While AIU alleges that this calculation assumes that Ameren will consistently borrow up to its sublimit over the life of the Illinois Facility, Staff opines that without this adjustment, AIU, and ultimately AIU customers, would pay costs associated with more credit facility capacity than it would have available if Ameren borrows more than $165 million under the Illinois Facility, which Staff notes occurred during July and August 2009.

While AIU asserts that Staff's methodology does not recognize that Ameren may borrow under the facility to provide AIU supplemental liquidity by acting as its "lender of last resort," Staff avers that this argument does not support AIU's claim that AIU should pay costs associated with the $135 million borrowing capacity that either AIU or Ameren could borrow. Staff opines that the AIU argument applies only to borrowing capacity over the aggregate AIU sub-limit of $635 million because, under the Illinois Facility, Ameren pays a higher short-term bank loan rate than any of the AIUs due to its Baa3/BBB- unsecured debt ratings from Moody's and S&P. Staff states it is clear the Commission's rules for utility money pool agreements prohibits utilities borrowing from affiliates whenever utilities may borrow at lower cost directly from banks or other financial institutions.

Although AIU argues that Ameren has access to $1.3 billion of credit facilities outside the Illinois Facility at a rate that is slightly lower than the rate it can borrow from the Illinois Facility, giving it a financial incentive to borrow from the other facilities, Staff opines that this wrongly implies that Ameren can borrow $1,150,000,000 – its entire sub-limit under the Missouri Facility – for the entire two-year term of the Missouri Facility at lower cost than Ameren can borrow from the Illinois Facility. Staff states that AIU fails to note that these lower borrowing costs are available only from "Declining Lenders" through July 14, 2010. Staff states that "Declining Lenders" are those lenders under the original Missouri Facility that declined the option to extend their original commitments beyond July 14, 2010.

Staff avers that amending and restating the 2006 and 2007 Illinois credit facilities would have benefited AIU by making lower borrowing rates available from Declining Lenders, citing the fact that under the prior facility's pricing schedule, the spread over LIBOR for a Level III borrower equals 0.60%, while the current spread over LIBOR for a Level III borrower equals 2.75%. Despite that, Staff notes that Ameren terminated the 2006 and 2007 Illinois credit facilities seven months before they expired.

Staff avers that Ameren is not obliged under any agreement to provide AIU supplemental liquidity, and in fact, Ameren has taken steps to insulate itself from AIU when the Illinois legislature was considering rate freeze legislation by removing AIU as borrowers under Ameren's credit facility and removing provisions from the credit agreement that would treat AIU as subsidiaries for purposes of cross-default provisions.

Staff opines that AIU ignores the rationale for a commitment fee, which as its name implies, compensates banks for making a firm commitment to provide up to a specified amount of credit on demand. Staff argues that the full commitment fee applies regardless of the amount of money borrowed or letters of credit issued by each borrower. Staff argues that because of the overlapping sublimits in the Illinois Facility, the commitment available to AIU is a function of the amount of credit already committed to Ameren, which means AIU can only count on $500 million of the Illinois credit facility, not the $635 million of its combined sublimits would otherwise suggest.

While AIU argues that adjusting the facility fee rates for AmerenCIPS and AmerenIP in response to Moody's ratings upgrades for AIU on August 13, 2009, is improper, Staff notes that prior to the August 2009 rating upgrade by Moody's, AmerenCIPS was a Level III borrower, and AmerenIP was a Level IV borrower. Staff argues that the Moody's upgrade did not change AmerenCIPS' Level III borrower status, but instead raised AmerenIP's borrower status to Level III from Level IV.

Staff disputes AIU's argument that using AmerenIP's current senior secured credit rating is a selective adjustment to the cost of capital. Staff explains that the adjustment is not the consequence of an out-of-measurement period change in capitalization, such as the issuance of new debt or common equity, the retirement of debt, or the payment of common dividends. Staff notes that selective capital structure adjustments such as those would be improper because they wrongly imply those events occur in isolation. Staff avers that while facility fees will change during the term of the credit agreement as each borrower's credit rating changes, the change in the fee rate does not significantly affect the amount of capital the utility needs to maintain. Staff argues that adjustable facility fee rates are similar to variable interest rates, which the Commission has estimated using current rates rather than those that were in effect during a historical measurement period. Staff further notes that if AIU's argument had any merit, then AIU cost of capital could not reflect any costs associated with the 2009 Illinois Facility because AIU was a borrower under the 2006 and 2007 credit facilities on the capital structure measurement dates.

3. Commission Conclusion

The Commission notes that the principal difference between the parties on this issue is that AIU weights each individual company's allocation in proportion to total borrowing sublimits, while Staff does not. AIU argues that the effect of this is that under Staff's approach, the three utilities could borrow 79.4% of the available facility, while bearing responsibility for only 62.5% of the associated bank commitment fees. AIU states that Staff assumes that utility borrowing would be limited to 62.5%, when there is no such strict limitation on AIU. AIU argues that the more reasonable approach is that of AIU: weight the allocation based on sublimits. Under AIU's approach, the utilities bear 67.9% of the commitment fees, while being able to borrow between 62% and 79.4% of the facility. Staff takes the position that to allocate 67.9% of the commitment fees to AIU has the potential of subsidizing Ameren, should Ameren choose to borrow its maximum of $300 million of the credit facility. As this would leave only $500 million available to borrow by AIU, such a borrowing by Ameren would cause AIU to pay a greater portion of the commitment fees than allowed by Section 9-230 of the Act. The Commission is rightfully concerned that the ratepayers of AIU not subsidize the cost of

Ameren's borrowing, and therefore the Commission will adopt Staff's proposal on this issue.

The Commission will also adopt Staff's adjustment to reduce the amount of fees associated with the Illinois Facility. Staff postulates that there were no benefits to jointly negotiating that Facility with the Missouri Facility and that the allocation of overall costs to the Illinois Facility was too high. The Commission finds Staff's arguments on this issue convincing, and will adopt Staff's proposed facility fee adjustments for the purposes of this proceeding.

F. Cost of Short-Term Debt

1. AmerenCILCO

AmerenCILCO maintains that its cost of short-term debt is 2.15%. As AmerenCILCO does not have any short-term debt currently outstanding, the cost of short-term debt was calculated in accordance with the terms of the source of AmerenCILCO’s last short-term borrowing—its credit facilities. AmerenCILCO states the cost is the sum of the April 30, 2009 one-month LIBOR and the applicable margin, which is based on both AmerenCILCO’s current senior secured credit ratings (Baa2/BBB+) and the current utilization of the facility at the time of the loan. Staff proposed in its Initial Brief a cost of short-term debt for AmerenCILCO of 2.5%, however in its Reply Brief, Staff recommended a cost of short-term debt of 2.15%, in accordance with the recommendation of AmerenCILCO. As the parties appear to be in agreement on this issue, the Commission will adopt a cost of short-term debt for AmerenCILCO of 2.15% for purposes of this proceeding.

2. AmerenCIPS

Staff and AIU agree that AmerenCIPS’ cost of short-term debt equals 1.50%. Staff calculated AmerenCIPS’ weighted cost of short-term debt based on the proportion of AmerenCIPS’ borrowings at a bank loan rate of 3.02% and an internal money pool rate of 0.19%. In her Direct Testimony, Ms. Phipps stated that during the short-term debt period, 46% of the Company’s short-term borrowings were at the bank loan rate and 54% were at the internal money pool rate. Thus, Ms. Phipps maintains the weighted average interest rate for AmerenCIPS' short-term debt equals 1.50%. While AmerenCIPS disagreed with Ms. Phipps' reasoning for not including upfront facility fees in A&G expenses, Mr. O’Bryan accepted her general methodology for the calculation of the costs and the addition of these costs as a direct adder to AmerenCIPS’ of capital. AmerenCIPS does not contest Staff’s adjustments, as the updated weighted average cost of capital schedule in Ameren Ex. 37.1 reflects a 1.50% weighted cost of short-debt for AmerenCIPS. The Commission finds that the parties agree that an appropriate cost of short-term debt for AmerenCIPS is 1.50%. The Commission finds this amount to be reasonable and it will be adopted for the purposes of this proceeding.

3. AmerenIP

Staff and AIU agree that AmerenIP's cost of short-term debt equals 3.02%. AmerenIP does not contest Staff's adjustments, as the updated weighted average cost of capital schedule in Ameren Ex. 37.1 reflects a 3.02% weighted cost of short-debt for AmerenIP. The Commission finds that the parties are in agreement that the cost of short-term debt for AmerenIP is 3.02%. The Commission finds this amount to be reasonable and it will be adopted for the purposes of this proceeding.

G. Cost of Common Equity

1. AIU Position

a. Return on Equity Estimates

AIU witness McShane recommends for the gas operations of AmerenCILCO, AmerenCIPS, and AmerenIP, the cost of common equity is 11.2%, 10.8%, and 11.2%, respectively. For the electric operations, the recommended cost of common equity is 11.7%, 11.3%, and 11.7%, respectively.

AIU notes that Staff, IIEC, and CUB have also recommended costs of common equity. Staff calculates costs of equity for the gas operations as 9.64% for AmerenCILCO, 9.38% for AmerenCIPS, and 9.64% for AmerenIP. For electric delivery service operations, Staff recommends costs of common equity of 10.38% for AmerenCILCO, 10.14% for AmerenCIPS, and 10.44% for AmerenIP. IIEC proposes a combined ROE of 10.0% for AIU that reflects AIU's actual combination gas and electric investment fundamentals, while AG/CUB calculates that the cost of common equity for AIU's electric operations is 8.76% and the cost of common equity for AIU's gas operations is 7.97%.

AIU notes that each party bases its analysis on a sample group for the respective service because AIU's operations should reflect the risk profile and cost of equity of comparable utilities. For AIU's gas operations, Ms. McShane selected a sample of nine comparable gas local distribution companies ("LDCs") according to certain criteria specified in her Testimony. For AIU's electric operations, Ms. McShane selected a sample of 29 electric utilities according to similar criteria specified in her Testimony. Staff witness Freetly uses the same gas sample as Ms. McShane and a subset of her electric sample. IIEC witness Gorman and CUB witness Thomas both rely on the same electric and gas proxy groups as Ms. McShane.

In its Reply Brief, AIU argues the Commission's January 21, 2010 decision in the Peoples/North Shore rate case, Docket Nos. 09-0166/09-0167 (Cons.) supports AIU's suggested use of a constant growth discounted cash flow ("DCF") model and argues that the Commission should follow its reasoning as expressed in that Order.

b. DCF and CAPM Model Issues

AIU notes that Ms. Freetly and Mr. Gorman criticize the use of the comparable earnings test for determining the cost of equity, while Mr. Thomas asserts that the Commission has rejected the comparable earnings method in the past. AIU asserts that this criticism misinterprets Ms. McShane's use of the comparable earnings test in her cost of equity analysis. AIU argues that Ms. McShane agrees that the comparable earnings test does not measure the investor's opportunity cost of attracting equity capital as measured relative to market values; therefore she does not use the comparable earnings test to actually determine the cost of equity. Rather, AIU asserts that the comparable earnings test provides a measure of the fair return based on the concept of opportunity cost, and the returns earned by relatively low risk unregulated companies provide a relevant perspective on the reasonableness of the recommended ROE. AIU argues that the results of its comparable earnings test here indicate that AIU's proposed returns on equity, as calculated by the DCF and equity risk premium tests, are conservative when compared to the earnings level of relatively low risk unregulated companies.

AIU avers that Ms. Freetly's use of a multi-stage non-constant-growth quarterly DCF model is a departure from Staff's typical model – a constant-growth, single-stage, DCF model. AIU argues that this departure is not warranted in this case because analysts' forecasts are indeed the most objective measure of investor expectation embedded in the stock prices and dividend yields used to estimate the DCF cost of equity. AIU opines that Ms. Freetly admits she has previously relied on a constant-growth DCF model when analysts' consensus forecasts were higher than the forecast long-term growth in the economy. AIU states Ms. Freetly's use of the average of the constant growth and the three-stage DCF models, rather than the results of the three-stage model alone, recognizes the imprecision of the period during which investors might expect analysts' forecast growth rates to persist.

c. Growth Rates

AIU notes that Ms. McShane relies on three DCF estimates: (1) a constant growth model that relies on analysts' earnings forecasts; (2) a sustainable growth model; and (3) a multi-stage model that includes both analysts' forecasts and nominal GDP growth as proxies for longer-term growth. AIU argues that because she weighs all three estimates, she incorporates a potential range of utility investor expected returns.

AIU observes that Ms. Freetly applies a multi-stage non-constant-growth quarterly DCF model to both her gas and electric samples, with her DCF analysis using three stages of dividend growth. AIU avers that Ms. Freetly's use of a multi-stage non-constant-growth quarterly DCF model is a departure from Staff's typical model, the constant growth (single stage) DCF model. AIU argues that Staff has not typically used a non-constant growth DCF model because it is more elaborate and has additional unobservable growth rate variables. AIU notes that Ms. Freetly argues that the levels of growth indicated by the average three- to five-year growth rates for her samples here are not sustainable over the long-term, largely because the analysts' growth forecasts for the samples are higher than the current growth expectations for the economy.

AIU opines that this departure is not warranted in this case, and argues that analysts' forecasts are the most objective measure of investor expectations that are embedded in the stock prices and dividend yields used to estimate the DCF cost of equity. AIU further notes that Mr. Freetly testified she has previously relied on a constant growth DCF model when analysts' consensus forecasts were higher than the forecast long-term growth in the economy. Ms. Freetly also uses a constant growth DCF test to develop her equity risk premium model; therefore AIU submits that if a constant growth DCF model is appropriate for the equity risk premium model, it is also appropriate for developing an expected return.

AIU avers that use of the average of the constant growth and the three-stage DCF models, rather than the results of the three-stage model alone, recognizes the imprecision of the period during which investors might expect analysts' forecast growth rates to persist and avoid potentially internally inconsistent results. As the multi-stage model can also create inconsistencies in the DCF cost estimates for the individual companies, AIU opines that it is more reasonable to give equal weight to the results of both the constant growth and multi-stage models.

AIU notes that in the final stage of her multi-stage DCF analysis, Ms. Freetly uses forward yields on the 20-year U.S. Treasury bonds as a proxy for long-term GDP growth, stating that the changes in the U.S. Treasury bond yield indicate that investors' current long-term expectations vary over time. Ms. Freetly argues the yield on U.S. Treasury bonds is a timely gauge of expected long-term economic growth because it reflects changing investor expectations due to current economic conditions, and posits that long-term forecasts, from which Ms. McShane implies that investor expectations of long-term growth are essentially static, might not be often updated.

While AIU admits Ms. Freetly is correct that the Blue Chip long-term consensus forecast of GDP growth extends only ten years, and that some long-term GDP forecasts are updated only annually or infrequently, AIU submits her arguments do not support the use of forward interest rates as a proxy for long-term GDP growth. AIU argues there is no basis to conclude that investors will not rely on forecasts of GDP over the next ten years as the best available estimate for very long-term growth and the stability of the Blue Chip ten-year consensus forecasts of GDP growth likely represents the expected reversion of growth to trend levels. AIU avers that compared to forward yields, it is more appropriate to use a direct estimate of long-term economic growth as provided by the consensus of economists' forecasts.

AIU opines that there are too many influences to conclude that the forward 20-year U.S. Treasury yield is a good proxy for investor expectations of long-term growth of the economy, with such factors as global influences on interest rate, high demand for U.S. securities, and the global savings glut putting downward pressure on U.S. Treasury bond yields. AIU notes that although the difference between the specific implied forward yield on the 20-year U.S. Treasury and the most recent consensus forecast of long-term economic growth is relatively small, the capital market experience over the past two years shows the differential can be substantial.

AIU avers that Ms. McShane applies an average daily stock price over a relatively short period of time when applying the DCF test, which Ms. Freetly criticizes and instead advocates a “spot” stock price. AIU opines that the price of a stock can rise or fall temporarily on any given day. AIU argues that “spot” stock prices are typically combined with a corresponding growth rate forecast, which may have been prepared and disseminated earlier, which may lead to a mismatch between the price and investor growth expectations – and thus, an erroneous DCF cost. AIU submits that the preferable price for the DCF test is an average daily price over a relatively short period of time.

AIU notes that Mr. Gorman employs three DCF models, a multi-stage model, a sustainable growth model, and a constant growth model, in which he gives his DCF and CAPM tests equal weight. AIU states that because he argues that AIU is a combination utility – a combined risk reflected in its bond rating, its operating risk, and the operating risk considered by its bond holders and equity holders – he recommends a single ROE to reflect this combined risk.

AIU disputes that because AIU is a combination of gas and electric utilities, the same cost of equity should apply to each of its operations. AIU opines that the return allowed for the electric utility operations should reflect the cost of equity for electric utility operations, and the same for the gas operations. AIU submits this combination results in cross-subsidies, erroneous investment decisions, and a misallocation of capital resources. AIU states that Staff agrees with AIU that the gas and electric operations should be considered separately to assign the proper ROR for each entity based on the level of operating and financial risk specific to the operations of each company.

While Mr. Gorman’s initial sustainable growth DCF study ignored the external growth component, AIU notes that Mr. Gorman updated his sustainable growth model to add the component, but argue he failed to estimate it correctly, incorrectly assuming book values per share will increase while stock prices stay the same. AIU submits that Mr. Gorman’s incorrect assumption about stagnant stock prices leads him to incorrectly conclude that the external growth component of the sustainable growth model is negative for the electric sample and minimal for the gas sample.

While Mr. Gorman criticizes the dividend yield in Ms. McShane’s constant growth DCF studies based on his view that her dividend yields are abnormally high, AIU notes that during much of the five-year period of dividend yields he compares to recent years, the cost of capital was abnormally low, characterized by easy credit, low economic volatility, and a relatively high investor tolerance for risk. AIU submits that the landscape has since been altered by the financial crisis of 2008-2009, and the current dividend yields, therefore, are more representative of its historic average levels.

AIU notes that Mr. Gorman also challenges Ms. McShane's constant growth DCF because he believes it includes irrationally high growth, and thus, unreasonably inflates AIU's ROE. Although Mr. Gorman argues that short-term analysts' growth rates in the market today are too high to be reasonable estimates of sustainable long-term growth, AIU avers that he is incorrect as analysts do not make forecasts beyond five years, and therefore, it is not possible to determine whether investors implicitly expect the forecast growth rates to continue indefinitely and when any decline, if any, may occur. Accordingly, AIU submits the constant growth DCF model is the only model that fully retains the only objective evidence of investors' growth expectations.

AIU states that Mr. Thomas uses a three-stage DCF test, with the three stages being for the short-term that the sample companies will grow at their average internal growth rate over the last five years, for the long-term that growth for the sample companies will trend toward the historical average growth rate in real GDP, and in the final stage he uses a forecast of real economic growth, rather than nominal growth. AIU opines that Mr. Thomas' choice of historical period for the first stage is purely subjective and not related to investor expectations embedded in current stock prices, while with respect to the long-term growth rate; his use of a real rate of growth fails to consider that investors require both a real return and compensation for inflation. AIU argues that the studies do not suggest that the actual nominal rate of long-term growth has been equal to the real rate of growth in the economy or that the expected nominal rates of long-term growth should be equal to the real rate of growth in the economy, and do not support using a real rate of GDP growth as a proxy for investors' expected long-term growth.

AIU states that Mr. Thomas recommends that the Commission place less reliance on analysts' forecasts of growth in the DCF calculation. AIU avers that Mr. Thomas argues that, due to discontinuity in the equity markets and uncertainty in information, the Commission should base its analysis of the DCF growth component on three criteria: (1) earnings growth rate inputs that are reasonable in light of anticipated growth in GDP; (2) the long-term growth rate must not implicitly require continued earnings above the regulated firm's cost of equity, as derived in the analysis; and (3) the long-term growth rates must not require dividend payout ratios that are not consistent with the capital expenditure growth rate and the ROE. AIU opines that Mr. Thomas argues incorrectly that current analysts' three- to five-year growth projections do not meet these criteria, but rather, he asserts that research demonstrates analysts tend to be optimistic about future growth and produce upwardly-biased forecasts, which translate into DCF costs of capital above the true required cost of capital. While Mr. Thomas states that Ms. McShane's proposed growth rates would require that the sample companies exceed their own historic growth, AIU notes that the Commission has not previously accepted this argument. AIU argues that the studies that Mr. Thomas cites to support his opinion that analysts are optimistic about future growth rates are less applicable to utilities, and utilities can not expect similar results. AIU avers that Ms. Freetly agrees these studies tend to report generalized findings and do not specifically suggest that growth rates for utilities are overstated relative to achieved growth, further noting that other studies indicate that analyst growth rate estimates for utilities are not overstated.

AIU submits that Mr. Thomas' proposed ROE is not comparable to any cost of equity or return granted by other regulators, which is significant because the national average allowed ROE can be interpreted as a consensus assessment of the expert testimony that has been proffered by a wide range of stakeholders. AIU avers that the national average allowed ROE is a relevant indicator of the capital markets in which AIU will have to compete for capital. AIU opines that returns at the levels proposed by Mr. Thomas are significantly below any reasonable indicator of the returns investors expect to receive on investments of comparable risk, and would not allow the utilities to attract capital as required on reasonable terms or meet the comparable returns standard.

d. Beta

AIU notes that both Ms. McShane and Mr. Gorman apply Value Line (adjusted, weekly) betas to their CAPM analyses, while Ms. Freetly recommends equally weighing weekly and monthly betas, contending that neither weekly nor monthly betas are superior to the other. AIU avers that Ms. Freetly explains that the better type of beta estimate is unclear because both Value Line and regression betas are estimates of the unobservable true beta that measures investors' expectations of the quantity of non-diversifiable risk inherent in a security. AIU opines that Ms. Freetly states that her method has been regularly used by both Staff and the Commission and employs the same monthly frequency of stock price data as the widely accepted Merrill Lynch methodology, while the Commission has rejected Ms. McShane's position in a prior proceeding.

AIU states that Ms. Freetly recognizes the strengths of weekly betas, but notes she asserts that weekly and monthly betas have strengths and weaknesses relative to each other, while recognizing that the standard deviation of weekly beta estimates is typically lower than for monthly beta estimates, making weekly betas usually more reliable. AIU avers Ms. Freetly incorrectly argues that non-synchronous trading is a problem with Ms. McShane's weekly data, but not for monthly data.

AIU asserts Ms. Freetly is incorrect when she asserts that non-synchronous trading is a problem with weekly betas. AIU states the non-synchronous trading effect arises when stock prices respond to economic events with a lag, which is a particular problem when analyzing daily data collected on thinly-traded stocks. AIU argues it is not a problem here because the companies are not thinly traded. Moreover, AIU avers that Ms. Freetly's analysis that portends to show a statistically-significant negative relationship between the lagged returns on the gas utilities and the returns on the equity market composite may actually relate more to the market conditions during the financial crisis than to non-synchronous trading issues. AIU opines that Ms. Freetly's calculation of the coefficient of variation for the monthly and weekly series of returns does not indicate that there is increased random error in the weekly series relative to the monthly series, but rather, higher coefficients of variation associated with weekly betas are consistent with higher weekly betas.

Staff argues that changes in risk can bias the beta estimate, asserting a decrease in a company's systematic risk can increase its estimated beta. Therefore, Staff avers that given the long time period examined in this case, one can not conclude that the Value Line betas underestimate actual returns or that using monthly returns would have further underestimated the actual returns for gas and electric utilities from those implied betas because the relatively high returns could be a consequence of declining systematic risk. AIU submits that greater confidence can be placed in weekly betas because weekly betas are less likely to be impacted by the presence of outlying observations, noting that weekly betas have five times as many observations, diluting the impact of observations that are outliers. AIU argues that regression betas calculated by Staff using monthly data have consistently been lower than the Value Line weekly betas, arguing that its analyses conclude that much greater confidence can be placed in weekly betas.

AIU notes that as Ms. McShane agrees that the calculated beta may decrease when "true" systematic risk is rising and may increase when "true" systematic risk is falling, she therefore compares a series of calculated betas for both the gas distributors and electric utilities to the average returns to assess whether, over time, the actual returns were in line with what the betas would have predicted. AIU avers that she concluded that the adjusted weekly Value Line betas underestimated the actual returns for both the gas distributors and electric utilities. While Staff faults Ms. McShane's analysis comparing weekly and monthly betas, AIU opines that Staff is incorrect in emphasizing Ms. McShane's report of the coefficient of determination ("R^2") and the statistical significance test and downplaying Ms. McShane's comments regarding the standard error, as AIU submits that standard errors are consistently lower and confidence intervals are consistently narrower for weekly betas, than monthly.

AIU states that Mr. Thomas recommends unadjusted, not Value Line, betas, asserting there is no evidence to support the rationale for the argument that utility betas trend toward the market mean of 1.0, citing financial literature purporting to demonstrate that the mean reversion adjustment is inappropriate and overstates the beta parameter. AIU notes that Mr. Thomas calculates corrected betas by removing the adjustment for each of the companies in his sample group, which AIU submits is incorrect. AIU avers there is significant empirical evidence indicating that "raw" or unadjusted betas underestimate the returns of low beta stocks and overestimate returns of high beta stocks, stating the adjustment corrects for the empirically observed relationships between betas and returns. AIU notes that Mr. Thomas admits that the Commission has accepted a static beta adjustment in the past, although Mr. Thomas argues there is absolutely no evidence that a one-size fits all adjustment is reasonable. AIU notes that Staff agrees betas should be adjusted, stating that the texts cited by Mr. Thomas concedes that adjustments result in appreciably better forecasts, and further noting that Mr. Thomas' proposal has been explicitly rejected in prior rate cases.

e. Market Risk Premium

AIU states that the CAPM requires determining the equity risk premium required for the market as a whole, and then adjusting it to account for the risk of the particular security or portfolio of securities using the beta. AIU notes the result (market risk premium multiplied by beta) is an estimate of the equity risk premium specific to the particular security or portfolio of securities, and the required market risk premium varies with the outlook for inflation and other economic and capital market conditions, interest rates, investors' willingness to bear risk, and profits.

AIU opines that required expected market risk premium ("EMRP") can be developed from estimates of prospective market risk premiums and from an analysis of experienced market risk premiums. AIU avers the DCF model can be used to estimate the cost of equity where the expected return is comprised of the dividend yield plus investor expectations of longer-term growth based on prevailing capital market conditions. AIU states that for the DCF-based market risk premium, an estimate of a forward-looking market risk premium is valuable because the required market risk premium is not static, and thus, a direct measure of the prospective market risk premium may provide a more accurate measure of the current level of the expected differential between stock and bond returns than experienced risk premiums. AIU submits that an estimate of a forward-looking market risk premium provides value because the equivalence of past return to what were investors' ex ante expectations may be pure coincidence, and the determination of a fair ROE reflective of the expected interest rate environment requires a direct assessment of current stock market expectations.

AIU states the forward-looking market premium may be determined by an application of the DCF model to the S&P 500 with the inputs of an expected dividend yield and an expected growth rate. AIU avers that the expected dividend yield is equal to the average of the month-end February and March 2009 market-value weighted expected dividend yields for the S&P 500 companies of 3.7%, while for the expected growth rate, the market-value weighted consensus forecasts of earnings growth for the companies in the S&P 500 were used as a proxy for investor expectations of long-term growth. For the risk-free rate, AIU notes Ms. McShane uses the forecast 30-year U.S. Treasury yield expected to prevail over the same 5-year time frame for which the forecast growth rates for the market are made.

Because the equity markets are currently experiencing significant turmoil and uncertainty, AIU avers that Ms. McShane recommends giving greater weight to the DCF-based market risk premium than she has in the past. Given the extent of equity market risk at present, with the current level of the market risk premium higher by a significant margin than its long-term average, AIU notes Ms. McShane made two CAPM estimates of the cost of equity – one based on ex post market risk premiums and one based on an ex ante estimate of the market risk premium.

Based on the DCF-based market risk premium, AIU states the forward-looking estimate of the CAPM market risk premium amounts to 6.8%, which, with a dividend yield for S&P 500 of 2.1% and a consensus IBES forecast of 5-year growth of 9.63%, results in an expected market return produced by the ex ante DCF-based market risk premium approach of 12.0%. AIU avers that CAPM ROE produced by the ex post market risk premium approach is 9.7% for the gas sample and 10.3% for the electric sample. Because the DCF-based market risk premium approach explicitly captures current financial market conditions, AIU recommends that the CAPM ROE produced by the ex ante DCF-based market risk premium approach be given greater weight than the CAPM ROE produced by the ex post (or historic) market risk premium approach.

As the estimation of the EMRP from achieved (ex post) market risk premiums is premised on the notion that investors' expectations are linked to their past experience, AIU opines that basing calculations of achieved risk premiums on the longest periods available reflects the notion that it is necessary to include as broad a range of event types as possible to avoid overweighing periods that represent unusual circumstances. Since the objective of the analysis is to assess investor expectations in the current economic and capital market environment, AIU avers that weight should be given to periods whose equity characteristics are more closely aligned with what today's investors are likely to anticipate over the longer term. When an estimated market risk premium is developed from historic average returns, AIU argues that arithmetic averages need to be used, and the income return – not the total return on long-term government bonds – should be the measure of the historic risk-free rate used when calculating historic risk premiums.

AIU states that Ms. McShane also performs an equity risk premium test based on utility achieved risk premiums. Ms. McShane estimated the historic equity risk premiums for utilities relative to long-term A-rated public utility bonds and BAA-rated public utility bonds, and AIU avers she estimated the historic equity risk premium for utilities relative to long-term A-rated public utility bonds and Baa-rated public utility bonds at 4.5% and 4.25%, respectively. AIU opines that adding the historic spreads between the utility and bond yields to the long-term U.S. Treasury yield of 5.5% results in a forecast A-rated utility bond yield of 6.8% and a Baa-rated utility bond yield of 7.2%, and the resulting required equity returns are 11.3% and 11.5% for the gas and electric samples respectively.

AIU states that in Ms. Freetly's CAPM test, for the risk-free ROR; she examines the suitability of the yields on 4-week U.S. Treasury bills and 30-year U.S. Treasury bonds, using a 4.4% "spot" 30-year U.S. Treasury yield in deriving her CAPM estimate. AIU notes Ms. Freetly then estimates the expected ROR on the market by conducting a DCF analysis on the firms composing the S&P 500 as of June 30, 2009, with the resulting rates of return on common equity of 9.46% for the gas sample and 10.21% for the electric sample.

AIU opines that Ms. McShane also advocates using a longer-term U.S. Treasury, to more closely match the duration of the risk-free rate and common equities, whose values reflect expected cash flows that are perpetual in nature. AIU states that most analysts rely on a long-term government yield, which is risk-free in that there is no default risk associated with U.S. Treasury securities; therefore Ms. McShane utilizes forecast yields on the 30-year U.S. Treasury bond. AIU states the 30-year U.S. Treasury bond is once again considered a benchmark bond for the purpose of pricing securities.

While Ms. Freetly criticizes Ms. McShane's use of historical data in developing her market and utility equity risk premiums, AIU asserts it is unreasonable to expect investors to ignore returns they have achieved historically when forming their equity market return expectations going forward. AIU avers that without a discernable trend in achieved returns over time, as is the case here, historic returns provide a relevant perspective on the returns investors may reasonably expect over the longer term.

AIU argues that Mr. Gorman's CAPM analysis is inappropriately based on his market risk premium. AIU notes Mr. Gorman makes two estimates of the market risk premium: a forward-looking estimate and an estimate based on a long-term historical average. Although Mr. Gorman re-did his CAPM estimates to reflect Ms. McShane's proposed modifications to his market risk premium estimate, AIU states Mr. Gorman's risk premium method also incorrectly estimates the market return by adding an estimate of the long-term rate of inflation to the historic average real return. AIU argues the real return should be correlated with historical stock returns, which Mr. Gorman does not do. AIU avers that combining the average real return achieved on the market with expected inflation would be appropriate only if there were evidence that the expected return on the market moves in tandem with the rate of inflation, which has not been shown here.

AIU states Mr. Gorman's evidence on the market risk premium also does not address the fact that the historic measured risk premiums through 2008 were negatively impacted by the significant sell-off in the equity market in 2008. As the 2009 upswing in the equity market, through the end of October, indicates a higher measured equity market risk premium than did the values calculated through the end of 2008, AIU asserts Mr. Gorman's estimate of the market risk premium and resulting CAPM costs of equity are too low.

Although Mr. Gorman also performs a multi-stage DCF model to support his risk premium estimate, AIU avers his model assumes investors expect that analysts' forecasts of growth will persist for ten years and that growth will then drop precipitously to the expected nominal rate of growth in the economy. AIU argues the result of Mr. Gorman's model is well below his multi-stage DCF estimates for both the electric and gas samples, which does not help assess the reasonableness of Mr. Gorman's equity market risk premium estimate.

AIU notes that Mr. Gorman criticizes Ms. McShane's risk premium studies for their use of long-term forecasts of interest rate in conjunction with her historic risk premiums, as well as her use of forecast of utility bond yields, particularly in her application of the equity risk premium tests. However, AIU asserts that when conducting her equity risk premium tests by reference to historic average returns and risk premiums for both the market as a whole and for utilities, Ms. McShane combines a long-term average risk premium with long-term average expected bond yields. AIU argues the combination of a historic risk premium with a spot interest rate will result in an under- or over-estimation of the cost of equity at any given point in time, which produces an estimate of the cost of equity that matches the constancy of the equity risk premium implied by the use of historic averages with a similarly estimated interest rate.

AIU opines that Mr. Gorman himself uses forecasts of long-term U.S. Treasury interest rates in his CAPM, which is comparable to Ms. McShane's use of forecasts of utility bond yields. AIU avers that as the economy recovers, if long-term U.S. Treasury bond yields are expected to rise, so will utility bond yields, therefore Ms. McShane's analysis correctly incorporates the impact of the expected increase in long-term U.S. Treasury bond yields on the corresponding utility bond yields.

While Ms. Freetly and Mr. Gorman recommend the Commission use current or "spot" interest rates rather than forecast interest rates in Ms. McShane's risk premium studies, AIU notes that to estimate the risk-free rate, Ms. Freetly states she used current U.S. Treasury yields that reflect all relevant, currently available information, including investor expectations regarding future interest rates. Ms. Freetly asserts that investor appraisals of the value of forecasts are reflected in current interest rates, and therefore, if investors believe that the forecasts are valuable, that belief would be reflected in current market interest rates.

AIU states that "spot" U.S. Treasury yields remain at relatively low levels as a result of several factors, including the global demand for U.S. Treasury debt and relatively weak economic conditions. With the U.S. federal budget deficit for 2009 topping $1.4 trillion, AIU argues that the most likely trajectory for U.S. Treasury bond yields, as the U.S. global economies strengthen, is an upward trajectory. AIU opines that since such an upward trajectory is reflected in the consensus of economists' forecasts, which recognize that interest rates will rise as the economy improves, therefore the application of the CAPM should recognize the high probability that U.S Treasury yields will increase, making current interest rates inappropriate.

IIEC argues that Ms. McShane's market risk premium estimated from historic data is overstated because it relies on income returns rather than on total returns on U.S. Treasury bonds, and because of Ms. McShane's use of Morningstar data, which overstate the market risk premium that would be measured from total U.S. Treasury bond returns because Morningstar risk premiums are measured using the U.S. Treasury bond income returns. While AIU agrees that the estimated risk premium using income returns on U.S. Treasury bonds is higher than it would be if it were measured using total returns AIU asserts that IIEC ignores the fact that proper application of CAPM requires a risk-free rate, therefore the income return is the best representation of the true long-term historical risk free rate.

While Mr. Thomas argues that an EMRP of 5% may be too high, indicating that current academic research estimates range from 3.4% to 5.1%, AIU opines that there is no reason to conclude that equity market returns will be lower in the future than they were in the past and that historic evidence supports an equity risk premium equal to or slightly higher than 6.5%. As Ms. Freetly asserts, because the relationship between returns of the stock market and U.S. Treasury bonds is not stable over time, current returns provide the best indication of what investors are expecting going forward. AIU concurs with Ms. Freetly when she disagrees that the proper expected common equity market risk premium for determining the investor-required ROR is between 3% and 5%.

f. Proposed Adjustments

(1) Financial Risk

AIU states that to determine a fair ROE for a utility, it is vital to recognize that the cost of capital is determined in the capital markets and reflects the market value of firms' debt and equity capital, which may differ from book value capital structures. AIU recognizes that both it and Staff agree that a market-based cost of equity is appropriate and that it is necessary to use a book value rate base for regulatory rate setting. Further, AIU notes that both agree that differences in financial risk must be accounted for in the cost of equity and that higher or lower financial risk than the proxy companies, given similar business risk, requires an adjustment to the proxy companies' costs of equity, however the issue is how to measure those differences.

AIU avers that Ms. McShane uses two approaches to quantify the impact of a change in financial risk on the cost of equity. AIU states her first approach is based on the widely accepted view that the overall cost of capital does not change materially over a relatively broad range of capital structures, while her second approach is based on the theoretical model that assumes that the overall cost of capital declines as the debt ratio rises due to the income tax shield on interest expense. AIU submits the latter approach will overestimate the impact of leverage on the overall cost of capital and understate the impact of increasing financial leverage on the cost of equity because that approach does not account for any of the factors that offset the corporate income tax advantage of debt.

AIU avers that to apply these approaches, Ms. McShane first determines the market value capital structures of the sample companies over the period corresponding to the relevant period of analysis for the specific cost of equity. AIU states she then estimates the utility samples' weighted average cost of capital using market value capital structures and the appropriate market value common equity ratio and cost of equity. Finally, she estimates the change in common equity return requirement for each of her tests (DCF, CAPM, and DCF-based risk premium tests) to account for the difference between the sample average market value common equity ratio and the company's book value common equity ratio. AIU opines that if the difference between the company's ratemaking common equity ratio and the relevant market value common equity ratios results in an adjustment, Ms. McShane recommends that the allowed ROE be adjusted accordingly. AIU argues that Ms. McShane's method has been accepted by other regulators in the past.

While AIU recognizes that in the past the Commission has rejected Ms. McShane's approach because the AIUs do not have market traded stock, AIU avers that applying a market-derived cost of equity to the book value (ratemaking) capital structure without recognizing the financial risk differences between the market value capital structures that underpin the estimates of the cost of equity and the book value capital structures of the AIU utilities will understate AIU's cost of equity. AIU opines this lack of observable market value capital structures for AIU does not alter this conclusion because the relevant comparison is between the financial risk inherent in the market value capital structures of proxy utilities and the financial risk inherent in the book value (ratemaking) capital structures of AIU.

AIU states that for each AIU gas utility relative to the gas sample, Ms. Freetly concludes that her revenue requirement recommendations, including her cost of common equity recommendations, indicate levels of financial strength commensurate with a Baa3 credit rating for AmerenCILCO Gas, an A3 credit rating for AmerenCIPS Gas, and a Baa3 credit rating for AmerenIP Gas. AIU notes that Ms. Freetly believes the gas sample's level of financial strength indicates it has more financial risk than AmerenCIPS and less financial risk than AmerenCILCO and AmerenIP. Given the difference between the credit ratings commensurate with the forward-looking financial strength of AIU gas operations and the credit rating commensurate with the gas sample, Ms. Freetly recommends that the sample's average cost of common equity be adjusted to determine the estimate of each company's cost of common equity, using the spreads for 30-year utility debt yields as of August 31, 2009. Ms. Freetly recommends a 10.5 basis point adjustment for AmerenCILCO and AmerenIP and a decrease of 15 basis points for AmerenCIPS.

AIU submits that for each AIU electric utility relative to the electric sample, Ms. Freetly concludes that her revenue requirement recommendations, including cost of common equity recommendations, indicate levels of financial strength commensurate with a Baa1 credit rating for AmerenCILCO, an Aa3 credit rating for AmerenCIPS, and a Baa2 credit rating for AmerenIP. According to Ms. Freetly, the electric sample has a lower average implied credit rating, which indicates that its financial risk is higher than that of either AmerenCILCO's or AmerenCIPS' electric delivery service operations. Given the difference between the implied forward-looking credit ratings for the Companies and the average credit rating of the electric sample, Ms. Freetly recommends that the sample's average cost of common equity be adjusted to determine the estimate of each company's cost of common equity. To make the adjustments to the cost of common equity of the electric sample, Ms. Freetly used Reuters Corporate Spreads for Utilities from August 31, 2009. Her analysis recommends a cost of equity adjustment for the electric operations of 6 basis points for AmerenCILCO and 30 basis points for AmerenCIPS. This equates to a 0.06% downward adjustment for AmerenCILCO and a 0.30% downward adjustment for AmerenCIPS. Ms. Freetly does not recommend adjusting for AmerenIP because the financial ratios for AmerenIP are commensurate with the same level of financial risk as the electric sample.

AIU argues that Ms. Freetly's adjustments are incorrect, in part because they are based on the assumption that AIU will achieve the credit metrics implicit in Staff's recommendations. While Ms. Freetly claims that Staff's revenue requirement recommendations, including her cost of common equity recommendations, indicate credit metrics commensurate with higher or lower debt ratings than the implied debt ratings suggested by the credit metrics of her utility samples, AIU avers that her comparisons are flawed because she compares credit metrics that her utility samples have actually achieved from 2006-2008 with credit metrics that could be achieved if AIU were able to earn the returns on equity that they are allowed. AIU submits that recent history, however, demonstrates AIU has significantly under-earned its allowed returns on equity and thus has not achieved the levels of financial strength assumed by Ms. Freetly's financial risk adjustments. By comparing the potential financial performance and credit metrics of AIU to the actual financial performance and credit metrics of the proxy utilities, Ms. Freetly understates AIU's financial risk relative to the proxy utilities.

Further, while Ms. Freetly's adjustments assume an equity investor quantifies financial risk differences identically to a bond investor, AIU avers that proper financial risk adjustments to the cost of equity for the electric and gas samples consider the higher or lower return that equity investors require for bearing the higher or lower financial risk inherent in AIU's proposed ratemaking capital structures. AIU submits that Ms. Freetly is also incorrect when she contends that Ms. McShane's adjustments would perpetuate further increases in earnings and the market value of the stock. Earnings, dividends, book, and market values increase at the same rate, arguing changes in the market/book ratio should occur only if the cost of capital or the expected return on book equity changes.

AIU notes that Mr. Gorman also disagrees with Ms. McShane's financial risk adjustment, asserting it inflates a fair and reasonable return. While Mr. Thomas disagrees with adjusting the market-based DCF model results before applying them to the book value of assets in rate base, arguing that the adjustment inflates the market-based DCF cost of equity and that no such adjustment is required, AIU opines that Mr. Thomas' recommended returns are too low and would deprive AIU of a chance to earn a return commensurate with those of comparable risk firms.

(2) Fixed Customer Charge

AIU notes Ms. Freetly recommends an additional downward adjustment to the gas distribution operations' Rate of return on common equity based on the Commission's recognition, in AIU's last rate cases, that the AIU gas utilities' move toward more fixed cost recovery – through the fixed monthly charge – gives AIU more assurance of recovering its fixed costs of service for gas operations. As Ms. Freetly contends this cost recovery reduces risk and provides greater assurance that the authorized ROR will be earned, she therefore recommends a downward adjustment of

10 basis points to the AIU gas utilities' Rate of return on common equity – the same adjustment the Commission found proper in the last rate cases.

AIU claims that Ms. Freetly disregards the fact that eight of the nine gas distributors in the gas sample have similar mechanisms in place; therefore the cost of common equity estimate for the sample already reflects the risk reduction. While Ms. Freetly argues that some of the mechanisms apply only to portions of a company's service territories, AIU opines if equity investors impute lower risk due to the adoption of such mechanisms, lower risk would already be reflected in the cost of equity estimates for the sample companies. AIU argues that Ms. Freetly's recommended reduction would double count the risk reduction that might be imputed by investors and should thus be rejected.

(3) Uncollectibles Riders

While Ms. Freetly asserts the uncollectible riders would reduce AIU's risk because they would reduce uncertainty of cash flows, AIU notes she admits she is unaware of an established approach for gauging the effect that adoption of the riders would have on investor perceptions of AIU's risk levels and the resulting costs of equity. AIU states she instead proposes adjustments for the riders, based on two distinct approaches: (1) estimate the effect of the adoption of the riders on AIU's Moody credit ratings, and then, adjust based on the resulting change in implied yield spreads; and (2) adjust cost of common equity downward to offset the increased operating income resulting from the adoption of the riders. AIU opines that like Ms. Freetly, Mr. Thomas states that the riders will reduce both uncertainty of cash flows and AIU's risk, but as he is not aware of an approach to gauge the effect of the riders, he therefore supports Ms. Freetly's methodology as reasonable, although conservative.

