be included as part of the workpapers.

Schedule III-G: Net Book Value of Nuclear Assets (if ECOM Model used)

This schedule should include the net book value of nuclear assets at 12/31/01 if nuclear assets are to be valued through the ECOM model.

Line 1 automatically reflects the net book value of generation assets before mitigation. No input is required.

Line 2 should reflect redirected depreciation applied to nuclear assets.

Line 3 should reflect excess earnings depreciation mitigation that has not been refunded to customers if applied to nuclear assets.

Line 4 automatically reflects the total net book value of nuclear assets to be included in the ECOM model. No input is required.

Schedule III-G-1: Net Book Value of Nuclear Assets before Mitigation (if ECOM Model used for valuation of nuclear assets)

Line 1 column (a) reflects nuclear related electric plant in service by FERC Chart of Account that is on the regulated books at 12/31/01. This amount must equal the amount reflected on the regulated balance sheet for the integrated utility or power generation company at 12/31/01.

Line 1 column (b) reflects nuclear related accumulated depreciation by FERC Chart of Account that is on the regulated books at 12/31/01. This amount must equal the amount reflected on the regulated balance sheet for the integrated utility or power generation company at 12/31/01.

Line 2 reflects the net of Line 1(a) and Line 1(b), which result in Net Electric Plant in Service

Line 3 reflects any nuclear related Construction Work in Progress on the books at 12/31/01.

Line 4 reflects any nuclear related Plant Held for Future Use on the books at 12/31/01.

Line 5 reflects any nuclear fuel on the books at 12/31/01.

Line 6 reflects any other generation-related assets sold that are not included above.

Line 7 reflects net book value of generation assets before mitigation as of 12/31/01.

Integrated Utility or Generation Company balance sheets on a regulated basis as of 12/31/01 should be included as part of the workpapers.

Schedule IV: Summary of Market Value of Generation Assets

No inputs are required on this schedule.

This schedule will automatically determine the market value of generation assets from all market value methods, based on items calculated on other schedules.

Schedule IV-A: Summary of Sale of Assets Method

No inputs are required on this schedule.

This schedule will automatically calculate the net value realized from all sales of assets.

Schedule IV-A-1, IV-A-2, IV-A-3: Sale of Assets Method--Detail

This schedule should be prepared for each sale transaction. **Three schedules have been provided, but additional schedules should be created if necessary.**

Line 1 should include any cash proceeds.

Line 2 should include any debt assumed by the buyer as part of the transaction.

Line 3 should list each type of other in-kind or non-cash compensation received as part of the transaction, including a copy of any agreements, indemnities, term sheets, or other explanation of the nature of each type of compensation.

Line 4 automatically calculates total sales proceeds from the transaction. No input is required.

Line 5 should list each transaction cost.

Line 6 automatically calculates the net value realized from the sale transaction. No input is required.

Detail and support for each sale should be included as part of the workpapers including a description of each asset sold, the sales price, and transaction costs related to the sale.

Schedule IV-B: Stock Valuation Method

This schedule should be prepared for each publicly traded corporation (transferee corporation) created pursuant to Section 39.262(h)(2).

Line 1 should include the total number of shares sold or spun off.

Line 2 should include the percent of shares sold or spun off.

The chart below Line 3 contains inputs for the closing stock price for the 120 consecutive trading days prior to the filing date.

Line 4 automatically calculates the highest resulting average daily closing price of the common stock over 30 consecutive trading days out of the last 120 consecutive trading days. The highest average is derived from all the possible consecutive 30-day averages automatically calculated on page 2 of this schedule (the bottom portion of the Excel sheet).

Line 5 reflects the total number of common stock shares for the publicly traded corporation.

Line 6 reflects the market value of the equity, which is the result of Line 4 average closing price multiplied by Line 5 total shares. No input is required.

Line 7 should reflect the amount of debt securities of the publicly traded corporation. The debt securities should be determined as the average debt balance over the same 30-day period used to determine the average stock price (i.e., for the same time period underlying the value on Line 4). Balance sheets that reflect as closely as possible the same 30-day time period should be included in the workpapers.

Line 8 should include the amount of preferred stock securities of the publicly traded corporation. The preferred stock securities should be determined as the average preferred stock balance over the same 30 days used to determine the common stock price (i.e., for the same time period underlying the value on Line 4). Balance sheets that reflect as closely as possible the same 30-day time period should be included in the workpapers.