AIU notes that for her first approach, Ms. Freetly assumes the credit rating assigned to the "ability to recover costs and earn returns" factor would improve by one credit rating with the implementation of the uncollectibles rider, while for her second approach, Ms. Freetly adjusts her cost of common equity downward to offset the increased operating income resulting from the adoption of Rider GUA-Gas Uncollectible Adjustment ("Rider GUA"). AIU states she adjusts her cost of common equity downward until the pro forma operating incomes under Rider GUA equal the original pro forma operating incomes she calculated for AIU without Rider GUA. For the electric operations, AIU says Ms. Freetly estimates the incremental recovery of uncollectibles expense had Rider EUA-Electric Uncollectible Adjustment ("Rider EUA") been in effect for the past ten years, then adjusting her cost of common equity downward until the pro forma operating incomes under Rider EUA equal the original pro forma operating incomes she calculated for AIU without Rider EUA.

AIU states Ms. Freetly averages the results of her two approaches to determine her recommended adjustments for the electric operations of AmerenCILCO, AmerenCIPS, and AmerenIP of 63, 64.5, and 34 basis points, respectively, to reflect the reduced risk due to Rider EUA; while she recommends adjustments to the costs of common equity for the gas operations of AmerenCILCO, AmerenCIPS, and AmerenIP of 87.5, 79.5, and 60.5 basis points, respectively, to reflect the reduced risk due to Rider GUA.

AIU argues Ms. Freetly's approaches are both flawed. AIU opines Ms. Freetly is incorrect to assume that the credit rating of Moody's "ability to recover costs and earn returns" will increase by one full credit rating as there is no empirical evidence to support that assertion. AIU avers that Ms. Freetly's assumption that Moody's would change both the "regulatory framework" and "sustainable profitability" factors by a full credit rating for the adoption of the riders is without merit. AIU claims Moody's already acknowledged the legislation and factored it into its decision to upgrade AIU to investment grade, so the actual adoption of the riders is unlikely to result in a full credit rating improvement in both regulatory framework and sustainable profitability. AIU states that even if this were the case, AIU would still have equivalent credit ratings to Ms. Freetly's electric utility operation proxies and lower credit ratings than her gas utility operation proxies. AIU asserts there would be no reason to conclude that, even with the riders, the equity market would view them as less risky than the proxies.

AIU argues Ms. Freetly's second approach presumes there is an expectation built into the proxy utilities' costs of equity, for when they systematically under-recover bad debt expense. AIU states there is no such expectation, and thus, there is no rationale for removing a premium that does not exist. AIU asserts Ms. Freetly did not look at the specific under- or over-recovery experience of the proxy utilities for the same ten-year period that she reviewed for AIU, therefore she can not know whether AIU faces greater risk; she only knows one side of the equation. AIU notes this second approach would also reduce the return for a risk for which AIU has never been compensated because, as historic evidence shows, risk is not symmetric and AIU has not historically earned more or less than the allowed return.

AIU opines that Ms. Freetly's downward adjustments for the uncollectible riders are effectively premised on the assumption that AIU has similar business risk to the proxy utilities before the adoption of the riders. AIU argues several factors – including regulatory lag and rising operating costs and capital expenditures – indicate AIU has higher business risk than the proxy companies. AIU avers that a relatively broad sample of gas and electric utilities has higher implied credit ratings on Moody's "regulatory framework" and "ability to recover costs and earn returns" factors than AIU, which suggests that Ms. Freetly's implicit point of departure for making her downward adjustments, similar business risk, is incorrect.

AIU states Ms. Freetly's approach is further flawed because her analyses of each of the AIUs' risk relative to each other, which are then applied to the sample group, arrive at disparate conclusions. AIU argues that the adjustment calculated by Ms. Freetly indicates that the reduction in risk would be higher for AmerenCILCO than for AmerenIP, indicating more uncollectible risk for AmerenCILCO. AIU points out however, that Ms. Freetly, based on her metrics applied relative to the sample group, indicated the two companies have the same indicated level of risk, which led her to recommend the same ROE for each. AIU argues the proposed adjustments are arbitrary and lack the precision needed to impact the Commission authorized rate or return on common equity. While Ms. Freetly denies that Moody's reflection of the bad debt rider legislation eliminates the need to adjust the costs of common equity of the gas and electric samples, AIU notes she provides no empirical evidence to support this assertion.

AIU argues that Staff's method of taking two estimates of the reduction in perceived investor risk is hopelessly flawed and offers false precision. By doing any calculation, Staff is suggesting that it can isolate the uncollectibles risk embedded in the ROEs produced by its analysis. To do this, Staff just takes two bad estimates and averages them, which AIU opines produces nonsensical results. Moreover, AIU avers that the two approaches she averages produce results so far apart that averaging offers no confidence that the resulting adjustment is reasonable. While Ms. Freetly acknowledged that she saw one method as being as likely as the other to be accurate, AIU submits that where one approach produces a result 16 times greater than the other approach, it is hard to say either is likely to be right. If the Commission concludes a downward adjustment is required, AIU suggests the Commission should simply adopt the 10 basis point adjustment it approved in the Peoples/North Shore dockets for each of the AIU companies.

2. Staff Position

a. Return on Equity Estimates

Ms. Freetly measured the investor-required Rate of return on common equity with the non-constant DCF and Capital Asset Pricing Model (“CAPM”) analyses. For AIU gas utilities, Ms. Freetly applied those models to the same sample of 9 local gas distribution companies utilized by AIU witness McShane. For the AIU electric utilities, Ms. Freetly began with Ms. McShane’s sample of electric utilities but eliminated the electric companies the Edison Electric Institute categorized as “Mostly Regulated” since her return on common equity recommendation is for the regulated electric operations of AIU. Ms. Freetly then eliminated the companies that were not assigned an industry classification code of 4911 or 4931 within S&P Utility Compustat. Then, Ms. Freetly removed companies that are, or recently have been, involved in mergers, acquisitions, or divestures. Finally, Ms. Freetly removed companies that lacked growth rate estimates from Zacks Investment Research (“Zacks”) or the data necessary to calculate beta. The remaining 16 regulated electric utilities compose Ms. Freetly’s electric sample.

Staff states that a DCF analysis assumes that the market value of common stock equals the present value of the expected stream of future dividend payments to the holders of that stock. Staff notes that since a DCF model incorporates time-sensitive valuation factors, it must correctly reflect the timing of the dividend payments that a stock price embodies, further noting that the companies in Ms. Freetly’s gas and electric samples pay dividends quarterly. Therefore, Ms. Freetly employed a multi-stage non-constant-growth DCF model that reflects a quarterly frequency in dividend payments.

Ms. Freetly modeled three stages of dividend growth. The first, near-term growth stage is assumed to last five years. The second stage is a transitional growth period lasting from the end of the fifth year to the end of the tenth year. The third or "steady-state" growth rate is assumed to begin after the tenth year and continue into perpetuity.

For the first stage, Ms. Freetly used market-consensus expected growth rates published by Zacks as of August 18, 2009. To estimate the long-term growth expectations for the third, steady-state stage, she utilized the implied 20-year forward U.S. Treasury rate in 10 years, 4.83%. The growth rate employed in the intervening, 5-year transitional stage equals the average of the Zacks growth rate and the steady-state growth rate. The growth rate estimates were combined with the closing stock prices and dividend data as of August 18, 2009. Based on these growth assumptions, stock price, and dividend data, Ms. Freetly's DCF estimate of the cost of common equity was 9.79% for the gas sample, and 10.67% for the electric sample.

Staff states that according to financial theory, the required ROR for a given security equals the risk-free ROR plus a risk premium associated with that security. Staff notes that the risk premium methodology is consistent with the theory that investors are risk-averse and that, in equilibrium, two securities with equal quantities of risk have equal required rates of return. Ms. Freetly used a one-factor risk premium model, the CAPM, to estimate the cost of common equity. In the CAPM, the risk factor is market risk, which can not be eliminated through portfolio diversification.

Staff avers that the CAPM requires the estimation of three parameters: beta, the risk-free rate, and the required ROR on the market. For the beta parameter, Ms. Freetly combined adjusted betas from Value Line, Zacks, and a regression analysis to estimate the beta of the gas and electric sample. For the gas sample, the average Value Line, Zacks, and regression beta estimates were 0.68, 0.56, and 0.51, respectively. For the electric sample, the average Value Line, Zacks, and regression beta estimates were 0.71, 0.72, and 0.66, respectively. The Value Line regression employs 260 weekly observations of stock return data regressed against the New York Stock Exchange ("NYSE") Composite Index. Both the regression beta and Zacks betas employ 60 monthly observations; however, while Zacks betas regress stock returns against the S&P 500 Index, the regression beta regresses stock returns against the NYSE Index. Since the Zacks beta estimate and the regression beta estimate are calculated using monthly data rather than weekly data (as Value Line uses), Ms. Freetly averaged those results to avoid over-weighting betas estimated from monthly data in comparison to the weekly data-derived Value Line betas. She then averaged the resulting monthly beta with the Value Line weekly beta, which produced a beta of 0.61 for the gas sample and 0.70 for the electric sample.

Staff avers that for the risk-free rate parameter, Ms. Freetly considered the 0.14% yield on 4-week U.S. Treasury bills and the 4.40% yield on 30-year U.S.

Treasury bonds, with both estimates measured as of August 18, 2009. Forecasts of long-term inflation and the real risk-free rate imply that the long-term risk-free rate is between 4.3% and 5.2%. Thus, Ms. Freetly concluded that the U.S. Treasury bond yield is currently the superior proxy for the long-term risk-free rate.

Staff opines that for the expected ROR on the market parameter, Ms. Freetly conducted a DCF analysis on the firms composing the S&P 500 Index. That analysis estimated that the expected ROR on the market was 12.70% for the second quarter of 2009. Inputting those three parameters into the CAPM, Ms. Freetly calculated a cost of common equity estimate of 9.46% for the gas sample and 10.21% for the electric sample.

Ms. Freetly estimated the investor-required rate of return on common equity for the gas sample of 9.63% by taking the simple average of the DCF-derived results (9.79%) and the risk-premium derived results (9.46%) for the gas sample. She then adjusted the gas sample's investor-required ROR downward by 15 basis points for AmerenCIPS to reflect the lower financial risk of AmerenCIPS relative to the gas sample. She also adjusted the gas sample's investor-required ROR upward by 10.5 basis points for AmerenCILCO and AmerenIP to reflect higher financial risk of AmerenCILCO and AmerenIP relative to the gas sample. Next, Ms. Freetly adjusted the companies' cost of equity downward by 10 basis points to reflect the reduction in risk associated with the recovery of a greater portion of fixed delivery services costs through the monthly customer charge, which was authorized in AIU's last rate cases, Docket Nos. 07-0585 et al. (Cons.). Staff therefore recommends that for the natural gas distribution operations of AIU, the investor-required rate of return on common equity is 9.64% for AmerenCILCO, 9.38% for AmerenCIPS, and 9.64% for AmerenIP.

To estimate the investor-required rate of return on common equity for the electric delivery service operations of AIU, Ms. Freetly first took the simple average of the DCF-derived results (10.67%) and the CAPM derived results (10.21%) for the electric sample, or 10.44%. Ms. Freetly then adjusted the electric sample's investor required ROR downward by 6 basis points for AmerenCILCO and 30 basis points for AmerenCIPS to reflect the lower financial risk of AmerenCILCO and AmerenCIPS relative to the electric sample. Thus, for the electric delivery service operations of the companies, the investor required rate of return on common equity is 10.38% for AmerenCILCO, 10.14% for AmerenCIPS, and 10.44% for AmerenIP.

Staff notes that AIU witness McShane estimated the cost of common equity using both the constant growth and non-constant growth DCF models and three equity risk premium analyses. Ms. McShane also applied the comparable earnings test for purposes of assessing the reasonableness of her results. Based on the updated analysis in Rebuttal Testimony, for the natural gas distribution operations, she recommended an 11.2% cost of common equity for AmerenCILCO and AmerenIP and a 10.8% cost of common equity for AmerenCIPS. For the electric delivery service operations, Ms. McShane recommended an 11.7% cost of common equity for AmerenCILCO and AmerenIP and an 11.3% cost of common equity for AmerenCIPS.

Staff asserts that Ms. McShane's analysis contains several errors that lead her to over-estimate AIU's cost of common equity. Staff argues the most significant flaws in Ms. McShane's analysis of the companies' cost of common equity are the use of historical data in her DCF and risk premium models; the inclusion of unwarranted adjustments to the DCF and risk premium results for alleged difference between market value and book value; and the inappropriate use of comparable earnings model as a check on her recommended cost of equity. Staff, therefore, recommends that the Commission reject AIU's recommended costs of common equity, and adopt Staff's recommendation, as stated above.

b. DCF and CAPM Model Issues

Staff argues that the use of historical data is problematic, as historical data favors outdated information that the market no longer considers relevant over the most-recently available information. Staff further opines that historical data reflects conditions that may not continue in the future. Staff avers that the use of average historical data implies that securities data will revert to a mean, and while state there is no evidence securities data is mean reverting, there is also no method for determining the true value of that mean let alone the length of time over which mean reversion will occur.

Staff states Ms. McShane uses historical data in determining the dividend yield in her DCF model, however, since stock prices reflect all current information; only the most recent stock price can reflect the most recently available information. Staff asserts that historical stock prices must include observations that can not reflect the most current information available to the market.

While Ms. McShane implies that her use of historical data to estimate the dividend yield is an attempt to reduce measurement error, Staff asserts that introducing old stock prices into an analysis simply substitutes one alleged source of measurement error, volatile stock prices, for another, irrelevant stock prices. Staff notes that stock prices can be influenced by temporary imbalances in supply and demand; however, any distortions such imbalances might have on the measured cost of common equity can be reduced through the use of samples, a technique which Ms. McShane already applies.

Staff notes that Ms. McShane performed an equity risk premium analysis, which calls for an estimate of the investor-required ROR on the market portfolio. Staff opines that to compute the achieved equity risk premium for her sample, she first calculated the achieved equity risk premium for the S&P 500 Common Stock Index for two historic periods (1926-2008 and 1947-2008) relative to the 20-year U.S. Treasury bond income return, then calculated the achieved equity risk premium for the S&P/Moody's Electric Utility Index and the S&P/Moody's Gas Distribution Utility Index relative to the 20-year U.S. Treasury bond income return. Staff notes she also estimated the historic equity risk premium relative to the total return on Moody's long-term A-rated public utility bonds.

Consequently, Staff argues Ms. McShane estimates the required ROR on the market using, in part, historical earned rates of return. Staff avers that as proxies for current required rates of return, historical earned returns possess several shortcomings, in that the returns an investment generates are unlikely to have equaled investor return requirements due to unpredictable economic, industry-related, or company-specific events. Staff further argues that even if an investment's return equaled investor requirements in a given period, both the price of, and the investment's sensitivity to, each source of risk changes over time. Further, Staff avers that the magnitude of the historical risk premium depends upon the measurement period used, therefore historical earned rates of return are questionable estimates of the required ROR that are susceptible to manipulation and whose use could distort the estimate of a company's cost of common equity. Staff notes the Commission has consistently rejected the use of historical dividend yields in calculating an appropriate ROE.

Ms. McShane argues that if the market value differs from book value, a cost of equity estimate derived from market values needs to be adjusted when applied to book values of common equity to determine utility rates. Staff argues that market to book adjustments such as Ms. McShane's are based on the flawed argument that a market-derived required ROR does not produce a "fair" return when applied to a book value rate base if the market to book ratio differs from one. Staff avers that the crucial flaw in that argument is that it equates secondary investing (i.e., the purchase of existing shares of stock from other investors) with primary investing (i.e., the purchase of new shares of stock directly from the company or the retention of earnings for reinvestment). Staff notes the former does not affect the amount of money available to the company to buy assets because the proceeds from the sale go to the previous stockholder, not to the company. Staff argues that under original cost ratemaking, ratepayers provide a return only on the amount of capital that is invested in assets that serve ratepayers, and that inflating that return to compensate investors for capital not invested in plant and equipment is neither fair nor appropriate. While book value represents the funds a company receives from investors though security issuances on the primary market, Staff states that book value does not adjust to reflect changing investor assessments; it only reveals how much money the company has to invest in assets to serve its customers.

Staff notes that the market price is the price investors are willing to pay each other for a security on the secondary market. Staff avers that cost of common equity analysis uses market price data because market data continuously adjusts to reflect investor return requirements as they are continuously re-evaluated. Staff states the market value of a stock would grow to exceed its book value only if investors expect to earn a return above their required return, and that the market price always reflects the investor-required return, regardless of the book value. Staff argues there is no merit to Ms. McShane's claim that her adjustment is required to recognize the higher return that equity investors require for bearing the higher financial risk inherent in AIU's proposed ratemaking capital structure in comparison to the market value capital structures of the gas and electric samples.

Staff submits that if a utility's services were entirely subject to original cost-based, ROR regulation and its rates perfectly and instantaneously reflected changes in its costs, then the market value of the firm would equal the book value whenever the expected ROR matches the investor required ROR. However, if the expected ROR exceeds the investor required ROR, Staff opines demand for the company's stock will increase as investors seek a share in those abnormally high returns, which will cause the stock's market value to rise until the expected ROR on market value equals the required ROR. Staff avers that the Commission should not further increase allowed rates of return when the benefits that utilities receive from other sources of earnings not recognized by the rate setting process increase stock prices above book value.

Staff further argues that allowing upward adjustments to the allowed ROR based on a market-to-book value ratio greater than one, would require the Commission to continually make upward adjustments to the allowed ROR, since such an upward adjustment would tend to again increase the market-to-book value ratio, thereby warranting another increase, resulting in a never ending upward movement in the allowed ROR.

While Ms. McShane argues that the lower book value common equity ratios of the companies relative to the gas and electric sample's market value common equity ratios indicate that the companies possess higher financial risk than the gas and electric samples, Staff opines that the intrinsic financial risk of a given company does not change simply because the manner in which it is measured has changed. Staff notes that capital structure ratios are merely indicators of financial risk; they are not sources of financial risk. Staff avers that Ms. McShane has previously proposed the same adjustment to her market-derived cost of equity estimates. In Docket Nos. 02-0798 et al. (Cons.), the Commission rejected her proposed market-to-book adjustment, noting that the Commission has a long history of applying its estimated market required rate of return on common equity to its book value, net original cost rate base for Illinois jurisdictional utilities. The Commission found that there was no evidence that this practice had served as an impediment to a utility's ability to raise capital or maintain its financial integrity. Ms. McShane's argument was similarly rejected in Docket Nos. 06-0070 et al. (Cons.).

Staff notes that Ms. McShane's comparable earnings model uses the average historical earned return on book value of common equity for a proxy group of 81 U.S. industrial companies over the period 1991-2007, claiming that her comparable earnings test indicates that competitive firms of similar risk to her sample of gas utilities may be expected to earn average returns of approximately 15.0% to 16.0%.

Staff opines that the comparable earnings methodology is based on the erroneous assumption that earned or expected returns on book equity are acceptable substitutes for investor-required returns. Staff avers that investor return requirements are a function of risk and manifested in the market prices of securities, while Ms. McShane's comparable earnings analysis is based on accounting returns, which are largely unresponsive to market forces. Staff argues that Ms. McShane herself acknowledges that the comparable earnings test does not measure the investor-required rate of ROE. Staff notes that the Commission has likewise repeatedly rejected the comparable earning methodology, finding that it is faulty as it incorrectly assumes that earned returns on book common equity are representative of investor required returns on common equity, referencing Docket Nos. 02-0798 et al. (Cons.) and Docket Nos. 06-0070 et al. (Cons).

Staff submits that both of the comparable earnings analysis in the prior cases cited above are based on earned returns on book equity as substitutes for investor required returns, while in this proceeding, Ms. McShane claims that the results of the comparable earnings test should be relied on as an indicator of whether her market-based test results (the DCF and equity risk premium), as adjusted for the market/book ratio are reasonable. Staff urges the Commission to once again disregard Ms. McShane's comparable earnings analysis.

c. Growth Rates

Staff notes that AIU insists that it is appropriate to include the results of the constant growth DCF analysis in the estimation of the investor required ROR for AIU, while in Staff's opinion, the three- to five-year growth rates for the companies in the Gas and Electric samples can not be sustained over the long-term.

While AIU notes that Staff did utilize a constant growth DCF to develop the expected return in the market in the risk premium model, Staff suggests its use of the constant growth DCF to estimate the return on the market does not support performing a constant growth DCF analysis on the gas and electric samples. Staff argues it did not use a non-constant growth DCF to estimate the return on the market because of the extreme difficulty of attempting to apply the more elaborate non-constant growth DCF on 500 companies. Staff avers that as with the three- to five-year growth rates for some of the companies in the gas and electric samples, some of the growth rates used in Staff's DCF analysis of the S&P 500 are unsustainably high, which produces an upward bias in Staff's market return estimate and, thus, in Staff's CAPM cost of equity estimate.

While Staff used the implied forward yield on 20-year U.S. Treasury bonds to estimate long-term overall economic growth during the steady state growth stage of the non-constant DCF analysis, AIU advocates using the Blue Chip forecast to estimate long-term economic growth. Staff states the Blue Chip forecast used by AIU to estimate long-term economic growth only projects forward 10 years, while the period for which the long-term growth rate is applied begins after 10 years. Staff argues the forecasts do not even overlap, much less coincide with, the period of time the steady-state growth stage covers.

While AIU points to the recent swings in the implied 20-year forward U.S. Treasury yield in comparison to the virtually unchanged consensus forecasts of long-term economic growth, Staff states the changes in the U.S. Treasury yield indicate that investor's current long-term expectations vary over time, while AIU's argument implies that investors' expectations of the long-term economic growth are essentially static. Since the yield on U.S. Treasury bonds reflects changing investor expectations due to current economic conditions, Staff submits it is a timely gauge of the expected long-term economic growth. In contrast, Staff argues as the long-term forecasts AIU relies on are not updated regularly, the alleged stability in the Blue Chip forecasts of long-term economic growth might come from a low update frequency.

While AIU notes that Staff's use of the non-constant DCF is a departure from Staff's typical use of the constant growth DCF, pointing out that Staff relied on the constant growth DCF model in previous testimony when analysts' consensus forecasts were higher than the forecast long-term growth in the economy, Staff states AIU's argument implies that Staff can not modify its methodology even when a revised methodology more accurately reflects existing circumstances, and is likely to yield more reliable results.

Staff notes that Ms. Freetly testified that a single-stage constant growth DCF model employs a single growth rate estimate, which is assumed to be sustainable infinitely. Staff argues a cost of common equity calculation derived from a constant growth estimate is correct only if the near-term growth rate forecast for each company in the sample is expected to equal its average long-term dividend growth, as no company could sustain into infinity a growth rate any greater than that of the overall economy. Staff states that given the difference between the growth rates for the gas and electric samples and the overall growth of the economy, the continuous sustainability of the analyst growth rates for the gas and electric samples is highly unlikely.

Staff agues that inclusion of the constant growth DCF analysis can not be reconciled with the compelling rationale for employing the non-constant DCF analysis, namely that the three- to five-year analyst growth rates are unsustainable, noting the decision as to which model to employ must be consistent with the judgment regarding the sustainability of the growth rate to be used in the model.

While AIU states that Staff's long-term growth rate used in the final stage of the non-constant DCF analysis based on the implied 20-year forward U.S. Treasury rate is inferior to the estimate of long-term economic growth provided by the consensus of economists' forecasts published by Blue Chip, Staff avers that AIU ignores Ms. Freetly's Testimony that she compared her 4.83% U.S. Treasury bond-derived estimate of long-term growth against the 4.5% forecast of Global Insight. While Staff agrees that with the use of a consensus forecast of long-term economic growth for a period that begins 10 years from now, the record contains nothing to suggest that any exists, noting the Blue Chip forecast that AIU espouses covers a period that ends 10 years into the future.

Staff submits that AIU's argument concerning the alleged stable nature of long-term growth forecasts aims at one target, Staff's long-term growth estimate, but hits another, the constant growth DCF. Staff notes that the constant growth DCF assumes that short-term growth equals long-term growth, and therefore the growth rates used in the constant growth DCF should be stable. Staff submits the evidence proves that the growth rates Ms. McShane uses in her constant growth DCF analysis are anything but. In the last rate case proceedings for AIU, Docket Nos. 07-0585 et al. (Cons.), Staff avers that Ms. McShane's constant growth DCF analysis used Institutional Brokers' Estimate System ("IBES") growth rate forecasts, with the IBES growth rate for the gas companies common to the 2007 and current cases averaged 4.6%. Staff notes that in the current proceeding, the IBES growth rate for the gas utilities in common to the 2007 and current cases averaged 5.7%. Staff submits that many of the electric companies common to the 2007 and current cases also exhibit some large differences in the IBES growth rate forecasts, with 13 of the 24 electric companies that were part of the electric sample in both 2007 and 2009 changing by more than two percentage points. Staff argues that those large differences indicate the IBES growth rates are not stable, which, according to AIU, disqualifies the IBES growth rates from being considered as long-term growth rates. Staff states that since the IBES growth rates can not be used as long-term growth rates, they can not be used in a constant-growth DCF model, and, therefore, the results of the constant growth DCF should not be considered in determining the investor required rate of return on common equity for setting rates in this proceeding.

Staff avers there is no valid justification for disregarding the investor expectations imbedded in objective, observable current market data in favor of a proxy for those expectations imbedded in speculative projections. Staff states it is important to note that U.S. Treasury bond yields directly reflect the expectations of investors, while Blue Chip forecasts do not. Staff argues the forecasts Ms. McShane advocates are merely proxies for investor expectations, and that proxies should be used only when the market factor in question is not observable. Staff states that since market expectations for U.S. Treasury bond yields are observable, proxies for those expectations, such as a Blue Chip forecast, should not be used.

Staff further notes that the Blue Chip Financial Forecasts relied on by Ms. McShane to estimate the long-term economic growth reveals that the forecast did not include the recessionary period in 2009 and 2010, and submits that when using a forecasted growth rate for the economy, the whole business cycle must be included in order to get a measure of the normal steady state rate of growth that can reasonably be expected over the long term.

d. Beta

Staff proposes to use regression betas in this proceeding, while AIU proposes to use Value Line betas. While AIU complains that regression betas have been consistently lower than Value Line betas, Staff notes this argument does not provide insight into which beta estimation procedure is superior. Staff opines that Value Line, Zacks, and regression betas are estimates of the unobservable true beta, which measures investors' expectations of the quantity of non-diversifiable risk inherent in a security. Staff avers that different beta estimation methodologies can produce different betas when those methodologies employ different samples of stock return data. Staff submits that its methodology used to calculate the regression betas for the gas sample, which Staff has regularly used and the Commission has consistently approved, employs the same monthly frequency of stock price data as the widely accepted Merrill Lynch methodology. Staff states further that Ms. McShane's argument to exclude Staff calculated betas and rely upon only Value Line betas was rejected by the Commission in Docket No. 00-0340.

Staff avers that while Ms. McShane presented an analysis comparing weekly and monthly betas to support her conclusion that weekly betas are to be preferred, the statistics that she presents do not compare the "superiority" of the parameter estimates, but rather they test the predictive ability of the model. Staff argues that to test the predictive accuracy of different betas, the beta estimate has to be the independent variable, while in Ms. McShane's analysis, beta is the parameter estimate. Staff opines her test simply indicates how much the variation in the market return explains the variation in the return of the stock, but does not support the conclusion that monthly betas are statistically inferior to weekly betas. Staff notes that Ms. McShane did not provide any academic support for her conclusion that weekly betas are superior to monthly betas. Staff avers that in response to Staff DR JF 6.04, AIU stated that Ms. McShane was not aware of any studies that have addressed whether weekly betas are more accurate predictors of future utility stock performance than monthly betas.

In contrast, Staff cites two studies that compared weekly and monthly beta estimates but neither concluded that either beta was superior. Staff opines that those studies found a relatively weak relationship between Value Line and Merrill Lynch betas and showed that the major cause of the significant differences in beta was the use of monthly versus weekly return intervals. Staff argues that the difference in beta estimates may be the effect of non-synchronous trading, which occurs when the market return reflects information that is not yet reflected in the stock's return.

Staff notes it investigated whether non-synchronous trading was a problem for weekly or monthly betas. Staff avers that to account for the lag in stock price reaction to economic events that affect the market, security returns can be regressed against the returns of the market in the current period as well as the returns of the market in prior periods, with the coefficients for the current and lagged regressions summed together to derive a beta estimate. Staff argues it calculated Ms. McShane's weekly regression betas with three lags, with the security returns of the gas sample lagging behind the market data by one, two and three weeks. Staff notes the one and two week lags, which are -0.07 and -0.11, respectively, are statistically different from zero, which indicates that non-synchronous trading is a problem with Ms. McShane's weekly data. Staff also calculated the lag beta for the monthly regression beta for the gas sample that Staff proposed. Staff avers the lag beta was not significantly different from zero, which indicates that non-synchronous trading was not a problem when using monthly data.

While Ms. McShane speculated that the results might relate to the market conditions during the financial crisis since the same analysis conducted for the periods ending 2005 and 2006 produces different results, Staff states that its lag beta analysis used the same five-year time period as Ms. Freetly's CAPM analysis to estimate the investor-required ROR. Staff opines it is the relevant time period to examine to determine whether non-synchronous trading affected the data Ms. Freetly used to calculate beta.

Further, Staff compared the coefficient of variation using Ms. McShane's weekly and monthly data, noting the coefficient of variation was higher for weekly data. Staff states although the higher number of observations of the weekly data increases the degrees of freedom, and hence narrows confidence intervals, it also increases the magnitude of the variation relative to the mean of the sample stock returns, which leads to an increase in random error.

Staff opines that weekly and monthly betas have strengths and weaknesses relative to each other. Staff states that Ms. McShane's analysis shows the standard error of weekly beta estimates is generally lower than those for monthly beta estimates, indicating that weekly betas are usually more reliable, or have lower variation in the beta estimate than monthly betas. Conversely, Staff avers that monthly betas are less susceptible to non-synchronous trading than weekly betas. Staff argues monthly betas are calculated from returns that have lower coefficients of variation than weekly betas, which indicates that the monthly betas are more accurate than weekly betas. Since neither type of beta is clearly superior to the other, Staff recommends the Commission equally weight weekly and monthly betas in determining a cost of common equity with the CAPM.

e. Market Risk Premium

While Ms. McShane states that a "spot" yield should not be relied upon as representative of expected yields and used as the risk-free rate in the CAPM, Staff avers that the current U.S. Treasury yields that Staff used to estimate the risk-free rate reflect all relevant, currently available information, including investor expectations regarding future interest rates. Staff argues that investor appraisals of the value of forecasts are reflected in current interest rates, therefore, if investors believe that the forecasts are valuable, that belief would be reflected in current market interest rates. As interest rates are constantly adjusting and accurately forecasting the movements of interest rates is problematic, Staff urges the Commission to continue to rely on current, observable interest rates rather than the forecasted rates supported by Ms. McShane.

Although AIU maintains that the "spot" interest rates are not appropriate for application of the CAPM since a forward looking estimate of the cost of equity should recognize the high probability that U.S. Treasury yields will increase, Staff argues the current U.S. Treasury yields that Staff used as the risk-free rate reflect all relevant, currently available information, including investor expectations regarding future interest rates. Staff avers that as of August 18, 2009, investors were willing to accept a 4.40% return on U.S. Treasury bonds. Staff states there is no valid justification for disregarding the investor expectations directly reflected in objective, observable current market data in favor of a proxy for those expectations imbedded in speculative projections.

Staff notes that AIU chose to initiate this proceeding during a severe economic recession when it appears a large segment of its customer base is suffering financially, and during economic downturn, interest rates have fallen. Staff's recommended cost of common equity reflects that economic reality, while AIU would have the Commission reward AIU's decision to file a rate case during a severe economic recession with a rate increase that assumes that AIU filed its requested rate increase during a far more favorable economic environment.

IIEC argues that Staff's market risk premium in its CAPM analysis is overstated, Staff recognizes that some of the growth rates used in Staff's DCF analysis of the S&P 500 are unsustainably high, which produces an upward bias in Staff's market return estimate, and, thus in Staff's CAPM cost of equity estimate. Staff avers that while there is upward bias in Staff's estimate of the market return, there is no way to know the extent of the bias. Staff notes it did not use a non-constant growth DCF to estimate the return on the market because of the extreme difficulty of applying the more elaborate model to 500 companies. Staff states Mr. Gorman's non-constant DCF analysis of the S&P 500 illustrates the difficulty of applying that model to the diverse group of companies that compose that index, as his estimate of the required return of the market is 8.71%, 129 basis points below his 10.00% rate of return on common equity recommendation for AIU. Staff asserts his results imply that the S&P 500 is less risky than AIU, which is not plausible.

f. Proposed Adjustments

(1) Financial Risk

Staff states that based on a simple average of her DCF and risk premium analyses, Ms. Freetly estimated that the investor-required rate of return on common equity is 9.63% for the gas sample and 10.44% for the electric sample, which are proxies for the gas and electric operations of AIU. Staff avers if the proxy does not accurately reflect the risk level of the target company, an adjustment should be made.

To estimate the financial risk of AIU going forward, Ms. Freetly compared the financial strength implicit in Staff's proposed revenue requirement for each company's gas and electric operations to Moody's guidelines for the regulated gas and electric utilities, focusing on four ratios: (1) Funds From Operations ("FFO") to interest coverage; (2) FFO to total debt; (3) retained cash flow to total debt coverage; and (4) debt to capitalization.

Staff states that Ms. Freetly concluded that Staff's revenue requirement recommendations, including Staff's cost of common equity recommendations, indicate levels of financial strength that are commensurate with a Baa3 credit rating for AmerenCILCO gas, an A3 credit rating for AmerenCIPS gas and a Baa3 credit rating for AmerenIP gas.

In contrast, Ms. Freetly notes the gas sample's average financial ratios for 2006-2008 are indicative of a level of financial strength that is commensurate with a credit rating of Baa1, which is consistent with the current average credit ratings Moody's has assigned the gas sample, indicating the gas sample's level of financial strength indicates that it has more financial risk than the gas operations of AmerenCIPS and less financial risk than the natural gas distribution operations of AmerenCILCO and AmerenIP. Given the difference between the credit rating commensurate with the forward-looking financial strength of AIU's gas distribution operations and the credit rating commensurate with the financial strength of the gas sample, Staff asserts the sample's average cost of common equity needs to be adjusted to determine the final estimate of AIU's cost of common equity.

Staff states that using 30-year utility debt yield spreads published by Reuters; Ms. Freetly calculated the yield spreads between the credit ratings implied by the financial ratios for AIU and those of the gas sample. Staff opines the spread between the implied ratings of A3 for AmerenCIPS and Baa1 for the gas sample is 50 basis points, while the spread between the implied ratings of Baa3 for AmerenCILCO and AmerenIP and Baa1 for the gas sample is 35 basis points. Staff notes to determine the cost of equity adjustment, Ms. Freetly then multiplied those yield spreads by 30%, which is the percent of the overall credit rating that Moody's assigns to the financial ratios under the new rating methodology for regulated gas and electric utilities. Staff therefore recommends a financial risk adjustment to the cost of equity for the gas operations of an increase of 10.5 basis points for AmerenCILCO and AmerenIP and a decrease of 15 basis points for AmerenCIPS.

Using the updated Moody's financial guideline ratios for electric utilities, along with AIU electric utilities' scores on those financial ratios, Staff submits Ms. Freetly concludes that Staff's revenue requirement recommendations, including Staff's cost of equity recommendations, indicate a level of financial strength that is commensurate with a Baa1 credit rating for AmerenCILCO, an Aa3 credit rating for AmerenCIPS, and a Baa2 credit rating for AmerenIP. In contrast, the electric sample's average financial ratios for 2006-2008 are indicative of a level of financial strength that is commensurate with a credit rating of Baa2, which Staff states is consistent with the current average credit ratings Moody's has assigned the electric sample. Staff argues the electric sample's level of financial strength indicates that it has more financial risk than the electric delivery service operations of AmerenCILCO and AmerenCIPS, therefore the sample's average cost of common equity needs to be adjusted to determine the final estimate of the cost of common equity.

Staff states that using 30-year utility debt yield spreads published by Reuters; Ms. Freetly calculated the yield spreads between the credit ratings implied by the financial ratios for AIU and those of the electric sample. Staff submits the spread between the implied ratings of Baa1 for AmerenCILCO and Baa2 for the electric sample is 20 basis points, while the spread between the implied ratings of Aa3 for AmerenCIPS and Baa2 for the electric sample is 100 basis points. To determine the cost of equity adjustment, Staff notes Ms. Freetly then multiplied those yield spreads by 30%, which is the percent of the overall credit rating that Moody's assigns to the financial ratios under the new rating methodology for regulated gas and electric utilities, therefore Staff's financial risk adjustment to the cost of equity for the electric operations is a decrease of 6 basis points for AmerenCILCO and 30 basis points for AmerenCIPS.

Staff and AIU agree that when a utility has more or less financial risk than the sample companies used to estimate the cost of equity, an adjustment to the cost of equity is necessary. Ms. McShane asserts that when the market value common equity ratio is higher than the book value common equity ratio, the market is attributing less financial risk to the companies than the book value capital structure suggests. Staff states she claims that since the investor required ROR is estimated based on the market value of the companies in the gas and electric samples, adjustments to recognize the higher financial risk implied by the book value capital structure of AIU is required.

Staff maintains that there is no merit to Ms. McShane's claim, arguing the fundamental problem with Ms. McShane's claim is that it assumes, without foundation, that the book value capital structure of AIU directly reflects investors' perceptions of the financial risk of AIU. Staff opines that while investors are unlikely to ignore the book value capital structure of companies generally and utilities specifically, investors' perceptions of AIU's financial risk inherent in its book value capital structure are not observable because its common stock is not market traded.

Staff states its recommendations reflect the revenue requirements necessary to set just and reasonable rates, which will remain in effect until a future rate proceeding. While Ms. Freetly used Staff's recommendations to estimate the credit metrics that may be achieved with the rates set in this proceeding, Staff's analysis of the implied level of financial strength of the gas and electric utility operations of each of the AIU is not an attempt to predict the rating outcome of Staff's position in these rate proceedings. Staff claims it did not attempt to determine its own credit ratings for AIU nor is Staff suggesting that simply because AIU's metrics fall within the guideline ranges that the implied ratings will result. Staff asserts it performed the ratio analysis in order to compare the financial strength of AIU, based on the FFO to interest coverage, FFO to total debt, DCF to total debt coverage and debt to capitalization, to those of the gas and electric samples. Staff opines the resulting ratios were translated into implied credit ratings only to have a metric on which to base an adjustment to the cost of equity.

Staff avers it did not use the current credit ratings of AmerenCILCO, AmerenCIPS and AmerenIP for comparison to the gas and electric samples for several reasons. Staff claims credit ratings reflect the risk of a company's entire operations, not just those operations subject to the Commission's rate jurisdiction. Further, Staff states credit ratings also reflect a company's affiliation with other companies, while Section 9-230 of the Act prohibits including in a utility's allowed ROR any incremental risk or increased cost of capital which is the direct or indirect result of a public utility's affiliation with unregulated or nonutility companies. Third, Staff asserts credit ratings reflect the credit ratings agency's forecast, and since those forecasts are not published, they can not be compared to Staff's revenue requirement recommendations. Staff states that based on this, AIU's credit ratings should not be relied upon absent an investigation of the underlying stand-alone, going forward strength of AIU.

Staff notes AIU claims that Staff's financial risk adjustment incorrectly assumes that equity investors quantify financial risk differences in the same manner as bond investors. Although Staff agrees that bond and common equity investors would not likely apply the same price to a given difference in financial risk, since Staff notes the price the latter would attach to financial risk can not be observed, a proxy is necessary. Staff claims the bond yield spreads that Staff's adjustment is based on are the best estimate of the different return requirements that investors would demand for varying levels of financial risk. Staff asserts it is an objective measure of the return equity investors would require to invest in AIU given the different levels of financial risk indicated by Staff's ratio analysis.

(2) Fixed Customer Charge

Staff notes the Commission authorized the AIU gas utilities to recover 80% of the fixed delivery service costs through the monthly customer charge in the last rate cases, which cost recovery method will remain in effect when the rates set in this proceeding go into effect. Staff asserts in AIU's last rate cases, the Commission recognized that this move toward more fixed cost recovery through the fixed monthly charge provides the AIU gas utilities more assurance of recovering its fixed costs of service for gas operations, reducing risk and providing the utilities greater assurance that the authorized ROR will be earned. Ms. Freetly's cost of common equity recommendation therefore includes the same 10 basis point adjustment to the cost of common equity for the AIU gas companies that the Commission found appropriate in the last rate cases to reflect the reduction in risk provided by this method of cost recovery.

While Ms. McShane claims that eight of the nine gas distributors in the Gas sample have similar mechanisms in place and therefore, the cost of common equity estimate for the gas sample already reflects the risk reduction, Staff states most of the companies in the gas sample have in place some sort of de-coupling mechanism, some of those mechanisms are only applicable to a portion of the company's service territories, and one of the companies has no de-coupling mechanism at all. Staff opines that a small cost of equity adjustment for the reduction in risk provided by this method of cost recovery is warranted, and the 10 basis point downward adjustment adopted in AIU's last rate case is appropriate in this proceeding.

(3) Uncollectibles Riders

Staff asserts its cost of equity recommendations do not take into account any change in risk associated with the new uncollectibles riders AIU approved in Docket No. 09-0399, therefore, Staff recommends further adjustment to the cost of common equity for the uncollectibles riders authorized by the Commission.

Staff argues the uncollectibles riders approved in Docket No. 09-0399 ensure more timely and certain collection of bad debt expense, which provides greater assurance that the Companies will earn their authorized rates of return. Staff states that since the uncollectible riders would reduce uncertainty of cash flows, it would reduce risk, and therefore, downward adjustments to AIU's rates of return on common equity would be appropriate to recognize the reduction in risk associated with the use of the uncollectibles riders.

Staff notes that Moody's recently upgraded the ratings of the AIUs to investment grade reflecting reflects positive developments in Illinois, including the recently passed legislation providing Illinois utilities with a bad debt rider. Staff avers that Moody's acknowledges that such riders would reduce the risk of the utilities by providing greater assurance of bad debt cost recovery and factored that into the decision to upgrade the AIUs to investment grade.

Staff states it is unaware of any established approach for precisely gauging the effect the adoption of the uncollectibles riders would have on investors' perceptions of AIU's risk levels and the resulting costs of equity, therefore any adjustment will inevitably be inexact. Therefore, Staff's proposed adjustments for Riders GUA and EUA reflect a range of alternatives using two distinct approaches.

In the first approach, Staff estimated the effect the adoption of Riders GUA and EUA would have on AIU's Moody's credit ratings and based the adjustment of the resulting change in the implied yield spreads. Staff states Moody's updated rating methodology for regulated electric and gas utilities focuses on four core rating factors: regulatory framework, ability to recover costs and earn returns, diversification, and financial strength and liquidity.

Staff avers that of the four updated rating factors, the adoption of an uncollectibles rider would affect the utilities' ability to recover costs and earn returns, which factor assesses the ability of the utility to recover prudently incurred costs in a timely manner. For local gas distribution companies in the United States, Staff opines this factor addresses the sustainable profitability and regulatory support assessments in the previous methodology. Staff argues a utility's score on this factor would improve with implementation of an uncollectibles rider that allows timely adjustment of rates to cover uncollectible costs since its ability to earn its authorized ROR would be enhanced, and notes Moody's assigns a 25% weighting to this factor.

Staff assumed that the credit rating assigned to this factor would improve by one credit rating (3 points on the numeric scale) with the implementation of the uncollectibles rider, which would raise the score for this factor by 3 rating points, and result in an improvement to the Companies' overall credit ratings of approximately one credit rating notch.

Staff asserts that for the natural gas distribution operations, this analysis indicates that the going forward level of financial strength is consistent with credit ratings which would change from Baa3 to Baa2 for AmerenCILCO and AmerenIP and from A3 to A2 for AmerenCIPS. Staff opines the returns on common equity would be reduced by the 15 basis point spread between credit ratings of Baa3 and Baa2 for AmerenCILCO and AmerenIP, and by the 10 basis point spread between credit ratings of A3 and A2 for AmerenCIPS.

For the electric delivery service operations, Staff argues its analysis indicates that the going forward level of financial strength is consistent with credit ratings which would go from Baa1 to A3 for AmerenCILCO, Aa3 to Aa2 for AmerenCIPS, and from Baa2 to Baa1for AmerenIP. Staff argues the returns on common equity should therefore be reduced by the 50 basis point spread between credit ratings of Baa1 and A3 for AmerenCILCO, the 10 basis point spread between credit ratings of Aa3 and Aa2 for AmerenCIPS, and by the 20 basis point spread between credit ratings of Baa2 and Baa1 for AmerenIP.

Staff states the second approach is an iterative process of adjusting Staff's cost of common equity estimate downward to offset the increased operating income resulting from the adoption of Rider GUA in Docket No. 09-0399 (hereafter, "Operating Income Analysis"). Based on Staff's pre-adjustment ROR recommendations of 9.64% for AmerenCILCO gas and AmerenIP gas and 9.38% for AmerenCIPS gas and Staff's rate base recommendations of $190,360,000 for AmerenCILCO gas, $193,701,000 for AmerenCIPS gas, and $511,117,000 for AmerenIP gas, Ms. Freetly calculated pro forma operating incomes without Rider GUA (Staff's rate base x ROR recommendations) of $15,135,546 for CILCO gas, $14,884,141 for CIPS gas and $44,473,038 for IP gas. To estimate the effect Rider GUA would have on the pro forma operating income of each of the AIU gas utilities, Staff avers that Ms. Freetly subtracted the companies' estimates of uncollectibles recovery via base rates from the Account 904 balances for the years 1999-2008, dividing the average difference between the companies' estimates of uncollectibles recovery via base rates and Account 904 balances over the last 10 years by the pro forma operating income without Rider GUA. If Rider GUA had been in effect during the last 10 years, Staff's analysis indicates if Rider GUA had been in effect during the last 10 years, the pro forma operating incomes for the gas operations of AmerenCILCO, AmerenCIPS, and AmerenIP would have been approximately 9.61%, 10.35%, and 5.60% higher, on average. Ms. Freetly then multiplied the pro forma operating incomes for the gas operations of AmerenCILCO, AmerenCIPS, and AmerenIP by those respective amounts to estimate the effective pro forma operating incomes if Rider GUA were adopted but no adjustments were made. Staff states Ms. Freetly then adjusted her cost of common equity downward until the pro forma operating incomes under Rider GUA equaled the original pro forma operating incomes Staff calculated for the companies without Rider GUA. Staff opines this process produced downward adjustments to the costs of equity for the gas operations of AmerenCILCO, AmerenCIPS, and AmerenIP of approximately 160, 149, and 106 basis points, respectively, to reflect the risk reduction associated with Rider GUA.

Staff states it performed the same calculation regarding AIU's electric operations, additionally performing various calculations involving Staff's pre-adjustment ROR recommendations for AIU, along with the ratio of average Account 904 balances to pro forma operating income for each AIU. Staff in its Initial Brief ("IB") discusses the exact formula it used to estimate the operating income for each company if the respective uncollectible rider had been in effect. (Staff IB at 137-140) Staff asserts that this process produced downward adjustments to the costs of common equity for the electric operations of AmerenCILCO, AmerenCIPS, and AmerenIP of approximately 76, 119, and 48 basis points, respectively, to reflect the risk reduction associated with Rider EUA.

While AIU Nelson criticizes Staff's recommendation to adjust the ROR downward to reflect the reduced risk from adoption of the uncollectibles rider, claiming there should be zero impact on the ROE; Staff claims this is contrary to financial theory on the trade off between risk and return. Staff claims the increased certainty of uncollectibles cost recovery by adoption of the riders results in a reduction in risk and, thereby, warrants a reduction to the cost of common equity, as the adopted riders remove uncertainty associated with the recovery of uncollectible expense.

Although Mr. Nelson claims that the riders provide reciprocal benefits to shareholders and ratepayers, Staff avers the uncollectibles riders shift the risk of under recovery of uncollectibles expense from investors to the customers who pay their bills, in essence requiring ratepayers who pay their bills to provide a guarantee to AIU that all of its uncollectibles expense will be recovered. Staff notes that if ratepayers are compensated for the guarantee that they will provide, Mr. Nelson would be correct that ratepayers would get a benefit from providing this guarantee to AIU and its investors; however AIU seeks to deny ratepayers that compensation.

AIU's claim that Staff's proposed adjustment to the ROE is an indirect approach to ensure that AIU continues to under recover uncollectibles and is punitive in nature ignores, Staff opines, that the uncollectible riders guarantee AIU recovery of uncollectible expenses, thereby reducing the uncertainty of cost recovery. Staff notes that guarantees have costs in the financial markets, and as AIU is asking its customers to guarantee the recovery of uncollectible expenses through the rider mechanism, AIU ratepayers should be compensated for providing that guarantee.

Staff opines that basing the magnitude of the ROR adjustment on the amount of uncollectibles is appropriate not only because the amount of risk that is shifted from investors to ratepayers is related to the amount of uncollectibles, but it also provides AIU with a financial incentive to reduce uncollectibles. Staff states the lower the amount of uncollectibles, the lower the downward adjustment to the ROR related to Riders GUA and EUA.

While AIU states that Moody's was aware of the passage of this rider prior to its recent upgrade of AIU's credit ratings and no further upgrade could be expected, Staff claims Moody's upgrade to AIU's credit ratings directly affects the cost of AIU's credit facilities and will affect the cost of future debt issues. Staff avers that upgrade does not affect the starting point for analysis of AIU's costs of common equity: the costs of common equity of the gas and electric samples. Staff notes it used the effect of the riders on credit ratings as one proxy of the effect of the riders on cost of common equity.

Staff states that AIU's comparison of Staff's financial risk adjustment and Staff's adjustment for the uncollectibles riders is not valid. Staff avers that the uncollectibles rider adjustment affects operating risk, not financial risk. Staff notes the operating income analysis recognizes the effect of the adoption of the uncollectibles riders and is based on the under-recovery experienced by each of the Companies over the last 10 years. The uncollectibles data shows that the affect of Rider GUA on AmerenCILCO gas would be greater than AmerenIP gas given the fact that uncollectibles is a much higher percentage of AmerenCILCO gas' operating income.

Staff notes that the results of its two analyses of the effects of the uncollectible riders range from 15 to 160 basis points for AmerenCILCO gas operations, 10 to 149 basis points for AmerenCIPS gas and 15 to 106 basis points for AmerenIP gas. Based on the midpoints of those ranges, Staff recommends adjustments to the costs of common equity for the gas operations of AmerenCILCO, AmerenCIPS, and AmerenIP of 87.5, 79.5, and 60.5 basis points, respectively, to reflect the reduced risk that will result from the adoption of Rider GUA. Staff states the results of this calculations range from 50 to 76 basis points for AmerenCILCO electric, 10 to 119 basis points for AmerenCIPS electric, and 20 to 48 basis points for AmerenIP electric. Staff recommends using the midpoints of those ranges, with adjustments to the costs of common equity for the electric operations of AmerenCILCO, AmerenCIPS, and AmerenIP of 63, 64.5, and 34 basis points, respectively, to reflect the reduced risk that will result from the adoption of Rider EUA.

3. AG/CUB Position

a. Return on Equity Estimates

AG/CUB states that the Commission's task is to ensure that the cost of equity capital used to develop rates compensates investors for their investment risk, while assuring that customers do not pay an excessive or unreasonable return in those rates. AG/CUB avers that this is a decision made by weighing the relative riskiness of the regulated company against the relative riskiness of other investments, a task complicated by the fact that a "fair" return changes over time as the debt and equity markets change. AG/CUB notes that in the past two years, the relevant market changes include a fall in stock prices (as measured by the S&P 500) of more than 50% from the fall of 2007 through March 2009.

AG/CUB suggests that the problem with using the DCF and CAPM with the inputs AIU proposes is that the limited credit availability that has been endemic of the crisis has been caused by uncertainty in market fundamentals. AG/CUB submits that as the financial crisis has made clear, financial information from typical financial industry sources, such as rating agencies, can be dramatically wrong and strongly biased.

AG/CUB argues that the financial climate requires the Commission to return to basics instead of simply repeating past approaches that ignore very different market circumstances. AG/CUB notes that while CUB witness Thomas uses the same DCF and CAPM models, he adjusts the models, as well as the data inputs used in the models, to reflect the credit crisis and resulting discontinuity in the financial markets.

AG/CUB argues that AIU's analysis of the appropriate ROE is flawed because it incorporates overstated estimates of company growth and overstates the degree to which utility stock prices correlate to market prices, both of which increase AIU's proposed cost of equity estimate. While Ms. McShane proposes to increase these estimates further, producing different returns for each operating subsidiary based on the mistaken notion that the Commission should adjust returns to reflect the divergence of market and book values, AG/CUB opines that this results in inflated and unsupportable results. AG/CUB also notes that Ms. McShane advocates a comparable earnings test which has been rejected by the Commission in recent cases.

While AIU argues the Commission should reject Mr. Thomas' cost of common equity because it is not comparable to any cost of equity or return granted by other regulators, AG/CUB notes that the Commission has rejected such arguments in the past, noting each company must show that its proposed ROE is just and reasonable. AG/CUB argues that instead of rejecting Mr. Thomas' results because AIU finds them to be lower than any reasonable indicator of the returns investors expect, the Commission should base its order on the entirety of the record evidence, including the reasonableness of the analysts' various models and the inputs and assumptions. AG/CUB notes that the Commission has historically used the DCF and CAPM models, however Mr. Thomas testified that real world investors use very different techniques to determine the true cost of equity capital.

AG/CUB states that all parties have observed that the economic recession that began in 2008 has produced a very different economic climate than that of times past. AG/CUB argues that financial information from typical financial industry sources, such as rating agencies, can be dramatically wrong and strongly biased, and opines that the use of DCF and CAPM, both of which has been relied upon by the financial markets for a number of years, have proven to be unreliable in estimating an appropriate ROE.

AG/CUB further urges the Commission to reject AIU's proposed financial risk adjustment, noting that the Commission applies a market-determined ROR to the book value of the capital structure, and AIU presents no evidence that a change from this practice is required. AG/CUB opines that adjusting market-based DCF results before applying them to the book value of assets in rate base inflates the market-based cost of equity.

AG/CUB further supports the proposal by Ms. Freetly to adjust the AIU gas utilities' rate of return on common equity downward by 10 basis points, and continues to support her proposed adjustment to account for the presence of the AIU uncollectibles riders. AG/CUB avers that such an approach is reasonable in the event the riders are implemented. AG/CUB therefore recommends a return on common equity for AmerenCILCO's gas and electric operation of 6.92% and 8.35%; AmerenCIPS' gas and electric operation of 7.13% and 8.09%; and AmerenIP's gas and electric operation of 7.12% and 8.47%, respectively.

b. DCF and CAPM Model Issues

AG/CUB notes that the DCF model estimates the cost of equity capital by assuming that investors who purchase stock are paying a price that reflects the present value of the cash flows they expect to receive from the stock in the future. AG/CUB avers that using information about the current stock price and expected future cash flows from dividend payments and earnings growth, the model, which is based on the relationships among various factors, estimates the return that investors expect to receive on their investment.

AG/CUB submits that the actual return required to induce investors to make a particular investment is not a directly observable number because investors' requirements for future dividends and rates of growth can not be found in the pages of the Wall Street Journal and plugged into the model. AG/CUB states that in this case, the analysis is further complicated by the current market upheaval and by the fact that AIU does not have publicly traded stock, which would provide current, objective dividend and price information. AG/CUB opines that instead, proxy groups of companies are used to estimate the investor-perceived level of risk associated with a company such as the AIU and make projections of AIU's future growth. AG/CUB states the fundamental difference between AG/CUB and AIU's analysis lies in what is used to project AIU's future growth.

AG/CUB opines that the CAPM is an alternative analytical tool commonly used in regulatory proceedings to estimate investors' required ROR, or the cost of equity capital for the firm. AG/CUB states that for a utility, the investors' required ROR is the risk-free rate plus the value of the non-diversifiable risk that investors take on by investing in the utility. AG/CUB avers that the amount of that non-diversifiable risk that investors are exposed to through their investment in a particular firm's shares is measured by a beta coefficient.

AG/CUB notes that the key assumptions of the CAPM are that (1) in the market, investors are compensated only for non-diversifiable risk, quantifiable as a uniform EMRP, and (2) beta is an accurate measure of the relative risk of an individual security when compared with the overall market. AG/CUB states that CAPM is generally best employed as a check of the DCF model, arguing there are several well-known problems with both the theory and practical application of the CAPM. AG/CUB opines that even in that limited role, the Commission must recognize the deficiencies of the CAPM, require appropriate inputs, and use the results judiciously. AG/CUB asserts that the CAPM analysis presented by Ms. McShane has both an inappropriate adjustment of the beta parameter, and a grossly overstated EMRP.

c. Growth Rates

AG/CUB notes that the growth rate component of a DCF model represents the sustainable growth that investors expect in their investment due to expected increases in a company's earnings, which growth rate must be consistent with, and supported by, the economic conditions and dividend payout policies expected to occur. AG/CUB argues that in this environment, investors are focused on short-term changes in the equity markets, and as a result, both forecasted and historical growth rate information become highly subjective measures of expected future growth for individual firms. AG/CUB avers that while it is difficult to predict with accuracy a sustainable constant growth rate for companies, expectations of long-term growth in the U.S. economy are reasonable, and can be measured by the historic growth in real gross domestic product.

AG/CUB urges the Commission to use the following three basic criteria to evaluate projections of company growth earnings: (1) growth rate inputs must be reasonable in light of anticipated growth in GDP; (2) the long-term growth rate must not implicitly require continued earnings above the regulated firm's cost of equity, as derived in the analysis; and (3) the long-term growth rates must not require dividend payout ratios that are not consistent with the capital expenditure growth rate and the ROE.

AG/CUB submits that current analysts' standard three- to five-year growth projections do not meet these tests, something the financial literature has examined in recent years. AG/CUB opines that many researchers have found that analysts tend to be optimistic about future growth and produce forecasts that are upwardly biased, which translates into DCF cost-of-capital estimates that are above the true required cost of capital.

Ms. McShane argues that various studies have concluded analyst forecasts are a better predictor of growth rates than historic growth estimates. In support of her contention, AG/CUB notes that Ms. McShane cited articles from more than 20 years ago, contrasted with the information Mr. Thomas relied on from the past decade. AG/CUB opines that if Mr. Thomas' and Ms. McShane's proposed growth rates are compared, it is clear that Ms. McShane's proposed rates would require the companies in her own sample to first, exceed their own historic growth rate, and second, significantly exceed the historic growth rate in GDP. AG/CUB avers that Ms. McShane has not supported this inflated level of growth with any meaningful analysis or explanation, and the Commission can not rely on her analysis because it relies on growth expectations that are inconsistent with expectations in growth for GDP.

AG/CUB states an additional problem with Ms. McShane's proposed growth rates is found in the projections of dividend payout ratios she uses in her analysis, which show that analysts do not expect the earnings and dividend growth rates of the sample companies to grow at the same rate. AG/CUB avers that in such a situation, neither the earnings nor dividend growth rates provide an accurate reflection of the sustainable growth investors are expecting.

AG/CUB states that when dividend payout ratios decline, investors will expect more growth to come from earnings, because more capital has been retained for internal investment in the business, which will result in the DCF overstating the cost of equity. Similarly, an increasing dividend payout ratio will cause investors to expect less growth from earnings, and the DCF will understate the cost of equity.

d. Beta

AG/CUB notes that Ms. McShane uses Value Line betas in her analysis, which are raw beta estimates adjusted for “mean reversion.” AG/CUB argues that when Value Line performs the mean reversion adjustment, it incorporates three key assumptions: (1) betas are unstable; (2) betas will eventually move to 1.0; and (3) the risk of the utility companies will eventually move toward the overall risk of other non-utility companies. AG/CUB avers that by “unstable,” Value Line is assuming that utilities, which typically have betas below 1.0, will tend to become more risky over time, and the beta will tend to move closer to 1.0. AG/CUB opines that this is essentially a presumption that state commissions will be unable or unwilling to maintain stability for a monopoly firm that can modify its earnings through a regulatory process, instead of against the opposition of competitors.

AG/CUB submits that studies show, however, that the beta of utility companies does move toward the average risk of other companies over time. AG/CUB argues that even the initial study commonly cited as the basis to support the mean reversion adjustment, by Professor Marshall E. Blume, questions the usefulness of a one-size-fits-all mean reversion adjustment. AG/CUB submits that while Dr. Blume found that the accuracy of betas was improved by some adjustment; he also noted that the use of the historical rate of regression to correct for the future rate will not perfectly adjust the assessments and may even introduce larger errors into the assessments than were present in the unadjusted data.

AG/CUB states that Dr. Blume uses a dynamic or changing adjustment factor in his study and concluded that a static adjustment, such as the one used by Value Line, was not conclusively better than a purely unadjusted beta. AG/CUB avers that while the Commission has accepted a static adjustment without question in the past, there is no evidence in this case that a “one-size-fits-all adjustment” is reasonable or results in appreciably better beta estimates, and that with utility betas typically below 1.0, the unwarranted adjustment has the effect of improperly increasing betas and the overall CAPM cost of equity. AG/CUB urges the Commission to use a beta that is derived from betas reported by a variety of financial reporting sources.

e. Market Risk Premium

AG/CUB states there are two main approaches to deriving the EMRP input for a CAPM analysis: either EMRP estimates derived from the academic studies of market performance are used, or an EMRP estimate is calculated for particular situations, noting Ms. McShane uses the latter approach. While Ms. McShane uses EMRP values of 9.1%, and 6.25 to 6.5%, in her analysis, AG/CUB argues the use of analysts' growth forecasts in determining investors' growth expectations is an unreliable method, and as a result, her EMRPs are grossly overstated.

AG/CUB avers that given the questions concerning how to determine the appropriate EMRP, the Commission should look to research and analysis performed by unbiased academics over many years instead of the assertions or ad hoc calculations of interested participants in economic contests. AG/CUB submits that the overwhelming conclusion from current research on the EMRP is that the return expected by investors and appropriate for use in the CAPM is far lower than returns calculated from selective samples of historic information. AG/CUB opines that the historic record, financial theory, and prospective estimates based on stock prices and growth expectations all indicate that the future equity premium in developed capital markets is likely to be between 3% and 5%, far lower than the 8% historic returns calculated from selective historic data.

AG/CUB asserts that in recent years, the Merrill Lynch expected return estimates have indicated an EMRP in the region of 4% to 5%, while an annual survey of pension plan officers regarding expected returns on the S&P's 500 for a five-year holding period indicated an EMRP in a 2% to 3% range. AG/CUB opines that Value Line projected market risk premiums are more volatile, ranging in recent years from 2% to 6%.

While Ms. McShane challenges this research, arguing it is no longer relevant because of the significant market correction and recent financial crisis, AG/CUB argues that Mr. Thomas examined this research, and provided updated information on current research reveals that a 5% EMRP may be too high. AG/CUB argues that current academic research looking at post-crisis equity risk premiums has shown that current estimates range from between 3.4% and 5.1%.

AG/CUB submits Ms. McShane's EMRP values are outside the estimates provided by the academic research, while Mr. Thomas used the higher end of the EMRP spectrum in his CAPM analysis, 5%. AG/CUB asserts that calculating an individual EMRP based upon analysts' forecasts inappropriately reflects the current short-term discontinuity, while the Commission's task is to set a cost of equity capital that is sustainable over the period that rates are in effect.

Ms. McShane proposes a historic equity risk premium and a DCF-based equity risk premium test, although AG/CUB notes the Commission has historically rejected risk premium analysis other than the CAPM. Ms. McShane also proposes a comparable earnings analysis, which AG/CUB points out the Commission has likewise traditionally rejected. AG/CUB submits that the Commission's task is to set rates for AIU based on the specific risks facing AIU.

While Ms. McShane argues that market-to-book adjustments are necessary to reflect differences between AIU book values of common equity and sample firms' market value capital structures, AG/CUB argues there is no evidence supporting such an adjustment, and the result would be to inflate the DCF cost of equity estimates above the already inflated results Ms. McShane's analysis produces. AG/CUB opines it has traditionally been the Commission's practice to apply unadjusted market-based DCF results to the book value rate base assets.

f. Proposed Adjustments

AG/CUB states that both of Staff's proposed calculations of the effect of the uncollectible riders are appropriate in determining the appropriate cost of common equity for AIU. AG/CUB submits these riders will ensure more timely and certain collection of bad debt expense and provide greater assurance that AIU will earn its authorized rates of return, reducing AIU's risk by reducing the uncertainty of cash flows by shifting the risk of under-recovery of uncollectibles expense from investors to the customers who pay their bills. AG/CUB avers that equity holders are exposed to more cash flow risk than debt holders because the structure of public utility debt assures that debt holders are paid first out of a companies' earnings, so the benefits of these risk reduction accrue directly to a companies' common equity shareholders. AG/CUB further notes that because these riders provide revenue stability, the value of this stability accrues directly to equity shareholders. AG/CUB states it is appropriate for the Commission to consider this when calculating AIU's cost of equity and the Commission should therefore adopt Staff's proposed adjustment for the uncollectible riders.

4. IIEC Position

a. Return on Equity Estimates

IIEC recommends that the Commission approve a ROE of 10.0% for the electric and gas utility operations of AIU. IIEC argues that its recommended ROE is a conservative estimate, as a comparison to Staff's recommended ROE shows that Staff's cost of equity estimate for gas operations is slightly lower, while the estimate for electric operations is slightly higher.

To estimate AIU's cost of equity, Mr. Gorman used a combination of analytical models. Employing a constant growth DCF model, a sustainable growth DCF model, a multi-stage growth DCF model, and a CAPM model, IIEC witness Gorman developed a return on common equity consistent with the governing legal standards. Because the AIU utility companies are not publically traded, Mr. Gorman and the other ROE witnesses in this case applied their models to groups of publicly-traded utilities with investment risk similar to that of AIU. IIEC states that Mr. Gorman analyzed the equity ratios and business risk profiles of the electric proxy group and AIU, and found that they are comparable in risk. Similarly, he found that the equity ratios, business risk profiles, and bond ratings of the gas proxy group are comparable. Mr. Gorman therefore used the electric and gas proxy groups developed and presented in the direct testimony of AIU witness McShane.

Mr. Gorman's DCF analysis is based on the premise that the price of an individual stock is determined by the present value of all expected future cash flows discounted at the investor's required ROR. IIEC notes that this theory has been accepted in the Commission's repeated reliance on DCF estimates as a basis for its cost of equity determinations. IIEC states that Mr. Gorman used two different versions of the constant growth DCF model. In both versions of his constant growth DCF model, Mr. Gorman relied on the average of the weekly high and low stock prices over a 13-week period ending August 21, 2009 for the stock price input into the model. Mr. Gorman judged the 13-week period to provide a reasonable balance between the need to reflect current market expectations and the need for sufficient data to smooth out aberrant market movements. For the dividend input to the model, he used the most recently paid quarterly dividend reported in the Value Line Investment Survey.

The first version of Mr. Gorman's constant growth DCF analysis relied on security analysts' growth rate estimates as the input representing the expected dividend growth rate. Specifically, he relied on security analysts' estimates for the companies in his proxy groups, from Reuters, Zacks, SNL Financial, and Thomson Financial, as reported on-line on August 24, 2009. Mr. Gorman averaged those results to develop growth rate estimate inputs. Mr. Gorman's constant growth DCF (analyst growth) analysis indicated average returns on equity of 12.19% for his electric group and 10.36% for his gas group.

IIEC avers, however, that Mr. Gorman concludes that this version of the constant growth DCF analysis produced unreliable results. Mr. Gorman observes that these results were based on a dividend yield (5.23%) that is distorted by current constrained market conditions and on a growth rate of 6.15%, which is not sustainable indefinitely, as the constant-growth DCF model requires. The growth rates for the electric group and gas groups exceed the projected rate of growth of the overall U.S. economy, are significantly higher than the historical dividend yield for the proxy groups, and diverge from their historical relationship with rate of inflation. The U.S. economy is projected to grow at a rate of 5% over the next 5-10 years. The average (6.67%) and median (5.63%) analysts' growth rate estimates for the electric group, and the average (5.84%) and median (5.67%) analysts' growth rates for the gas proxy groups exceed the projected rate of growth rate for the U.S. economy over the next 5-10 years. IIEC states that investment in utility plant is made to meet growth in demand for the utility's products, and that growth in demand is tied to economic growth of the utilities' service area. IIEC avers that historically, utility sales growth has lagged behind GDP growth, which thus represents a ceiling or high end sustainable growth rate for a utility over time.

IIEC argues that these dividend yield and growth factors are also inconsistent with each other, as they reflect contradictory outlooks for the utility industry. The factors that account for the recently higher dividend yield are drops in the stock price due to concerns about the economy, the level of utility sales, and decreased capital spending that slows rate base growth. Such factors tend to limit future earnings and dividend growth, but the growth rate component of the DCF model continued to reflect extraordinary and robust growth outlooks for both the electric and gas groups. Mr. Gorman, therefore, concluded the current market growth estimates for the proxy groups appear to contradict the growth outlooks reflected in the growth rate projections of security analysts. Specifically, Mr. Gorman notes that the historic dividend yields for his proxy groups were significantly lower than the current dividend yields for those groups. Mr. Gorman opines that the current dividend yield is driven by market uncertainty and the decrease in the stock prices of the proxy group, which in turn increased the proxy group dividend yield.

Mr. Gorman’s second version of the constant growth DCF model uses the same inputs as the first, with the exception of the growth rate input. There Mr. Gorman uses a sustainable growth rate proxy for the expected growth rate. To develop this input, Mr. Gorman uses an internal growth rate methodology that includes external financing to develop that input. A sustainable growth rate estimates the amount of growth a utility can sustain indefinitely by retaining a percentage of its earnings, reinvesting those earnings in plant, and growing rate base and earnings for an indefinite period of time. Based on an assessment of sustainable long-term earnings retention rates, earned return on book equity, and an assessment of external growth opportunities if the utility sells stock at prices above book value, Mr. Gorman developed sustainable growth estimates for the electric and gas proxy groups. This constant growth DCF (sustainable growth) analysis produced an average return on common equity for his electric group of 10.48% and 9.62% for his gas group.

IIEC notes that Mr. Gorman conducted an additional DCF analysis that avoided the errors that arise from using current high analysts’ growth rates that are not indefinitely sustainable, as proper application of the DCF model requires. IIEC opines that analysts’ growth rate projections are intended to be a reflection of rational investment expectations over only the next 3 to 5 years. IIEC avers that a constant growth DCF model can not reflect a rational expectation that a period of high/low short-term growth can be followed by a change in growth rates that are more reflective of long-term sustainable growth. Mr. Gorman, therefore, performed a multi-stage growth DCF analysis to reflect the expectation of changing growth rates. Mr. Gorman's multi-stage growth DCF model reflects three growth periods: short-term (first 5 years); transition period (next 5 years); and long-term (11th year through perpetuity). For the short-term growth input, Mr. Gorman relied on the consensus analysts' growth projections used in his constant growth DCF (analyst growth) model. For the long-term period, he used the consensus projected growth rate in the U.S. economy, represented by GDP. For the transition period, the growth rate was changed annually to move linearly from the analysts' growth rates to the GDP growth rate. For the other model inputs, Mr. Gorman used the same 13-week stock price and quarterly dividends used in his constant growth DCF models.

This multi-stage growth DCF model produced an estimated common equity cost for his electric proxy group of 11.30%, and 9.93% for his gas proxy group. His estimates reflect the median return for the proxy groups, to eliminate the distorting effect of outliers among the results.

IIEC states that based on the results of only his sustainable growth rate, constant growth DCF model and his multi-stage, non-constant growth DCF model, Mr. Gorman concluded that the DCF returns on common equity for his electric and gas proxy groups were 10.78% and 9.79%, respectively. IIEC notes that Mr. Gorman excluded the unreasonable results of the constant growth DCF based on analysts' growth projections.

Mr. Gorman also relies on a CAPM analysis to develop his recommended return on common equity for AIU. IIEC asserts that because the risk-free rate is typically represented by U.S. Treasury securities, Mr. Gorman uses Blue Chip Financial Forecasts' projected 30-year U.S. Treasury bond yields for his risk-free rate. The beta term in Mr. Gorman's CAPM analysis is the average Value Line beta estimate for his electric and gas proxy groups of comparable companies. The expected market return used to calculate the market risk premium was developed by Mr. Gorman using two market risk premium estimates of the return on the market. The first was a forward-looking estimate based on published estimates of the long-term historical real return on the market (proxied by the S&P 500), plus consensus analysts' inflation projection. The second estimate was based on estimates of total return and risk-free return components of the long-term historical market risk premium published in Morningstar's Stocks, Bonds, Bills, and Inflation 2009 Yearbook.

IIEC states that because of concerns the Commission has expressed in the past about the use of only historical data in cost of equity analyses, Mr. Gorman confirms the reasonableness of the market returns used in his CAPM analyses by developing a third estimate. This return was an expectational market risk premium estimate using a DCF return on the market derived from multi-stage and sustainable constant growth models.

Mr. Gorman's CAPM analyses for his proxy groups produce a midpoint ROE estimate of 9.43% for his electric group and 9.01% for his gas group.

Based on the analyses discussed above, Mr. Gorman recommends a cost of equity for AIU of 10.0%. That recommendation reflects a two-thirds weighting for the electric proxy group result of 10.1% and a one-third weighting for the gas proxy group result of 9.4%. IIEC argues that because Mr. Gorman's recommended return on common equity is based on the cost of equity for companies with risks similar to that of AIU, it is commensurate with returns investors could earn by investing in other enterprises of comparable risk, and will allow capital to be attracted to AIU under reasonable terms.

IIEC avers that a 10.0% return on common equity will also allow AIU to maintain its financial integrity, as represented by an investment grade bond rating. Mr. Gorman's financial integrity analysis also confirms the consistency of his recommendation with the requirements of the foundational judicial decisions of Bluefield and Hope.

IIEC notes that Mr. Gorman assesses the adequacy of his recommended return on common equity by comparing key financial ratios for AIU to both the old and the new

S&P credit rating financial ratio guidelines for A and BBB rated utilities, with a business profile score of 5. IIEC states that Mr. Gorman constructed the S&P financial ratios for AIU's utility operations using its utility operations cost of service data (not parent company financials), its respective proposed capital structures, and his return on common equity of 10.0%.

IIEC opines that Mr. Gorman's analysis demonstrates that AmerenIP would be provided with the opportunity to produce a FFO to debt interest expense ratio of 2.7x. This interest coverage ratio is near the low end of the old range for BBB rated utility companies (2.8x to 3.8x) and within the new range (2.0x to 3.5x). IIEC notes that AIU's total debt to total capital ratio would be 54%, which is within the old ranges for BBB rated utilities. IIEC further states that AIU's retail operations FFO to total debt coverage would be 14%, which is within the new ranges for BBB rated utilities.

IIEC asserts that Mr. Gorman's analysis shows that AmerenCIPS would have the opportunity to produce an FFO to debt interest expense coverage ratio of 5.7x, which ratio is above the high end of the old range for BBB rated utility companies and above the high end of the new range. IIEC opines that this will support a strong A credit rating with AmerenCIPS' total debt to total capital ratio at 47%, which is within the old ranges of 42% - 50% for A rated utilities, while AmerenCIPS' retail operations FFO to total debt coverage would be 28%, which is within both the new and the old ranges for A rated utilities.

For AmerenCILCO, IIEC indicates that Mr. Gorman's analysis shows the utility would be provided with the opportunity to produce an FFO to debt interest expense coverage of 3.3x. This interest coverage ratio at the high end of the old range for BBB rated utility companies (2.8x to 3.8x) and within the new range (2.0x to 3.5x), while AmerenCILCO's total debt to total capital ratio would be 54%. IIEC avers that this is within the old ranges for BBB rated utilities. IIEC notes that AmerenCILCO's retail operations FFO to total debt coverage would be 18%, which is within both the old and new ranges for BBB rated utilities.

IIEC submits that its recommended return on common equity for AIU (10.0%) will allow each of AmerenCIPS, AmerenCILCO and AmerenIP to maintain its financial integrity. IIEC asserts that Mr. Gorman’s DCF and CAPM analyses, updated to reflect more recent information, also support the recommended ROE of 10.0%.

IIEC argues that the costs of equity estimates developed by AIU are overstated, and should be rejected as the basis for the cost of equity determination in this case. IIEC asserts that there are several reasons why AIU's recommendations are inappropriate. IIEC avers that the most significant non-technical flaw is the fact that AIU's recommendations do not reflect recent changes in the financial market environment, with data taken mainly from time periods when the market was still severely distressed due to the market collapse of late 2008 and early 2009. IIEC opines that Mr. Gorman provides versions of his analyses that were modified to incorporate most of the methodology changes Ms. McShane recommended as part of her critique of his estimates and to use more recent data. IIEC states that these analyses show that simply updating Ms. McShane's input data had the most significant effect on her cost of equity estimates. Mr. Gorman's updated analyses produces a ROE of approximately 10.1%. IIEC argues that the 10.1% result of Mr. Gorman's updated analysis, incorporating the recommended changes of Ms. McShane, validates his original recommended ROE of 10.0% for AIU's gas and electric operations.

IIEC opines that a second reason Ms. McShane's recommended returns are overstated is her use of short-term growth forecasts in a constant growth model. IIEC notes that every expert in this case, including Ms. McShane, concludes that future growth will not be constant, because the forecast growth rates can not be sustained. IIEC avers that Ms. McShane's analyses incorporate the results of a model that assumes infinite constant growth, using an unsustainable growth rate, which mismatch has the effect of artificially inflating AIU's cost of equity estimates.

While AIU argues that Mr. Gorman's proposed combined ROE of 10.0% for AIU's gas and electric operations would result in cross-subsidies, erroneous investment decisions, and a misallocation of capital resources, IIEC argues that Mr. Gorman's recommendation reflects AIU's actual combination gas and electric investment fundamentals. IIEC notes that when AIU seeks capital in the market, AIU issues debt that reflects the risk of the combined gas and electric companies.

IIEC opines that from the perspective of the market, there is no separation in the investment risk of AIU's electric and gas operations, therefore a determination of the market-required cost of equity will reflect that consolidated risk profile, which results in common ROE, capital structure, and embedded debt cost determinations. IIEC avers that any separation of the electric and gas operations would not be based on true market information, but rather some allocation method devised to accomplish an artificial separation that does not exist in the market. IIEC asserts that the more direct and accurate measure of AIU's cost of equity is a determination of a fair ROE for AIU's consolidated operations. Should the Commission desire a ROE estimate that reflects the separation that AIU desires, then IIEC recommends 10.37% for electric operations, and 9.62% for AIU gas operations.

b. DCF and CAPM Model Issues

IIEC notes that through the testimony of its witness, Ms. McShane, AIU recommends that the Commission approve a ROE in the range of 11.75% to 12.25% for AIU's electric utility operations and a ROE in the range of 11.25% to 11.60% for AIU's gas utility operations, based on three DCF analyses, several risk premium studies, and a CAPM analysis. IIEC states that Ms. McShane also included in her recommendation, as an add-on to her model results, a leverage-type adjustment in the range 0.00% to 0.50% for electric, and 0.75% to 1.10% for gas.

IIEC argues that Ms. McShane's DCF return estimates are overstated, as they rely on growth rates in the constant growth rate DCF model that exceed reasonable estimates of long-term sustainable growth; while, Ms. McShane's DCF return estimates reflect dividend yields affected by the recent stock market downturn.

While Ms. McShane stated that Mr. Gorman's sustainable growth DCF model was in error because it did not include the external financing component, Mr. Gorman noted the external financing component was excluded because it indicated negative growth, which he concluded was not reasonable. Further, IIEC notes Mr. Gorman updated his sustainable growth DCF model to include the external financing model and it actually resulted in lower DCF return estimates.

IIEC avers that Ms. McShane's CAPM also produced an excessive return on common equity, in the range of 10.1% to 11.2% for her electric group, while her CAPM return estimates for her gas group were in the range of 9.8% to 10.7%; based primarily on her use of an overstated market risk premium.

While AIU proposes to inflate its cost of equity estimates, to take account of the difference between AIU's equity ratios computed using the book value of its equity share, and those ratios when computed using the market values of equity shares, IIEC notes that the Commission has repeatedly rejected numerous variations of such "leverage" adjustments that artificially boost the amount on which a utility earns a return. IIEC submits that no new evidence has been presented by AIU that should alter the Commission's position on this subject.

IIEC avers that Ms. McShane also estimated a ROE in the range of 15.0% to 16.0% based on a comparable earnings analysis that calculated the historical and projected returns on equity of 81 publicly traded companies. IIEC argues that this accounting-based return methodology does not measure the current market-based cost of capital necessary to attract investment and produces overstated returns in comparison to market-based (DCF, CAPM and Risk Premium) return estimates. IIEC opines that the Commission should continue to reject this flawed methodology.

While AIU argues in support of Ms. McShane's DCF estimate, stating that since she uses three DCF estimates, she therefore incorporates a potential range of utility investor expected returns, IIEC notes that one of the estimates incorporated in her analysis is the result of a constant growth DCF model that is inappropriate for the economic circumstances of record. IIEC opines that incorporating an estimate from a constant growth DCF model, which uses analysts' current growth forecasts as its long-term growth input, is not justified as its results are so inflated as to artificially raise an average with the other estimates.

Although AIU attacks Mr. Gorman's use of a multistage model, arguing that he has previously relied on a constant growth DCF model, IIEC notes that AIU's argument would appear to bind an expert to one estimation model and set of inputs for life, no matter the relevant circumstances. IIEC submits that Mr. Gorman relied on a constant growth model when it was appropriate, however as it does not now appear appropriate, he relies on a multi-stage model that is appropriate to the circumstances of record.

While AIU argues that Mr. Gorman's model selection substitutes subjective judgment for objective analysis, IIEC avers that Mr. Gorman used analysts' short-term projection for the period they are intended to represent, but rejected the short-term analysts projections as long-term growth projections. IIEC opines that short-term growth rates are not reasonable long-term growth rates estimates, and they are unsustainable when used for that purpose. IIEC submits that instead Mr. Gorman used an accepted estimate of a ceiling rate for utilities' long-term growth, and a gradual transition between the short and long-term rates.

c. Growth Rates

IIEC notes that Ms. McShane performed several DCF analyses, presumably for the same reason Mr. Gorman did, to take account of the current unsustainable nature of analysts' growth estimates. IIEC avers that Ms. McShane acknowledges, as the Commission has found, that long-term growth is effectively capped by GDP growth.

IIEC opines that Ms. McShane's estimates of growth are too high to be reasonable estimates of long-term sustainable growth, noting her constant growth DCF returns on equity were 13.6% for her electric group and 10.8% for her gas group. IIEC submits these returns were based on group average growth rate estimates of 7.1% and 5.3%, respectively, which growth rates IIEC finds far too high to be reasonable estimates of long-term sustained growth. IIEC avers it is not rational to expect that a utility company can grow indefinitely at a rate greater than the U.S. economy, noting U.S. economic growth is projected to be about 5.1% over the next 5 to 10 years.

IIEC argues that Ms. McShane's DCF estimate incorporates effects of the outlier estimate generated by that constant growth DCF model and her use of unsustainable analysts' growth rates as an input. IIEC states that her application of the DCF model failed to take proper account of the requirement that the indefinite cash flows discounted in a DCF analysis be generated using a growth rate that is sustainable indefinitely.

IIEC avers that Ms. McShane's DCF estimates also suffer from her use of stock prices that reflect anomalous market indicators from the recent financial crisis. IIEC argues that dividend yields calculated using stock prices from that period are unrepresentative of the improved financial environment, and using a more recent period that reflects the continuing market recovery would produce significantly lower dividend yields for her proxy groups.

While AIU asserts that analysts' growth forecasts are the most objective measure of investor expectations, incorporating them into a single-stage constant-growth DCF model, IIEC notes that Ms. McShane's own testimony contradicts the assumption of indefinite sustainability incorporated in her single-stage DCF model since she acknowledges that the growth rates used in constant growth DCF must be sustainable over the indefinite period the DCF model encompasses. IIEC avers that to the extent current three- to five-year earnings growth rate estimates are not reasonable estimates of long-term sustainable growth, the constant growth DCF analysis will produce highly problematic results.

Although AIU initially contended that Mr. Gorman did not accurately estimate the growth rate for his sustainable growth rate DCF model, IIEC states he updated his sustainable growth rate model which still supports an ROE of 10.0%. Although Ms. McShane opines that Mr. Gorman's revision to incorporate an external growth component failed to estimate it correctly, IIEC avers that despite her conclusion that Mr. Gorman's revision implies a significant decline in the utilities' market/book ratios, Ms. McShane presents no evidence to rebut Mr. Gorman's findings.

AIU argues that Mr. Gorman was incorrect in his assessment that analysts' short-term growth rates are too high to be reasonable estimates of long-term sustainable growth require one to reject investors as reasoning actors, and the market as an efficient reflector of investors' rational decisions. IIEC avers it simply is not reasonable to conclude that informed investors can not distinguish short-term and long-term forecasts, or that they would expect abnormally high growth rates to persist indefinitely. IIEC therefore requests the Commission reject AIU's argument on this issue.

d. Market Risk Premium

IIEC takes the position that Ms. McShane's CAPM produced an excessive return on common equity, in the range of 10.1% to 11.2% for her electric group, while her CAPM return estimates for her gas group were in the range of 9.8% to 10.7%. IIEC states these estimates are the result of Ms. McShane's use of significantly overstated market risk premium inputs.

IIEC notes that Ms. McShane developed two estimates of the market risk premium, the first being based on a forward-looking equity risk premium. IIEC avers that in this study she used DCF analysis on the S&P 500 and subtracted her projected risk-free rate to estimate the market risk premium. IIEC states that her second estimate was based on the difference between the total achieved ROE securities and the income return on 20-year U.S. Treasury yields over the period 1926 through 2008, which produced an equity risk premium of 6.5%, comparable to the result (6.25%) of a similar analysis based on a 1947 through 2008 time frame.

IIEC opines the forward-looking market risk premium was calculated on the basis of her constant growth DCF return on the market of 13.8%, which was largely driven by a long-term sustainable growth rate of approximately 10.1% and dividend yield of approximately 3.7%. IIEC argues that such growth is more than twice the estimated growth rate of the overall U.S. economy and it is not rational to expect that a utility growth rate can be sustained indefinitely at a level above the growth rate of the U.S. economy.

IIEC states that if Ms. McShane's DCF return on the market and estimated market risk premium were adjusted to reflect rational growth outlooks and reasonable expectations by applying a multi-stage growth DCF model (short-term growth of 10.1% for 5 years, average growth rate of 7.5% for the 5-year transition stage, and a long-term growth at of 5.0% GDP rate), a more reasonable market DCF return of 9.8% would result. IIEC avers that subtracting Ms. McShane's risk-free rate of 4.7% results in a market risk premium of 5.1%, significantly lower than Ms. McShane's forward-looking market risk premium estimate of 9.1%.

IIEC notes that Ms. McShane also developed a historical market risk premium in the range of 6.25% to 6.5% which was based on the difference between the total achieved ROE securities and the income return on 20-year U.S. Treasury yields over the period 1926 through 2008. IIEC avers this produced an equity risk premium of 6.5%, which was comparable to the result of 6.25% of a similar analysis based on a 1947 through 2008 time frame. IIEC witness Gorman noted that despite Ms. McShane’s flawed estimation process of subtracting only the income return (instead of the total return) on the U.S. Treasury yields, from the market equity return, recent anomalous movements in the stock market made the result (and only the result) of her estimation acceptable.

Mr. Gorman also noted that Ms. McShane uses a projected long-term risk-free rate of 5.7% for periods beyond the time rates set in this case will be in effect. IIEC argues those risk free rates are not representative of costs during the period rates are in effect and are not appropriate in setting rates that recover AIU's costs of service during that period. Further, Mr. Gorman noted that this risk-free rate significantly exceeds the current long-term U.S. Treasury yields in the range of 4.0% to 4.5% and the projected long-term U.S. Treasury yield of 5.0% over the next two years.

IIEC states that using a market risk premium in the range of 5.8% to 6.0%. a projected two-year U.S. Treasury bond yield of 5.0%, and beta estimates of 0.71 and 0.66 for electric and gas, respectively, would result in a CAPM ROE of 9.2% and 8.89%, which it would recommend.

IIEC opines that Staff's cost of equity recommendation is flawed by reliance on an overstated market risk premium in its CAPM analysis. IIEC notes Ms. Freetly recommended a ROE based on a non-constant DCF model and a CAPM risk premium analysis. IIEC states her CAPM estimate was based on market risk premium of 8.3%, estimated by subtracting her risk-free rate of 4.40% from the market return of 12.70%. IIEC avers this market return of 12.70% implies a dividend yield of 2.2% and a growth rate above 11.0%. IIEC argues this growth rate estimate is more than twice the expected long-term growth rate of the U.S. economy and produces an unreliable and inflated DCF market return. Mr. Gorman also noted that Ms. Freetly recognized the need for a sustainable long-term growth estimate, specifically, in the application of her non-constant DCF model.

IIEC notes that Ms. McShane used an ex-post (historical) market risk premium and one based on ex-ante (forward-looking) estimate in her analyses. IIEC states that Ms. McShane's forward-looking risk premium is a DCF-based return estimate for the

S&P 500, as a proxy for the market. IIEC avers the market-based DCF return used by Ms. McShane was based on an S&P dividend yield of 2.1% and a five-year IBES growth rate of 9.63%, yielding an expected return on the market of 12.0%. IIEC avers the 9.63% growth rate is substantially higher than the long-term expected growth of the U.S. economy, as represented by a GDP growth rate of 5.0%. IIEC argues that growth considerably faster than U.S. GDP growth can not be sustained indefinitely, making this DCF return of the market inflated and unreliable and overstating the market risk premium.