Line 9 should include the net book value of assets acquired by the transferee corporation from an entity other than the affiliated electric utility or power generation company that should be subtracted from market value.

Line 10 is the market value determined through the stock valuation method.

Schedule IV-C: Partial Stock Valuation Method

This schedule should be prepared for each publicly traded corporation (transferee corporation) created pursuant to Section 39.262(h)(3).

Line 1 should include the total number of shares sold or spun off.

Line 2 should include the percent of shares sold or spun off.

The chart below Line 3 contains inputs for the closing stock price for the 120 consecutive trading days prior to the filing date.

Line 4 automatically calculates the highest resulting average daily closing price of the common stock over 30 consecutive trading days out of the last 120 consecutive trading days. The highest average is derived from all the possible consecutive 30-day averages automatically calculated on page 2 of this schedule (the bottom portion of the Excel sheet).

Line 5 reflects the total number of common stock shares for the publicly traded corporation.

Line 6 reflects the market value of equity, which is the result of Line 4 average closing price multiplied by Line 5 total shares. No input is required.

Line 7 should reflect the amount of debt securities of the publicly traded corporation. The debt securities should be determined as the average debt balance over the same 30-day period used to determine the average stock price (i.e., for the same time period underlying the value on Line 4). Balance-sheet information from the most recent quarter preceding the period reflecting the highest 30-day stock price average should be provided in workpapers. Additionally, monthly updates of the balance sheet and debt balances until the most recent month that overlaps—*i.e.*, extends beyond—the period reflecting the highest 30-day stock price average should be included in the workpapers.

Line 8 should include the amount of preferred stock securities of the publicly traded corporation. The preferred stock securities should be determined as the average preferred stock balance over the same 30 days used to determine the common stock price (i.e., for the same time period underlying the value on Line 4). Balance-sheet information from the most recent quarter preceding the period reflecting the highest 30-day stock price average should be provided in workpapers. Additionally, monthly updates of the balance sheet and preferred stock balances until the most recent month that overlaps—*i.e.*, extends beyond—the period reflecting the highest 30-day stock price average should be included in the workpapers.

Line 9 should include the net book value of assets acquired by the transferee corporation from an entity other than the affiliated electric utility or power generation company that should be subtracted from market value.

Line 10 is the market value determined through the partial stock valuation method for each publicly traded corporation.

Schedule IV-D: Exchange of Assets Method

List the market value of assets received through the Exchange Method. Include all supporting workpapers.

Schedule IV-E: ECOM Model Method—Stranded Cost Valuation of Nuclear Assets

This schedule should include the stranded-cost amount of nuclear assets calculated pursuant to the ECOM model if a market valuation method has not been used to value nuclear assets. ECOM model reports should be included as part of the workpapers.

Schedule V: Final Fuel Balance (Including Interest)

This schedule should include the final fuel balance from the fuel reconciliation approved in 2003 and interest on that balance through the projected date of the true-up final order, as calculated pursuant to the provisions of PUC Substantive Rule 25.263(h)(4).

Include all supporting workpapers.

Schedule VI: True-up of Capacity Auction Proceeds

Lines 1 through 4 should contain market-revenue data from the ECOM model underlying the company's UCOS ECOM estimate. Data for 2002 and 2003, lines 12, 13, and 14 from the "Plant Economics" worksheet of the ECOM model should be used as inputs.

Lines 5 through 8 should contain fuel data from the ECOM model's "Cost Partition" worksheet. Data from 2002 and 2003, lines 33, 34, and 35 should be used as inputs.

Line 9 should contain total busbar sales, by meter, per books for 2002 and 2003. Include a breakdown of the monthly busbar sales by unit and by capacity auction product and all other supporting workpapers. If this type of information is not available, please explain and demonstrate how the company can comprehensively assess its operations without the use of such detailed sales information, and why it is not necessary and prudent to compile and maintain a detailed record of relevant data.

Line 10 automatically calculates the average capacity auction price for 2002 and 2003 based on inputs to the bottom portion of the schedule. No input is required directly into line 10.

Line 11 automatically calculates the total capacity auction revenues for 2002 and 2003 based on the amounts from lines 9 and 10. No input is required directly into line 11.