IIEC states that Staff developed a similar DCF return on the market which was also based on a growth rate that is too high to be sustainable. IIEC opines that both AIU's and Staff's market-based DCF estimates of the market risk premium are flawed and produce overstated premiums and CAPM return estimates.

IIEC states that Ms. McShane's historical estimate of utility equity risk premiums is derived based on achieved returns on utility stock relative to that of utility bond yields and U.S. Treasury bond yields. IIEC avers that Ms. McShane did not compare the actual historical achieved total return on utility stocks, relative to the historical total achieved returns on utility bonds and U.S. Treasury bond investments, but rather considered only the income portion of the total return of U.S. Treasury bonds to produce this equity risk premium. IIEC opines that Ms. McShane ignores changes in capital appreciations and losses for bonds, but she does reflect the change in market value for stock, resulting in a methodology that exaggerates the difference in actual total returns, and does not properly measure the premium investors actually achieved by investing in utility equities versus the compared bonds. IIEC submits that her methodology overstates the equity risk premium, and that correcting her analysis would substantially lower her utility bond equity risk premium estimates.

e. Proposed Adjustments

With regard to a proposed financial risk adjustment, IIEC notes that AIU criticizes Mr. Gorman's estimates as too low, in part because he did not include a leverage adjustment. IIEC states that Ms. McShane proposed to increase the electric ROE by 0.50%, and for the gas utilities in the range of 0.75% to 1.0%. While AIU attempts to validate its proposed adjustment by comparing it to Staff's risk adjustment, IIEC opines this is not an apt comparison. IIEC avers Ms. McShane's "financial risk" adjustment is simply the latest guise for the leverage adjustment the Commission has consistently rejected as inappropriate. IIEC submits that by attempting to embed current market-to-book differentials in the Commission's authorized returns, the focus of the adjustment is Ameren's stock price performance, not the utility's market-required cost of equity. In contrast, as IIEC understands Staff's adjustment, it seeks to correct for measurable differences in the relative risk of AIU and the proxy groups used to estimate AIU's cost of equity.

5. IBEW Position

In IBEW's opinion, a sufficient ROE, as proposed by AIU, is necessary for the economic health of not only AIU, but also its employees, and should therefore be allowed by the Commission. Adoption of lower estimates, such as those proposed by Staff could potentially lower AIU's credit rating. Such downward pressure on AIU's credit ratings would create difficulties in securing financing and could force AIU to take other actions to maintain its financial integrity. Such measures could include a reduction in staff and contractors. Termination of employees, including members of IBEW, would result in further unemployment and damage to the Illinois workforce in this time of economic hardship.

6. AARP Position

AARP notes that in the previous AIU rate case, the Commission awarded its gas utilities an authorized ROE of 10.68% and its electric utilities an authorized ROE of 10.65%. (Docket Nos. 07-0585 et al. (Cons.)). AARP states that since that time, turmoil in the credit markets has created uncertainty about future expectations, due to an inability to predict deep, broad-scale declines in value, like the one that preceded our nation’s recent recession. AARP believes, in light of this recent crisis, that the inputs to the accepted DCF analysis and the CAPM must be seriously re-evaluated, as these tools failed to fully predict or explain recent market behavior.

AARP submits it has also been shown how financial information from ratings agencies can be dramatically wrong, and states that serious allegations regarding the objectivity of credit ratings agencies are being made by former employees of these firms. AARP opines that utilities are now considered a safe haven for many investors, and thus it would not be reasonable to use the recent chaos of the markets as a basis for allowing an excessive ROE.

Therefore, AARP supports the cost of common equity recommendations of CUB witness Thomas. AARP notes Mr. Thomas performed an independent estimate of the cost of capital for the utilities in this case, using as a primary tool a DCF model that used a multi-stage, or “non-constant growth model," along with a separate CAPM analysis that confirmed these results. Based on these studies, AARP states Mr. Thomas recommends an 8.76% cost of common equity for AIU’s electric operations and 7.97% for AIU’s natural gas operations.

After the Commission has determined the proper cost of equity for AIU, AARP further recommends the Commission make downward adjustments to recognize the lessened risk associated with the new uncollectibles riders. AARP opines these riders will create greater certainty regarding the collection of bad debt expense, creating greater assurance of cash flows and greater likelihood that AIU will earn its authorized rates of return, significantly reducing the companies’ risk.

AARP states that while the various consumer parties in this case generally agree that the risk reduction impact of the new Riders GUA and EUA should be taken into account, Staff witness Freetly is the only witness that has attempted to develop a comprehensive metric for quantifying the impact that would have on the cost of equity for AIU. While Mr. Thomas describes her methodology as conservative, he suggests that Ms. Freetly's recommended adjustments would be reasonable. AARP endorses Ms. Freetly's approach, because it reasonably quantifies significant factors that undoubtedly lessen business risk going forward if the new Riders GUA and EUA are adopted.

7. Commission Conclusion

AIU, Staff, IIEC and AG/CUB have each presented their own cost of equity analyses for this proceeding. AIU witness McShane's recommendation is based on her three DCF models, (1) a constant growth model that relies on analysts' earnings forecasts; (2) a sustainable growth model; and (3) a multi-stage model that includes both analysts' forecasts and nominal GDP growth as proxies for longer-term growth; as well as her risk premium studies and a CAPM analysis. Staff witness Freetly's recommendation is based on a non-constant DCF analysis and CAPM analysis. CUB witness Thomas utilized a non-constant growth DCF model to estimate AIU's cost of equity, along with CAPM to justify the results. IIEC witness Gorman employed a constant growth DCF model, a sustainable growth DCF model, a multi-stage growth DCF model, and a CAPM model to attempt to develop a return on common equity.

AIU recommends for the gas delivery service operations of AmerenCILCO, AmerenCIPS, and AmerenIP, the cost of common equity be set at 11.2%, 10.8%, and 11.2%, respectively, while for the electric utilities, the recommended cost of common equity is 11.7%, 11.3%, and 11.7%, respectively. Staff calculates costs of equity for the gas operations as 9.64% for AmerenCILCO, 9.38% for AmerenCIPS, and 9.64% for AmerenIP. For electric delivery service operations, Staff recommends costs of common equity of 10.38% for AmerenCILCO, 10.14% for AmerenCIPS, and 10.44% for AmerenIP. IIEC proposes a combined ROE of 10.0% for AIU's that reflects AIU's actual combination gas and electric investment fundamentals, while AG/CUB calculates that the cost of common equity for AIUs' electric operations is 8.76% and the cost of common equity for AIU's gas operations is 7.97%.

Before the Commission turns to the details of the parties ROE estimates, it is apparent some parties want the Commission to abandon or deviate from certain past practices in light of new evidence or circumstances. The Commission must balance two competing interests in evaluating such proposals. While the Commission does not wish to totally ignore its past practices, which appear to have served utilities and ratepayers for many years, neither does the Commission wish to engage in cost of equity estimation in a manner that might be viewed as random or arbitrary. The Commission recognizes that it must also consider the possibility that new evidence or research has been developed that should cause the Commission to deviate from past practices. While the Commission recognizes that due to the competing interests present, it is not possible to satisfy all parties, the Commission will undertake to reach well-reasoned conclusions that are based on the record, and consistent with previous Commission decisions, to the extent possible.

a. CAPM

According to financial theory, the required ROR for a given security equals the risk-free ROR plus a risk premium associated with that security. This risk premium methodology is consistent with the theory that investors are risk-averse and that, in equilibrium, two securities with equal quantities of risk have equal required rates of return. The Commission notes that the parties are in agreement that a CAPM analysis requires three inputs or parameters, the beta, the risk-free rate, and the required ROR on the market. It is there, however, that the parties begin to diverge.

It appears to the Commission that both Ms. McShane and Mr. Gorman utilize Value Line (adjusted, weekly) betas to their CAPM analyses, while Ms. Freetly recommends equally weighing weekly and monthly betas, contending that neither weekly nor monthly betas are superior to the other. Mr. Thomas argues in favor of the use of unadjusted betas, asserting there is no evidence to support the use of regression betas, and claims the mean reversion adjustment is inappropriate and overstates the beta parameter, particularly for utility companies. Mr. Thomas urges the Commission to reject the analyses of AIU, Staff, and IIEC, as all parties used adjusted betas in arriving at their results, and Mr. Thomas suggests that unadjusted betas are superior when calculating a utility's ROE.

Staff calculated the risk-free rate parameter by considering the 0.14% yield on four-week U.S. Treasury bills and the 4.40% yield on 30-year U.S. Treasury bonds, with both estimates measured as of August 18, 2009. Staff noted that forecasts of long-term inflation and the real risk-free rate imply that the long-term risk-free rate is between 4.3% and 5.2%. Thus, Ms. Freetly concluded that the U.S. Treasury bond yield is currently the superior proxy for the long-term risk-free rate. For the risk-free rate, Ms. McShane uses the forecast 30-year U.S. Treasury yield expected to prevail over the same five-year time frame for which the forecast growth rates for the market are made. IIEC states that because the risk-free rate is typically represented by U.S. Treasury securities, Mr. Gorman used Blue Chip Financial Forecast's projected 30-year U.S. Treasury bond yields for his risk-free rate.

It appears to the Commission that Ms. McShane first calculated the achieved equity risk premium for the S&P 500 Common Stock Index for two historic periods (1926-2008 and 1947-2008) relative to the 20-year U.S. Treasury bond income return, then calculated the achieved equity risk premium for the S&P/Moody's Electric Utility Index and the S&P/Moody's Gas Distribution Utility Index relative to the 20-year U.S. Treasury bond income return. Ms. McShane also estimated the historic equity risk premium relative to the total return on Moody's long-term A-rated public utility bonds.

Staff performed a constant-growth DCF analysis on the electric and gas samples to determine an appropriate market risk premium. Staff recognizes that some of the growth rates used in Staff's DCF analysis of the S&P 500 are unsustainably high, which produces an upward bias in Staff's market return estimate, and, thus in Staff's CAPM cost of equity estimate. Staff avers that while there is upward bias in Staff's estimate of the market return, there is no way to know the extent of the bias. Staff notes it did not use a non-constant growth DCF to estimate the return on the market because of the extreme difficulty of applying the more elaborate model to 500 companies.

AG/CUB argue that to determine an appropriate EMRP, the Commission should look to research and analysis performed by academics over many years instead of the assertions or ad hoc calculations of interested participants in economic contests. AG/CUB state that current research on the EMRP shows the return expected by investors and appropriate for use in the CAPM is far lower than returns calculated from selective samples of historic information. AG/CUB opines that the historic record, financial theory, and prospective estimates based on stock prices and growth expectations all indicate that the future equity premium in developed capital markets is likely to be between 3% and 5%, far lower than the 8% historic returns calculated from selective historic data.

IIEC calculated the expected market return to determine the market risk premium in two ways. The first was a forward-looking estimate based on published estimates of the long-term historical real return on the market, proxied by the S&P 500, plus consensus analysts' inflation projections. The second estimate was based on estimates of total return and risk-free return components of the long-term historical market risk premium published in Morningstar's Stocks, Bonds, Bills and Inflation 2009 Yearbook. IIEC states that it applied a multi-stage growth DCF model (short-term growth of 10.1% for 5 years, average growth rate of 7.5% for the 5-year transition stage, and a long-term growth at of 5.0% GDP rate) to arrive at a reasonable market DCF return of 9.8%. IIEC suggests then subtracting Ms. McShane's risk-free rate of 4.7% to arrive at a market risk premium of 5.1%, significantly lower than Ms. McShane's forward-looking market risk premium estimate.

The Commission has reviewed the testimony and arguments of the parties on this issue, and does not find AG/CUB's arguments regarding betas convincing. The Commission is of the opinion that the continued use of adjusted betas, when combined with appropriate proxy groups, is appropriate and should continue. The Commission further finds that Staff's use of both weekly and monthly betas, is superior to the use of only one or the other. It appears from the testimony that there are weaknesses present in both monthly and weekly beta estimates; however the use of both should ameliorate those weaknesses and assist the Commission in identifying this input which measures investor's expectations of the quantity of non-diversifiable risk inherent in a security. The Commission finds that Mr. Thomas' use of unadjusted betas is inconsistent with the determination of an appropriate return on common equity; therefore his CAPM analysis will be rejected and will not be considered.

The Commission believes that both AIU and IIEC appear to rely too heavily on historical data for the calculation of what should be a forward-looking rate of return on common equity for the market. The Commission finds that Staff's constant-growth DCF analysis of the S&P 500 to determine the appropriate market risk premium is superior in this instance. The Commission further finds that the current yield on long-term U.S. Treasury bond is a more appropriate proxy for the long-term risk-free rate than forecasts of that rate.

As the Commission does not find significant fault with any of the inputs of Staff's CAPM, the Commission will utilize it in developing estimates of cost of equity.

b. DCF

The Commission will next consider the various issues relating to the DCF model and the inputs thereto. Ms. McShane proposes the use of both constant growth and non-constant growth DCF models, while Ms. Freetly applied a multi-stage, non-constant growth quarterly DCF model. Mr. Gorman performed both constant growth and non-constant growth DCF models; however, he rejected the use of the constant growth model as its results were based on growth rates that were not sustainable. Mr. Thomas also suggests a non-constant growth DCF model be adopted. Mr. Gorman did, however, rely of his estimate of sustainable growth in the constant-growth DCF model, which he combined with his non-constant growth DCF model results. The Commission believes that the quarterly DCF model should be utilized to estimate the cost of common equity, as demonstrated by numerous previous Commission decisions. It is the Commission's opinion that the use of this model accurately recognizes the timing of cash flows to investors, which is necessary to estimate the investor required ROR. Use of an annual DCF model, the Commission believes, would unnecessarily introduce measurement error and downward bias to the results.

Ms. McShane uses two DCF models which the Commission will consider for this proceeding. Her testimony indicates she has modeled both a sustainable-growth DCF model and a three-stage DCF model, both with quarterly compounding of dividends. For the three-stage model, she relies on the IBES consensus of analysts' earnings forecasts for the first five years, and the average of this growth rate with the forecast nominal growth in the economy for the second five-year period, while for the third stage, growth equals the forecast nominal rate of growth in the economy (GDP). The expected long-run rate of growth in the economy is based on the consensus of economists' forecasts found in Blue Chip Economic Indicators. As estimates of the growth parameter in the constant growth model, Ms. McShane relies on analyst's growth forecasts and her estimate of sustainable growth.

AIU argues the use of the average of the constant growth and the three-stage DCF models, rather than the results of the three-stage model alone, recognizes the imprecision of the period during which investors might expect analysts' forecast growth rates to persist and avoids results that are potentially internally inconsistent. As a result, AIU believes a reasonable approach is to give equal weight to the results of both the constant growth and multi-stage models.

Staff and IIEC believe analyst growth rates are currently so high as to not be sustainable in the long run for use in a constant growth model, and this model therefore produces ROE results which are unreasonable in this instance.

Ms. Freetly modeled three stages of dividend growth for use in her multi-stage, non-constant growth DCF model. For her first stage, she assumed a growth stage of five years. Her second stage is a transitional stage lasting from the fifth to the tenth year, while the third or "steady" stage growth rate begins after the tenth year. For the first stage, Ms. Freetly used the market-consensus expected growth rates from Zacks, for the third stage she used the 20-year forward U.S. Treasury rate, and the middle stage was an average of the first two rates.

Mr. Gorman modeled a three-stage, non-constant growth DCF model, where the short-term growth period (years 1-5), relied on the consensus analysts' growth projections. In the third stage starting in the year 11, he used the long-term GDP forecast as a long-term sustainable growth rate, while the transition growth stage (years 6-10), used an annual linear change from the short-term growth to the long-term growth.

Mr. Thomas uses a three-stage DCF test, with the three stages being 1) for the short-term that the sample companies will grow at their average internal growth rate over the last five years, 2) for the intermediate-term that growth for the sample companies will trend toward the historical average growth rate in real GDP, and in the final stage, 3) a forecast of real economic growth excluding inflation, rather than nominal growth.

The Commission notes that in the past, it had traditionally relied on a constant growth DCF model with analysts' estimates of EPS growth in developing the cost of common equity for utilities in rate cases. In recent years however, the Commission has begun using a non-constant growth model as analysts projected growth rates for utilities have exceeded the projected growth rate of the U.S. economy as a whole. The Commission notes that the recent Peoples/North Shore rate case, Docket Nos. 09-0166/09-0167 (Cons.) did adopt the use of a constant growth DCF model, however, as each utility is different, and each rate proceeding should be judged on its own merits, the Commission finds that the record supports a conclusion that it would be inappropriate in this matter to adopt a constant growth DCF model.

The Commission notes that Staff and IIEC and AG/CUB are in agreement that at least in this instance, the use of a single-stage, constant growth DCF model is inappropriate, as analyst's estimates for earnings growth are currently unreasonably high and are not sustainable for utilities. The Commission agrees that the traditional constant growth model would in this instance result in suggested growth rates that would exceed the growth rate for the U.S. economy in perpetuity, which appears unlikely. The Commission finds that Mr. Thomas' DCF model inappropriately uses historical growth rates for near term growth. An additional problem with Mr. Thomas' DCF analysis is his proposal to rely upon expected real growth in the economy, which ignores the fact that investor expectations include a return that reflects expected inflation. Mr. Thomas' DCF analysis is problematic and it will not be considered here. The Commission will also decline to use either Ms. McShane's sustainable growth DCF model, or her three-stage DCF. The Commission finds that like Mr. Thomas, Ms. McShane's over-reliance on historical data is problematic. Like Ms. McShane, Mr. Gorman also used a sustainable growth factor in the constant-growth DCF model. The Commission is of the opinion that sustainable growth estimates are problematic in that they rely upon a proxy for ROE as an input when estimating the investor required return. The Commission finds such an approach troubling and notes it has traditionally rejected DCF models that rely on sustainable growth, and will continue this practice in this proceeding.

The Commission finds merit in both IIEC and Staff's non-constant growth DCF models, and as such they will be considered when estimating AIU's costs of common equity for this proceeding. It further appears to the Commission that while Mr. Gorman generally recommends a combined cost of equity for the gas and electric operations of AIU, the Commission finds it more appropriate to use the results of his non-constant growth DCF model with the results computed separately for the gas and electric operations, as evidenced by Mr. Gorman's rebuttal testimony. (See IIEC Ex. 6 at 4)

c. Risk Premium Study

Mr. Gorman and Ms. McShane also presented the Commission with a risk premium analysis in addition to the DCF models and CAPM models. Although it does not appear to the Commission that a great deal of discussion occurred in the parties briefs on this model, other than footnotes by AIU and IIEC, the Commission notes it has traditionally rejected risk premium analyses. The Commission finds no reason to deviate from past practice wherein it has relied on the DCF and CAPM models to estimate cost of common equity. The Commission declines to consider either AIU's or IIEC's risk premium analysis.

d. Adjustment for Financial Risk

AIU has proposed that an adjustment be made to the cost of common equity calculations to reflect increased financial risk for AIU. Staff and AIU agree that when a utility has more or less financial risk than the sample companies used to estimate the cost of equity, an adjustment to the cost of equity is necessary. Ms. McShane asserts that when the market value common equity ratio is higher than the book value common equity ratio, the market is attributing less financial risk to the companies than the book value capital structure suggests.

Staff maintains that there is no merit to Ms. McShane’s claim, arguing the fundamental problem with Ms. McShane’s claim is that it assumes, without foundation, that the book value capital structure of the AIU directly reflects investors’ perceptions of the financial risk of the AIU. Staff opines that while investors are unlikely to ignore the book value capital structure of companies generally and utilities specifically, investors' perceptions of AIU's financial risk inherent in its book value capital structure are not observable because its common stock is not market traded. IIEC states that the financial risk adjustment proposed by AIU attempts to change the focus of this proceeding to Ameren's stock performance, rather than AIU's market required cost of equity. IIEC recommends adopting Staff's adjustment, as it seeks to correct for measurable differences in risk between AIU and the various proxy groups. AG/CUB urge the Commission to reject AIU's proposed financial risk adjustment, noting that the Commission applies a market-determined ROR to the book value of the capital structure, and AIU presents no evidence that a change from this practice is required. AG/CUB opines that adjusting market-based DCF results before applying them to the book value of assets in rate base inflates the market-based cost of equity.

The Commission is satisfied that Staff's suggested adjustment is appropriate to compensate for the different financial risk between AIU and the gas and electric proxy groups, and it is approved for the purposes of this proceeding. It appears to the Commission that AIU's proposed adjustment is, as suggested, an attempt to impose a market value adjustment, which the Commission has consistently rejected. The Commission does not support making an adjustment to the authorized ROE due to differences and book value and market value, and the Commission declines to adopt the recommendation that it do so.

e. Adjustment for Reduced Risk of Gas Operations

The Commission notes that in AIU's last rate proceeding (Docket Nos. 07-0585 et al. (Cons.)), the Commission chose to make the decision to authorize the recovery of more of AIU's fixed costs through the customer charge, with 80% of fixed costs being recovered through the fixed customer charge. As a consequence of that decision, the Commission also chose to reduce the return on common equity for AIU's gas operations by 10 basis points, to reflect what was viewed as a reduction in the risk that AIU would not recover its fixed costs of doing business.

Staff has recommended that the Commission again reduce the authorized rate of return on common equity for AIU's gas operations due to the increased fixed customer charge, while AIU claims the reduced risk has already been reflected in the gas sample used to estimate the cost of common equity, obviating the need for any additional reduction. The Commission, however, agrees with Staff's analysis that although some of the companies in the gas sample may have some type of de-coupling mechanism in place, there is no showing that it applies to the entire gas sample. The Commission will therefore adopt a 10 basis point reduction in the return on common equity for AIU's gas operations to reflect the reduced risk to due to the increase in fixed portion of the customer charge. The Commission is satisfied that this change, adopted in AIU's last rate proceeding, and continued here, places AIU at less risk of recovering less than its fixed costs of service for gas operations, which should be reflected in a reduction in the approved cost of common equity for AIU's gas operations.

f. Adjustment for Uncollectible Riders

The Commission takes note that in Docket No. 09-0399, uncollectible riders were approved for both the electric and gas operations of AIU, in conformity with Public Act 96-0033, which added Section 16-111.8 to the Act for electric utilities and Section 19-145 for gas utilities. These sections of the Act are substantively identical and provide electric and gas utilities with the opportunity to establish an automatic adjustment clause tariff for the collection of "uncollectibles," which opportunity AIU availed itself of. The Commission agrees with Staff that there is a benefit to AIU with the adoption of the uncollectible riders, and a portion of that benefit should accrue to ratepayers through a reduction in the allowed cost of common equity. AIU disputes there is a benefit such as Staff suggests, and criticizes Staff's method of attempting to calculate the effect of the riders on AIU. AIU suggests that should the Commission find a reduction to the cost of common equity appropriate, no more than a 10 basis point reduction would be appropriate. With regard to AIU's claim that the uncollectibles riders do not reduce its risk because there is still a chance that the Commission may find that it acted imprudently, the Commission reminds AIU that it largely controls the outcome of any such prudence review so long as it acts prudently in attempting to recover unpaid amounts.

Staff has attempted to calculate the effect of the uncollectible riders in two ways. The first attempts to discern the effect the riders will have on the rating agencies opinion of each utility by updating the rating factors, and thereby determining a proposed new credit rating for AmerenCILCO, AmerenCIPS, and AmerenIP. The second approach is characterized as a more iterative process with Staff attempting to calculate what the effect would have been on each utility in years past had the riders been in effect and thereby determining the differences in income for each company with and without the rider. Staff then would have the Commission average the results of each method to determine an appropriate reduction.

While the Commission commends Staff for its efforts in determining the effects of the uncollectibles riders, it appears to the Commission that the results of what is characterized as the iterative approach does not appear to provide a reliable estimate of the reduction in risk. Staff states the results of its iterative approach would produce downward adjustments in the costs of equity for the gas operations of AmerenCILCO, AmerenCIPS, and AmerenIP of approximately 160, 149, and 106 basis points, respectively, to reflect the risk reduction associated with Rider GUA; while producing downward adjustments to the costs of common equity for the electric operations of AmerenCILCO, AmerenCIPS, and AmerenIP of approximately 76, 119, and 48 basis points, respectively, to reflect the risk reduction associated with Rider EUA.

The Commission contrasts these results with Staff's first approach, which suggests reductions of 15 basis points for AmerenCILCO and AmerenIP, and 10 basis points for AmerenCIPS natural gas operations; and reductions of 50 basis points for AmerenCILCO, 10 basis points for AmerenCIPS, and 20 basis points for AmerenIP electric delivery service operations. The Commission finds Staff's reasoning in calculating its first approach persuasive and reasonable, and the Commission will adopt the results set forth in this paragraph for this proceeding. The Commission agrees with Staff that the adoption of the uncollectible riders ensure more timely and certain collection of bad debt expense and should provide AIU with greater assurance that they will earn their authorized rates of return. Due to this reduction in uncertainty, the Commission finds it appropriate to adopt a reduction to the approved cost of common equity. Staff's first approach, which estimates the effect the adoption of the uncollectible riders will have on AIU's Moody's credit rating and the resulting change in implied yield spreads appears to be reasonable to reflect the benefit of the adoption of the uncollectible riders. While Staff's second approach is intriguing, it appears the results shown from the second set of calculations are somewhat in excess of what might be expected from the adoption of these riders, and they will therefore not be used in calculating the appropriate reduction in ROE.

g. Authorized Returns on Equity

Having addressed the significant contested issues that relate to cost of common equity, it appears to the Commission, as discussed above, that there are significant shortcomings with respect to the analysis of CUB witness Thomas. His suggested non-constant growth DCF analysis employs inappropriate inputs, particularly his growth rates. His suggestions concerning CAPM are also rejected, along with his suggested EMRP and his proposal to use unadjusted betas. Likewise, Mr. Gorman's Risk Premium and CAPM analysis are rejected and will not be considered as they rely too heavily on historical returns in calculating a forward looking recommended ROE. Similarly, Ms. McShane's CAPM analysis is rejected, primarily for its reliance on historical data and its questionable reliance on forecast U.S. Treasury rates. As discussed above, the Commission finds Mr. Gorman's constant growth DCF analysis which incorporates his estimate of sustainable growth to be problematic and the Commission declines to rely upon it.

The Commission finds value in both Staff's and IIEC's non-constant DCF analyses, along with Staff's CAPM analysis. Each has suggested the use of a multi-stage DCF model in this instance to mitigate the impact of unsustainable analyst estimates of growth, using instead estimated proxies of U.S. GDP growth as the long-term growth rate. Staff's DCF analysis, based on a three-stage model, results in a recommended ROE of 9.79% for AIU's gas operations, and 10.67% for AIU's electric operations. IIEC's non-constant DCF analysis, likewise using a three-stage approach, results in a ROE estimate both electric operations of 10.73% and 9.46% for gas operations. Staff's CAPM analysis resulted in a cost of equity recommendation of 9.46% for AIU's gas operations and 10.21% for AIU's electric operations.

The Commission finds IIEC's non-constant growth DCF analysis, along with Staff's non-constant growth DCF and CAPM analyses, to be without material flaws, and should be considered in establishing AIU's cost of common equity. The Commission further notes that Staff proposes to adjust the recommended electric results downward by 6 basis points for AmerenCILCO and 30 basis points for AmerenCIPS, to reflect the lower financial risk of AmerenCILCO and AmerenCIPS relative to the electric proxy group. Staff further proposes to adjust its recommended gas results upward by 10.5 basis points for Ameren CILCO and AmerenIP to reflect a higher financial risk than the gas proxy group, and the results for AmerenCIPS down by 15 basis points to reflect a lower financial risk relative to the gas proxy group. The Commission notes this adjustment appears reasonable and it will be adopted for calculating the recommended ROE.

Having reviewed the evidence and arguments, the Commission concludes that AIU's cost of common equity is 9.54% for gas operations and 10.46% for electric operations. These returns on common equity give equal weight to the results of Staff and IIEC DCF analyses, which is combined with Staff's CAPM analysis. As indicated above, the authorized ROE for AIU's natural gas operations is adjusted downward by 10 basis points to reflect the reduced risk from the approved gas customer charge. The authorized ROE will also be reduced by 15 basis points for AmerenCILCO and AmerenIP, and 10 basis points for AmerenCIPS natural gas operations; and by 50 basis points for AmerenCILCO, 10 basis points for AmerenCIPS, and 20 basis points for AmerenIP electric delivery service operations to reflect the reduced risk to each company as a result of the adoption of the uncollectible riders.

The tables below illustrate the approved ROE that the Commission adopts for purposes of this proceeding.

AmerenCILCO

	Electric		Gas	
	DCF	CAPM	DCF	CAPM
Staff	10.67%	10.21%	9.79%	9.46%
IIEC	10.73%		9.46%	
Average	10.70%	10.21%	9.63%	9.46%
Unadjusted ROE	10.46%		9.54%	
Risk Adjustments				
Financial Risk	-0.06%		0.105%	
Uncollectibles	-0.50%		-0.15%	
Fixed Customer Charge			-0.10%	
Approved ROE	**9.90%**		**9.40%**	

AmerenCIPS

	Electric		Gas	
	DCF	CAPM	DCF	CAPM
Staff	10.67%	10.21%	9.79%	9.46%
IIEC	10.73%		9.46%	
Average	10.70%	10.21%	9.63%	9.46%
Unadjusted ROE	10.46%		9.54%	

Risk Adjustments		
Financial Risk	-0.30%	-0.15%
Uncollectibles	-0.10%	-0.10%
Fixed Customer Charge		-0.10%
Approved ROE	**10.06%**	**9.19%**

AmerenIP

	Electric		Gas	
	DCF	CAPM	DCF	CAPM
Staff	10.67%	10.21%	9.79%	9.46%
IIEC	10.73%		9.46%	
Average	10.70%	10.21%	9.63%	9.46%
Unadjusted ROE	10.46%		9.54%	
Risk Adjustments				
Financial Risk	0.00%		0.105%	
Uncollectibles	-0.20%		-0.15%	
Fixed Customer Charge			-0.10%	
Approved ROE	**10.26%**		**9.40%**	

H. Commission Authorized Rates of Return on Rate Base

Taking into consideration the Commission's conclusions regarding capital structure, cost of short-term debt, cost of long-term debt, and cost of common equity, the Commission finds that AmerenCILCO should be authorized to earn an 8.05% ROR on net original cost rate base for electric operations; AmerenCIPS should be authorized to earn an 8.02% ROR on net original cost rate base for electric operations; and AmerenIP should be authorized to earn an 8.97% ROR on net original cost rate base for electric operations.

Taking into consideration the Commission's conclusions regarding capital structure, cost of short-term debt, cost of long-term debt, and cost of common equity, the Commission finds that AmerenCILCO should be authorized to earn an 7.83% ROR on net original cost rate base for gas operations; AmerenCIPS should be authorized to earn an 7.59% ROR on net original cost rate base for gas operations; and AmerenIP should be authorized to earn an 8.59% ROR on net original cost rate base for gas operations. The appendices to this order show the development of the authorized returns on rate base.

VII. RIDERS

A. Revisions to Rider S - System Gas Service and PGA Uncollectibles

In AIU's last rate cases, the Commission directed AIU to remove the uncollectible expense component associated with the PGA from the gas delivery service base rates paid by transport customers served under Rider T - Gas Transportation Service ("Rider

T"). In response to this directive, AIU proposes to unbundle PGA-related uncollectible expenses and incorporate those expenses into Rider S - System Gas Service ("Rider S") with class-specific uncollectible recovery factors that will apply to the PGA charge components. AIU states that this will provide more precision in ratemaking by segregating delivery costs from purchased gas costs and provide a better matching of revenue and uncollectibles expense. AIU and Staff have agreed to calculate the Rider S uncollectibles factor using an average of the most recent actual information for the period January 2007 through September 2009. AIU provided revised PGA uncollectibles factors that are based entirely on actual information. AIU proposes to incorporate those proposed PGA uncollectibles factors into Rider S on Sheet 24.001 of the Gas Services Tariffs. The Commission finds this proposal reasonable and adopts it.

B. Rider VGP - Voluntary Green Program

1. AIU Position

As part of its rate cases, AIU proposes a new rider for Commission approval: Rider VGP - Voluntary Green Program ("Rider VGP"). Rider VGP would be available to electric delivery service customers interested in financially supporting the development of renewable energy technologies. If approved, AIU states that Rider VGP will be another means to promote the federal and state policy for cleaner, renewable energy. AIU also requests that the Commission find that the offering and promotion of Rider VGP to delivery service customers will not be deemed a violation of Section 452.230, Permissible and Impermissible Integrated Distribution Company Services, of the Commissions rules concerning integrated distribution companies ("IDC") set forth in 83 Ill. Adm. Code 452, "Standards of Conduct and Functional Separation." Because participation in Rider VGP does not alter the amount of energy and power supply commodity purchased by a customer, nor does it limit or alter the customer's energy and power supply options, AIU does not believe that the offering of Rider VGP pursuant to the proposed rider would violate the IDC rules. If approved, AIU proposes that the rider begin 60 days from the date of service of the order.

In describing Rider VGP, AIU states that the program relies on renewable energy credits ("REC"), meaning there is no renewable power and energy commodity provided to participants. Unlike power and energy, which are physical commodities, a REC can not power homes or businesses; rather, a REC represents the intangible environmental attributes of one megawatt-hour of power produced from a renewable energy project and is sold separately from the actual electricity commodity. AIU adds that RECs have been accepted by the Illinois Power Agency ("IPA") and the Commission as an appropriate method for complying with Illinois renewable energy requirements.

AIU plans to purchase RECs with revenue received from program participants. To offset out-of-pocket and other incremental costs, AIU proposes to mark-up the actual cost of the program RECs by 5%, not to exceed $1 per REC. AIU indicates that it may later request additional cost recovery in future rate cases if more costs are incurred than expected. Subsequent to each month, AIU will use the proceeds received from program participants, less administrative mark-up, to purchase the corresponding number of RECs on behalf of participating customers. AIU states that it is important for program participants and it to know the REC prices in advance of customer participation. The planned approach is for the customer to select its own level of participation: residential participants would select one of three monthly contribution levels ($3, $7, or $15), and non-residential customers would elect the number of RECs they wish to purchase each month. AIU will use a single round, pay as bid request for proposal ("RFP") process to acquire RECs for the program and will seek price certainty for RECs for an extended number of months, if not a year at a time. AIU plans to directly administer the RFP process and advertise in trade publications for broad exposure.

AIU is still attempting to determine the initial REC quantity. AIU proposes flexibility regarding the REC procurement process because this program is new and AIU can not predict the number of customers signing up or the financial level at which those customers wish to participate. Moreover, AIU plans to seek REC procurement terms that will keep REC costs reasonable and also allow as much flexibility as possible regarding the number of RECs, timing of REC payments, and deliveries. AIU prefers a flexible pay-as-you-go approach, but indicates that that preference must be balanced with the overall price of RECs under such an arrangement and the willingness of REC suppliers to sell under those terms. AIU believes that it would be premature to begin its REC procurement process prior to an order approving Rider VGP. AIU’s preferred approach for contracting the purchase of program RECs would be to pay the supplier for RECs with proceeds collected from VGP participants. Since it can not predict the pace of customer sign-up, participation levels, and payment levels, however, AIU recognizes that it is possible that it will be required to pay for RECs before program participants pay for them. AIU states that it must be cautious that overly restrictive REC procurement requirements may limit the number of bidders or result in paying premium prices for the RECs. AIU also intends to make retirement of the RECs the responsibility of the REC supplier. AIU's role would be to (1) accumulate the quantity of RECs purchased under the program, at the end of the month, (2) notify the REC supplier of the quantity to be retired in AIU’s name, and (3) review documentation provided by the supplier to verify the appropriate quantity was retired in AIU’s name.

AIU’s procurement objective would be to spread delivery and payment for the RECs (actual delivery of RECs retired on behalf of VGP participation) over an annual period. AIU adds that it may also have to purchase RECs at a faster pace than planned if program sign-ups exceed the monthly REC supply. The accounting entries present in Ameren Ex. 39.1 are intended to provide accounting entry detail to cover a REC prepayment scenario as well as a pay-as-you-go REC procurement scenario.

AIU will prepare internal reports on Rider VGP program activity to provide a transparent accounting for the program revenues, RECs, and incremental costs. Additionally, AIU explains it intends to procure RECs from resources located within the MISO or PJM regional transmission organization areas. AIU will rely on the same criteria for Rider VGP RECs as are set forth in Public Act 95-0481, regarding RECs for the Illinois Statewide Renewable Portfolio Standard. AIU plans to adapt a version of the REC contract used for its 2009 IPA Procurement.

The incremental costs of implementing Rider VGP are expected to be minimal. AIU states that it already has infrastructure in place to administer the program, channels to promote it, internal expertise to acquire and manage the RECs and to educate customers, and a capable billing system. AIU intends to use its current information channels and emerging communication avenues to publicize Rider VGP. AIU indicates that no additional costs have been built into the revenue requirement in this case for administering the proposed program.

In light of the experience of its affiliate AmerenUE and its own survey data, AIU contends that a market exists for Rider VGP among its customers. First, AIU indicates that its customers, especially those residing in the St. Louis metropolitan area, have expressed interest in participating in the AmerenUE Pure Power Program. Similar to Rider VGP, the Pure Power Program is a voluntary non-commodity program that provides an opportunity for AmerenUE electric customers to purchase RECs. Second, AIU conducted surveys to assess the level of Illinois residential customer interest in participating in a green program. According to AIU, survey results indicate a substantial level of customer interest in paying an additional monthly fee to participate in a green program.[10] Finally, the AmerenUE program, implemented in 2007, is similar to the AIU proposed program, and in its first year, 4,000 participants purchased approximately 42,000 RECs. AIU adds that the AmerenUE program is nationally recognized, including by the U.S. Department of Energy, which named it the "most successful" New Green Power Program of the year.

With regard to Staff's position on Rider VGP, AIU understands that Staff would like to see additional details in updated responses to Staff data requests and is unable to decide at this time whether Rider VGP would violate the IDC rules. Why Staff can not address the IDC rules at this time is unclear to AIU. AIU also understands that Staff is particularly critical of the lack of specific detail regarding the process to account for program transactions and reconcile program revenues with RECs. AIU acknowledges that its accounting systems must be able to track the Rider VGP program residential billed charges, non-residential billed charges, receipt of payment from participants, REC purchases, RECs retired by virtue of program revenues, and how to account for customers not paying for three consecutive billing periods. The AMS Controller's group recommended journal entries for the Rider VGP program. The proposed accounting entries are set forth in Ameren Ex. 39.1. AIU states that the proposed accounting entries will treat program revenue in above the line revenue accounts. Special monthly

[10] AIU reports that nearly 2,200 customers were asked if they would be willing to pay more on their electric bill each month to help produce additional power from renewable resources and answered as follows: 22% responded "Yes;" 65% responded "No;" and 13% responded "I Don't Know." Customers that responded "Yes" were asked how much extra they were willing to pay: about 33% agreed they would be willing to pay between $1 and $5 per month extra; 33% agreed they would be willing to pay between $5 and $10 extra per month; 14% agreed they would be willing to pay between $10 and $15 extra per month; 11% agreed they were willing to pay between $15 and $20 extra per month; and 8% agreed they would be willing to pay $20 or more extra per month.

reports will track and report participant payment data. AIU maintains that its financial system will facilitate separate tracking and reporting of program billed revenue, participant payments, and program costs. The entries also provide for the purchase of RECs.

Staff also recommends that, if the Commission adopts Rider VGP, the acquisition of RECs, as it relates to estimated participation levels, should first be addressed. Specifically, Staff asserts the timing for the purchase of RECs is unclear from the information provided by AIU. Staff's concern is that, if the RECs are pre-purchased in anticipation of estimated participation levels, a procedure should be in place for the variance between anticipated and actual participation levels. AIU states that it appears that Staff’s confusion stems from Ameren Ex. 39.1, which illustrates accounting entries for the program costs and revenues. The prepaid accounting scenario is set forth in the second set of entries under Section 1 of Ameren Ex. 39.1, and Section 3 of that exhibit illustrates when Rider VGP participants pay for their program participation. Section 1 of that exhibit shows when there is a purchase of RECs from a supplier funded by Rider VGP revenues. Moreover, AIU believes that the Rider VGP program will provide Staff and the Commission with adequate data and information on which to monitor the financial transactions under the program.

2. Staff Position

In response to AIU's proposed Rider VGP, Staff opines that the program is not sufficiently designed or explained for it to recommend approval. Staff notes that AIU continues to discuss the accounting for Rider VGP in rebuttal testimony. Staff is also concerned with the timing of acquisition of the RECs. AIU admits that the REC procurement process has not yet been designed and that it is proposing to maintain flexibility regarding the procurement. Staff states further that its concerns with the treatment of the variance between anticipated and actual participation levels have not been addressed by AIU. If AIU is not yet able to clearly define and present its proposal, Staff contends that the Commission should be concerned that the customers to whom this plan will be marketed might not have a clear understanding of exactly what would be bought.

3. AG/CUB Position

Although the AG and CUB voice support for green energy initiatives, they urge the Commission to deny approval of Rider VGP. AG/CUB contends that AIU has not provided nearly enough information about Rider VGP to warrant Commission approval. As an example, AG/CUB notes that AIU has not yet designed the REC procurement process for the VGP Program. When asked for sample copies of whatever agreements, product orders (confirmations), and related documents that AIU intends to use when contracting with the REC suppliers, AG/CUB reports that AIU had no such agreements or documents at that time. This response concerns AG/CUB since AIU wants to begin offering RECs under Rider VGP 60 days from the date of the Commission’s order.

AG/CUB notes that AIU has proposed numerous riders before the Commission and should be well aware of the type of detailed plan that Staff needs to review. Such detail, they contend, is sorely lacking as to Rider VGP. Nor, they continue, is there sufficient information for a review of any potential conflict with the Commission's IDC rules. AG/CUB finds this lack of information particularly troubling since this program will be marketed to residential consumers. Overall, AG/CUB argues that approval of Rider VGP based on such minimal information would be premature at this point.

Even if one assumed that Rider VGP does not violate IDC rules, AG/CUB states that AIU has not provided any details of what information (such as marketing materials) will be used to explain the program in plain language so that customers will understand. Information that they believe is missing includes: 1) what the cost/benefits of the Rider VGP program are; 2) how to meaningfully compare the value of the Rider VGP program with other potential or existing green programs, such as those offered by Alternative Retail Electric Supplier ("ARES") programs; 3) language clearly indicating to customers that the REC based program does not relate to physical delivery of green power to the customer, or does not directly relate to the development of green projects (such as a wind farm) locally or even in the AIU territory; and 4) a disclosure that every AIU customer will be contributing long term to green energy in Illinois through the IPA's procurement process. (See Docket No. 09-0373) Because there is nothing in the record for the Commission to evaluate the programs risks, or the customer value and benefits, AG/CUB recommends that Rider VGP be rejected.

4. AARP Position

AARP neither supports nor opposes Rider VGP. If Rider VGP is to be approved, however, AARP urges the Commission to mandate in its order that this program be clearly voluntary and that consumers be given enough accurate information to ensure that an informed decision can be made about whether to participate. Because of the risk of confusion, AARP further urges the Commission to require that all promotional materials relating to this program be reviewed and approved by the Commission to ensure that it is accurate and not misleading.

5. Commission Conclusion

While appreciative of AIU's effort to support renewable energy through the purchase of RECs under Rider VGP, the Commission is not convinced that the proposed Rider VGP is ready for approval. As Staff and AG/CUB noted, much remains to be determined about exactly how Rider VGP would function. The Commission understands that AIU can not predict participation levels in advance, nor can it be certain of REC prices and what terms REC sellers would accept. But beyond these uncertainties, too many other aspects of Rider VGP are unclear.

For instance, AIU proposes to markup RECs by 5%, not to exceed $1 per REC. How AIU determined that a 5% markup is appropriate is unclear. AIU also indicates that it may later request additional cost recovery in future rate cases if more costs are incurred than expected. The Commission finds unsettling the notion that it should approve this rider when the potential exists that its implementation costs may go up by an unknown amount. While it is reassuring to know that AIU believes that it can offer a new program without seeking new revenue, the Commission would prefer to know more about Rider VGP's costs before authorizing its initiation. If the Commission authorizes the program now only to learn during the next rate case that it may be too costly, customers may be unnecessarily confused.

The Commission is also concerned that end-user customers may not fully appreciate the character of RECs. While associated with renewable energy, no actual energy commodity is bought and sold when acquiring a REC. Whether customers would fully appreciate this distinction is unknown, but the answer would depend in large part on the Rider VGP educational materials provided by AIU. Sufficiently educating customers on RECs is certainly feasible.

The Commission notes that AIU customers are currently obligated to purchase RECs pursuant to section 1-75(c) of the Illinois Power Agency Act. (Pub. Act 95-0481) AIU is free to inform and educate customers regarding these REC purchases.

AIU is welcome to provide additional details regarding Rider VGP and resubmit it for the Commission's review. To avoid the potential for customer confusion, however, AIU may want to consider ways to participate in the Chicago Climate Exchange, Acid Rain Program, or another emissions trading program. Such programs clearly do not involve purchasing electricity and have a definitive benefit of reducing airborne pollutants. To be clear, the Commission is not requiring AIU to make emissions allowances available for customers' purchase. The Commission is merely suggesting an alternative to Rider VGP that the AIU may want to consider. Like RECs, the trading of emissions allowances has environmental benefits. Emission allowances, however, may be easier for customers to understand. Additionally, while it does not appear to be the case, until a more complete Rider VGP (or some alternative) is put forth, the Commission will reserve judgment on whether such a rider constitutes a violation of Section 452.230.

VIII. COST ALLOCATION

As a part of every rate case, the Commission must determine what portion of a utility's costs each class of customers will be responsible for. Each of the three utilities currently divides retail electric customers into five rate classes. The DS-1 Residential Delivery Service rate class tariff contains meter, customer, and delivery charges for residential customers. The DS-2 Small General Delivery Service class tariff includes meter, customer, and delivery charges for non-residential customers with demands up to 150 kilowatts ("kW"). The DS-3 General Delivery Service class tariff includes meter, customer, delivery, and transformation charges for non-residential customers with demands equal to or greater than 150 kW but less than 1,000 kW. The DS-4 Large General Delivery Service class tariff includes meter, customer, delivery, transformation, and reactive demand charges for customers with demands exceeding 1,000 kW. The

DS-5 Lighting Service class tariff provides for street lighting and protective lighting service to customers. While similarities exist among the three utilities' current gas delivery service rate class tariffs, many differences remain. AIU has proposed revisions in this proceeding toward the goal of making the gas delivery service tariffs more uniform.

Generally, the Commission prefers to allocate costs among the various classes as close to the cost of serving each class as is reasonably possible and/or appropriate. The purpose of doing so is to assign costs to those who cause them. The Commission typically accomplishes this goal through a cost of service study ("COSS"). A COSS compares the cost each customer class or subclass imposes on the utility's system to revenues produced by each class or subclass. A properly performed COSS shows the cost to serve each class or subclass and the ROR for each class or subclass. Customer classes or subclasses with a ROR equal to the total system ROR are paying their cost of service. Customer classes paying less than the total system ROR are not paying their cost of service. From time to time circumstances arise that warrant allocating costs at least in part on non-cost based criteria. Whether such circumstances are present in this proceeding is discussed below.

A. Resolved Issues

1. Rate Classes

AIU proposes to maintain six general gas rate classes for each of the three gas utilities: (1) GDS-1 Residential Gas Delivery Service, (2) GDS-2 Small General Gas Delivery Service, (3) GDS-3 Intermediate General Gas Delivery Service, (4) GDS-4 Large General Gas Delivery Service, (5) GDS-5 Seasonal Gas Delivery Service, and (6) GDS-7 Special Contract Gas Delivery Service. AIU's only proposed change to the general rate classifications is to eliminate a rate class that only AmerenCILCO has: GDS-6 Large Volume Gas Delivery Service. AIU proposes to eliminate AmerenCILCO’s GDS-6 tariff as a stand-alone rate class and modify AmerenCILCO’s GDS-4 tariff to address the large usage customers. Staff recommends approval of AIU’s proposal to eliminate AmerenCILCO’s GDS-6 on a stand-alone basis. No other party comments on AIU’s rate classification approach. The Commission finds the rate classification proposal reasonable and adopts it.

2. Billing Determinants

AIU proposes adjustments to the billing determinants used in the gas COSS and ratemaking. AIU recommends adjusting the existing non-residential customer billing determinants for the GDS-2, GDS-3, and GDS-4 classes for AmerenCILCO and AmerenCIPS to accommodate the revision to these two utilities' rate class availability provisions to match the AmerenIP class definitions. These adjustments anticipate the changes that would be necessary if AIU's contested reclassification proposal regarding the GDS-2, GDS-3, and GDS-4 classes is adopted. Staff agrees with AIU’s proposed adjustment to the billing determinants assuming the reclassification of the GDS-2, GDS-

3, and GDS-4 classes. Although GFA recommends modifying AIU's proposed availability criteria regarding the GDS-2, GDS-3, and GDS-4 classes, it does not address AIU's billing determinants adjustments. No other party comments on AIU’s billing determinants adjustments. Given the Commission's conclusion below regarding AIU's proposed availability terms for the GDS-2, GDS-3, and GDS-4 classes, AIU's billing determinants for the GDS-2, GDS-3, and GDS-4 classes for AmerenCILCO and AmerenCIPS are approved.

3. Weather Normalization

Regarding gas delivery service rates, the weather normalization analysis and adjustments proposed by AIU are uncontested. AIU prepared a detailed weather normalization analysis and proposes to use an average of 10 years annual HDD based on historical data from the Champaign-Urbana weather station. AIU utilizes this weather normalization analysis in the gas COSS and rate design to adjust the historic test year so that it represents typical or normal circumstances from an HDD perspective. Staff recommends that the Commission approve AIU’s proposal. No other party commented on AIU’s weather normalization approach. The Commission finds AIU's weather normalization analysis and adjustments reasonable and adopts them.

4. Account 904

AIU addressed net write-offs recorded in Account 904, Uncollectible Expenses, as part of its gas cost of service analysis. Staff pointed out that the net write-offs recorded in Account 904 had been allocated in the same percentage for each class in each of the three gas COSS. AIU responded that the AmerenIP allocation was correct, but that the initial Account 904 allocations were incorrect for AmerenCIPS and AmerenCILCO. AIU re-ran the gas COSS to quantify the impact of the oversight and provided updated COSS for AmerenCIPS and AmerenCILCO that corrected for the Account 904 allocation oversight. AIU states that while the class impacts of the updated COSS for AmerenCIPS and AmerenCILCO are de minimis, the results of the updated COSS should be factored into the final rate design approved by the Commission. Staff does not object to the corrections relating to Account 904. The Commission finds the corrections reasonable and accepts them.

B. Contested Electric Issues

1. Cost Allocation for Customers at 100+ kilovolts

Customers receiving service at 100+ kilovolts ("kV") in the DS-4 customer class essentially take service at a transmission voltage. Unlike AIU’s other customer classes, the DS-4 customer class contains a relatively few customers with large electric demand. Additionally, these DS-4 customers often have multiple service points. They can own or rent substations or transformers, use AIU's substations or transformers, or use some combination thereof. AIU and IIEC disagree on the proper allocation of costs to such customers who make relatively little use of the distribution system.

a. AIU Position

In the current rate cases, AIU allocates costs to the DS-4 customer class using class demand studies different from those used in its prior rate cases. Previously, allocation factors were based on supply voltage alone. The allocation factors used in the current cases are based on a combination of supply and delivery voltage. This change in allocation factors increases the costs to be recovered from the DS-4 customer class.

IIEC acknowledges that 100+ kV DS-4 customers should pay something for their delivery service, however, it disagrees with AIU's allocation of costs to the customers that operate at the highest voltage level--100 kV or higher. IIEC specifically contends that customers taking service at a voltage above 100 kV do not receive any benefit from the portions of the distribution system that operate below the 100 kV level. AIU counters that IIEC fails to consider the new allocation factors reflecting delivery voltage. AIU explains that based on its voltage definitions, customers can be supplied via a substation feeder at one voltage level, but ultimately delivered at a lower voltage level. AIU adds that many customers supplied at 100+ kV use transformers and substations owned by AIU, and should not be able to bypass delivery service rate responsibility associated with use of the system. According to AIU, the current case's allocations are a better representation of cost causation due to the recognition of delivery voltage.

AIU contends that its transformation charge provides additional support for the proposition that customers can be supplied at one voltage but delivered at a lower voltage. More particularly, a customer will be billed a transformation charge to compensate AIU for providing transformation of voltage from the customer's supply voltage to the delivery voltage used by the customer. AIU maintains that costs are properly allocated to customers supplied at 100 kV and above, but delivered at lower voltages to match how AIU's assets are being used by customers.

Furthermore, AIU continues, if customers use their own transformers, those customers' demands are not included in the lower delivery voltage category. The same effect holds true for customers who rent transformers. AIU explains that those delivery voltage demands for customers who rent transformers are included and costs are appropriately allocated but revenues from rentals are included as an offset to the revenue requirement.

Additionally, AIU asserts that the DS-4 class represents only a small number of its customers and these few customers accept delivery service in differing configurations. There is, for instance, one customer that does not require transformation because that service is provided to a switchyard. There are three customers that own their transformers. Of the remaining customers, ten either rent or are charged for transformation service from AIU on their entire load and two customers receive transformation service on a portion of their load. All totaled, five customers do not take transformation service from AIU, and 12 customers do take transformation service from AIU.

AIU reminds the parties that a COSS will not always match costs, expenses, and miscellaneous revenues perfectly, since it allocates to all customer classes. AIU states that outliers in a COSS will always exist as uniform rates by class are produced. Outliers in customer classes with relatively few customers will be difficult to address. While AIU can refine its methodologies to be as accurate as possible, it avers that it is important to continue the practice of allocating costs at a class level rather than focusing on the particulars of individual customer cost causation. With the modification described above regarding FERC Account 362, AIU urges the Commission to accept its general approach for allocated costs to the 100+ kV class of customers.

b. IIEC

IIEC agrees that all customers should be allocated the costs of the distribution system that they use. IIEC adds, however, that it is of vital importance that AIU demonstrate that the customers do, in fact, use the subject facilities, and are therefore responsible for the facility costs allocated to them. Contrary to AIU's suggestion, IIEC does not claim that 100+ kV customers do not use transformers and substations owned by AIU. Nor does IIEC suggest that these customers should be able to by-pass delivery service rate responsibility associated with the use of such transformers. As AIU witness Althoff testified during cross-examination by Staff, the use of the "DDSUBTR" allocation factor does, in fact, allocate costs to customers supplied at 100+ kV. (See Tr. 609-610)

AIU also claims that IIEC's statements regarding the proper allocation of costs to customers that operate at the highest voltage level only considers the "supply voltage" of these customers. IIEC notes that it has not disputed the difference between, or the importance of, supply, and delivery voltages. IIEC merely attempts to ensure that the costs of 34 kV and 69 kV substations are not misallocated to customers taking service at 100 kV and above. While IIEC believes that AIU must go to the next step and actually provide the Commission with the results of a corrected COSS, IIEC has not made any recommendations with regard to the use of supply or delivery voltages or disputed those differences in this case.

c. Commission Conclusion

For reasons that are not entirely clear, AIU modified the class demand study used in the COSS from its previous rate proceeding. As noted above, the allocation factors were previously based on supply voltage alone. The allocation factors used in the current cases are based on a combination of supply and delivery voltage. This new allocation factor results in an increase in the costs to be recovered from the DS-4 customer class.

Before the Commission consents to the use of the AIU's new allocator, it must be sure that the resulting allocations are appropriate. In other words, the Commission must try to ensure that costs are allocated to those who cause the cost. From the record, it is not clear that DS-4 customers receiving service at 100+ kV are using those portions of the distribution system associated with providing service at less than 100 kV, at least not in a way in which they are not already paying for it. AIU's new allocator in its demand study appears to unnecessarily shift costs to customers taking service at 100+ kV. Unless more persuasive evidence is provided in a future proceeding, AIU should return to using supply voltage alone.

2. Cost Allocation of Primary Distribution Lines and Substations

AIU's electric COSS uses the non-coincident peak ("NCP") allocator to allocate costs associated with primary distribution lines and substations among the rate classes. Staff, however, recommends that substation and primary line costs be allocated on a basis of coincident peak (“CP”) rather than NCP. The CP method allocates costs based on the demands of individual customers at the time of the overall system peak, while the NCP method allocates costs based on the demands of individual customers at the time of peak for the class. Under the NCP method, classes may experience their respective peak at different times of the day, which may or may not occur at the same time as the overall system peak. IIEC supports AIU's use of the NCP allocator.

a. Staff Position

Staff prefers the CP allocator over the NCP allocator because it does not believe that the latter accurately reflects how the costs of distribution lines and substations are incurred. Staff points out that the individual class demands do not necessarily shape the costs of primary distribution lines and substations which are generally constructed to serve the demands of multiple rate classes that collectively use those facilities. This is evident from AIU’s own statements, Staff continues, acknowledging that distribution facilities are not designed based on rate classes, but instead are designed based on the aggregate load in a locale. Staff observes that AIU also concedes that for both distribution lines and substations specifically, it is reasonable to assume that they would serve multiple rate classes. Staff maintains that these admissions by AIU have direct implications for allocating primary distribution line and substation costs. If these facilities were to serve customers from a single rate class, Staff agrees that the peak demands of individual classes would determine their size and ultimate cost. But because that is not the case in most instances, Staff states that the design would have to take into account the combined CP demands of customers from all classes served.

Staff rejects AIU's argument that local demands (as cost drivers) justify the use of an NCP approach for primary lines and substations. Staff counters that neither a CP allocator nor an NCP allocator measures “local” demands. Each seeks to represent demands on a utility-wide basis. The key difference is that the CP reflects the collective demands of multiple rate classes while the NCP is based on the peak demands of individual rate classes. The issue for primary lines and substations concerns which of the two allocators reflects the collective peak demands of multiple rate classes at a local level. Since the CP focuses on multiple rate classes and the NCP on individual rate classes, Staff contends that the CP is the more cost-based approach.

Staff asserts that the DS-5 lighting class illustrates the shortcomings of an NCP allocator for primary distribution lines and substations. This class, which uses most of its electricity during off-peak, evening hours, is penalized in Staff's opinion by the NCP which factors those full off-peak demands into the development of the allocator. Those off-peak demands are used to allocate to lighting customers the costs of primary distribution lines and substations which AIU admits are designed based on the collective demands of ratepayers from all rate classes served at that locale. Staff maintains that this clearly conflicts with cost causation principles. Staff argues that the more equitable approach for lighting and other classes, as well, is to allocate primary distribution lines and substations according to CP demands. The individual class shares represent the contribution of each to this overall peak demand on the system. The CP is the allocator that most accurately represents the combined demands of multiple rate classes and is, therefore, most appropriate for distribution lines and substations that collectively serve customers from different classes.

AIU criticizes the CP approach for allocating “zero costs” of primary lines and substations to DS-5 customers. Staff responds again that the issue here concerns causation and what allocation classes receive should reflect their contribution to these costs. If lighting customers use electricity when other classes use less, Staff asserts that their demands will not drive the causation of these costs. What AIU leaves unsaid, Staff continues, is that the NCP allocates primary line and substation costs to lighting customers based on their maximum demands which occur during off-peak hours. Staff maintains that it is patently unfair to give as much weight to these off-peak demands as for maximum demands by other classes that do coincide with the peak. Staff believes that it is clear that it is these latter demands, not lighting demands, that drive primary line and substation investments. Staff also notes that AIU states that while the NCP demand allocation may allocate too much to the DS-5 class, the CP demand allocation will allocate too little. (See Ameren Ex. 41.0 at 5) Staff finds this statement notable because it seems to acknowledge that the NCP allocates too much to the lighting class. Since the CP approach comports most closely with the way these costs are determined, Staff insists that that is the methodology that should be used.

Staff is also not persuaded by AIU's example using grain drying customers as support for the NCP approach. Specifically, AIU argues that a single CP allocator would fail to recognize that “several circuits that serve grain drying customers in fact peak during the fall grain drying season.” (Ameren Ex. 41.0 at 6) Staff finds this argument problematic. For one, AIU does not identify the circuits or provide a number to accompany the claim of “several.” This makes it difficult for Staff to determine whether these circuits comprise a significant share of the total investment in primary lines. Second, it is not clear to Staff why AIU is focusing on cost allocations to grain dryers since these customers do not constitute a separate class for allocating the cost of service. Instead, they constitute subclasses of the DS-3 and DS-4 classes and receive cost allocations in conjunction with all other customers within their class. Furthermore, Staff relates that the rate limiter in effect for grain dryers is not directly based on the cost of service, but rather is driven by bill impact concerns for a subgroup of DS-3 and DS-4 customers. Staff therefore concludes that grain dryers are not a relevant example for this cost of service issue.

AIU's argument that CP demands are not appropriate for allocating primary lines and substations to DS-3 and DS-4 customers is likewise dismissed by Staff. AIU contends that these classes "are not weather sensitive" and could peak during various times throughout the year. Since its CP occurs in the summer season reflecting the impact of weather, AIU considers the CP's failure to capture these off-peak DS-3 and DS-4 demands a problem. To the extent that demands by these customers take place during off-peak periods, Staff states that their contribution to investments in primary lines and substations will be reduced. Staff maintains that this off-peak usage should be rewarded, not punished, which would be the case under the CP rather than the NCP allocator.

Regarding AIU's discussion of the impact of using the CP allocator on each customer class, Staff asserts that such an argument does not belong in a discussion of cost allocation. Staff maintains that a COSS should allocate costs solely based on how classes cause those costs to be incurred. Only after costs are allocated and class revenue responsibility is determined does Staff believe that it is appropriate to consider bill impacts in the ratemaking process. Staff insists that injecting bill impacts into the cost allocation process makes it impossible to determine the real responsibility of customer classes for system costs. As a result, it will be that much more difficult to make an informed decision concerning the appropriate balance of costs and bill impacts in the ratemaking process.

IIEC also criticizes Staff's preference for the CP allocator. IIEC notes that there are conditions wherein the CP method fails to allocate costs to certain classes because, though they use the distribution system, they do not use electrical power at the time of the system peak demand. Staff finds IIEC's argument misplaced. For one, Staff states that it is not advocating the CP approach for all distribution costs, only those pertaining to primary lines and substations. Second, Staff asserts that the cost of service issue should not focus on the amount of costs the CP allocates to any individual class, but rather on whether that allocation most accurately reflects how costs are caused by AIU ratepayers. Staff relates that the NCP allocator is based on the sum of individual class demands based upon the separate peaks of each rate class. So, if one class uses less when the system peaks and uses more when overall demand is low, the NCP will allocate system costs to that class based upon its off-peak usage. The problem is that equipment such as primary lines and substations are generally constructed to serve multiple rate classes, not just one class at a time. Because the demands of multiple classes more closely correspond to CP rather than NCP demands, Staff insists that the most reasonable, cost-based approach is to allocate the cost of this equipment according to the collective peak demands of all rate classes.

b. AIU Position

In defense of its use of the NCP methodology, AIU observes that the Commission approved of its use in allocating distribution plant costs in AIU's prior delivery services rate orders. Continued use of NCP is fitting, according to AIU, because it more appropriately allocates costs to customers that cause the costs to arise since, on-balance, NCP demands more closely match the demands placed on local substation and primary line facilities. AIU agrees with Staff that its facilities are built to serve demands based on locality and that geographical locations do encompass customers in multiple rate classes. The fault in Staff's position, in AIU's opinion, is that Staff does not consider the fact that customers within these geographical locations can peak at various times throughout the year.

AIU states that Staff's focus appears to be on the "multiple rate classes" element of CP demand, ignoring the fact that CP demand is always less than the sum of the localized demands placed on distribution facilities. AIU indicates that local facilities such as substations and primary lines are not built and sized with this level of diversity in mind. Instead, AIU explains that distribution system planners look at the expected peak of customers connected to the facilities, whether they occur in summer, fall, winter, or spring. This is based on the fact that the collective peaks on individual systems are greater than the CP. AIU maintains that the NCP demand more closely matches the load diversity on these more localized systems.

AIU states further that the use of CP demand would not be beneficial to many of its customers. According to AIU, the use of CP would increase costs to the DS-1, DS-3, and DS-4 rate classes but would lower costs to the DS-2 and DS-5 classes for AmerenIP. For AmerenCIPS, the DS-3 and DS-5 classes would be allocated lower costs under the CP allocation; however, the DS-1, DS-2, and DS-4 customers' costs would increase. The affects for AmerenCILCO are that the DS-1 and DS-5 rate classes receive less costs utilizing CP while DS-2, DS-3, and DS-4's costs would be higher.

The notion that DS-5 customers should not bear any costs for substations or primary lines, since they peak during off-peak, evening hours, is also problematic for AIU. AIU states that lighting customers use primary lines and substations and should be allocated at least some costs for the use of these assets. To allocate zero substation and primary line costs to the DS-5 class is flatly incorrect.

AIU disagrees that the use of NCP "punishes" non-weather-sensitive customers, as Staff contends. Instead, AIU contends that it appropriately allocates the cost of facilities to match how the facilities were designed, built, and sized. CP, on the other hand, is a detriment to these rate classes, according to AIU. AIU maintains that allocating substations and primary lines based on CP is improper because it would fail to appropriately align costs with the cost causers for which the systems are designed and constructed. AIU argues that the use of NCP provides the most accurate methodology for allocating distribution assets to ensure that no customer rate class subsidization occurs.

With regard to GFA's seasonal pricing concerns and the allocation of primary lines and substation costs, AIU continues to believe that such seasonal rates for the DS-2, DS-3, and DS-4 classes will ultimately create a subsidy by non-seasonal customers. AIU nevertheless does not object to examining a sample of circuits serving the DS-3 and DS-4 in order to bring clarity to the debate in the next rate case. AIU acknowledges that such a review may lead to improvements in its COSS.

c. IIEC Position

IIEC opposes Staff's recommendation that the CP allocator be used to allocate costs of primary distribution lines and substations. Contrary to Staff's suggestions, IIEC argues that the NCP method reflects the collective demands of every rate class and, in certain instances, reflects the collective demands of more rate classes than does the CP method. IIEC contends that this point is best illustrated by Staff's discussion of how the NCP method penalizes the lighting class. Staff's discussion ignores the fact that in the AIU COSS, the CP method does not recognize that the DS-5 rate class has any demand whatsoever and allocates no costs for primary lines and substations to the DS-5 class. IIEC states that it is obviously necessary to use primary lines and substations to serve the DS-5 class. IIEC avers that an allocation method that results in this class being assigned none of the cost of those facilities is clearly an erroneous method. The NCP method, on the other hand, does not suffer from this deficiency and recognizes the collective demand of every rate class regardless of when it occurs, according to IIEC.

d. GFA Position

GFA agrees with AIU that substations and distribution lines are designed to serve the maximum demand expected on the facilities regardless of the season. GFA, however, is still interested in the possibility of seasonal class distribution rates. GFA recognizes that grain companies can contribute to significant loads on substations and primary lines, particularly in the fall. Of concern to GFA, however, is the fact that AIU has provided no system-wide seasonal load data for primary lines and substations, the costs of which are being allocated to each of the DS-2, DS-3, and DS-4 customer classes from which grain companies are served, along with many other users. GFA understands that summer month coincident peaks are typically higher on the AIU system than are winter month coincident peaks. Because the coincidental system peaks on the AIU system vary by season, GFA opines that AIU's distribution system cost of service varies by season. This leads GFA to the conclusion that AIU should price its distribution delivery service charges, excluding monthly fixed charges, higher during the summer and lower during the non-summer months. GFA has not requested a special rate for grain dryers. Rather, it is requesting that AIU begin collecting the necessary data to conduct analysis of prospective seasonal cost based rates for DS-2, DS-3, and DS-4 customers with regard to costs of primary lines and substations. While AIU continues to disagree with GFA's conclusion regarding seasonal pricing, GFA states that AIU concedes that the information requested by GFA could lead to more proper cost allocation and pricing, and has agreed to perform further study and provide the result in the next rate case.

e. Commission Conclusion

As with any cost allocation issue, the Commission's goal is to allocate costs to those customers who cause the costs. In this instance, the Commission must determine which allocation method, NCP or CP, best allocates the costs of primary distribution lines and substations. When constructing or expanding primary lines and substations, a utility considers what load those customers to be served by the facilities will impose on the facilities. In most situations, the facilities will serve customers from more than one customer class. The peak of each individual class to be served by the facilities is irrelevant. What is relevant is the combined or coincident peak of all of those served by the facilities, regardless of which class each customer is in. The utility therefore sizes and constructs primary lines and substations to accommodate the anticipated coincident peak.

Why the allocation of the costs of primary lines and substations should be considered differently is unclear to the Commission. Consistent with cost-causation principles, those customers imposing a demand on the facilities at the time of the coincident peak (which was the primary driver in determining the facility size) should be allocated a proportionate share of the costs. The Commission recognizes that under this analysis, DS-5 lighting customers, because they tend to have zero demand during the coincident peak, are not allocated any of the costs of primary lines and substations. In other words, DS-5 customers are not responsible for any of peak demand on primary lines and substations. Because, however, DS-5 customers are rarely, if ever, considered in sizing primary lines and substations, this result is not inappropriate. This is not to suggest that DS-5 customers should not be expected to pay for distribution service. DS-5 customers' delivery service charges will consist of costs for facilities and services other than primary lines and substations. Because the demands of multiple classes on primary lines and substations more closely correspond to CP rather than NCP demands, the Commission agrees with Staff that the most reasonable, cost-based approach is to allocate the cost of this equipment according to the collective peak demands of all rate classes.

AIU's discussion of impacts on customers from using the CP allocator is misplaced. As Staff indicates, the underlying goal of any COSS is to allocate costs to those customers who cause the costs to be incurred. While rate impacts are of concern, the appropriate time to consider rate impacts is after costs have been allocated. At that time, rate mitigation efforts could be used to address any unreasonable or inappropriate rate impacts. In addition, that IIEC would oppose an allocator that shifts costs to larger customers comes as no surprise to the Commission. But given IIEC's concerns about assigning costs to cost-causers, the Commission finds IIEC's position on this issue somewhat inconsistent.

3. Allocation of Electric Distribution PURA Tax

Following the 1970 elimination of the Personal Property Tax, Illinois utilities became subject to a tax on invested capital, pursuant to the PURA. Prior to 1998 for electric utilities, the tax was assessed at a rate of 0.8% of the utility's invested capital. In conjunction with the electric restructuring legislation adopted in 1997, Illinois revised the PURA to impose a per kWh tax on electricity distribution by electric public utilities, rather than a tax on invested capital. AIU proposes that the electric distribution tax be allocated and collected from customers based on kWh sales as well. IIEC opposes that proposition and, instead, contends that the tax should be allocated on a demand basis, using the manner in which the tax was assessed and collected before the 1997 revisions to the PURA. Staff supports AIU's proposal.

a. IIEC Position

In support of its position, IIEC asserts that when Illinois restructured the electric utility industry, it also determined that it would change the basis of the PURA tax to keep it competitively neutral, while maintaining essentially the same level of tax revenues from each of the Illinois utilities individually and in the aggregate, through a series of charges designed to be applied to each utility's delivered energy. IIEC contends that this design protected the tax revenue stream from variation due to utility sale or transfer of generating or transmission assets, since such sale had the potential to reduce a utility's level of invested capital and thus its tax liability. In 1997, the level of tax on invested capital for the three utilities was about $4 million for CILCO, $9 million for CIPS (including the former Union Electric Company), and $23 million for IP.

As a protection for utilities and their customers, IIEC states that the aggregate level of electric PURA tax that the state could collect was capped at $145,279,553 in 1998, adjusted for growth in subsequent years at the lesser of 5% or the percentage increase in the CPI. IIEC reports that the cap has been exceeded every year from 1997 through 2007, prompting annual proportional refunds. IIEC expects that this is likely to be the case for the foreseeable future.

Traditionally, the PURA tax imposed on the utilities has been considered a recoverable test year expense and has been allocated among the rate classes in the COSS based on the classes' share of the cost of utility plant in service, since plant in service represented the capital investments of the utilities. Although the PURA tax was restructured in 1997, IIEC relates that in each of the delivery service rate cases initiated by AIU or their unaffiliated predecessors since 1997 (12 cases in all) the PURA tax has been allocated on the basis of plant in service. As indicated above, however, in the current case AIU proposes to change its allocation from one based on plant in service to one based on the number of kWh delivered to each class. IIEC complains that this proposal would have the effect of shifting millions of dollars of revenue responsibility from the small customer classes to the large customer classes. IIEC asserts that the change in allocation accounts for much of the large increases in delivery service charges proposed by AIU for the DS-4 customers, particularly those taking service at higher voltages.

IIEC opposes AIU's proposed change in the allocation of the PURA tax for four primary reasons. First, IIEC claims that AIU has not justified changing the PURA tax allocation method. In response to discovery requests from IIEC, AIU indicates that it does not have any documents regarding its determination that the traditional approach is no longer appropriate. According to IIEC, AIU's entire rationale for the change is that the annual tax is assessed to AIU based on the quantity of retail electricity delivered in Illinois, making it clearly driven by kWh sales and not based on plant assets. (See Ameren Ex. 16.0E Second Revised at 8)

In response, IIEC argues that kWh sales are only one of several factors, and not the main factor, that determine a utility's PURA tax responsibility in any given year. IIEC insists that the main factor determining a utility's PURA tax responsibility today is the utility's 1997 level of invested capital (and associated tax). The tier levels and tier rates in the PURA, IIEC continues, were custom-designed to approximate the same level of total tax revenue from all utilities and the proportion of tax paid by each utility, as the utilities paid based on their invested capital. IIEC contends that AIU's allocation of the PURA tax on the basis of energy delivered actually moves rate making away from cost causation, giving more weight to the words used to describe or compute the tax than to the actual causes of the tax assessed. IIEC maintains that AIU's proposal to change the only allocation basis it has ever used without any evidence of a change in cost causation and without any quantitative evidence of causation for kWh delivered is not consistent with cost causation principles or AIU's obligation to demonstrate that the change is just and reasonable.

Second, contrary to AIU's and Staff's suggestion, IIEC states that any correlation between kWh sales and the utilities' PURA tax liability in a given year is very weak--at least that is what IIEC says it found when it analyzed the actual kWh sales reported by AIU and the actual PURA tax payments. IIEC witness Stephens explains that if the level of usage determines the amount of PURA taxes, one would expect a linear positive relationship between the PURA tax and kWh deliveries, with the slope of the line representing the marginal (last block) tax rate. The actual AIU data, however, indicates a very weak explanative value of kWh deliveries for changes in the PURA tax, according to Mr. Stephens. He notes further that the slopes of the regressed lines are different from the applicable marginal tax rates set forth in the 1997 legislation. That is, the PURA taxes that a utility pays and kWh the utility delivers change at different rates. Mr. Stephens states that this is another indicator of lack of correlation between the kWh sales and expected tax levels. IIEC asserts that its analytic evidence was unrebutted by AIU or Staff, who rely instead on the simplistic, erroneous assertions that kWh sales drive or cause the utilities' PURA tax liability, without conducting any investigations of the actual cause of the tax liability incurred by the utility.

Third, IIEC maintains that the large majority of the current PURA tax is simply inherited 1997 invested capital tax. IIEC states that approximately 84% of the PURA tax assessed to AIU in 2008 was attributable directly to the 1997 invested capital taxes. Given the Commission’s commitment to cost causation principles in setting rates, IIEC contends that it would be unreasonable and unfair to allocate the PURA tax entirely on the basis of energy usage, when nearly 84% of the tax is caused by historical utility plant investment unrelated to energy delivery. Furthermore, IIEC asserts that even the growth in tax liability post-1997 is closely tied to 1997 invested capital levels, through the utility-specific tax rates. IIEC insists that there is virtually no evidence to compel a change in the allocation of this significant cost item.

Fourth, IIEC argues that AIU's proposed allocation of the PURA tax is not consistent with the legislature’s desire to maintain the 1997 invested capital tax levels and utility shares. IIEC states that Section 1a of the PURA describes the legislative intent of the statute. According to IIEC, the legislative intent clearly indicates that the legislature had two goals in mind: 1) to assess the tax in a way that would be fair, as between utilities and other energy suppliers in the restructured industry, and 2) to maintain tax levels, with comparable allocations among the utilities. IIEC states that no where in the law is there expressed an expectation that the redesign could shift tax burdens from one customer class to another.

With regard to the legislature's first purpose, IIEC explains that it was necessary to change the collection basis from utility invested capital to delivered kWh because the restructuring law paved the way for new electric suppliers who would not be utilities under applicable law. These new suppliers would not be regulated by the Commission, and might not own physical assets. The new suppliers would enter the Illinois market to compete against utilities or other suppliers that would have been subject to the invested capital tax. Moreover, IIEC continues, the 1997 restructuring law allowed utilities to sell or transfer capital assets to affiliated or unaffiliated third parties, with very limited Commission oversight. Thus, IIEC concludes, converting the form of the tax to a delivered energy calculation and collecting it only from the regulated delivery utilities leveled the playing field among competing suppliers.

With regard to the legislature's second purpose, IIEC states that the structure of the statute indicates that the legislature wished to maintain tax revenues comparable to the amount collected before the change in the law. Since the invested capital of the utilities in 1997 caused a specific level of PURA tax for each utility, IIEC states that it would not have mattered whether the legislation achieved its revenue neutrality by replicating the amount using a calculation based on per kWh rates or by simply enumerating each utility’s starting tax level in the law. IIEC asserts that the same level of tax could be derived under any number of custom approaches; the Illinois Legislature happened to use the custom-designed per kWh approach. IIEC contends that the approach chosen by the legislature simply to maintain tax revenue stability does not dictate a shift in cost responsibilities among customer classes.

IIEC acknowledges that the Commission did approve an allocation based on kWh delivered in the initial ComEd delivery service rate case. (Docket No. 99-0117, August 26, 1999, Order at 40) IIEC suggests that the Commission did not, at that time, have the breadth of information on the tax, its cause, and the lack of correlation between kWh delivered and the amount of the tax that is contained in the record in this case. IIEC therefore believes that this record is distinguishable and requires a different result from that in the ComEd proceeding.

If none of its arguments persuade the Commission to retain the traditional allocation of the PURA tax, IIEC offers an alternative tax allocation method which it believes even more precisely allocates tax costs to cost causers. IIEC proposes that the Commission recognize the distinctive cost-causation of portions of the PURA tax by creating two separate cost categories for the tax in the COSS, with different allocation factors for each. The first cost category would be the 1997 levels of PURA tax for each utility. This cost category should be allocated on the traditional basis of utility plant in service. The cost should be recovered in the distribution delivery charge, as is currently the case. The second category of costs would reflect PURA tax amounts in excess of the 1997 levels. These are subject to increase over time as the PURA tax level grows with the escalators on the statewide cap. Under IIEC's alternative proposal, this second category of PURA tax, the "post-1997 PURA tax" could be allocated based on kWh sales, in recognition that kWh sales may, under some circumstances and in some years, be a contributing factor to PURA tax levels. The 1997 PURA tax and the increases in post-1997 PURA tax levels for each of the three utilities necessary for implementation of this approach are shown in Table 1 of IIEC Ex. 5.0 Corrected at 14-15. IIEC computed revised cost of service results based on this alternative approach and provided them in IIEC Ex. 5.2. IIEC believes that this alternative approach provides a reasonable and practical compromise position on this contentious issue, should the Commission seek such a compromise.

b. AIU Position

AIU maintains that IIEC's approach is inappropriate because the structure of the tax is such that as a utility delivers more or less energy, the amount of tax will increase or decrease, all other things constant. Such a result indicates that plant is not a determining factor of the tax amount, but rather that the amount of kWh delivered is determinative. AIU states further that the difference between AIU today and CILCO, CIPS, and IP in 1997 is that in 1997 each of the utilities owned its own generation facilities that were part of the utility plant in service and provided fully bundled electric service. AIU insists that allocating and assigning the cost based on kWh is far superior to allocating the tax based on costs that no longer include generation plant. AIU adds that its proposal to collect the electric distribution tax based on kWh sales is consistent with the legislative intent of the law. Accordingly, AIU urges the Commission to adopt its kWh-based proposal.

c. Staff Position

Staff maintains that AIU's proposal to allocate the PURA tax by usage is consistent with cost causation and should be adopted in this proceeding. Staff observes that since the 1997 revisions to the PURA, usage has determined the amount of distribution taxes collected from ratepayers. Since usage is the driver, Staff states that cost causation principles would argue for allocating these costs on a per kWh basis. Section 1a of the PURA clearly shows, according to Staff, that the legislature made a conscious decision to change the way the distribution tax is determined, from a tax based on invested capital to a tax determined by usage.

The proposal to change from a plant allocator to a usage allocator would shift responsibility for these tax costs from smaller to larger customers on the system. Staff relates that large DS-4 customers account for 43% of system usage and, therefore, would be allocated 43% of these costs in contrast to the 8% they now pay. Staff states further that the allocation to residential DS-1 customers would decline from 56% to 30% of these costs.

Staff notes that the Commission has a longstanding goal of basing rates on cost. Staff contends that IIEC's argument is flawed because cost causation, rather than precedent, should be the deciding factor in the allocation process. If an existing method of allocating a cost that the Commission has approved is not cost based, then the most equitable and efficient solution is to adopt a cost based approach.

Staff rejects IIEC's argument that the continued allocation of distribution taxes according to plant in service is justified on cost principles. Staff also denies that the current level of the tax is primarily a function of the past levels of plant assets, as IIEC contends. While the starting point for the tax levels after the amendatory act corresponded to previous tax levels that were based on invested capital, Staff asserts that the yearly changes for taxes as a whole for all Illinois utilities are not. Staff observes that each year the total amount of distribution taxes collected by utilities increases by the lesser of 5% over the existing level or by the yearly CPI. Neither of these factors, Staff points out, bears any relationship to plant investments.

Furthermore, Staff continues, plant in service is no longer considered in the calculation. If the level of plant were to double or to decline by half, that specific change would have no impact on the utility’s distribution tax. In contrast, Staff observes that the level of deliveries by electric utilities directly affects distribution taxes. If a utility’s level of deliveries increases relative to other electric utilities in Illinois, its share of distribution taxes will increase. If its relative level of deliveries decline, the utility’s share of the distribution tax total will fall. Staff believes that it is clear that usage is the driver now.

There is no doubt that the legislature initially set the level of PURA taxes for each utility calculated on a usage basis approximately equal to the level under the previous plant-based method. Staff asserts, however, that the legislature made it explicitly clear that this tiered method of allocating PURA taxes to utilities would be based on a going-forward basis according to usage, not plant. There is no ambiguity in Staff's opinion that the legislature intended to replace the invested capital tax on electric public utilities with a new tax based on the quantity of electricity that is delivered. Staff notes further that the PURA goes on to state that this usage-based approach is fairer and more equitable.

Staff goes on to suggest that the continued allocation of these costs by the plant in service method directly conflicts with the intent of the law.

d. GFA Position

GFA expresses concern over the impact on larger customer's bills that collecting the PURA tax on a per kWh basis may produce. If the Commission adopts the AIU/Staff proposal for recovering the PURA tax, GFA respectfully suggests that the Commission consider alternatives that would mitigate some of that bill impact.

e. Commission Conclusion

At the outset, the Commission recognizes that allocation of the PURA tax among the electric rate classes involves millions of dollars. Properly assigning these tax costs to the cost causers is clearly important to both customers and the Commission. What drives these tax costs, however, is not entirely clear. IIEC makes interesting arguments in support of its position that invested capital (or plant in service), and not kWh, is the primary cost causer in this instance. IIEC relies on the fact that prior to 1997 plant in service was the basis for the PURA tax. IIIEC maintains that the legislature did not intend to alter this approach when it amended the PURA in 1997.

AIU, Staff, and IIEC each make compelling arguments for and against allocating the PURA tax on the basis of either plant in service or kWh. To resolve these competing concerns, a review of the PURA is necessary. Section 1a of the PURA addresses legislative intent and provides as follows:

> The General Assembly previously imposed a tax on the invested capital of electric utilities to replace in part the personal property tax that was abolished by the Illinois Constitution of 1970. Subsequent to the enactment and imposition of the invested capital tax on electric utilities, State and federal laws regulating the provision of electricity have been enacted which provide for the restructuring of the electric power industry into a competitive industry. In response to this restructuring, this amendatory Act of 1997 is intended to provide for a replacement for the invested capital tax on electric utilities, other than electric cooperatives, and replace it with a new tax based on the quantity of electricity that is delivered in this State. The General Assembly finds and declares that this new tax is a fairer and more equitable means to replace that portion of the personal property tax that was abolished by the Illinois Constitution of 1970 and previously replaced by the invested capital tax on electric utilities, while maintaining a comparable allocation among electric utilities in this State for payment of taxes imposed to replace the personal property tax.
> (Source: Pub. Act 90‑561, eff. Jan 1, 1998.)

This section leaves no doubt that the legislature intended to replace the invested capital/plant in service tax with a kWh tax in response to the changing nature of the Illinois electric utility industry. Also apparent from this language is that the legislature did not want to lose any tax revenue as a result of this change. What remains unclear to the Commission, despite IIEC's assurances, is that the legislature did not intend for any change in how a utility's PURA tax liability is allocated to customers.

While it is true that the statutory language does not expressly direct that the manner in which the tax is allocated be changed, the language also does not require that the allocation method remain the same. The Commission notes that shortly after the revisions to the PURA took effect, it approved allocating the PURA tax on a kWh basis for ComEd in Docket No. 99-0117. Either ComEd's current allocation approach is appropriate or it has been contrary to the legislative intent behind the PURA revisions for nearly 11 years. If the former characterization is accurate, and AIU has been allocating the PURA tax contrary to the legislative intent, nothing prevents the Commission from correcting such an oversight in this proceeding.

In resolving this issue, the Commission notes that the legislature clearly contemplated that regulated electric public utilities might shed much of their plant in service (primarily generation assets) and become regulated distribution utilities. Hence, the need to modify how the PURA tax was assessed. The possibility that the legislature contemplated has occurred, and much of that plant in service is no longer owned by the regulated electric utilities. The disconnect between plant in service and the distribution tax under the current PURA provisions is apparent from the fact that as the level of a utility's plant increases or decreases, that specific change would have no impact on the utility’s distribution tax. A break from historic plant in service is also suggested in Section 2a.1 of the PURA, which imposes an annual cap on the aggregate amount of the distribution tax which can be collected statewide from electric public utilities and ARES, as those terms are defined in the Act. As a practical matter, no ARES deliver electricity. But if one ever did using its own plant in service, it would have no historic invested capital value for the legislature to try to preserve through the per kWh tax rates in the PURA.

For these and the foregoing reasons, the Commission is inclined to find the interpretation of the PURA by AIU and Staff more reasonable than that of IIEC. Adoption of the AIU and Staff position is also consistent with Docket No. 99-0117. If the legislature intended a different result, the Commission would welcome any such clarification. In the absence of any clear legislative intent to the contrary, AIU should recover PURA tax costs in base rates through the kWh-based Distribution Delivery Charge from the DS-1, DS-2, and DS-5 classes. AIU should create a kWh charge to reflect the PURA tax allocation that applies to the DS-3 and DS-4 classes.

4. Overall Suitability of AIU's COSS

AIU presented a separate electric COSS for each of the three utilities using a test year of 12 months ending on December 31, 2008. AIU's proposes rates based on the

COSS. IIEC contends that AIU's electric COSS are riddled with errors and should not be relied upon. Instead, IIEC recommends that the Commission allocate any rate change approved in this docket on an equal percentage, across-the-board basis. Staff generally supports AIU's electric COSS (but recommends specific revisions discussed below).

In Docket 07-0585, the Commission directed AIU to take into account alternative rate structures for the heavily subsidized all-electric residential customer sub-class that would incorporate the effect of innovative market-based dynamic or real-time pricing rate structures for retail all-electric customers. AIU was also directed to develop a separate sub-class for the residential space-heat customers and consider the use of a straight-fixed-variable rate design for this sub-class of customers if a dynamic pricing rate design utilizing market-based rates can be shown to be beneficial. 07-0585 Order at 281-282.

a. AIU Position

AIU explains that the class COSS presented in these cases are the result of the process of allocating and assigning the various cost elements of providing electric delivery service to the various customer classes in a way that best reflects the manner in which such costs are incurred in providing delivery service. The results of the class COSS are often referred to as the "class revenue requirements." AIU identifies three steps in preparing a COSS: functionalization, classification, and allocation. Functionalization is the assignment of rate base items and operating expenses to major functions such as production, transmission, distribution, and customer service. Classification is the assignment of the functionalized costs to categories of cost causation. For example, costs may be classified as demand-related, energy-related, or customer-related. Allocation is the process of assigning the classified costs to the various classes of service.

With specific regard to the classification step, AIU states that it classifies each rate base and expense item in the electric delivery revenue requirement on the basis of cost causation to demand-subtransmission, demand-distribution, or customer. Demand-subtransmission and demand-distribution costs, AIU continues, are those investments and expense items that are incurred to meet system peak load requirements and local maximum demands, respectively. AIU relates further that customer-related costs are those investments and expense items which are incurred to serve customers and which do not vary with changes in consumption, such as the cost of the customer's meter and service drop.