Line 12 should contain the company's actual fuel costs per books for 2002 and 2003. Include a breakdown of monthly actual fuel costs, capacity rating and heat rate by unit and by capacity auction product, and all other supporting workpapers. As part of these workpapers, companies should include, for the period from 1/1/02 to 12/31/03, the daily gas prices as defined in PUC Subst. R. §25.381(c)(9) and, additionally, the Houston Ship Channel gas prices contained in the publication *Inside FERC* (as referred to in Schedule CA at Section K(2)(c)(ii)(B)(1)(a)(ii) of the stipulation in Docket No. 23744).

Line 13 automatically calculates the total amount of capacity auction true-up based on the amounts in lines 4, 8, 11, and 12. No input is required directly into this line.

The bottom portion of the schedule, under the heading "Capacity Auction Sales," should contain data from the company's capacity auctions held during the years 2002 and 2003. No input is required. Based on information in Schedule VI-A, the average capacity auction price is automatically calculated at the bottom of the schedule and carried over to line 10.

Schedule VI-A: Detailed Summary of All Capacity Auctions by Product

No inputs are needed for the capacity auction revenues shown in the first set of columns, which have amounts carried over from Schedule VI-B. In the second set of columns, include the MWh sales by month by capacity auction product. Separate rows are provided for the auctions conducted each trimester and for the one-year and two-year strips. The sum of Total Revenues and MWh sales of capacity auction products is carried over to Schedule VI.

Schedule VI-B: Detail of Capacity Auction Revenues

Include revenues derived from capacity payments, energy payments, and other revenues by month by capacity auction product. Separate rows are provided for the auctions conducted each trimester and for the one-year and two-year strips. The sum of the revenues by product for each auction is carried over to Schedule VI-A.

Schedule VI-C: General Summary of Capacity Auction Results

For each auction and for each auction product, input the number of entitlements offered, the number of entitlements sold, the fuel price (in $/MWh) for base load products, the minimum opening price (in $/kW), and the final sale price in ($/kW). A separate set of columns is provided for the auctions conducted each trimester and for the one-year and two-year strips. The workpapers accompanying this Schedule should show that the number of entitlements offered is consistent with PUC SR §25.381. This information should be consistent with the information provided prior to each auction and reported to the Commission.

Schedule VII: Summary of True-Up of Price-To-Beat Revenues (Retail Clawback)

No inputs are required on this schedule.

This schedule will automatically determine the total amount of the true-up of price-to-beat revenues, based on items calculated on other schedules.

Schedule VII-A: True-Up Of Price-To-Beat Revenues (Retail Clawback)—RESIDENTIAL Customers

Note: To the extent that final information for end-of-year 2003 and beginning-of-year 2004 is not yet available at the time the company files its report, the company should include in the filing its best estimate of the data and then provide finalized updates during the pendency of the proceeding.

Line 1 should reflect the residential Net **Price to Beat** in the ATDU Region in cents/kWh as of the last day of each of the eight quarters in the years 2002 and 2003. This price is the average residential PTB rate for 1,000 kWh per month (expressed in cents per kWh) less the average nonbypassable delivery charge for 1,000 kWh per month (expressed in cents per kWh) established under PURA Section 39.201 applicable to residential customers.

Line 2 shall reflect the residential Net **Market Price** in the ATDU Region in cents/kWh as of the last day of each of the eight quarters in the years 2002 and 2003. This price is the volume-weighted average price, less average nonbypassable charges (each expressed in cents per kilowatt-hour), calculated by the independent third party for residential electric service provided by non-affiliated retail electric providers and non-provider of last resort (POLR) service providers competing in the TDU region.

Line 3 automatically calculates the differential between Residential Net Price to Beat and Net Market Price.

Line 4 shall reflect the total kWh billed to residential PTB customers of the AREP for each of the eight quarters in the years 2002 and 2003.

Line 5 automatically calculates any excess revenues resulting from the excess of the PTB over the market price for each quarter multiplied by the total kWh consumed for that quarter. No input is required directly into this line.

Line 6 automatically calculates the total revenue differential for all eight quarters. No input is required directly into this line.

Line 7 should reflect the number of residential customers served by the AREP ***inside*** the ATDU region on 1/1/04.

Line 8 should reflect the number of residential customers served by the AREP ***outside*** the ATDU region on 1/1/04.

Line 9 automatically subtracts line 8 from line 7 and shows the net residential customers served by the AREP on 1/1/04. No input is required directly into this line.