In the development of distribution plant in the COSS model, AIU explains that the capital asset costs are segregated according to voltage level. AIU indicates that demand-related costs were allocated to customer classes based on the contribution of each customer class to the system's NCP demand based on the costs at the various voltage levels.

AIU asserts that its COSS preparation methodologies were approved by the Commission in its Order in Docket Nos. 06-0070 et al. (Cons.), AIU's second most recent electric delivery service rate proceeding. AIU notes, however, that some allocation factors were modified to more appropriately follow current operations and customer demand. Ameren Ex. 17.0 contains a discussion of AIU's allocation methodologies.

After reviewing the other parties' positions, AIU identified one necessary change to the COSS. Specifically, AIU realizes that the allocator used to determine how FERC Account 362 (reflecting costs for distribution substations) is allocated to customers was initially incorrect. AIU now agrees with IIEC that the DDSUBTR allocator should be used to allocate the costs in FERC Account 362. AIU explains that the DDSUBTR allocator is more appropriate because it selectively allocates the costs in Account 362 to customers with delivery voltage less than 100 kV. AIU adds that the change to the DDSUBTR allocator is proper because it more closely matches the function of the substations – lowering the supply voltage down to delivery voltage. According to AIU, adoption of the DDSUBTR allocator results in the reallocation of approximately $25 million to the DS-4 100+ kV customer subclass, out of $4.3 billion in total AIU allocable gross distribution plant. AIU states that the $27 million value cited by IIEC is a gross number before depreciation is applied, and ultimately translates into a revenue requirement reallocation totaling approximately $4 million (calculated as ROR multiplied by cumulative depreciation, less allocation depreciation, plus allocation depreciation expense) of associated revenue requirement to the DS-4 100+ kV customer subclass. The practical effect is that the revenue requirement reallocation will not reach $4 million if the Commission approves a revenue requirement lower than what AIU requests.

Even with the correction regarding the DDSUBTR allocator, AIU does not assert that its COSS are perfect. AIU acknowledges that assigning specific costs to broad rate classifications involves some subjective consideration, which includes some degree of generalized application and educated assumption. Regardless, AIU maintains that it is the steward of the COSS it maintains. AIU indicates that it is always willing to redress legitimate concerns regarding the study, as well as any similar models offered by Staff and customers. AIU is confident that its COSS presents a highly accurate allocation of cost causation. AIU states that it will continue to address stakeholder recommendations that could enable it to allocate costs more precisely in future rate cases. AIU urges the Commission to accept its COSS in this proceeding. To the extent that modifications have been proposed in this case, AIU asks that the Commission refrain from rejecting its COSS and instead direct that such modifications be implemented in future COSS.

Regarding the errors in the AIU COSS that IIEC claims to have identified, AIU points out that IIEC nevertheless used AIU's study rather then create its own. Concerning IIEC's allegation that AIU misallocates the PURA tax, AIU insists that its allocation is consistent with the statutory assessment of the tax. AIU also denies that its use of the NCP demand allocator is inappropriate. AIU maintains that IIEC provides little more than conclusory assumptions and generalized criticism of the NCP allocator that is unsupported by the record. As an example, AIU points to IIEC's claim that AIU fails to allocate the costs of poles, wires, and substations to nearly 2,000 large customers taking service at secondary voltage. AIU contends that IIEC cites no evidence to support this assertion. As for the allegedly ambiguous voltage definitions which IIEC complains of, AIU asserts that this is merely another iteration of IIEC's misplaced argument that AIU's use of both supply and delivery voltages in the cost allocations for large (100+ kV) customers is inappropriate. AIU also asserts that it provided responses to all of IIEC's discovery requests in a timely manner.

With respect to IIEC's complaints regarding allocation of transformer revenue, AIU argues that its approach is reasonable. AIU explains that transformer rental revenue, like other forms of revenue, is an off-set to the overall revenue requirement—which AIU states it recognized when it allocated that revenue in the COSS. Although IIEC contends that AIU has misallocated transformer rental revenue, it presents no alternative approach. If IIEC had proposed an alternate approach, AIU states that it would have considered it. Instead, IIEC merely reiterates its argument that AIU's COSS are not perfect, and as a result, the Commission should reject them in their entirety.

In response to IIEC's claim that the COSS reflect a discrepancy in the number of DS-2 customers, AIU contends that IIEC misinterprets AIU witness Althoff's testimony, as well as the data in Schedule E-6. During Ms. Althoff's cross-examination, AIU relates that IIEC displayed certain customer count statistics on the E-6 schedule. AIU asserts, however, that those statistics are unrelated to the metered delivery points utilized in AIU's COSS. Ms. Althoff noted during her examination that there are various customer count and delivery service point metrics, many of which are related to one another to some extent. AIU maintains that minor differences among these statistics are not indicative of underlying problems with the data it used in the COSS. AIU states further that it used customer count data by class to allocate certain costs, and NCP demand to allocate others. To the extent that the IIEC is suggesting differences between customer counts, meters, and delivery points are indicative of missing information, AIU contends that IIEC is simply presenting an apples-to-oranges comparison.

Because of the errors that it perceives in AIU's electric COSS, IIEC recommends that the Commission revise rates on an across-the-board basis rather than rely on the allegedly faulty COSS. AIU takes exception to this proposal and notes that IIEC advocates this position for the first time in its Initial Brief. AIU also points out that in AIU's last rate proceeding, Docket Nos. 07-0585 et al (Cons.), IIEC was steadfast in its support of cost based rates and openly criticized AIU for proposing an across-the-board increase in rates.

AIU notes further that during the course of the hearing, IIEC raised the notion of rerunning the COSS. AIU contends that this would not be a useful exercise and would not benefit the Commission's consideration of the issues in this case. According to AIU, utilities do not typically completely rerun a COSS during a rate case. Expanding the evidentiary phase of the case, AIU adds, only prolongs and complicates an already arduous process. AIU asserts that the COSS is merely a foundational step that is only conducted to provide support for its ultimate rate design recommendations. Absent the rate design considerations it is intended to support, AIU contends that a COSS update would not provide any additional analytical value. The revenue requirement values entered into the COSS at the beginning of the case will change as a result of the Commission's decision in these cases. AIU maintains that conforming the rate design to the final revenue requirement, both at aggregate and class levels, should not be addressed by reopening the evidentiary record. Instead, AIU believes that the final revenue requirement is more properly addressed by reference to witness testimony specific to that very subject. In this instance, AIU states that AIU witness Jones and Staff witness Lazare have offered testimony with regard to the methodology utilized to adjust proposed rates to the final revenue requirement.

To comply with the directive from Docket 07-0585, AIU performed an analysis to determine if marginal prices for the all-electric residential customer sub-class were competitive with market prices for power and energy. Results of this study show that with the subsidy that remains to this sub-class there continues to be a disparity in pricing by comparing marginal prices with market prices. (AIU Ex. 16.0E at 22)

b. IIEC Position

IIEC's criticism of AIU's electric COSS begins with the observation that the results of any COSS are only as valid as the inputs and assumptions used to develop the study. In this instance, IIEC contends that AIU's COSS contain errors in logic and factual inconsistencies that render them deficient for the purpose of setting rates in this proceeding. IIEC asserts that some of these errors and inconsistencies were identified in its written direct and rebuttal testimonies, while others were identified through cross-examination. In its direct testimony, IIEC claims to have identified (1) the misallocation of the cost of 34.5 kV and 69 kV substations (in FERC Account 362) to customers taking services at a voltage of 100 kV or higher, (2) the misallocation of PURA taxes, (3) errors in the development of the NCP demand allocators, and (4) a failure to properly allocate transformer rental revenue.

Regarding the alleged misallocation of the cost of 34.5 kV and 69 kV substations, IIEC claims that the AIU COSS allocated these sub-transmission costs to transmission level customer classes that take service at 100 kV or higher. IIEC suggests that in total, AIU's COSS improperly allocated $27 million in primary voltage and/or sub-transmission voltage substation equipment costs to transmission level customers. IIEC points out that the misallocation of these costs appeared to be associated with a change in the allocation factor used to distribute sub-transmission station equipment in the current studies. In the current studies, AIU used a factor identified as "DEMSUBTR." IIEC observes that in its prior COSS AIU used the DDSUBTR allocator, which IIEC believes properly allocates sub-transmission substation costs. Although AIU eventually agreed with IIEC that use of the DEMSUBTR allocator was an error, IIEC notes that AIU's acquiescence does nothing to remedy the COSS at issue which incorporates the DEMSUBTR allocator.

As for the new demand study component of AIU's COSS, IIEC understands AIU to believe that its new studies are more reflective of the demand incurred on the secondary voltage portion of its distribution system with respect to the DS-2 class. IIEC, however, contends that the new study actually results in the allocation of costs used to serve customers at secondary voltage levels to customers who do not use the secondary system. Specifically, IIEC states that the study does not distinguish between DS-2 customers taking service at primary voltage and DS-2 customers taking service at secondary voltage. Therefore, IIEC argues that it is difficult to see how the new study is more reflective of demand incurred on the secondary voltage portion of the system with respect to the DS-2 class if it attributes secondary system costs to customers who do not use that system. IIEC also fears that AIU has not properly counted the number of DS-2 customers.

IIEC further complains that AIU's COSS for AmerenIP does not allocate costs relating to substation equipment, poles, towers, fixtures, overhead conductors and devices, and underground conduit reflected in FERC Accounts 362, 364, 365, and 366 to 1,936 DS-3a, DS-3b, and DS-4 secondary customers. IIEC contends that a similar situation occurs in the AmerenCIPS and the AmerenCILCO COSS. IIEC acknowledges AIU's suggestion that because these DS-3a, DS-3b, and DS-4 secondary customers are really supplied at primary voltage, the costs reflected in Accounts 362, 364, 365, and 366 would not be assigned to these customers. In IIEC's view, however, AIU’s response calls into question class definitions in the AIU COSS. If classes clearly identified in the study as “secondary” are, in fact, supplied at primary voltage levels, IIEC does not understand how one can possibly determine, based on the COSS, whether secondary and primary costs have been properly allocated.

IIEC is also troubled by the testimony of AIU witness Althoff at the evidentiary hearing that the term “secondary” for the DS-3a secondary, DS-3b secondary, and DS-4 secondary classes refers to "metered voltage," and are totally separate and different from supply voltage and delivery voltage as AIU has used those terms in this case. (See Tr. at 586-587) IIEC states that AIU does not explain the significance of the term “metered voltage” in its description of its COSS. According to IIEC, Ms. Althoff's cross-examination testimony conflicts with her prepared written testimony wherein she stated that all customers have a supply and delivery voltage, where the supply voltage is the voltage of the feeder line from which the customer is supplied, and delivery voltage is the voltage at the point of connection between the customer’s facilities and the AIU facilities. (Ameren Ex. 41.0 at 7) Under the circumstances, IIEC contends that it is difficult to see how the Commission can determine whether or not the AIU COSS in this case have properly identified the cost of serving these customer classes.

With regard to the assignment of transformer rental revenues, IIEC claims to have identified an error in the way AIU's COSS credited transformer rental revenues to the customer classes. AIU agrees that the revenues in question should be credited as closely as possible to the classes from which those revenues are collected. In the AIU COSS, however, IIEC notes that the transformer revenues were allocated on the basis of each class’ contribution to NCP demand as determined by the new demand studies.

As a result of AIU's improper treatment of rental revenues, IIEC contends that customer classes from which rental revenues are collected do not receive the full credit of that revenue. This in turn, IIEC continues, understates the rate or return developed in the COSS for the customer classes that contributed to the rental fees. At the same time, the customer classes with relatively large contributions to peak demand are credited with a relatively large portion of the rental revenues, irrespective of the amount of rental revenues actually contributed by those classes. Although AIU has expressed a willingness to correct this error in the next rate case, IIEC asserts that waiting until then does little to help determine the cost of serving these classes in this case.

IIEC states that it re-ran the AIU COSS to correct for the first two deficiencies. The correction of these two deficiencies alone, IIEC avers, had a significant impact on the class rates of return and the revenue allocations in each of the COSS. As an example, IIEC states under the revised COSS, the DS-4 class as a whole provided higher rates of return than AIU's original studies suggested and that the DS-4 100 kV and above subclass provided rates of return significantly above the total rates of return for each of the three utilities. IIEC indicates that it did not receive the data it needed to modify the NCP demand data allocators from AIU in a timely manner, and was therefore, unable to correct the third deficiency in the COSS.

When all of these errors and inconsistencies are considered, IIEC argues that the fundamental validity and accuracy of AIU's COSS are called into question. Unfortunately, IIEC continues, analyses or alternate versions of the COSS, such as its own, that are based on AIU's flawed COSS are themselves flawed (although perhaps to a lesser degree). Under the circumstances, IIEC asserts that the Commission can not be sure that the costs of serving the classes and subclasses within each of the three utilities have been accurately and properly determined. Therefore, it is IIEC's primary recommendation in this case that the Commission reject the use of AIU's COSS for revenue allocation and rate design purposes, and allocate any increase authorized in this case on an equal percentage across-the-board basis. At a minimum, if the Commission decides to use AIU's COSS for rate design and revenue allocation purposes, IIEC urges the Commission to correct the COSS for at least the deficiencies IIEC identifies.

c. Staff Position

Staff contends that the fact that only AIU offered a COSS does not mean that AIU's arguments on related issues should carry more weight. Staff points out that utilities are required to provide such studies under Part 285. Moreover, Staff continues, utilities are typically the source of COSS in rate cases because it is their overall costs that are being allocated among customer classes. Staff adds, however, that there is no guarantee that a utility's COSS is accurate. As an example of inaccuracies in COSS, Staff notes that AIU proposes to change the allocation of PURA taxes in this case as a delayed reaction to legislation passed in 1997. Thus, Staff reasons, AIU's action in this case corrects an inappropriate allocator from previous cases. Staff notes that AIU also accepts a revised allocator for Account 362. Staff contends that these are not the only shortcomings with AIU's COSS, noting its arguments regarding the allocation of primary lines and substations costs. Staff maintains that each cost of service argument should be assessed on its own merits and the fact that AIU furnished the original COSS for this case should not influence the Commission's decision on this issue in any manner.

d. Commission Conclusion

By AIU's own admission, its electric COSS are not perfect. The question for the Commission is whether the COSS are too imperfect to be used in this proceeding. The Commission recognizes that it approved use of similar electric COSS in AIU's second most recent rate proceeding, Docket Nos. 06-0070 (Cons.). The fact that AIU modified the COSS since then, however, warrants fresh consideration.

Some of the alleged errors in the COSS have already been reviewed and addressed in this Order. AIU acknowledges that use of the DEMSUBTR allocator was in error and has agreed to renew use of the DDSUBTR allocator. IIEC's concerns about the class demand study employing a combination of supply and delivery voltage have been considered above as well. The Commission concluded that the class demand study should use supply voltage alone. Allocation of AIU's PURA tax liability has also already been discussed, with the Commission concluding that no change in the COSS is warranted in this respect.

One of IIEC's criticisms that has not been previously addressed pertains to the allocation of transformer rental revenue. Whether AIU acknowledges a possible error in its allocation method is not clear. AIU does, however, allege that IIEC failed to provide it an alternative to consider. The Commission understands IIEC to simply argue that transformer rental revenue from DS-4 customers should be used to offset the DS-4 class revenue requirement. IIEC seems to make the same straightforward argument for the DS-3 class. The Commission agrees with IIEC's recommendation. Under IIEC's approach, the revenues in question will be credited to the classes from which those revenues are collected. To the extent that AIU's method differs in its COSS, the Commission directs AIU to implement IIEC's straightforward approach to allocating transformer rental revenue the next time it runs its COSS.

With regard to IIEC's complaint that AIU's COSS fails to allocate costs relating to substation equipment, poles, towers, fixtures, overhead conductors and devices, and underground conduit reflected in FERC Accounts 362, 364, 365, and 366 to over 2,000 DS-3a, DS-3b, and DS-4 secondary customers, the record lacks sufficient evidence to find that IIEC is correct. If AIU has not allocated such costs to all of the appropriate customers, the Commission directs AIU to correct this deficiency the next time that it runs its COSS.

Despite having confirmed the presence of some of the errors that IIEC alleges, the Commission is not prepared to disregard AIU's electric COSS. In AIU's last rate proceeding, the Commission authorized rate adjustments on an across-the-board basis, not because of deficiencies in AIU's COSS but because the recently redesigned electric rates stemming from Docket No. 07-0165 had been in effect for less than one year. The Commission feared that returning to cost based rates so soon would lead to the same rate shock that warranted the rate redesign in Docket No. 07-0165. Since then, electricity commodity prices have dropped (for now) and the Commission generally believes that the overall impact of bills reflecting cost based delivery services will be tolerable. Therefore, the Commission finds that AIU's electric COSS, as modified in this Order, should be used in setting rates in this proceeding. IIEC may be correct regarding the other errors that it alleges exist in AIU's electric COSS, but the Commission does not consider them fatal to the COSS. AIU should therefore rerun its COSS incorporating the corrections and adjustments discussed above before finalizing rates.

The Commission notes that AIU complied with the directive in Docket 07-0585 to analyze rate alternatives for the subsidized all-electric residential customer sub-class. At this time the Commission does not direct AIU to develop an alternative rate class for all-electric customers; however, in subsequent rate proceedings, as subsidies for these customers are reduced, AIU should continue to analyze whether market based prices are competitive with marginal prices and alternative rate designs more beneficial for this sub-class of customers.

C. Contested Gas Issue - Storage Cost Allocation

AIU incurs storage costs associated with both on-system storage facilities and off-system storage facilities. On-system underground storage facility costs are recovered in base rates. Off-system underground storage facility costs are recovered only from sales customers through a different recovery mechanism and are not at issue in this proceeding. In its gas COSS, AIU allocates such on-system costs to both sales and transportation customers.[11] AIU segregates these on-system storage costs into a portion that supports the delivery function applicable to all sales customers and a portion assignable to transportation customers based on their actual peak day usage during the historic test year. Staff, on the other hand, proposes to allocate these costs based on the transportation customers' Daily Confirmed Nomination ("DCN")[12] on the same day. Nominations are the amount of gas scheduled for delivery on a pipeline to the LDC system.

1. AIU Position

Transportation customers have a limited ability to withdraw gas from their transportation banks on a peak day. AIU bases the on-system underground storage

[11] AIU provides two general categories of service to its commercial customers: they can either receive sales service (i.e., AIU sells and delivers gas to the customer) or transportation service (i.e., AIU delivers to the customer gas that the customer purchased from a third party).

[12] As defined AIU's tariffs, a DCN is the volume a transportation customer nominates and delivers to the company's delivery system for any single day. The absence of a DCN is equivalent to a DCN of zero. Such deliveries shall reflect adjustments for losses on the company's gas system. (See Ill. C. C. No. 20, 1st Revised Sheet No. 25.001)

cost allocation on the relative size of the transportation customers' withdrawal ability. On a Critical Day ("CD"), daily balanced customers can call on their storage bank for up to 20% of their DCN and monthly balanced transportation customers can call on the storage bank for up to 50% of their DCN. AIU states that it must operationally plan to serve transportation customer banks on a CD, but does not know what the transportation customers will nominate on any given day in the future. From a planning perspective, AIU assumes that transportation customers as an aggregate will call on the storage bank for 20% of their usage on a future peak day. AIU, therefore, determined the amount of on-system storage capacity planned to serve 20% of the transportation customers' peak day usage and allocated a portion of the on-system storage capacity costs based on the ratio of the transportation customers' peak day capacity usage to the total on-system storage capacity.

AIU's proposed allocation of on-system underground storage costs to transportation customers is based on the transportation customers' actual peak day usage during the 2008 test year. The following table shows the how AIU determined the allocation percentage for AmerenCIPS. In this example, AmerenCIPS' 2008 peak day usage was 60,436 therms. Excluding the usage associated with special contracts and GDS-7 customers results in 34,204 therms of relevant peak day usage. Applying AIU's actual 20% planning assumption to the 34,204 therms of relevant transportation customer peak day usage results in an expected bank withdrawal of 6,841 therms. AmerenCIPS has 38,000 therms of on system storage capacity. The 6,841 therms of expected bank withdrawal rights represents 18.00% of the 38,000 therms of on-system storage capacity available to the transportation customers.

	Calculation of the Transportation Customers' Allocation of On-System Storage Facility Costs	AmerenCIPS
(a)	Transportation customers' relevant 2008 peak day usage	34,204 therms
(b)	Planning Factor	20%
(c)	Bank Withdrawal Rights – *i.e.,* (a) times (b)	6,841 therms
(d)	Total On-System Storage Capacity	38,000 therms
(e)	Allocation Percentage – *i.e.,* (c) divided by (d)	18%

AIU therefore allocated 18% of AmerenCIPS' on-system underground storage costs to the AmerenCIPS transportation customers. The remaining 82% of the on-system storage costs was allocated to sales customers. Using the same methodology, AIU produced allocation percentages for AmerenCILCO and Ameren IP. AIU offers the following table depicting the percentage of on-system underground storage costs allocated to transportation customers under the AIU and Staff proposals. AIU and Staff disagree not only on the resulting allocation percentages, but also on the method for developing those percentages.

Proposed Allocation of On-System Storage Costs to Transportation Customers		
	AIU Allocation Based on Actual Planned Peak Day Usage (Ameren Ex. 27.3)	Staff Allocation Based on DCN (Staff Ex. 27.0 Revised at 38)
AmerenCIPS	18.00%	14.02%
AmerenCILCO	5.53%	3.96%
AmerenIP	5.21%	3.80%
Total	6.19%	4.55%

AIU, therefore, bases its proposed gas rates on the following allocations of on-system storage costs to transportation customers: (a) AmerenCIPS – 18.00%, (b) AmerenCILCO – 5.53%, and (c) AmerenIP – 5.21%. These percentages are based on the transportation customers' ability to rely on these facilities to serve their peak day usage with bank withdrawals.

Rather than allocate costs based, in essence, on the AIUs' planned deliverability to customers (i.e., the amount of capacity that AIU actually acquired and accounted for in its peak day planning for these customers), Staff recommends that AIU allocate on-system storage costs based on 20% of the transportation customers DCN on the 2008 test year peak day. The DCN for that peak day represents the amount of gas that the transportation customers intended to deliver for that peak day. Staff claims that it is more appropriate to allocate the on-system storage cost based on a percentage of DCN because AIU's tariffs allow transportation customers to call their bank capacity for up to 20% of their DCN. AIU contends that Staff's proposal is flawed.

AIU's first criticism of Staff's approach is that using only the DCN understates the cost responsibility to transportation customers with the remaining cost responsibility being absorbed by sales customers. AIU maintains that its approach of using actual peak day usage mirrors more closely a true and reasonable design day level requirement from which costs can be reasonably assigned to transportation customers. AIU's second criticism is that transportation customers' DCN is discretionary and not predictable. A transportation customer can nominate as little as zero therms for a peak day, as much as 100% of the maximum daily contract quantity ("MDCQ") for daily-balanced customers, or 200% of MDCQ for monthly balanced customers. AIU states that it is up to each transportation customer to decide how much gas to nominate on a day. The customer may not be able call on storage bank if, for example, the customer did not have a positive bank balance. Moreover, AIU adds, the customer may choose not to call on its storage bank for a commercial reason. Alternatively, AIU states that transportation customers can call on the transportation bank for as much as 20% to 40% of their MDCQ if they nominated the maximum amount available under the tariff. AIU does not know what a transportation customer individually, or transportation customers in aggregate, will nominate for any given day. Due to the discretionary nature of the DCN, AIU does not plan its resources assuming 20% of historic DCN.

AIU disagrees with Staff's contention that basing the allocation on 20% of peak day usage rather than 20% of DCN over-allocates costs to transportation customers.

While DCN levels are a fair starting or reference point, AIU maintains that the transportation customers' DCNs are significantly lower than the transportation customers' actual peak day usage. Basing the on-peak storage allocations on transportation customers' DCNs would materially understate the storage cost responsibility to transportation customers, according to AIU. Instead, when allocating the storage costs, AIU states that it should consider not only the starting DCN, but also the actual peak day use of transportation customers. AIU concludes that the Commission should permit it to allocate on-system storage costs based on the transportation customers' peak day usage that would capture the initial DCN levels, plus rather large additional levels of use.

2. Staff Position

Staff has no objections to the allocation of on-system underground storage facility costs based on the ability to withdraw gas on a peak day. Staff notes, however, that while AIU reasonably allocates these costs based on ability to withdraw gas on a peak day, it measures that ability as 20% of transportation customers' usage rather than the smaller amount allowed in the tariff, which is 20% of a customer's DCN for GDS-4 customers. DCN is the amount that the pipelines have confirmed will be delivered. Staff states that AIU treats any volume of gas that a customer uses above its DCN as a bank withdrawal. Therefore, on days where a customer expects to withdraw gas from its Rider T bank as is assumed in allocating storage cost responsibility, AIU assumes that the customer will nominates a volume of gas less than its anticipated usage. Staff asserts that AIU acknowledges that DCN will be less than usage and 20% of DCN will be less than 20% of usage. (Tr. at 856-857) According to Staff, the practical result of AIU using 20% of usage is to over-allocate storage costs to transportation customers. Consistent with AIU's tariffs that provide that transportation customers may withdraw 20% of their peak day DCN, Staff recommends that these customers be allocated the share of storage costs based on 20% of DCN rather the 20% of their peak day usage.

Staff asserts that AIU set out to allocate storage costs to transportation customers "based on the transportation customers' actual peak day usage during the historic test year," and "based on their ability to withdraw gas from their transportation banks on a peak day." (AIU Initial Brief at 218) Staff notes that these are not the same thing. AIU later offered a third reason: that 20% of usage (an amount in excess of tariff limits on withdrawals) represents "expected bank withdrawals" on a design day. (AIU Initial Brief at 220) Staff criticizes AIU for changing the reason behind its allocation method.

Staff understands that AIU has designed the gas distribution system for a CD. Therefore, Staff believes that it is appropriate to compare the relationship between expected usage and DCN on a CD, rather than simply on an historic peak day. AIU, however, continues to argue that bank withdrawals will be in excess of that allowed in the tariff. Staff states that AIU bases this view on the assumption that customers will under-nominate on a CD. Staff argues that under-nomination on a CD is unlikely in light of the tariff conditions that exist on CDs. For example, usage in excess of nominations and allowed bank withdrawals are subject to significant penalties of over $6 per therm.

In response to AIU's assertion that it can not predict DCN on peak days and therefore relies on usage, Staff acknowledges that it may be easier to estimate usage on peak days but contends that DCN on a CD must be close to usage. If AIU has chosen to plan its system based on bank withdrawals that are not supported by the tariff, Staff states that this should not influence cost allocation. Staff contends that transportation customers should pay based on what they can expect to withdraw on a CD. Staff relates that it is neither usage alone nor DCN alone that dictates the level of bank usage; rather, it is the difference in DCN and usage. On a CD, Staff explains that these numbers will closely track because of AIU’s tariff provisions approved by the Commission to prevent one thing: the excess use of system gas that results from under-nomination.

With respect to AIU's complaint that the transportation customers’ DCN is discretionary and not predictable, Staff counters that just because customers' nominations are “discretionary” does not make them arbitrary as AIU infers. Staff maintains that AIU has not established that its transportation customers individually vary their nominations between 0 and 200% despite the allegation to that effect. Certainly this will not be the case, Staff continues, when transportation customers are considered in aggregate--which is what is what is at stake here. According to Staff, the maximum aggregate that AIU alleges individual transportation customers can nominate is not the issue here because if transportation customers nominate and deliver up to MDCQ or even 2 times MDCQ on a peak day, they would be injecting gas, not withdrawing it. Staff observes that such nominations would only cause the transportation customers’ aggregate bank usage to go down.

Staff goes on to state, however, that the minimum aggregate expected nomination would be a legitimate concern. On a CD, Staff relates that transportation customers have certain “rights” to nominate as stated by AIU; they have certain obligations as well. Realistically, Staff doubts that transportation customers would nominate that little gas. The factor limiting potential under-nomination, Staff continues, is CD penalties. All transportation customers, regardless of whether they are daily or monthly–balanced customers, face the $6-per-therm Unauthorized Gas Use Charge which could be 10 times the price of gas on that day or more. In addition, Staff reports that transportation customers would also face stringent Operational Flow Order (“OFO”) balancing provisions that charge transportation customers up to 2 times the spot price for the use of system gas. Furthermore, transportation customers stand responsible for potential pipeline imbalances that they may cause. Staff argues that all of these things combine to constrain transportation customers’ nominations to a reasonable level. AIU’s assertion of wildly vacillating nominations between 0 and 200% of MDCQ is simply not realistic, according to Staff, in light of AIU's exiting tariff terms. Staff maintains that AIU focuses on serving the bank withdrawals of transportation customers and ignores the other side of the tariff that is designed to protect the system on a CD.

AIU also indicates that some customers may not be able to withdraw gas on the CD because they may lack sufficient capacity in those banks. These customers, AIU states, will have to nominate below their usage to reduce the risk of Unauthorized Gas Use Charges, which would reduce the aggregate bank withdrawal below the 20% amount. Staff observes that another reason listed by AIU is that customers may choose to not use banks for commercial reasons. Staff states that this would once again mean that they would have to nominate more than they would otherwise and would also reduce the aggregate bank withdrawal. According to Staff, these examples of discretionary behavior actually point to a lower expected bank withdrawal. Staff contends that AIU can not point to a singe reason why transportation customers would reduce nominations on a CD and completely ignores the CD penalties which may be 10 times the market price or more.

Therefore, Staff continues to recommend that these customers be allocated the share of storage costs based on tariff rights that provide withdrawals of 20% of DCN rather the 20% of their peak day usage. Using 20% of DCN changes the storage allocator in Ameren Ex. 27.3 from 18.00% for AmerenCIPS to 14.02%, from 5.53% for AmerenCILCO to 3.96% and from 5.21% for AmerenIP to 3.80%.

3. Commission Conclusion

Generally, the Commission approves of allocating on on-system underground storage costs based on the relative size of the transportation customers' withdrawal ability on a peak day. While AIU bases the allocation on 20% of transportation customers' aggregate usage on the 2008 peak day, Staff recommends basing the allocation on 20% of transportation customers' aggregate DCN on the 2008 peak day. There is no dispute that 20% of usage is a greater number than 20% of DCN on the peak day. Nor is there a dispute that AIU's method allocates more on-system storage costs to transportation customers that Staffs' method. The question is which method is more representative of costs transportation customers impose on the storage system.

While AIU's method attempts to consider bank withdrawals by transportation customers on a CD, when storage capacity is arguably the most important, the Commission is concerned that AIU has neglected to consider the big picture. By "big picture," the Commission is referring to AIU's existing tariff provisions which would deter transportation customers from making a reliability problem worse on a CD. Staff's method, on the other hand, appears to reflect the operational realities of a CD. The Commission finds Staff's approach to more reasonably reflect the withdrawal capacity of transportation customers on a peak day. Basing the allocation on 20% of peak day usage rather than 20% of DCN over-allocates costs to transportation customers. The more appropriate method is to allocate the on-system storage cost based on 20% of DCN, as suggested by Staff. Accordingly, AIU's gas COSS should reflect an allocation of on-system underground storage costs based on 20% of transportation customers' aggregate DCN on the 2008 peak day.

IX. RATE DESIGN/TARIFF TERMS AND CONDITIONS

The above discussion on how to allocate costs among the classes of electric and gas customers is but one component of rate design. Rate design, in the parlance of the Commission, also encompasses the terms and conditions of service in a utility's tariffs. Over the course of this proceeding, parties raised several issues and presented arguments concerning the terms and conditions of service. Some of these issues have been resolved, while others remain contested.

A. Resolved Gas and Electric Issues

1. Uncollectibles Factors

Pursuant to Section 2 of the stipulation in Docket No. 09-0399, AIU and Staff have agreed to the following regarding the determination of uncollectibles factors concerning Rider EUA and Rider GUA:

> . . . the uncollectible amounts included in rates for the periods on and after the date new rates take effect (pursuant to 09-0306 et al (Cons.)) shall be determined for each relevant customer rate class as defined in Rider EUA as follows:
>
> a. For [delivery service ("DS")], the uncollectible amounts included in rates shall be the amount equal to the DS uncollectible component as stated in the compliance DS tariff sheets as a dollar amount per customer, per month multiplied by the number of customers. The DS uncollectible component would be included within the stated DS monthly customer charge and not appear on customer bills as a separate line item. The AIU will provide Surrebuttal Testimony on this item in the pending rate case.

The parties agreed in Docket No. 09-0399 to a similar provision with respect to Rider GUA. AIU proposes that the “average amount per customer per month” be listed in the appropriate DS tariff in the Terms and Conditions section. These amounts will be tracked within AIU’s billing system and serve as the base amount of uncollectibles included in rates, required for use in conjunction with Riders EUA and GUA. AIU’s calculations will be updated to conform to the expense level authorized by the Commission at the conclusion of the rate case. AIU and Staff are in agreement on this issue. The Commission finds the resolution of this issue appropriate and consistent with its decision in Docket No. 09-0399.

2. Miscellaneous Tariff Language Changes

With regard to the Terms and Conditions of Service section of AIU's gas and electric tariffs, Staff and AIU are in agreement on various modifications. Language revisions that AIU proposes include wording modifications and date changes in the electric “Switching Suppliers” subsection and language changes in the electric “Disconnection and Reconnection” subsection. Staff is agreeable to AIU's proposed $400 fee for customers whose service has been disconnected at the main because access to the meter was blocked. Staff also supports AIU's proposal to eliminate the references to GDS-6 in AmerenCILCO's gas tariffs if the Commission approves the elimination of GDS-6 for AmerenCILCO.

Concerning AIU's Standards and Qualifications for Electric Service, AIU and Staff are in agreement on AIU's proposed language changes to paragraph 4(B), which imposes a $170 fee per meter read. Effectively, this section was amended to include a provision to require non-residential customers to provide a means for remote meter interrogation or to require a $170 meter reading fee when AIU’s personnel do not have free access to the meter. Staff also recommends approval of AIU's proposed word additions/deletions and page updates in the Index subsection of the tariffs, AIU's proposed elimination of certain sentences and phrases in the Service Extension paragraph including ones exclusive to Ameren IP, AIU's proposed language additions and deletions to the Interval Metering subsection paragraph, and AIU's proposed language revisions in section C of Standards and Qualifications for Gas Service.

Regarding the DS-2, DS-3, and DS-4 tariffs, AIU proposes language changes to 4th Revised Sheet No.12.002 where the wording was changed to clarify that AIU’s personnel could install unmetered services without first receiving a request from customers to do so. In 7th Revised Sheet No. 13, 6th Revised Sheet No. 13.001, 6th Revised Sheet No. 13.002, 7th Revised Sheet No.14, and 6th Revised Sheet No. 14.001, AIU proposes minor language and sentence changes to the last two paragraphs. Staff recommends approval of the proposed language changes because it improves clarity across AIU’s tariffs without changing the substance of the current tariff language.

In the context of Rate DS-5, since some light fixtures are no longer available, AIU proposes language modifications to 4th Revised Sheet No.12.002. Staff accepts AIU’s proposed modifications.

With regard to the Miscellaneous Fees and Charges Section of its tariffs, AIU proposes changes in 2nd Revised Sheet No. 35.001. Staff agrees that the proposed changes add clarity and helpful directional information. Staff also accepts the establishment of a $170 non-scheduled meter read for customers in the GDS-4 and GDS-7 rate classes.

The Commission finds all of the miscellaneous changes described in this subsection reasonable and accepts them for inclusion in AIU's tariffs.

B. Resolved Gas Issues

1. Rate Capping Mechanism

AIU's current gas rates generate different rates of return for each rate class. One of AIU's rate design goals in these proceedings is to move each of the utilities' rate classes closer to its revenue requirement by assuming an equalized revenue requirement for each rate class within each utility. An equalized class revenue requirement would be those revenue levels required for each rate class if they were to eliminate all inter-class subsidization and produce exactly the same ROR as the overall level for each utility.

AIU, however, determined that adopting an equalized ROR level for each rate class would result in rate increases that in many instances would be so great as to result in rate shock. AIU, therefore, proposes to limit the rate increase for each rate class to a specified percentage over present rates to avoid these adverse bill impacts. If a class rate increase is limited by the rate capping mechanism, then the amount of that rate class' revenue requirement that is above the cap would be recovered from the rate classes that have not reached the cap. AIU proposes a 20% cap for AmerenIP customers and a 30% cap for AmerenCILCO and AmerenCIPS customers. The higher increase for AmerenCILCO and AmerenCIPS addresses a much larger difference in ROR and revenue deficiency levels for certain rate classes.

Staff agrees with AIU's proposed gas rate capping mechanism and recommends that the Commission approve it. Staff believes that AIU considered bill impacts and notes that while some inter-class subsidies will be necessary, those subsidies will lessen the impact of the rate increase for many AIU customers. According to Staff, AIU's proposed rate capping mechanism mitigates the concerns associated with adopting the full cost of service results and the prospect of unfavorable rate impacts that could otherwise result for some rate classes, especially due to the reclassification of rate class definitions for AmerenCILCO and AmerenCIPS. Staff also observes that the rate capping mechanism levels the distribution of the increase and spreads the proposed interclass subsidy over all other rate classes.

No other party commented on AIU's proposal. The Commission finds AIU's proposed rate capping mechanism reasonable and approves it. However, the Commission generally supports rates designed to reflect the cost of service, and is committed to eliminating these subsidies at the earliest opportunity. Continued movement toward cost-based rates and the elimination of inter- and intra-class subsidies should be considered a priority in AIU's next rate filing.

2. Overall Rate Design (Scale to Final Revenue Targets)

AIU proposes a gas rate design using the cost of service based on each of the utility's revenue requirements. Once revenue targets were established for each of the rate classes, AIU relates that the rate design process was guided by three general principles moving rates towards reasonable customer impacts: (1) considering the rate capping mechanism described above; (2) eliminating inconsistencies between the three utilities' rate designs; and (3) emphasizing the 80%/20% fixed/variable thresholds authorized by the Commission for GDS-1 and GDS-2 rates in AIU's last rate cases.

Staff agrees with and recommends approval of AIU's overall proposed rate design. Staff believes that AIU properly considered bill impacts and the Commission's directives from the last rate order. To account for the difference between AIU's revenue requirement and Staff's revenue requirement, Staff proposes to scale AIU's proposed rates by the ratio of Staff's revenue requirement for each utility. This method does not alter AIU's general rate design. Instead, it simply increases or decreases the rates in proportion to the change in the revenue requirement.

In the event the Commission determines a different revenue requirement, AIU and Staff agree that use of Staff's scaling method is appropriate. No other party addressed this issue. The Commission finds AIU's overall rate design reasonable and directs that Staff's scaling proposal be used to reconcile the approved revenue requirement with the adopted rate design.

3. Interval Meter Data Access Fees

AIU no longer needs real-time data connections to its GDS-2 and GDS-3 customer meters. Because many of these customers have expressed a desire to maintain access to daily usage information, AIU proposes an optional Daily Usage Information Service with a data access fee that would reflect the cost of modifying the existing metering to make it capable of transmitting the daily meter information to AIU. AIU estimates that the installation of a modem and associated equipment necessary to provide this optional service would result in an upfront, one-time charge of either $1,944 (if an Electronic Pressure Corrector – Pulse Accumulator is required) or $812.25 (if no Electronic Pressure Corrector – Pulse Accumulator is required). AIU proposes a $5.00 monthly service charge for this optional service. AIU proposes and Staff accepts the following new tariff language to implement the updated installation charge:

> If Customer elects such service, the Company may be required to install a remote monitoring device to provide daily usage information to Customer. If Company is required to install a remote monitoring device in order for Customer to receive Daily Usage Information Service, Customer will be required to pay Company for the cost of equipment and installation, prior to receiving service, as follows.
>
> $1944.00, for each meter where installation of a pulse accumulator is required.
>
> $812.25 for each meter where installation of only a modem is required.

GFA also approves of this provision and states that it supports making the service available as an option at a fee that recovers actual costs. No other party addressed this issue. The Commission finds the proposal reasonable and approves its inclusion in AIU's tariffs.

4. Calculation of "Highest Average Daily Use"

AIU proposes to determine the eligibility for a number of rate classes based on the customers "highest average daily usage" ("HADU"). AIU proposes to determine the HADU by dividing the customer's total usage in a billing period by the number of days in that billing period. GFA agrees with this method. No other party commented on the calculation method. The Commission accepts the proposed method for calculating a customer's HADU for determining a customer's rate eligibility.

5. Rider T - Gas Transportation Service

a. NAESB Intraday Nomination Cycles

The North American Energy Standards Board ("NAESB") is a non-profit industry forum created to develop uniform business practices intended to create a seamless marketplace for wholesale and retail natural gas and electricity. NAESB has developed gas industry standards on many matters for improved functionality in the gas industry between pipelines, LDCs, third party suppliers, and other industry participants. Among the standards developed by the NAESB is one which calls for four nomination cycles. A "nomination" is how transportation customers schedule gas deliveries from a pipeline onto a LDC's system.

AIU initially proposed to retain its existing two nomination deadlines for transportation customers. Currently, AIU permits transportation customers to submit nominations at 11:30 a.m. and 4:00 p.m. to identify the gas to be delivered on the next gas day. Staff and CNE-Gas, on the other hand, proposed that AIU permit transportation customers to submit nominations based on NAESB's Intraday 1 and Intraday 2 nomination schedules. After discussing the issue amongst themselves, AIU, Staff, and CNE-Gas now agree that new tariff language implementing a single "same day" nomination schedule at 7:30 a.m. (rather than the NAESB Intraday 1 and Intraday 2 schedules) is a reasonable solution. The parties agree that the same day nomination reasonably balances AIU's interest in maintaining system reliability with the customers' interest in additional flexibility. AIU's tariffs require the utilities to use their best efforts to accommodate any other off-cycle nominations. AIU, however, currently does not provide transportation customers with the firm right to submit intraday nomination changes. The new tariff language implementing a new "Same-Day" nomination as part of the Nomination of Customer-Owned Gas section of each of the Rider-T tariffs reads as follows:

> Same-Day
> Customer desiring a change in Nomination for transportation of Customer-Owned Gas after the Intra-Day deadline specified above shall notify Company by 7:30 A.M. CST of the business day on which the Nomination is to take effect, subject to confirmation by the pipeline. Company may accept such change to Customer's Nomination if the Company determines in its sole discretion that such a change to Nomination will not adversely impact the operation of the Company's gas system or adversely impact Company's purchase and receipt of gas for other Rates or Riders.

No other party addressed the issue of nomination deadlines. The Commission finds the resolution of this issue and the new tariff language reasonable and approves of the inclusion of the language in AIU's tariffs.

b. Notice for Operational Flow Orders and Critical Days

When a gas utility needs to curtail gas to customers, it may declare an OFO or CD. AIU initially proposed to retain the existing tariff language regarding prior notice of OFOs and CDs. Staff proposed that AIU make a good faith effort to give a 24-hour notice of OFOs or CDs. CNE-Gas proposed that AIU provide notice as far in advance as possible--normally not less than two hours, unless conditions warrant immediate implementation of the OFO or CD. In response to the concerns expressed by Staff and CNE-Gas, AIU agrees to provide advance notice of an OFO or CD as far in advance as reasonably possible. Moreover, AIU agrees to submit a report to the Commission (specifically, the Director of the Energy Division) within two business days if it does not provide a 24-hour notice. In particular, AIU states that it is willing adopt the following tariff language as part of the Rider T section titled System Integrity Protection:

> The Company shall provide notice of a Critical Day and OFO as far in advance as reasonably possible, normally not less than two hours, unless the Company believes conditions warrant immediate implementation of the Critical Day or OFO. If the Company issues a Critical Day or OFO notice within 24 hours of the Critical Day or OFO taking effect, the Company will report to the Commission indicating why customer notice of less than 24 hours was necessary.

Staff and CNE-Gas support adoption of the proposed addition to Rider T. The Commission finds the proposed language reasonable and approves of the inclusion of the language in AIU's tariffs.

6. Large Customer Rate within GDS-4 Rate Class

Of the three gas utilities, only AmerenCILCO currently has a rate class for customers with annual usage in excess of 2,000,000 therms--the GDS-6 rate class. AmerenCIPS and AmerenIP customers with usage in excess of 2,000,000 therms are covered under the GDS-4 rate class. AIU proposes to eliminate AmerenCILCO's GDS-

6 rate class as a stand-alone tariff and transfer the GDS-6 customers to AmerenCILCO's GDS-4 rate class. AIU then proposes to modify only AmerenCILCO's GDS-4 tariff to mitigate any adverse rate impact for former GDS-6 customers. Because neither AmerenCIPS nor AmerenIP have a GDS-6 rate class, AIU states that introducing large customer provisions to the AmerenCIPS and AmerenIP GDS-4 tariffs is unwarranted and would introduce an unnecessary level of complexity. AIU proposes to include a price step in AmerenCILCO's GDS-4 tariff simply to promote stability for the existing customers served under AmerenCILCO's GDS-6 tariff. AIU states further that AmerenCILCO’s special provisions for large customers are one of the few instances where other factors take precedence over the desire for tariff uniformity.

AIU agrees with Staff’s recommendation that, in the time between these rate cases and the next rate cases, AIU should assemble data associated with AmerenCIPS’ and AmerenIP’s GDS-4 customers with annual consumption over 2,000,000 therms to evaluate whether AmerenIP and AmerenCIPS should implement special GDS-4 rate provisions for those customers. While AIU is only proposing these tariff provisions for AmerenCILCO in these rate cases, AIU agrees that assembling this data may help provide support to AIU’s gas tariff design in the next rate case.

Staff recommends approval of (1) AIU’s proposal to eliminate AmerenCILCO’s GDS-6 tariff as a stand-alone rate class and (2) the special large customer provisions under AmerenCILCO’s GDS-4 rates. Staff does not seek the immediate adoption of identical terms for larger AmerenCIPS and AmerenIP GDS-4 customers because it recognizes that AIU has not assembled the necessary data to implement this change. By its next rate case, Staff believes that AIU should have evaluated the relevant data to determine whether a similar rate design is appropriate for large customers of AmerenCIPS and AmerenIP with usage of more than 2,000,000 therms annually.

The Commission understands no other party voiced a position on this matter and that AIU and Staff are in agreement. The Commission finds AIU's proposal to eliminate AmerenCILCO’s GDS-6 tariff reasonable, as well as its proposal to modify AmerenCILCO's GDS-4 tariff to mitigate any adverse rate impact for former GDS-6 customers. The Commission also considers it appropriate for AIU to assemble data associated with AmerenCIPS’ and AmerenIP’s GDS-4 customers with annual consumption over 2,000,000 therms to evaluate whether AmerenIP and AmerenCIPS should implement special GDS-4 rate provisions for those customers. The Commission expects the results of such efforts to be presented in AIU's next rate case.

C. Resolved Electric Issues

1. Rider PER - Purchased Electricity Recovery

AIU proposes to modify Rider PER - Purchased Electricity Recovery ("Rider PER") so that it identifies this docket as establishing Basic Generation Service ("BGS") base prices, replacing a reference to the rate redesign case, Docket No. 07-0165. AIU states that this change is necessary to the extent the Commission accepts AIU’s proposal to adjust BGS-1 and BGS-2 prices in this proceeding. In response, Staff suggests one minor change to Sheet No. 31.008, which AIU accepts. The Commission finds the agreed to language reasonable and adopts it.

2. Supply Cost Adjustments for Rider PER

A Supply Cost Adjustment ("SCA") is applied to customers billed under Rider PER for recovery of certain costs for procurement (Supply Procurement Adjustment), working capital (CWC Adjustment), and uncollectibles (Uncollectibles Adjustment). AIU describes a detailed plan for recovering the costs related to its power supply through the SCA. In response, Staff proposed one change to the Supply Procurement Adjustment and two changes to the Uncollectibles Adjustment. Those changes are: (1) a corrected amount for costs associated with the procurement of power; (2) the uncollectibles factors for recovery under Rider PER should be consistent with the uncollectibles to be recovered through base rates; and (3) the allocation of write-offs between gas and electric service for combination customers should be based on the relative revenues for each type of service. AIU agrees with Staff's recommendation that $1,278,100 should be approved as the Supply Procurement Adjustment component of Rider PER. Staff also accepts AIU's counter proposal for the uncollectibles percentages based on net write-offs as a percentage of revenues, using calendar years 2007 and 2008 and year-to-date September 2009. Staff is no longer advocating its third recommendation. AIU and Staff are now in agreement on these revisions. The Commission finds the proposal reasonable and adopts it.

3. Rider RDC - Reserve Distribution Capacity

AIU proposes a change to Rider RDC - Reserve Distribution Capacity to ensure that the phrases “Demand” and “Billing Demand” are not interchangeable terms. Presently, “Demand” and “Billing Demand” share the same definition, but the term “Billing Demand” is adjusted within both the DS-3 and DS-4 tariffs to carry a different meaning. In response, Staff suggests that the term “billing demand” not be capitalized. AIU has agreed to this revision. The Commission finds the revisions reasonable and adopts it.

4. Rider QF - Qualifying Facility

AIU proposes to eliminate a provision in Rider QF - Qualifying Facility ("Rider QF") that allows it to refuse to accept output from a qualifying facility when the purchase of the output does not permit it to avoid costs. AIU currently uses energy purchases to offset power procured on behalf of fixed-price customers. Qualifying facility purchases usually influence the quantity of energy AIU buys and sells through the MISO-administered markets as AIU balances its fixed price energy portfolio. As long as there is a MISO-administered market, AIU does not anticipate a situation where the purchase of output from a customer's qualifying facility would permit AIU to avoid costs. As such, AIU proposes to eliminate this section. No party opposes this revision. The Commission finds the proposed change reasonable and approves it.

5. Rider HMAC - Hazardous Materials Adjustment Clause

Costs related to hazardous materials claims are recovered under AIU's Rider HMAC - Hazardous Materials Adjustment Clause ("Rider HMAC"). The HMAC BASE Amount, as defined in Rider HMAC, is the amount of HMAC costs reflected in the test year in the most recent electric rate case Commission order. This amount is needed to determine the amount to be withdrawn or deposited annually into the HMAC Cost Fund. Staff observes that the BASE Amount included in AmerenIP's revenue requirement is $411,889 and requests that the final order in this proceeding clearly indicate this BASE Amount for ease in applying Rider HMAC in future periods. AIU agrees that the HMAC BASE Amount included in AmerenIP's revenue requirement is $411,899. The Commission concurs.

6. DS-4 Reactive Demand Charge

Staff recommends that AIU modify language in the Standards and Qualifications for Electric Service section of each utility's tariffs. Staff believes that the existing language could give the false impression to Rate DS-4 customers that they can avoid monthly reactive demand charges if they maintain a power factor within the range 95% lagging to 95% leading. In actuality, based upon AIU's Rate DS-4 tariff, Rate DS-4 customers with a supply voltage below 100 kV can not, in practical terms, avoid a monthly reactive demand charge. In response to Staff's concerns, AIU proposes to add an additional sentence to this section of its tariffs that better explains reactive demand charges for Rate DS-4 customers. Staff finds AIU's proposed language adequate. The Commission finds the modification reasonable and approves its inclusion in AIU's tariffs.

7. Tail Block Variable Charges

While AIU initially proposed a 10% increase in the total variable charges for tail block BGS-1 and BGS-2 rates, it now agrees with Staff and urges the Commission to approve an increase to the total variable charges for tail block BGS-1 rates of 13%. AIU and Staff continue to support a 10% increase in the total variable charges for tail block BGS-2 rates. As Staff noted in its Initial Brief, without this increase in the BGS-1 rates, AIU incurs a shortfall of approximately 4 cents for each kWh sold to AmerenCIPS-ME and AmerenIP space heating customers, as well as a deficit of between 2 and 3 cents for each kWh sold to AmerenCIPS space heating customers. AIU adds that this increased charge unburdens the remaining bundled customers who would otherwise have to make up for this shortfall. AIU states that this increase is necessary to assist in reducing the amount of subsidy inherent in the present BGS-1 rates for non-summer use over 800 kWh.

Staff and AIU also agree that the annual cost effect of increasing the tail block variable charge by 13% for DS/BGS-1 customers would be minimal. The incremental increase for customers using 18,000 kWh per year would be about $1.50 at AmerenIP, $3.50 at AmerenCIPS, $1.00 at AmerenCIPS-ME, and $4.50 at AmerenCILCO.

Similarly, a space-heat customer using 26,000 kWh per year would experience annual increases of about $7.00 at AmerenIP, $10.00 at AmerenCIPS, $5.30 at AmerenCIPS-ME, and $11.75 at AmerenCILCO.

The Commission concurs with AIU and Staff that the tail block variable charge for DS/BGS-1 customers should increase by 13%. The customer impacts of this change are minimal. Raising the tail block rate is also a step in the right direction toward eliminating a subsidy. The Commission also finds the proposal to raise the tail block rate for DS/BGS-2 customers by 10% reasonable. The AIU and Staff agreement on the issue of tail block rates for BGS-1 and BGS-2 rates is adopted.

8. Cost Based Seasonal Rate

In support of its argument for seasonal distribution rates, GFA states that transformers for DS-3 and DS-4 customers are often sized to serve only one customer, for which costs are recovered via a Transformation Charge specific to that customer. Similarly, meters and service are specific to one customer and these costs are recovered in the Customer Charge and Meter charges. As AIU confirms in response to data request PL4.02, however, GFA asserts that the rest of the electric distribution line and substation system capacities are built to carry the aggregate peak coincidental load of all customers served from each part of the system. GFA understands that summer month coincident peaks are typically higher on the AIU system than are winter month coincident peaks. Because the coincidental system peaks on the AIU system vary by season, GFA concludes that AIU’s distribution system cost of service varies by season. Therefore, GFA maintains that AIU should price its distribution delivery service charges, excluding monthly fixed charges, higher during the summer and lower during the non-summer months. As in AIU's last rate case, GFA simply requests that AIU begin collecting the necessary data to conduct analysis of prospective seasonally cost based rates for the DS-2, DS-3, and DS-4 classes with regard to costs of substations and primary lines within the Distribution Delivery Charge.

AIU does not believe that implementation of a seasonal Distribution Delivery Charge is as simple as GFA suggests. GFA reasons that since as a group, the non-residential classes tend to peak in the summer, additional costs, and thus, greater rates, should be assigned to the summer period. AIU points out, however, that substations and primary lines are designed to serve the maximum demand expected on the facilities, regardless of the season. AIU adds that circuits serving customers with large grain drying loads can, and do, peak in the fall season. To provide this subclass with a lower rate in the non-summer season, AIU continues, would send an incorrect price signal to these customers. Instead, AIU asserts that a cost-based seasonal rate for this subclass would likely have greater demand charges in the fall, which would encourage customers to be as efficient as possible in managing their peak demands, since it is their demands that contribute the most to the need for substation and primary line capacity.

Additionally, because the DS-2 class already contains a seasonally-differentiated price, and the non-summer delivery charge is lower than the summer charge, AIU contends that seasonal pricing is unnecessary with respect to that class. AIU goes on to state that one can not consider seasonal rates without examining the price incentives and the possible cost consequences those price signals would have on distribution system costs. AIU suggests that a lower non-summer rate for certain customers (here, grain dryers) would signal that delivery service to them is cheaper, providing customers an incentive to use more, even though the delivery system with large grain drying load may already be constrained at the time of the fall peak.

AIU states further that DS-4 and large DS-3 customers connected at the primary voltage supply level can be large enough to drive local circuit peaks. AIU also indicates that examining seasonal rates for non-residential customers requires attention to circuit level details rather than aggregate demands of all customers -- a highly manual process. Nevertheless, AIU acknowledges that examining a sample of circuits serving DS-3 and DS-4 customers may help bring additional clarity to the debate. The study would also measure such customers' revenue contribution relative to their cost responsibility -- the issue GFA wishes AIU to examine. AIU is interested in proper cost allocation and pricing, and thus does not object to further study in the next rate case.

The Commission understands that GFA and AIU are in agreement that this issue will be addressed in AIU's next electric rate proceeding. The Commission also understands that prior to that time AIU will study a sample of circuits serving DS-3 and DS-4 customers to evaluate such customers' revenue contribution relative to their cost responsibility. The Commission believes that doing so is reasonable and directs AIU to conduct the described study and provide the results with its next electric rate case filing.

D. Contested Gas Issues

1. Availability Tariff Provisions

a. AIU Position

Pursuant to the Commission's direction in its last rate cases, AIU proposes a number of changes to its tariffs in these rate cases with the goal of achieving uniformity in tariff provisions. AmerenCILCO, AmerenCIPS, and AmerenIP all have similar non-residential rate classes GDS-2, GDS-3, and GDS-4. The availability (or eligibility) provisions of those rate classes, however, differ from company to company. In considering an appropriate availability threshold, AIU sought to use the existing availability provisions and/or methodologies of one of its companies. The AmerenIP tariff currently assigns customers to rate classes GDS-2, GDS-3, and GDS-4 based on each customer's actual HADU. AIU observes that the AmerenIP availability provisions provide customers with an immediate and definitive classification method using easily accessible information. On the other hand, the current AmerenCILCO and AmerenCIPS availability criterion rely upon methods of meter size, calculation of connected gas load, and definition of "general" use. Because AIU believes that usage-based availability provisions are the easiest for customers to understand and its staff to administer, AIU proposes moving AmerenCILCO and AmerenCIPS to the AmerenIP availability methodology.

AIU analyzed the major cost differences in the meters that are currently used to serve the various customer groups in order to determine whether the usage thresholds should be adjusted from the current AmerenIP levels. AIU reports that the analysis indicated that the existing AmerenIP usage thresholds follow the major cost differences in the meters. AIU conducted the COSS and individual customer impact studies on customers of all three utilities using the HADU thresholds proposed in its tariffs. The result of this change for most gas customers will be some migration from GDS-4 to GDS-3 or from GDS-3 to GDS-2. AIU states that customers moving down a rate class as a result of this change should not face detrimental bill impacts.

AIU notes that GFA supports its goal of achieving uniformity of in its tariff provisions. But GFA objects to two elements of AIU's availability proposal. First, GFA argues that a customer's HADU should be based only on the customer's usage in the months of December through March. Second, GFA argues that the cutoff between GDS-3 and GDS-4 should be based on the annual usage criteria currently employed at AmerenCILCO rather than HADU. The following table summarizes the key differences between AIU's proposal and GFA's proposal:

	AIU's Proposed Availability Provision	GFA's Proposed Availability Provision
GDS-2	<u>Upper Limit</u>: HADU < 200 therms	<u>Upper Limit</u>: HADU < 200 therms – measured only in the billing months of December through March
GDS-3	<u>Lower Limit</u>: HADU ≥ 200 therms <u>Upper Limit</u>: HADU < 1000 therms	<u>Lower limit</u>: HADU ≥ 200 therms – measured only in the billing months of December through March <u>Upper Limit</u>: annual usage of 250,000 therms. <u>Alt. Upper Limit</u>: HADU < 1000 therms – measured only in the billing months of December through March
GDS-4	<u>Lower Limit</u>: HADU ≥ 1000 therms	<u>Lower Limit</u>: annual usage of 250,000 therms. <u>Alt. Lower Limit</u>: HADU ≥ 1000 therms – measured only in the billing months of December through March

With regard to GFA's first complaint, AIU understands why GFA would pursue rate structures that are advantageous to its membership – a group whose primary gas usage typically occurs outside the months of December through March. AIU understands that a typical grain drier will use about 80% of its annual natural gas volume during harvest, which is about a two month period in the fall. AIU suggests that the intent of GFA's proposal is to address the seasonal usage of its membership. But according to AIU, its tariffs already recognize the different impacts that seasonal customers have on fixed and variable costs, and reflect that recognition in the billing components and associated charges in the GDS-5 rate class. The GDS-5 rate class enables customers who use gas only on days when the average temperature is forecasted to be above 25 degrees Fahrenheit to avoid paying a demand charge. Since the December through March timeframe is the time of year when it is most likely that the temperature will be 25 or lower, AIU asserts that the GDS-5 rate accomplishes GFA's goal. AIU maintains that using GFA's proposed four-month calculation period to determine rate availability would simply result in an inequitable assignment of fixed costs. Moreover, AIU states that adding a seasonality component to the other gas delivery service tariffs is unsupported, redundant, and inconsistent with the goal of uniformity.

AIU strongly disagrees with GFA's contention that there is little difference between its proposal and AIU's proposed availability criterion. By grossly understating the impact that its proposal will have on customers, AIU argues that GFA fails to recognize that its proposed modification is likely to lead to an inequitable assignment of costs among customer classes. In fact, AIU continues, under the GFA proposal, it is very likely that many of the seasonal customers would move to a lower tariff class than would be justified, based on the investment and equipment needed to serve their loads. AIU insists that GFA's position for restricting HADU measurement to the December through March timeframe ignores that the bulk of the costs to build, operate, and maintain gas delivery systems are fixed charges which do not vary based on the time of year that the usage occurs, and that all users of the system should pay an equitable share of those costs. According to AIU, GFA's proposal would result in customers using the system during non-peak periods paying nothing towards the fixed costs of operating the system. AIU asserts that the Commission previously recognized the need for all users of the system to pay their share of the fixed costs, regardless of the amount of gas they use or the time of year when the usage occurs, by placing 80% of fixed cost recovery into the Customer Charge for GDS-1 and GDS-2 customers.

Furthermore, AIU maintains that GFA's proposal is unworkable because customers could simultaneously qualify for the GDS-2 and GDS-3 or GDS-4 rate classes. As an example, AIU states that if a grain-drying customer had an average daily use of 1,500 therms during the September through November harvest season, and minimal usage for the rest of the year, under GFA's proposal, the customer's annual usage could exceed 250,000 therms and result in the customer being assigned to GDS-4. The customer would then be required to implement daily balancing and install a phone line, and AIU would need to install interval metering to record this usage appropriately. The same customer, however, plausibly would have a HADU of less than 200 therms per day during the non-harvest December through March timeframe, which would result in the customer being assigned to GDS-2 and able to balance monthly, with no need for a phone line or extensive metering. AIU does not mean to suggest that the customer would change between rates more than once a year. AIU simply means that the GDS-2, GDS-3, and GDS-4 rates are not intended to be a menu of options from which customers can choose once each year. AIU states that this would not only cause confusion for customers, but also add ambiguity for rate administration, which would result in financial uncertainty for the recovery of a utility's approved revenue requirements. AIU adds that tariff applicability provisions that allow a customer to select between standard GDS rate classes without any meaningful change in usage patterns can also be detrimental to other customers over the long run, as rates are established in future rate cases.

Despite proposing entirely new availability provisions for all three of the companies, AIU points out that GFA does not provide any rate design, cost allocation, or bill impact analysis. AIU contends that GFA simply desires a change that it thinks will benefit its membership without any consideration of the potential impact on other customers. In contrast, AIU asserts that it has prepared and presented a unified, consistent rate design plan supported by the appropriate analysis and consideration. AIU also contends that GFA simply rehashes arguments from the last AIU rate cases, which the Commission rejected.

Regarding GFA's second complaint concerning the cutoff for service under the GDS-3 and GDS-4 rate classes, AIU asserts that GFA provides no analysis supporting its proposal to use a maximum annual usage of 250,000 therms as the cutoff. Instead, AIU notes that GFA supports its availability proposal only with the claim that the 250,000-therm maximum annual usage limit is based on the existing lower limit of AmerenCILCO's GDS-4 rate class. AIU contends that GFA does not explain why it prefers the AmerenCILCO cutoff to the AmerenIP cutoff. To determine availability for GDS-3 using the GFA methodology, AIU would use both a daily average calculation based on a four-month window (to determine the lower limit), as well as a total usage threshold that considers 12 months of usage (to determine the higher limit). In contrast, AIU states that its proposal is easier for customers to understand, and for AIU to administer, because it relies only on a single calculation of the customer's HADU to determine both the upper and lower limits. AIU finds it notable that GFA supports using a 1,000-therm HADU cutoff (measured from December through March) between GDS-3 and GDS-4 as an alternative.

b. GFA Position

GFA supports consistent eligibility requirements and tariff structures among the three companies. GFA, however, questions whether AIU has chosen the most appropriate eligibility requirements from among all AIU current rates. While GFA agrees with using a 200 therm or less HADU eligibility requirement for the GDS-2 rate class, GFA recommends that the HADU be tested only for usage during the billing months of

December through March, when system daily maximum usage is greatest. GFA denies that its proposal would result in customers potentially simultaneously qualifying for the GDS-2 and GDS-3 or GDS-4 rate classes, because of differing monthly usage throughout the year. GFA, like AIU, proposes only one annual eligibility test and supports the proposed AIU tariff provision which specifically prohibits customers from switching between rates throughout the year. The GDS-2, GDS-3, and GDS-4 tariffs each contain similar language to prevent switching under the heading Delivery Service Rate Reassignment. The GDS-2 tariff states, "[o]nce the Customer has been assigned to Rate GDS-3 or GDS-4, the Customer will not be eligible to receive service under Rate GDS-2 for a minimum of 12 monthly billing periods following such reassignment." The GDS-3 and GDS-4 tariffs have comparable language. GFA concludes that its proposal would therefore give customers a choice only once annually, but each choice carries a year long commitment.

Regarding the next rate class, GFA observes that both its and AIU's GDS-3 recommendations match up low-end GDS-3 eligibility to the high-end eligibility for GDS-2 (with the exception of GFA's December through March measurement period). GFA's high-end cutoff for the GDS-3 rate class, however, differs. GFA notes that the current AmerenCILCO and AmerenCIPS GDS-3 rates have no maximum to qualify for the rate. The current AmerenCIPS GDS-4 rate has no minimum use requirement and the current AmerenCILCO GDS-4 has a minimum annual use requirement of 250,000 therms. To be more consistent with current eligibility requirements of all three companies' GDS-3 and GDS-4 rates, and to have the high-end requirement for GDS-3 match up with the current low-end requirement of AmerenCILCO's GDS-4 rate, GFA recommends matching all three companies' GDS-3 high-end eligibility to AmerenCILCO's simple and straightforward current minimum GDS-4 requirement of a maximum annual use of 250,000 therms. Alternatively, GFA recommends AmerenIP's current GDS-3 requirement of HADU equal to or greater than 200 therms per day and less than 1,000 therms per day, except that the annual eligibility test be made on customer usage only for the peak system usage billing months of December through March.

GFA disputes the appropriateness of the cutoff between the GDS-3 and GDS-4 rate classes as well. Despite AIU's claim that it analyzed appropriate cutoff points, GFA in essence suggests that AIU arbitrarily chose to apply the AmerenIP cutoff points. Contrary to AIU's use of the AmerenIP cutoff points, GFA recommends an annual minimum use of 250,000 therms to be the eligibility threshold for the GDS-4 rate schedule for all three companies. Alternatively, GFA recommends AmerenIP's current GDS-4 requirement of HADU equal to or greater than 1,000 therms per day, except with the annual eligibility test being applicable to customer usage only for the billing months of December through March. GFA believes that its proposal would promote system reliability by discouraging system utilization during peak or near peak load periods, and greater system utilization during non-peak periods.

GFA denies that its proposal would result in some customers using the gas distribution system during off-peak periods paying nothing towards the fixed costs of operating the system. GFA suggests that AIU could establish a minimum billing demand, similar to used in its electric tariff. AIU's math regarding its hypothetical customer's usage is also suspect, which GFA implies calls into question the rest of AIU's analysis.

c. Staff Position

Staff does not object to AIU's proposal to apply the AmerenIP usage-based availability criterion to the GDS-2, GDS-3, and GDS-4 rate classes of AmerenCILCO and AmerenCIPS. Staff states that the modifications provide more uniformity in the gas rate class structures as well as uniformity with the AIU electric tariffs. Staff believes that the resulting uniformity may also avoid potential confusion. Regarding the bill impacts of this change, Staff finds that the proposed rate class definition changes and resulting reclassifications would result in comparable increases for the majority of AIU customers.

d. Commission Conclusion

The Commission appreciates GFA's concerns, but at this time is not confident that implementation of its proposal is as straightforward as GFA suggests. Specifically, the Commission is concerned that GFA has not provided any rate design, cost allocation, or bill impact analysis in support of its position. AIU's proposal to make the gas rate classes more uniform among the three companies is likely to raise questions for some customers. To risk further complicating any explanation with potential problems that may arise from implementation of GFA's proposal is not in the customer's best interest. While the Commission may entertain different availability criteria in the future, for purposes of this rate case, the Commission finds AIU's proposed revisions regarding non-residential rate classes GDS-2, GDS-3, and GDS-4 for each company reasonable and authorizes the implementation of such.

2. Seasonal Prices for all GDS Rates

a. GFA Position

GFA understands that AIU’s gas distribution system is designed to accommodate peak usage, which occurs during winter months. Therefore, GFA recommends that all delivery charges, excluding monthly fixed charges, reflect seasonal prices. Such a proposal benefits typical grain dryers, which use about 80% of their annual natural gas volume during harvest, which is about a two month period. Thus, a typical size grain dryer can expect to use approximately 40% of annual usage in each of two harvest months and approximately 2% of annual usage in each of the other ten months.

With regard to seasonal rates and the GDS-2 tariff, GFA states that AIU seems to recognize the value of encouraging use during the non-winter months of April through November, but fails to recognize that the GDS-5 tariff does not send appropriate price signals to customers small enough that they qualify for service under the GDS-2 tariff. GFA states that a typical grain dryer of the GDS-2 size would never be expected to utilize the GDS-5 tariff because of the proposed high monthly fixed charges. Using the typical usage profile, GFA observes that a GDS-2 grain dryer using 15,000 therms annually under the proposed AmerenIP GDS-2 rate will pay $1,710.00 annually in Distribution Delivery Charges. Because the GDS-5 rate has relatively high fixed monthly charges and is designed for larger customers, however, GFA points out that the proposed GDS-5 rate annual charge for this same GDS-2 grain dryer would be $5,377.50. GFA states that a small GDS-2 grain dryer would not be expected to pay over three times the GDS-2 rate delivery charges to avail itself of the off-peak provisions of the GDS-5 rate like larger GDS-3 or GDS-4 customers may do. Although the GDS-5 off-peak provisions is an excellent way to increase off-peak system utilization, GFA asserts that the proposed GDS-5 rate needs to include levels of fixed monthly charges which are comparable to the respective GDS-4, GDS-3, and GDS-2 rates. To address this concern, GFA suggests that AIU could have a second tier lower fixed charge within its GDS-5 rate for smaller off-peak customers to encourage greater utilization of its distribution system. Alternatively, GFA states that AIU could adopt GFA's recommendation of making the availability limit of the HADU of 200 therms or less be applicable once annually for only the billing months of December through March when system daily maximum usage is greatest.

In response to AIU's assertion that it designs its gas distribution systems to carry the peak needs of its customers regardless of the time of year in which they occur, GFA argues that a more important consideration for seasonal rates than maximum annual design capacity is how price signals can maximize utilization of the system through interruptible incentives at times of peak system use. GFA appreciates that AIU has recognized the need to have price signals within the GDS-5 rate which encourage customers to interrupt when the temperature is below 25 degrees. GFA maintains, however, that AIU has provided no data to support not also having a cost-based distribution seasonal rate within its GDS-2, GDS-3, and GDS-4 rates, particularly for the GDS-2 small customer rate for which the temperature-based GDS-5 rate is of no practical value.

GFA states further that AIU has missed the fundamental point that the fixed costs of building a distribution system are correlated with the capacity of the system. That is, the system capacity is determined by its pressure and pipe size. GFA avers that customers who are willing to be interrupted or do not use the system at time of system peak loads of other firm customers certainly reduce overall system average fixed costs. GFA does not propose the extreme referred to by AIU that customers using the system during non-peak periods pay nothing towards fixed costs. GFA, however, does recommend that not just larger interruptible or seasonal-use GDS-3 and GDS-4 customers have access to a seasonal-based or temperature-based tariff such as the optional GDS-5 rate, but that GDS-2 customers also have a similar option, either within the GDS-2 tariff or feasible access to the GDS-5 tariff.

GFA disagrees with AIU's argument that typical GDS-2 size customers do not affect reliability of the distribution system during periods when space heating load occurs, but that GDS-3 and GDS-4 customers can have a profound negative impact on system reliability during periods when peaks occur. GFA asserts that the aggregate load of a group of GDS-2 customers can equal or exceed the load of a GDS-3 or GDS-4 customer. GFA's position is that prices in tariffs for GDS-2 size customers should provide similar incentives as tariffs for GDS-3 and GDS-4 size customers: to utilize the system during non-peak load periods and not to utilize the system when heating loads are at or near peak. That can be accomplished, GFA concludes, through either making the GDS-5 tariff feasible for GDS-2 sized customers and/or by implementing seasonal prices within the GDS-2 tariff.

b. AIU Position

AIU contends that GFA's position is based on its misplaced belief that AIU's distribution system is only designed to carry the utilities' overall winter peak usage. In fact, AIU states, it designs its systems to support the peak needs of its customers, regardless of the time of year in which they occur. If the sole design criteria were based on system peak usage during the winter months, AIU contends that off-peak gas users (like GFA's members) would have insufficiently sized facilities to support their operations, since their winter gas usage is either minimal or non-existent. AIU argues that GFA's recommendation is inconsistent with the principles of system design and the recovery of system investment costs.

AIU asserts that the GDS-5 tariff is the tariff most applicable to GFA's members. The GDS-5 tariff reflects the different impacts seasonal-use customers have on costs associated with gas delivery. According to AIU, the purpose of the GDS-5 tariff is to promote system reliability by discouraging gas use by individual customers whose operation on days when space heating demands increase would cause reliability issues. AIU states that usage by GDS-3 and GDS-4 customers during periods when peak space heating load occurs can have a profoundly negative impact on system reliability. As a result, AIU continues, the GDS-5 tariff is designed to provide incentives to GDS-3 and GDS-4 customers whose processes enable them to avoid operating during periods of heating loads. AIU acknowledges that GDS-2 customers might not financially benefit from selecting to be billed under the optional GDS-5 tariff, but maintains that this does not inappropriately exclude those customers from the optional GDS-5 tariff because the usage of small GDS-2 customers typically does not affect the reliability of the distribution systems that serve them when space heating load occurs. Accordingly, AIU urges the Commission to reject GFA's proposal to implement seasonal pricing provisions for all delivery charges.

AIU is also critical of GFA's proposal because it offers no detail concerning its implementation. Nor, AIU continues, does GFA offer any analysis evaluating the actual financial effects of its proposal. For these reasons alone, AIU believes that GFA's proposal should be rejected.

c. Commission Conclusion

The Commission understands that AIU's non-residential gas customers may take advantage of seasonal rates under GDS-5 at their discretion. Certainly one factor customers would consider in whether to do so is whether it would be financially practical. The essence of GFA's concerns appears to be that under AIU's current tariffs, it is very unlikely that it would ever be financially practical for a GDS-2 customer to make use of GDS-5 seasonal rates. AIU does not deny this possibility, but also contends that such a seasonal rate for GDS-2 customers may not be worthwhile in terms of system reliability. AIU indicates that its primary concern with implementing a seasonal rate is that it helps reduce load when peak space heating load occurs. AIU maintains that GDS-2 customers do not typically affect the reliability of the distribution systems that serve them when space heating load occurs.

The Commission understands GFA's concerns, but is not convinced that modifications concerning seasonal rates are warranted at this time. The record lacks evidence indicating that a seasonal rate for GDS-2 customers would benefit system reliability. Moreover, the record lacks evidence on the impact of GFA's proposal on rate design overall, not to mention how to even implement GFA's proposal. If GFA continues to believe that accommodations should be made for additional seasonal rates, GFA should bring specific proposals, containing tariff language and analysis, for the Commission and other parties to consider.

3. Banking under Rider T - Gas Transportation Service

Those customers who purchase their gas supply from a third party have the gas delivered by AIU under Rider T. Such customers tend to be larger customers with commercial or industrial process load. By way of contrast, sales customers are primarily residential heating load customers.

AIU provides banking service to its transportation customers. Under this service, if a transportation customer delivers more gas in a day to AIU than the customer uses for that day, then AIU will hold – or “bank” – that excess gas until it is needed by the customer. In this way, customers can bank an amount of gas equal to up to ten times its MDCQ under current tariff language. If a customer has a positive balance in its “bank” account, then the customer can call on its bank by using more gas in a day than it delivers in that day. In that situation, AIU would make up the difference by using its storage, line pack, or imports from off-system resources. To be clear, gas used from a bank is not gas "borrowed" from the utility; it is gas owned by the transportation customer. The costs of providing the banking service are recovered through base rates as part of the distribution service.

a. Staff Position

Staff recommends that the Commission require AIU to work with Staff and other interested parties (1) to develop an equitable allocation process for storage assets, (2) to allow customers to select the level of banking that best suits their needs, and (3) to develop an equitable allocation of the costs of providing those services. Staff proposes that workshops be held to examine these issues. Staff further recommends that AIU be required to propose in its next rate case tariffs consistent with these goals using language agreed upon in the workshops.

To accomplish these goals, Staff believes that it is necessary to unbundle banking service. Staff defines bundling as the practice of a seller selling several services together for one price. Therefore, unbundling allows individual customers to buy only the services that they desire and at a level that best meets their needs.

Staff explains that under Rider T, banking services are bundled with distribution service and costs are allocated based on peak day deliverability. In comparison, Staff reports that Nicor, Peoples, and North Shore offer banking to their transportation customers without bundling those services with base rates. In fact, Staff continues, amongst these large utilities, only AIU prevents transportation customers from selecting a level of bank capacity that meets their individual needs. Staff adds that other utilities allocate their seasonal capacity equitably to reflect their assets. Staff recommends that AIU provide banking in a manner similar to the way Nicor, Peoples, and North Shore do.

While AIU recognizes some merit in such proposals, Staff notes that AIU has some concerns about expanding bank size. AIU has commented that expanding bank capacity could create a subsidy from sales customers to transportation customers because capacity might not be available and if it is, it would be more expensive. Although Staff supports allowing a subscribable bank, it suggests that the total capacity available should be limited to a proportional level of seasonal capacity in a manner similar to the way Nicor limits bank capacity. The size of the individual customer's allocation should be constrained as well, according to Staff. To protect against exorbitant prices for transportation customers based on off-system storage assets, Staff further recommends that the Commission order that the unbundled Rider T bank be based on on-system storage assets (like Nicor) or total system assets (like Peoples).

Regarding the size of any unbundled bank, Staff notes that in AIU's previous rate cases, the Commission found that a 10-day MDCQ bank is an appropriate size for each of the three gas utilities despite each having different storage capacity. Staff contends that each of the three companies' bank size should be related to their respective storage capacity. Staff also maintains that whatever bank size is eventually adopted, the capacity should be notably larger than ten days of MDCQ. Using the seasonal capacity allocation methods of Nicor and Peoples to show that the proportional capacity is very similar to the AIU systems, Staff calculates that AIU's total system capacities, relative to peak day needs, are comparable to the other utilities. This evidence shows that, while AIU has less capacity in an absolute sense than Nicor, Peoples, and North Shore, a similar allocation method would yield banks significantly larger than the current level. Staff points out that Peoples, which has just a single on-system storage field, and North Shore, which has no on-system storage, both offer relatively large banks when compared to AIU despite the fact that AIU has numerous on-system storage fields that provide more flexibility.

In determining the appropriate bank size for each of the three companies, Staff is also concerned about the allocation being done equitably. Staff disagrees with AIU's contention that the ten-day MDCQ banks are fair and equitable because transportation customer banks have increased significantly since the last case. Staff asserts that this change is the result of customer migration from sales to transportation service since the last rate case.

Nor does Staff find any merit in AIU's claims that (1) there is no demand for unbundling the Rider T bank, (2) it is too soon to consider changing the current tariffs, and (3) increasing bank sizes will result in an allocation away from sales customers to transportation customers. Staff states that CNE-Gas has expressed support for allocating storage assets using the methodologies the Commission approved for Nicor and Peoples, which unbundle banks from base rates, allow transportation customers to select a level of banking they need, and ties cost recovery to the selected bank level. Staff adds that IIEC, another transportation intervenor, states that its member companies would "likely" be supportive of these same issues in its responses to Staff data requests DAS 9.1-9.3. In response to AIU's claim that there is insufficient experience with the current banking provisions to support a change at this time, Staff notes that AIU is actually reducing its off-system storage capacity, which indicates to Staff that AIU has not had a difficult time supplying the increased bank capacity provided through the Commission's prior rate order. Staff denies that its proposal will create a subsidy from sales to transportation customers. In contrast, Staff argues that its proposal corrects the inequity that occurs when a customer must give up storage when switching to transportation service as transportation customers receive too little storage. Staff explains that sales customers benefit from storage assets both in terms of meeting peak day requirements as well as seasonal hedging regardless of their size. If a sales customer loses all or part of that benefit when they switch to transportation service, Staff maintains that they will be unduly deterred from transportation service.

Staff seems to suggest that once at the workshops, the participants should use the bank capacity calculation methods of Nicor or Peoples/North Shore to determine appropriate bank sizes for the AIU systems. Peoples and North Shore use a method that allocates the total system storage capacity (on- and off-system) divided by system deliverability on a peak day. Staff conducted a comparative analysis and found that if AIU were to allocate its storage using the Commission-approved method used by Peoples and North Shore, transportation customers' allocation would be 37, 35, and 27 days of MDCQ for AmerenCILCO, AmerenCIPS and AmerenIP, respectively. Nicor allocates total on-system storage capacity divided by the peak design day demand. Staff determined that if AIU were to allocate its storage using the Commission-approved method used by Nicor, transportation customers' allocation would be 24, 11, and 24 days of MDCQ for AmerenCILCO, AmerenCIPS and AmerenIP, respectively.

Despite objecting to the use of the Nicor or Peoples/North Shore methods, Staff contends that AIU has presented no clear reason to support its objections. According to Staff, AIU's witness on this issue, Kenneth Dothage, appears to be unfamiliar with the methods utilized by the other gas utilities. Moreover, Staff notes that he attempts to impose operational significance on these results. This is something that Staff does not propose or even suggest, and something that the Commission does not do. Staff asserts that it, Nicor, Peoples, North Shore, and the Commission all understand the purpose of these bank sizing calculations and the logic behind why such calculations makes sense. Staff adds that these methods have not even been contested in other gas utilities' rate proceedings.

In comparing the cost allocation methods, Staff states that a peak day allocator favors sales customers. Smaller customers generally have usage that is largely influenced by heating load and is therefore more weather sensitive. Thus, Staff continues, they represent a relatively larger portion of peak day demand relative to annual usage than transportation customers who tend to include larger process load customers. Therefore, transportation customers' share of annual use is greater than their share of peak day use. If capacity is allocated to individual customers based on their peak day usage (or MDCQ) or the "days of bank" and allocate underground storage costs based on peak day deliverability, then Staff believes that it makes sense to divide the seasonal bank capacity into peak days. While Mr. Dothage objects to using a peak day allocator and claims that the annual capacity and peak day demand are not related, Staff notes that AIU witness Normand uses a peak day allocator to allocate annual underground storage costs to transportation customers.

Staff advises the Commission to be wary of AIU's claim that bank unbundling may be hampered by (1) a lack of additional off-system storage and/or (2) off-system storage that is only available at a higher cost than existing assets. Staff states that these claims are similar to arguments made by AIU in its last rate cases. (See Docket Nos. 07-0585 - 0590 (Cons.), Ameren Ex. 30.0) After imposing a bank size equal to ten times a customer's MDCQ, however, Staff points out that these fears went unrealized.

Staff explains that AIU's fears failed to materialize because migration of customers from sales to transportation service reduces AIU's peak day or seasonal storage requirements. The reason for the decrease is that transportation customers must deliver most of their peak day usage from the interstate pipelines, getting the remainder of their needs from their banks using AIU's storage resources. In contrast, a sales customer receives his entire supply from AIU either through AIU's deliveries into its systems or from on system storage assets. Staff adds that net migration is overwhelmingly from sales service to transportation service. AIU identifies only one instance of a customer moving from transportation service to sales, which resulted from the elimination of a unique transportation service. Staff states further that it seems very likely that its proposals will make transportation more attractive to customers and that net migration to transportation service will continue.

With regard to AIU's claim that additional off-system storage capacity would be necessary but unavailable, Staff points out that after increasing the bank size in the prior rate cases, AIU is now reducing its off-system storage capacity. This is so, Staff observes, even though the storage capacity devoted to AmerenIP transportation customers increased over 450% following AIU's last rate Order. Staff reports that the only change in AmerenIP's off-system storage was a reduction of 15% in its Mississippi River Transmission storage contract level. AmerenCILCO and AmerenCIPS experienced similar results. In response to AIU's claim that it could not currently obtain additional off-system storage if it needed it, Staff contends that this is not surprising since capacity is usually not available during the withdrawal season.

b. AIU Position

AIU notes that the current bank size provisions went into effect in October 2008 and claims that insufficient data exists to make an informed decision that would warrant any material changes to the balancing or metering requirements. AIU has not recommended any operational changes to the transportation services. AIU notes, however, that Staff makes two recommendations with regard to the bank size. First, Staff recommends that bank service be unbundled from base rates as part of AIU's next rate cases and that bank service be provided as a subscription service. Second, Staff recommends that the Commission determine the bank size in the next rate cases based on a specified methodology. AIU agrees that these issues should be addressed in its next rate cases and has agreed to participate in the public workshops proposed by Staff. AIU would welcome the input at the workshops of all those interested. AIU, however, urges the Commission to not implement any changes to the Rider T banking program as part of these rate cases.

If the Commission directs that workshops be held on these issues, AIU recommends that it refrain from mandating specific tariff or rate structures or otherwise inhibit the workshop process. According to AIU, the workshop process will be best served by letting the participants determine the nature and scope of the discussions. An unfettered workshop process, AIU continues, will permit the participants to identify the unbundling structures that best serve AIU and the customers. AIU adds that any interested party can present alternative positions in the next rate cases if they wish.

With regard to the concept of allowing transportation customers to determine the size of the bank that they desire and are willing to pay for, AIU asserts that a reasonable approach to follow in the workshop process would be to first identify the available resources needed to support the bank service, determine the price/cost of the resources, make the service available at a specified price, and then let the customer elect a certain level of bank service. AIU states that it would be inconsistent to allocate a fixed amount of capacity to all such customers and permit each to choose the amount of capacity it desires from that fixed amount until the fixed amount is spoken for. AIU maintains that the Commission should not address the merits and applicability of the Nicor and Peoples methods in this case. Likewise, the Commission should not limit the workshop discussion to the Nicor or Peoples methods.

In response to Staff's suggestion that the Peoples and Nicor methods should be used to guide the determination of the appropriate size of the Rider T banks in the workshop process, AIU argues that they produce meaningless results when applied to AIU and should be rejected. AIU alleges that the methods have material defects that may not have been identified in previous Commission proceedings. AIU maintains that the Commission should not require it to follow either of these methods simply because they have been previously used by other utilities, without first reviewing the results of their application to AIU. AIU relates that the Peoples method divides the utility's total storage capacity by the utility's system's total deliverability on a peak day. The Nicor method divides the on-system storage capacity by the system's total deliverability on a peak design day. Both methods purport to arrive at a number of days of peak deliverability. AIU contends that the defect of both methods is that there is no relationship between the numerator of the equation (storage capacity) and the denominator (peak day deliverability of the system). AIU asserts that the methods are merely mathematical calculations that do not speak to the operational issues or system constraints. The methods, AIU continues, do not show any real relationship between the seasonal working inventory of the storage field and the system peak day deliverability. One is an inventory volume over the entire five month winter season, while the other is a daily deliverability volume. AIU states that dividing the two produces a mathematical result, but that result does not have a rational meaning in the real world of physical deliverability and capacity.

AIU states that Staff's suggestion that the Commission consider the Nicor and Peoples models in the future might result from a failure to appreciate the difference between a storage field's peak day deliverability and its total storage capacity. A storage field can not release 100% of the gas in storage on the peak day. As an example, AIU states that AmerenCILCO's on-system storage has a total capacity of 8,172,473 MMBtu, but AmerenCILCO can only withdraw 190,000 MMBtu from those fields on a peak day. While there is some relationship between the peak day withdrawal capabilities and total system peak day deliverability, AIU argues there is no relationship between the total storage capacity and total system peak day deliverability.

AIU further argues that determining the unbundled bank size using either of the Nicor or Peoples methods will have a negative impact on the system sales customers because any additional seasonal storage capacity that is allocated to support additional days of banking for the transportation customers ultimately will be seasonal storage capacity taken away from the system sales customers. If it must provide additional days of banking rights to the transportation customers, AIU claims that it will have to acquire new seasonal storage capacity for their sales customers to replace the storage allocated to the increased banking service. AIU indicates that the availability and cost of additional storage capacity is unknown. AIU claims that its 821,300 sales customers could suffer for the benefit of its 481 transportation customers. AIU adds that in order to unbundle appropriately the Rider T banking service, a portion of each gas supply system resource would need to be carved out and packaged in a separately priced banking service.

c. IIEC Position

IIEC strongly supports the concept of workshops prior to AIU's next rate proceeding to discuss unbundling Rider T's bank from base rates and determine equitable methods of allocating both storage capacity and costs. IIEC is particularly interested in Staff's recognition of the need to coordinate changes in capacity rights with cost allocation procedures. Unless both aspects of the rate design process are treated consistently, IIEC states that there is no guarantee that customers will truly realize any unbundling of assets approved by the Commission.

d. CNE-Gas Position

CNE-Gas supports bank unbundling and notes that in 2008 it urged the Commission to study the utilization of the Nicor and Peoples bank allocation methodologies in order to more equitably allocate assets between sales and transportation customers. CNE-Gas further suggests that the existing bank limits are inequitable and contends that AIU has provided no empirical evidence to support retention of ten days of storage for transportation customers based upon its actual storage assets. CNE-Gas requests that the Commission remedy the existing inequitable allocation of storage assets. Illinois utilities, CNE-Gas continues, have used one of two Commission-approved methodologies for a number of years and both are viable options. At minimum, CNE-Gas states that the Commission should direct AIU to review its current storage allocation methodologies in order to assure equitable storage allocation between sales and transportation customers. CNE-Gas adds that AIU should be required to work with Staff and other interested parties to develop a proposal to unbundle storage for transportation customers that will be included in AIU's next rate case filing.

e. Commission Conclusion

At the outset, the Commission wishes to assure all parties that it will not be directing any changes to the banking provisions of Rider T in this Order. All parties appear to agree that workshops should be held prior to AIU's next gas rate cases for the purpose of discussing alternatives to AIU's current banking terms and conditions. The Commission favors this approach as it may reduce the number of contested issues in AIU's next gas rate cases.