Line 10 reflects the maximum per-customer charge of $150 that an AREP may credit an ATDU.

Line 11 automatically calculates the maximum amount that the AREP will credit the ATDU based on the net number of customers calculated in line 9 multiplied by the $150 maximum per-customer charge in line 10. No input is required directly into this line.

Line 12 automatically calculates the lesser of line 6 or line 11 as the actual amount that the AREP will credit the ATDU. No input is required directly into this line.

Schedule VII-B: True-Up Of Price-To-Beat Revenues (Retail Clawback)—SMALL COMMERCIAL Customers

Note: To the extent that final information for end-of-year 2003 and beginning-of-year 2004 is not yet available at the time the company files its report, the company should include in the filing its best estimate of the data and then provide finalized updates during the pendency of the proceeding.

Additionally, note that for purposes of this schedule, the term "small commercial customer" does not include unmetered lighting accounts unless such an account has historically been treated as a separate customer for billing purposes

Line 1 should reflect the small commercial Net **Price to Beat** in the ATDU Region in cents/kWh as of the last day of each of the eight quarters in the years 2002 and 2003. This price is the average small commercial PTB rate for 35 KW or 75,000 kWh per month (expressed in cents per kWh) less the average nonbypassable charges for 35 KW or 75,000 kWH per month (expressed in cents per kWh) established under PURA Section 39.201 applicable to small commercial customers.

Line 2 shall reflect the small commercial Net **Market Price** in the ATDU Region in cents/kWh as of the last day of each of the eight quarters in the years 2002 and 2003. This price is the volume-weighted average price, less average nonbypassable charges (each expressed in cents per kilowatt-hour), calculated by the independent third party for small commercial electric service provided by non-affiliated retail electric providers and non-provider of last resort (POLR) service providers competing in the TDU region.

Line 3 automatically calculates the differential between the small commercial Net Price to Beat and Net Market Price.

Line 4 shall reflect the total kWh billed to small commercial PTB customers of the AREP for each of the eight quarters in the years 2002 and 2003.

Line 5 automatically calculates any excess revenues resulting from the excess of the PTB over the market price for each quarter multiplied by the total kWh consumed for that quarter. No input is required directly into this line.

Line 6 automatically calculates the total revenue differential for all eight quarters. No input is required directly into this line.

Line 7 should reflect the number of small commercial customers served by the AREP ***inside*** the ATDU region on 1/1/04.

Line 8 should reflect the number of small commercial customers served by the AREP ***outside*** the ATDU region on 1/1/04.

Line 9 automatically subtracts line 8 from line 7 and shows the net small commercial customers served by the AREP on 1/1/04. No input is required directly into this line.

Line 10 reflects the maximum per-customer charge of $150 that an AREP may credit an ATDU.

Line 11 automatically calculates the maximum amount that the AREP will credit the ATDU based on the net number of customers calculated in line 9 multiplied by the $150 maximum per-customer charge in line 10. No input is required directly into this line.

Line 12 automatically calculates the lesser of line 6 or line 11 as the actual amount that the AREP will credit the ATDU. No input is required directly into this line.

Schedule VIII: Summary of Regulatory Assets

No inputs are required on this schedule.

This schedule will automatically determine the utility's regulatory assets to be included in the true-up amount, based on items calculated on other schedules.

Schedule VIII-A: Regulatory Assets That Exceed The Amount Approved in a Rate Order

If as part of a Financing Order, all issues regarding recovery of regulatory assets have been fully resolved, this schedule does not apply. Include a copy of Financing Order in workpapers.

This schedule should list out each regulatory asset amount that was included in a transition charge not previously included in a rate order effective on or before September 1, 1999. The Line 6 disallowance amount should be assumed to be zero until after commission review. Detail of the costs should be included as part of workpapers.

Schedule VIII-B: Regulatory Assets On Books as of 12/31/98 Not Covered Under a Financing Order

This schedule should list out each regulatory asset amount on the books as of 12/31/98 not previously covered by a Financing Order. Detail and support of each regulatory asset amount should be included as part of workpapers.

Schedule IX: Tax Information Related to Generation Assets as of 12/31/01

Provide detailed information on the amount of generation-related accumulated deferred federal income taxes, excess accumulated deferred income taxes, and investment tax credits as of 12/31/01. Provide supporting workpapers in your filing.