As for the subject of the workshops, which should be open to all those interested, the Commission notes less agreement by the parties. While Staff proposes that specific methods employed by other Illinois gas utilities be considered and modified for use by AIU, AIU urges the Commission to refrain from limiting discussion in any way. The Commission finds merit in Staff's proposal since it concerns methods which it is familiar with and would promote consistency among the gas utilities operating in Illinois. Customers with facilities served by differing gas utilities are apt to find such consistency attractive. AIU's view, however, deserves consideration as well. By directing that the workshop participants develop tariffs implementing the same banking provisions of Nicor, Peoples, and North Shore, the Commission fears that it would be making a decision before having all of the facts. In light of AIU's arguments, enough doubt exists over whether the practices of Nicor, Peoples, and North Shore are appropriate for AIU that the Commission is not comfortable with limiting the workshop discussions.

To resolve this issue in a way that would be most beneficial to its ability to address these questions in AIU's next gas rate cases, the Commission directs AIU and Staff to participate in workshops which will at a minimum result in tariffs implementing for AIU the banking provisions currently employed by Nicor, Peoples, or North Shore. Said tariffs are to be provided in AIU's next gas rate cases. AIU is also free, however, to raise at the workshops its concerns about adopting such banking provisions. AIU may submit in its next gas rates cases as an alternative to what Staff seeks tariffs implementing banking provisions that AIU believes are appropriate. The workshops shall be open to any other stakeholders wanting to participate. The Commission expects all participants to take AIU's concerns seriously. By requiring proposed tariffs implementing either the Nicor or Peoples method but also giving AIU the option to offer an alternative, the Commission preserves for itself flexibility in determining the most appropriate banking provisions under Rider T for AIU. Nothing in this conclusion should be read to prohibit any other party in AIU's next case rate cases from proposing other banking provisions.

E. Contested Electric Issues

1. Overall Rate Design

a. AIU Position

AIU’s overall rate design utilizes a cost basis as a starting point, applies a rate mitigation approach to the cost basis, and adjusts rates among classifications in an attempt to comport with its own goals as well as those expressed by stakeholders and the Commission. While changes to the DS-1 and DS-2 rate classes are not contested issues in this proceeding, AIU states that the changes are an important component of its overall rate design. Specifically, AIU seeks to conform its rate design to the Commission’s Order in the previous rate case with respect to DS-1/BGS-1 space heat customers. AIU also seeks to move closer to rate uniformity among the three companies. To do so, AIU modified its DS-1 rates, in order to move towards a “Straight Fixed Variable” or “SFV” approach. Under the proposed rates, AIU will recover approximately 39% of allocated delivery service charges through the customer and meter charges, an increase from the current rates. The change to the BGS-1 supply rate structure compliments this approach and refines AIU's approach to rates for customers using electric space heating. AIU states that the changes to BGS-1 are complimentary to the changes to DS-1. Rates for classes DS-2/BGS-2 are also realigned in this manner.

AIU also proposes changes to general service (DS-3) and large general service (DS-4) customers. The rate design for these classes remains a contested issue. Similarly, rate design for lighting customers (DS-5) remains a contested issue.

AIU recognizes that the Commission is unlikely to approve its requested revenue requirement without change. The conformance of the final rates to the adjudicated revenue requirement is an essential task in this case. AIU proposes that the final rates be adjusted to meet certain rate design objectives, which AIU contends provides a better balance between movement toward cost-based rates and mitigating bill impacts. AIU states that its approach recognizes that simply shifting rates based on some percentage places disproportionate rate burdens on certain customer classes. Specifically, AIU proposes to retain all Customer, Meter, Transformation, and Reactive Demand charges for all the rate classes. Then, for DS-1 and DS-2 classes, AIU would adjust Distribution Delivery Charges based on a uniform percentage, in order to achieve the final rate requirement. For the DS-3 class, AIU proposes to achieve final revenue targets through a uniform percentage reduction to the $/kW Distribution Delivery Charge for each of the companies. Finally, for the DS-4 class, AIU proposes to adjust the new variable Delivery Charge to a level to match the revenue target, but not lower than one half of the average PURA tax amount. If necessary, AIU would also lower the DS-4 $/kW Distribution Delivery Charge in order to achieve the revenue allocation target. AIU reports that its approach has been used by the Commission in the past. (See, e.g., Docket No. 91-0335 at 70-72; Docket No. 93-0183 at 90-107; and Docket Nos. 99-0120/99-0134 (Cons.) at 64.)

While Staff's and IIEC's across-the-board approach to conforming rates with the final revenue requirement is easy to administer, AIU maintains that their approach misses an opportunity to address subsidy elimination, rate continuity, and bill impact concerns. The Staff and IIEC approach, AIU continues, also misses an opportunity to better address concerns raised by various parties in this case. For example, AIU contends that Staff's approach exacerbates a problematic divergence between DS-3 and DS-4 delivery rates and, as such, fails to address this important concern. Because such an oversimplified approach strays from the goals of cost-based ratemaking and mitigating bill impacts, and AIU's approach embraces those goals, AIU asserts that its rate design approach should be approved by the Commission in this docket.

b. Staff Position

Staff generally supports AIU's rate design for the BGS classes and DS-1 and DS-2 classes, but disagrees on how the DS-3, DS-4, and DS-5 rates should be designed. Given the Commission's stated preference for SFV rate design, Staff considers AIU's proposals for the DS-1 and DS-2 rate classes acceptable in this case. Staff considers AIU's proposals to be a reasonable solution to the challenges posed by the rate redesign conducted in Docket No. 07-0165. In that proceeding, the Commission faced a common problem of disproportionate bill impacts for customers with high consumption levels in non-summer months. For each class, the problem was addressed by reducing BGS supply charges for higher usage blocks in the non-summer months and increasing other BGS charges accordingly. These adjustments in Docket No. 07-0165 have created a discrepancy between supply charges and costs. To reduce these imbalances, Staff relates that AIU proposes to move tail block non-summer rates closer to costs.

While Staff suggests that the Commission consider raising non-summer tail block rates for the DS-1 class, it does not make a similar proposal for DS-2 customers. Staff explains that it does not do so because the gap between BGS charges and costs for bundled DS-2 customers in the non-summer tail block is not nearly as great as for residential DS-1 customers. For some residential customers, the current per kWh tail block supply charge falls to one cent or below, while for bundled DS-2 customers the charge remains above 4¢/kWh. Staff states that this much smaller gap between supply charges and costs for residential space heating tail block usage provides the reason to suggest that the Commission consider going further than AIU proposes to raise that supply charge for residential customers.

With regard to conforming the final rates with the final revenue requirement, Staff prefers to lower all DS components to achieve the final revenue requirement allocated to a class. In order to accomplish that goal, Staff recommends adjusting the rates that are uniform among the three companies – Customer, Meter, Transformation, and Reactive Demand Charges – on a combined AIU basis, and then adjusting the remaining rate components by an across-the-board amount to achieve the desired revenue target. Staff favors its rate adjustment methodology over AIU's because it considers its own method simpler to implement.

Staff adds that compliance rates are not a good place in which to adjust rates for specific rate design objectives. Any changes to rates at that juncture have important implications for all AIU ratepayers. To the extent that one rate element is adjusted and another is not, Staff fears that certain ratepayers will benefit while others will be disadvantaged. The problem, Staff continues, is that no ratepayers have recourse at this stage of the process. If a group of customers loses out, Staff states that they must wait until the next rate case to seek redress. In contrast, Staff observes that its equal percentage adjustment approach to compliance rates has the same impact on all ratepayers. Staff points out that ratepayers will know they receive the same treatment as everyone else in the adjustment of their rates to the final revenue requirement. Staff contends that this is more transparent and equitable.

c. IIEC Position

With the three exceptions of (1) AIU's proposed collection of PURA taxes through a new line item charge on customers' bills, (2) the combination of the DS-3 and DS-4 classes for Distribution Delivery Charges, and (3) the failure to allow for combined billing for multiple meters on the same or adjacent premises, IIEC does not oppose the basic rate structure and design used by AIU, which are mostly consistent with prior rate determinations. IIEC, however, does have some concerns regarding how to conform the final rates with the approved revenue requirement. The problem with both Staff's and AIU's approach, IIEC argues, is that they begin with AIU's flawed COSS, which are used to develop class revenue allocations under both of their proposals. IIEC complains that adjusting proposed rates downward on a full across-the-board basis, as proposed by Staff, or by a constrained across-the-board basis as proposed by AIU, will maintain the underlying class and subclass revenue allocations proposed by each.

Since these revenue allocations are based, at least in part, on the flawed cost studies, IIEC asserts that they result in the same objectionable revenue shifts between classes. To address such concerns, IIEC recommends starting with current rates and adjusting rates upward on an across-the-board basis to meet the utility revenue requirements, which would result in minimal or no cost shifting between classes.

If the Commission accepts AIU's COSS for revenue allocation and rate design purposes and decides to increase rates from current rates on something other than an across-the-board basis as recommended by IIEC, IIEC originally suggested that the Commission order AIU to rerun its COSS and determine class and subclass revenue allocations in accordance with the Commission's findings in this case. In that event, IIEC supported Staff's method to adjust downward the resulting rates on an across-the-board basis to conform the rates to the final utility revenue requirements. If, however, the rerun cost studies also reflected the final approved utility revenue requirements, IIEC stated that no downward scaling would be needed.

IIEC originally preferred Staff's position over AIU's if its own was not adopted at least in part because it found AIU's approach to final rate conformance unclear. After having reviewed AIU's Reply Brief and giving AIU's approach more consideration, however, IIEC now favors that approach if the Commission does not accept IIEC's position on the PURA tax and allows AIU to establish a new tax line item on delivery service bills. IIEC believes it would be appropriate to reduce the charge associated with that new line item as much as possible in order to conform rates to class or subclass revenues resulting from lowering the revenue requirement. If AIU's position on the conformance of rates to the approved revenue requirement includes lowering the proposed DS-4 PURA tax charge as described by AIU witness Jones (see Ameren Ex. 40.0 Second Revised at 15-17), IIEC now supports AIU's proposal if its positions on the relevant issues are not adopted by the Commission. While Staff's approach does not address the onerous PURA Tax charge, it is IIEC's understanding that AIU's approach does. IIEC, however, believes that AIU has not provided justification for limiting the reduction in the charge to one-half of the PURA tax amount as recommended by Mr. Jones, and therefore recommends that the artificial limitation be eliminated, allowing the tax charge to be reduced as much as needed to conform the class or subclass rates to the reduced revenue requirement.

d. Commission Conclusion

Except as modified below, the Commission generally finds AIU's electric rate design acceptable. In addition to the modifications set forth below, however, the Commission must also determine to what extent the overall rate design should change to reflect the final revenue requirement adopted in this proceeding for each electric utility. As discussed above in the context of cost allocation, the Commission does not find AIU's electric COSS fatally flawed and will therefore not be implementing an equal percentage across-the-board change to reflect the final revenue requirements. Instead, after rerunning the COSS as directed above, adjustments will need to be made reflecting the difference from AIU's proposed revenue requirements and the approved revenue requirements.

Despite some ambiguity and changing positions, the Commission believes that it understands the positions of AIU, Staff, and IIEC. The Commission finds that a simple approach in this situation is preferable. As proposed by AIU, the Customer, Meter, Transformation, and Reactive Demand charges for all of the rate classes should be retained. Any change in the revenue requirements should then be reflected through a uniform percentage reduction in the Distribution Delivery Charges for the DS-1 through DS-3 rate classes, which is consistent with what the Commission understands AIU to be proposing for these rate classes. For the DS-4 rate class, AIU's proposal appears to be a form of rate mitigation for larger customers. The proposal appears reasonable and as it is endorsed by IIEC, the Commission accepts it for purposes of this proceeding. The Commission finds AIU's proposal in this context for the DS-5 class acceptable as well.

2. Rate Moderation/Mitigation

In order to establish a rate design, AIU and Staff utilized the results of their respective electric COSS methodologies and applied mitigation strategies to underlying cost indicators. Given its concerns with AIU's COSS, IIEC developed a mitigation strategy separate from a COSS. Those mitigation strategies serve an important role in promoting rate continuity and rate stability while considering potential bill impacts that could result as rates are moved toward the actual cost of service.

a. AIU Position

AIU proposes to mitigate bill impacts resulting from this rate case by limiting the increases to rate classes DS-1 through DS-4 to 125% of the system average increase, excluding the DS-5 class and the PURA tax. AIU excludes the PURA tax from its rate mitigation calculations because it is assessed to utilities on a kWh or energy basis, which leads AIU to believe that the tax should be assessed to customers in the same manner, without effectuating cross-subsidies that would otherwise invariably be created by rate mitigation strategies. According to AIU, Staff acknowledges that the ultimate effect of “mitigating” cost assignments by including the impact of the PURA tax assessed to utilities would be subsidized rates. Staff further acknowledges, AIU adds, that using AmerenCILCO as an example, DS-2, DS-3, and DS-4 customers would be receiving a subsidy on a class total revenues basis, inclusive of a portion of the PURA tax associated revenue requirement. AIU therefore concludes by the process of elimination that the incremental effect of including the PURA tax in a rate mitigation approach serves to increase the subsidy burden imposed upon residential (DS-1) and lighting customers (DS-5). AIU argues that it is intrinsically unfair to hold residential and lighting customers responsible for tax liabilities that would not exist but for the kWh usage of larger customers. In other words, AIU does not believe that it is appropriate to collect tax costs from any ratepayers other than those that created the tax obligation. AIU claims that its proposed revenue allocation approach provides a better balance between movement toward cost-based rates and mitigating bill impact.

In response to Staff's proposal to constrain rate increases to 150% of the overall average, including the PURA tax, AIU argues that doing so would put a disproportionate burden on classes DS-3 and DS-4, and, consequently, widens the gap between DS-3 and DS-4 on a dollar per kW demand charge basis. Even if the Commission adjusts the revenue requirement downward due to proposals by the parties, AIU states that the relative differences and relative magnitude of the difference remains the same. AIU maintains that the disproportionate burden created for the DS-3 and DS-4 rate classes under this approach moves away from the stated goal of cost-based rates and mitigation of bill impact. Regarding Staff's concerns for the DS-5 class, AIU defends the fixture charges as promoting rate uniformity across the three utilities, consistent with the Commission's Order in AIU's last rate proceeding.

In response to IIEC's proposal to limit increases (if rates are based on AIU's COSS) to the overall average plus 25% for each class or subclass, inclusive of the PURA tax, AIU contends that the problem with this proposal is that it defines "subclasses" based on the customer's supply voltage and customers often use more than one voltage. AIU points out that many customers take service supplied at a higher voltage than that delivered and metered. AIU urges the Commission to reject IIEC's proposed rate mitigation method because it is lacking in both detail and guidance.

AIU suggests further that IIEC does appreciate AIU's obligation to consider both its large and small customers when it developed its rate mitigation proposal. So, to the extent that a small number of customers experience a larger-than-average rate increase, AIU contends that those increases are consistent with the principles of rate mitigation. AIU asserts that its proposal is simply the most equitable for the rate classes, collectively.

AIU also acknowledges the concern expressed about bill impacts on small customers and maintains that such concern is justified. After power supply price increases followed AIU's emergence from a ten-year rate freeze in 2007, it had to redesign its rates in Docket No. 07-0165, in order to address rate continuity issues. As a result of that proceeding, and the rate increases that resulted from it, AIU states that it must examine rate design changes for small customers carefully. On the other hand, however, AIU states that it also considered bill impacts to large customers, as evidenced by the fact that its proposed mitigation strategy utilizes a 125% revenue allocation constraint for all the customer classes, including DS-4.

Additionally, IIEC contends that AIU's rate moderation approach is inappropriate because AIU examines bill impacts on a total bill basis. Instead, IIEC contends that AIU should consider only the Distribution Delivery Charges when determining rate impacts. AIU counters that doing so would not provide it or the Commission with an adequate indicator of true bill impacts on customers. Instead, AIU continues, IIEC's approach benefits customers who currently have low delivery service rates, because any substantive increase to those rates results in a much higher percentage increase. AIU maintains that its total bill approach is the only way to truly understand bill impacts here.

AIU attempts to demonstrate its point by way of an example using postage delivery rates. AIU asserts that delivery charges, whether they are for a parcel or electricity, are a concern for consumers within the context of the overall bill or transaction. If an individual is thinking about ordering merchandise for home delivery, the impact of the shipping charge is relevant within the overall context of the economics presented by the transaction. According to AIU, a consumer would not exclude the price of the merchandise in deciding whether the shipping rates are unreasonable. If a person is debating whether to order a $1000 oil painting, and the gallery decides it will increase its shipping charges from $30 to $60 dollars, the purchaser is confronted with a total price for the item that has increased by approximately 3%. On the other hand, if the customer is purchasing a $50 reproduction print, the differential in the shipping price becomes more material to the customer’s economic choices. AIU believes that this example shows that examination of total bill impacts is a common sense approach.

b. Staff Position

Staff proposes to allocate electric revenues according to their underlying costs subject to the limitation that no class would receive an increase greater than 150% of the system average increase. While Staff contends that its proposal appropriately balances costs and bill impact concerns, it maintains that AIU's alternative proposal to limit increases for any individual class to 125% of the system average increase is contradictory and confusing. Staff adds that AIU's proposal excludes PURA taxes from the constraint and thereby produces much larger increases for individual classes.

Staff understands that AIU wishes to mitigate the impact of any rate increase stemming from this proceeding in light of the difficulties ratepayers have encountered in recent years adjusting to electric rate increases. Staff notes that the relative newness of the then current rates during AIU's last rate case contributed to the Commission decision to adjust rates on an across the board basis. Staff further notes that AIU now believes that sufficient time has passed and circumstances have changed enough to warrant taking steps again toward implementing cost-based rates while attempting to minimize rate shock.

The first problem for AIU, according to Staff, is that the rate mitigation constraint it has chosen does not cover costs associated with the PURA tax. AIU appears to believe, Staff continues, that ratepayers will accept disproportionate increases as long as they are tied to PURA taxes. Staff avers, however, that there is no evidence in the record to indicate that customers make such a distinction. Furthermore, Staff finds AIU's approach to rate mitigation contradictory, since logic which would indicate that ratepayers care about all components of their electric bills including PURA taxes.

The second problem centers on AIU's unequal treatment of DS-5 lighting customers. AIU proposes significantly higher revenues for the lighting classes than justified by the underlying cost. Staff understands that AIU bases this proposal on the ostensible objective of making lighting charges more uniform across the three companies. According to Staff, AIU acknowledges that the result of the DS-5 revenue allocation methodology is revenue reductions of approximately $1.97 million, $1.62 million, and $60,000 reallocated to each electric utility's DS-1 through DS-4 classes. Staff maintains that this allocation is unfair to lighting customers who receive a higher increase than justified by the methodology applied to other rate classes. Staff reminds the Commission that lighting bills are paid by municipalities that, in turn, must recover the costs from taxpayers. If lighting rates go up, the higher costs will be borne by taxpayers. Staff believes that the more equitable alternative is to apply the same revenue allocation rules to all rate classes. Staff also rejects AIU's claim that higher revenue allocations are necessary to make progress toward the goal of equalizing lighting rates. While the Commission directed AIU to address the possibility of doing so, Staff contends that considering the possibility is far different from imposing such higher revenue allocations on DS-5 customers.

The third problem, Staff reports, is that AIU's proposed class revenue allocations rest upon a flawed cost of service foundation that features an NCP allocator for primary distribution lines and substations. To the extent that the COSS deviate from cost causation principles due to this error, Staff states that this error will distort the resulting class revenue allocations regardless of the methodology employed.

Staff, like the other parties to this case, states that it is concerned about bill impacts for AIU ratepayers. Staff adds, however, that bill impacts are not the only concern in allocating the revenue requirement. Costs are important as well. Staff believes that the best way to balance these two concerns is through a constrained class revenue allocation. Staff maintains, however, that any effort to address bill impacts in the revenue allocation process must be consistent and fair to all rate classes. Staff contends that its proposed 150% constraint represents a reasoned judgment of how much progress can be made towards cost-based revenue allocations while addressing bill impact concerns. While the Staff constraint is higher than the AIU proposal (150% vs. 125%), Staff points out that its proposal encompasses all costs in the revenue requirement while the AIU proposal exempts PURA taxes. Staff therefore concludes that its proposal is more consistent and equitable.

Staff's approach accords the largest percentage increases to the biggest customers on the system. This result is largely driven by the reallocation of costs associated with PURA taxes among rate classes. The shift in allocation of PURA taxes from utility plant to usage shifts responsibility for these costs to DS-3 and DS-4 customers who account for 12% and 43% of sales, respectively. Despite this shift, Staff insists that the proposed increases for these classes will not produce an undue increase in their overall cost of electricity. Utility bills for large customers generally extend to delivery service costs only because they tend to purchase power from non-utility suppliers. Thus, Staff asserts that a significant increase in delivery services does not necessarily translate into a large increase in the overall cost of electricity.

Staff insists that its approach is more equitable for DS-5 customers as well. Staff essentially argues that AIU has arbitrarily increased lighting rates above the cost of service for the sake of consistency among the three utilities. According to Staff, AIU readily admits that it has applied one standard to lighting customers and another to all remaining customers. Staff states that this is clearly unfair to the lighting class. When utilities factor bill impacts into the revenue allocation process, Staff maintains that their approach should be based on a transparent set of rules fairly and consistently applied to all rate classes to ensure that some are not shortchanged in the process. Staff contends that AIU's proposal clearly falls short in this regard.

Staff notes that AIU criticizes its mitigation approach by claiming that a 150% limit puts a disproportionate burden on the DS-3 and DS-4 classes. But later AIU also complains that Staff's approach to distribution taxes would subsidize the DS-3 and DS-4 classes as well as the DS-2 class. Staff therefore understands AIU to argue at the same time that Staff's approach both burdens and subsidizes the DS-3 and DS-4 classes. Staff contends that this confused argument can be readily dismissed by the Commission.

With regard to IIEC's rate mitigation argument, Staff asserts that IIEC's proposals do not appear to satisfactorily address the Commission's concerns about returning the focus of AIU ratemaking to cost of service. Staff recalls from AIU's last rate case that the Commission "finds value in Staff's recommendation that AIU provide gas and electric rates in the next rate cases based on cost of service and directs AIU to do so in the next rate cases." (Docket Nos. 07-0585 et al. (Cons.) (September 24, 2008) Order at 281) Staff contends that neither IIEC's proposed across-the-board allocation nor its limited constraint of 25% over the system average increase at the subclass level appears to be consistent with the Commission's statement.

c. IIEC Position

IIEC complains that AIU is requesting an unprecedented level of rate increases for its largest, highest load factor customers but is doing little in terms of rate mitigation for the affected customer classes and subclasses. IIEC contends that the two main failings in AIU's approach are its failure to reflect the impact of the PURA tax in its analysis and its failure to apply its moderation criteria at the subclass level. In contrast to AIU's proposal, IIEC argues that its approach properly recognizes the cost differences and bill impact differences among subclasses within a customer class, rather than considering only "average" impacts of widely varying increases.

Although AIU claims to have taken into account cost impacts and rate moderation, IIEC asserts that the proposed increases for the customers in the DS-4 class illustrate an unfortunate disregard of the principles of rate continuity and avoidance of rate shock. IIEC notes that in some instances the increase in delivery service charges is in excess of 1,000%. For some customers, this translates to increases in delivery costs of over $1 million per year. IIEC contrasts this result with AIU's position on the rate limiter in this case (discussed below) and its response to delivery service rate increases as high as 42% for certain customers subject to the rate limiter. IIEC maintains that the disconnect between AIU's position on the rate limiter and its attempts to justify unprecedented rate increases as high as 1,000% for other customers makes more apparent its intent to impose as much of its rate increase on its largest customers as possible, in order to avoid adverse political responses to its overall rate request in this case. While the Commission may wish to give favorable consideration to AIU's proposal for extension of the rate limiter for grain drying customers, and if it does, IIEC would not object, IIEC urges the Commission to also give favorable consideration to any reasonable recommendation to reduce the level of the rate increase requested by AIU for all customers, and to the specific recommendations of IIEC on appropriate cost allocation and rate mitigation measures in this case.

IIEC accuses AIU of attempting to mask the level of its proposed increases in DS-4 charges by providing comparative statistics that include costs that have no bearing on the delivery service charges that are at issue in this case. IIEC relates AIU's claim that increases of as much of 100% in the delivery bill are acceptable if viewed from the perspective of a total bill that includes power commodity costs. AIU witness Jones' focus on masking the impacts of increases in delivery service bills is understandable, according to IIEC, since he was instructed to do so by Ameren management. IIEC offers the following excerpts from an e-mail exchange between Mr. Jones and AIU witness Mill on May 17-18, 2009:

> By Mr. Jones: "How comfortable are you and do you think others will be showing a DS-4 increase in the 70% - 90% range (56-30% without the Distribution [PURA] Tax influence)?"
>
> Response by Mr. Mill: "If you were to assume 5 cent power for DS-4, what is the weighted bundled increase for the 70-90%?"
>
> Response by Mr. Jones: "The large percentages do not look as bad when power is included…"
>
> Response by Mr. Mill: "On a bundled basis it looks like the % increases for all but primary are near the average bundled price increases that residential will face. If you go this route, you need to be strong in your testimony re a bundled viewpoint to help soften reactions"
> (IIEC Ex. 1.2, [partial Ameren response to data request IIEC 4.09] – tables omitted)

From this exchange, IIEC believes that it is clear that AIU knew the impact its proposals would have on large customers' delivery service bills, including the impacts with and without the PURA tax. But rather than proposing to implement any meaningful rate moderation, IIEC states that AIU chose instead to try to obscure the unprecedented size of its delivery service rate increase to these customers by considering irrelevant costs in its analysis. IIEC insists that costs other than delivery service costs have no bearing on delivery service rates, or the need for rate moderation.

AIU consciously chose to add to the revenue requirement of the DS-4 customers, IIEC continues, in order to benefit the DS-1 residential class. According to IIEC, AIU's strategy is to make the requested revenue increase as palatable for residential customers as possible by shifting cost responsibility to large customer classes. A rate moderation proposal that mutes the impact of the increase on large customers, IIEC continues, might also mute the impact of the revenue shift from residential customers. In an e-mail from Ameren president Scott Cisel to Mr. Jones and Mr. Mill, IIEC states that Mr. Cisel emphasized the need to protect residential customers. In e-mails dated May 25, 2009, IIEC reports that Mr. Cisel makes the following observations:

> "It appears that most of the charges, graphs for residential and small business customers are contained in this exhibit. As we all know, residential and small businesses are lightning rods."
>
> "I want to better understand the proposed rate changes on residential customers and small businesses and how they will play on 'Main Street'. Good rate design based on the data is important; however if the design causes major public unrest, we will have difficulty in achieving our desired success. Balancing all interest is difficult."
>
> "My intuition tells me without seeing the data a much smaller decrease would seem appropriate for the large usage customers and use the difference to reduce the increase of the lower usage customers."
> (IIEC Ex. 1.0-C at 15)

In addition, in an e-mail dated the following day, May 26, 2009, IIEC relates that Mr. Mill observes, "Scott very concerned re optics and outcry from small customers." (Id.) In light of these comments, IIEC argues that AIU's revenue allocation and class rate increase proposals are not driven by rate making principles such as rate impacts, rate stability, and rate moderation, but by its desire to protect itself from adverse political reaction to its overall increase and to help ensure it receive its desired level of rate relief. IIEC urges the Commission to set delivery service rates that are stable, fair, equitable, and take into account the principles it has espoused in the past and which are present in the Act. IIEC insists that stable rates, that avoid rate shock, are a necessity for all customer classes and subclasses.

To moderate the rates which it complains of, IIEC originally proposed a rate mitigation approach that limits the increase to any subclass' revenues to 25% above the average change in rates of each company's overall increase. But given its concerns over AIU's electric COSS, which came to light in AIU's prepared surrebuttal testimony and cross-examination testimony, IIEC finds itself unable to rely on AIU's COSS to allocate costs and set rates. If the Commission is left without a valid measure of class and subclass cost of service because it can not rely on AIU's COSS, IIEC asserts that it has no basis for shifting revenue responsibility between classes and should implement any increases or decreases to the rates on an across-the-board basis.

IIEC asserts that an across-the-board rate allocation would still address the rate moderation concerns expressed by IIEC and Staff, as the resulting impacts on bills would, by definition, fall within the rate moderation criteria expressed by each. An across-the-board increase in rates affects all classes and subclasses equally, by the percentage increase (or decrease) in revenues. Thus, IIEC states, the 25% above the average increase proposal of IIEC, and the 150% of the average increase proposal of Staff are automatically met. According to IIEC, this approach would also meet the Commission's goal to avoid rate shock and ease rate impacts.

Because of the huge increases that AIU's proposals produce for subclasses within the DS-4 rate class, IIEC maintains that the subclass revenue allocations should include the impact the PURA tax. Should the allocated revenues that result in this case exceed the rate moderation thresholds, IIEC contends that the most reasonable approach to implementing this allocation would be to first spread any revenue deficiencies to other subclasses within a rate class, e.g., DS-4, on a proportional basis, unless and until the 25% above system average threshold is reached for any of the other subclasses. If all subclasses within a delivery rate class reach the maximum of 25% above the system average increase, IIEC recommends spreading any remaining revenue shortfall among the other subclasses, again on a proportional basis. IIEC adds, however, that Staff's rate moderation approach to limit the increase on current rates for any class at 150% of the system average increase approved in this proceeding, including the impact of the PURA tax, would be acceptable, assuming the application is done at the subclass, rather than full class level.

IIEC insists that rate moderation occur at the subclass level since it is the actual bills that customers pay which determine the degree of rate shock. IIEC reports that the bills that the subclasses would pay under the AIU proposed increase in this case are dramatically different, even within the same rate class. IIEC states that the increases in delivery charges vary for the DS-4 class from 35% to 541% for AmerenCILCO, from 24% to 1,270% for AmerenCIPS, and 20% to 760% for AmerenIP. IIEC's point is that, regardless of the final revenue requirement in this case, the actual bills that a customer must pay depends not so much on the class to which it belongs (e.g., DS-4), but on the subclass to which it belongs (e.g., DS-4 100+ kV).

IIEC is also concerned about the effect that recovering the PURA tax as a separate line item will have rate moderation efforts. IIEC maintains that it will be impossible to implement Staff's rate moderation proposal and simultaneously collect an equal PURA tax per kWh charge as a separate line item on the bill. IIEC explains that this is because the PURA tax has such a dramatic effect on the overall delivery service bills of some customer classes and subclasses (See IIEC Ex. 1.0-C at 5: Table 1--showing class increases of about 60% for DS-4 customers; and at 7: Table 2--showing increases ranging from 78% to 131% for DS-4 High Voltage customers and 541% to 1,270% for DS-4 100 kV and Above customers). Using a uniform PURA tax recovery charge for all customers would require that the base delivery service charges for certain customer classes or sub-classes would need to be reduced to zero, or even go negative, which, according to IIEC, is obviously an illogical result. Of the two factors, IIEC argues that adequate rate moderation is far more important than implementing a new line item on a bill associated with a tax that is already being collected in base rates.

Therefore, in order to comply with IIEC's, or Staff's, rate moderation proposal, IIEC states that the Commission must reject AIU's and Staff's proposal to collect the PURA tax charges on a ¢/kWh basis as a separate line item and instead, maintain the current recovery of the costs through base rates.

d. Commission Conclusion

It is a widely held ratemaking policy that rates should be designed to reflect cost causation, maintain gradualism, and avoid rate shock. Given the history concerning AIU's rates and the change in the PURA tax allocation, among other conclusions in this Order, the rate impact on all of AIU's rate classes is of great importance to the Commission. One of the Commission's first observations on this issue pertains to AIU's exclusion of the PURA tax from its rate mitigation proposal. While AIU's reasons for excluding the PURA tax in its proposal are understood, the Commission can not accept them. As argued by Staff and IIEC, the Commission can not agree that customers are not concerned about their bill total as long as increases in individual components are arguably reasonable. Examples may be offered on both sides of the argument, but the fact remains that when it comes time to pay a bill, a customer's budget, whether it be a residential or industrial customer, is impacted by the bill total regardless of the reasonableness of the bill's components. Accordingly, rate mitigation efforts should be looked at from the perspective of the bill total.

Setting aside IIEC's preference for an across-the-board rate change, Staff and IIEC both offer rate mitigation approaches which include the PURA tax. Neither is perfect, but entering an order lacking rate mitigation is not an option. In reviewing the proposals, IIEC's proposal raises a point worth serious consideration. IIEC recommends that rate moderation be implemented at the subclass level. Given the concern over the impact of the change in the PURA tax allocation, the Commission is inclined to agree. Moreover, IIEC has expressed its willingness to accept Staff's rate mitigation approach if it is applied at the subclass level. The Commission sees no reason why Staff's proposal based on a 150% increase limit could not be applied at the subclass level, as suggested by IIEC.

In arriving at this conclusion, the Commission must also find that AIU should recover the PURA tax through a separate line item on bills. The Commission believes ratepayers should be made aware of taxes they are being charged.

3. DS-3 and DS-4 Distribution Delivery Charges

The DS-3 rate class is comprised of non-residential customers that have billing demands ranging from 150 kW up to 1,000 kW. The DS-4 rate class is comprised of all non-residential customers with billing demands of 1,000 kW or greater. There are four basic categories of charges for DS-3 and DS-4 customers: (1) Customer Charges; (2) Meter charges; (3) Distribution Delivery Charges; and (4) Transformation Charges. In addition, DS-4 customers are subject to a Reactive Demand Charge. The first three categories of charges are differentiated by voltage, e.g., secondary, primary, high voltage, and transmission voltage. At each voltage level, the Customer Charge is uniform between DS-3 and DS-4. Likewise, the proposed Transformation Charge is uniform between DS-3 and DS-4 in each service territory. The Distribution Delivery Charge is a demand charge levied on a per-kW basis, with rates differentiated with respect to voltage level: primary, high voltage, and transmission voltage. There is no separate Distribution Delivery Charge for secondary voltage. Secondary voltage customers pay the primary Distribution Delivery Charge plus the Transformation Charge. Unlike the Customer Charge and the Transformation Charge, the Distribution Delivery Charge is not uniform between the DS-3 and DS-4 rate classes.

a. AIU Position

AIU indicates that customers served at lower voltages require additional investment in distribution facilities as compared to customers served at higher voltages. As a result, AIU states that voltage differentiated pricing reflects the costs incurred to serve customers, and is higher for low voltage customers and lower for high voltage customers. AIU proposes Distribution Delivery Charges that were developed using an approach similar to that used to establish prices for the same elements in AIU's second most recent set of rate cases, Docket Nos. 06-0070 et al (Cons.). The distinction being that in this pending proceeding, AIU combined the demand-related costs for the DS-3 and DS-4 classes and divided by the combined voltage differentiated demands.

AIU argues that its revenue allocation approach should be used to determine the Distribution Delivery Charge for DS-3 and DS-4, as it establishes more consistent bill impacts among customer classes. AIU adds that its approach provides for relatively moderate differentiation between classes when compared to Staff's approach. Under Staff's approach, AIU states that AmerenIP and AmerenCILCO DS-3 customers take on a greater burden. AIU indicates that Staff's approach also unnecessarily provides marginal relief to the DS-4 class for each of the three companies. AIU contends that this issue is important when considering that DS-3 customers with larger demands, or DS-4 customers with smaller demands, may reclassify from DS-3 to DS-4, and vice versa. Under Staff's proposal, a customer reclassifying from DS-4 to DS-3 may experience a rate increase if their demand did not drop by an amount more than the price increase. While some difference between the rates is justified, AIU fears that large differences may encourage inefficient use. AIU maintains that Staff's proposal widens the gap between DS-3 and DS-4, increasing the potential for such inefficiency. In response to Staff's contention that the greater burden its method places on the DS-3 class will be mitigated to the extent that the Commission adjusts the revenue requirement downward, AIU states that the relative differences in the revenue requirements and price disparity remain. Because its proposed Distribution Delivery Charges for the DS-3 and DS-4 classes are closer together than those proposed by Staff, AIU asserts that its revenue allocation and rate design will produce final rates that are closer together.

Furthermore, AIU contends that its method for determining the DS-3 and DS-4 Distribution Delivery Charge addresses the concerns of many of the parties. For example, AIU states that its rate adjustment approach reduces DS-3 Distribution Delivery Charges, which closes the gap between DS-3 and DS-4 – a concern of Kroger. AIU adds that its method also reduces the amount of rate limiter credits – a goal of GFA. Moreover, AIU asserts that its rate adjustment approach reduces the proposed DS-4 ¢/kWh charge first, and if necessary, the $/kW Distribution Delivery Charge, which is responsive to the concerns of IIEC. Further, both LGI and AIU contend that there is merit in moving toward more uniform Fixture Charges among the three companies – AIU's rate adjustment approach moves toward that goal. AIU contends that Staff has overlooked all of these concerns in its approach. Because it considers its proposal directly responsive to many of the concerns of the numerous intervenors, and creates more consistent bill impacts, AIU deems its method preferable to Staff's and urges the Commission to accept it.

In response to Kroger's proposal to bridge the gap between the DS-3 and DS-4 classes by removing 50% of the difference between the DS-3 and DS-4 Distribution Delivery Charges, with an adjustment for the DS-4 reactive power revenues, AIU argues that Kroger's proposal does not measure potential bill impacts for the affected customers. AIU states that Kroger could have prepared that analysis, but did not. Without further analysis by Kroger, AIU asserts that the Commission can not seriously consider the proposal. AIU also observes Kroger's own acknowledgement that it has submitted the same proposal in three consecutive AIU rate cases with no success. AIU agrees that the DS-3 and DS-4 Distribution Delivery Charges should move closer together, but disagrees that now is the time to take such drastic measures, particularly given the ongoing concerns of bill impact and rate mitigation.

b. Staff Position

Staff understands AIU's proposed rates to include a common set of Customer and Meter charges for the DS-3 and DS-4 classes that are set at current levels. For demand charges, Staff states that AIU first develops a unit cost for demand that applies to both the DS-3 and DS-4 rate classes. Staff understands that that unit cost is then adjusted by AIU to reflect that revenue contributions from the DS-3 class will be slightly less than those for the DS-4 class through the year. Because of these adjustments, Staff observes that the demand charges for the two classes diverge to some degree. Staff notes that AIU relies on the Commission's Orders in its prior rate cases to justify combining elements of the DS-3 and DS-4 rate classes. (See Docket Nos. 07-0585 et al. (Cons.), Order at 362-63) A central tenet of AIU's analysis supporting its ratemaking approach for the two classes is the assumption that conceptually, it costs about the same to provide a kW of service to a DS-3 customers as it does a DS-4 customer. AIU's analysis, Staff continues, finds that the $/kW charges for the DS-3 and DS-4 rate classes should be close together.

Staff maintains that AIU's proposal to collectively design rates for the DS-3 and DS-4 classes conflicts with basic principles of utility ratemaking and should be rejected. Because its alternative approach designs rates for the two classes based on each class' costs of service, Staff contends that its way is more reasonable and should be adopted in this case. Staff argues that the problem with AIU's analysis lies with the assumption that it costs about the same to provide a kW of service to DS-3 and DS-4 customers. Staff contends that that is not necessarily the case because a customer's impact on the distribution system depends not just on the level of his or her demand, but also on when that demand takes place. Staff asserts that that is particularly true for facilities such as distribution lines and substations which may be constructed to meet the collective peak demands of many customers from different rate classes. The impact of any individual customer's demand on the cost of a distribution line or substation depends on how his or her demand coincides with the peak demand for that equipment. If one customer peaks when other customers use less, Staff observes that that customer may have minimal impact on the cost of a distribution line or substation. If another customer's peak demands coincide with the collective peak demands for this equipment, Staff relates that the utility may find it necessary to invest in more capacity. Therefore, because not all electricity demands are the same from the standpoint of distribution costs, Staff asserts that there is no reason to assume that unit demand costs for DS-3 and DS-4 customers will be comparable. Staff points out that AIU witness Jones even acknowledges that "one class may have a greater contribution to the peak demand than another, thus yielding different costs per kW." (Ameren Ex. 40.0 Second Revised at 8)

As alluded to above, Staff also complains that AIU's combined ratemaking approach for the DS-3 and DS-4 classes conflicts with general ratemaking principles which first allocate costs to individual rate classes and then design rates to recover those costs from individual ratepayers. Customers are placed into different rate classes because their usage characteristics are assumed to have a differing effect on system costs. Staff contends that AIU's combined approach does not fully recognize these cost differences and instead essentially treats the DS-3 and DS-4 classes as a single class for ratemaking purposes with some adjustments thrown in to reflect some differences between the two classes. Staff believes that AIU's proposal would send inaccurate price signals to DS-3 and DS-4 customers about their relative cost of delivery services. Specifically, it would understate the cost of delivery service for DS-3 customers and overstate the cost for DS-4 customers. Staff states that this would signal customers in the two classes to use either too much or too little electricity, resulting in an inefficient level of use.

Staff complains further that the assumed commonality between DS-3 and DS-4 customers for rate design inappropriately lumps together customers that are much different in size. Customers in the DS-3 class have demands ranging from 150 kV up to 1 MW while DS-4 class demands range higher. A common rate design for the two classes would lump together 150 kW customers with customers 10 MW or larger. The cost of serving these two customers can be considerably different simply because of their relative demand sizes without considering their respective load shapes.

In response to Staff's concerns about size differences among customers, AIU asserts that its rate design method carefully groups customers by voltage level such that customers' demands supplied from Primary Voltage are grouped together, as are those from High Voltage and +100 kV groupings. Staff contends that this argument is undermined by the fact that DS-3 and DS-4 customers face the same set of customer charges with differences based solely on voltage levels under AIU's proposal. As an example, Staff states that a 500 kW DS-3 customer could pay a higher customer charge than a 5 MW DS-4 customer if the former was served at a higher voltage level. The fact that the DS-4 customer's demand is ten times as high as for the DS-3 customer would play no role in determining their relative customer charge levels. Staff maintains that this is an unreasonable assumption on AIU's part.

Staff notes as well that AIU's cost of service and rate design approaches for the DS-3 and DS-4 classes are fundamentally inconsistent. Staff explains that AIU considers the classes different from a cost of service standpoint, but then lumps them together for the purpose of designing rates. Evidently, AIU believes there are sufficient cost differences between the two groups of customers to justify putting them into two separate classes for allocating the cost of service. Staff points out, however, that AIU then fails to recognize those differences in cost when it comes to rate design. Staff asserts that it is illogical to allocate costs separately to the DS-3 and DS-4 classes and then implement a collective rate design that tries to paper over the cost differences between the two.

Staff presents an alternative which designs rates separately for the two classes based on the respective costs and billing determinants for each class. Staff maintains that designing rates for the DS-3 and DS-4 classes separately promotes equity by ensuring that customers in each class pay rates designed to recover the costs that have been allocated to that class. The alternative approach of collectively designing charges that apply to both the DS-3 and DS-4 classes produces rates for customers in each class that do not necessarily correspond to the level of costs they have been allocated. Staff states that AIU's approach can result in an over-recovery of costs for one class and under-recovery for the other.

c. IIEC Position

Because AIU's approach to determining Distribution Delivery Charges has the effect of combining the DS-3 and DS-4 rate classes for cost allocation purposes, IIEC opposes this rate design approach. IIEC argues that AIU's approach is inconsistent with traditional ratemaking, which first allocates costs to rate classes and then designs rates to recover costs from customers within each class. Costs are generally allocated to classes of customers with similar cost characteristics. IIEC complains that AIU's approach, in contrast, treats the DS-3 and DS-4 classes as a single rate class and obscures the level of costs imposed by members of the classes. Despite AIU's assertions to the contrary, IIEC insists that this rate design approach is not consistent with any past Commission orders. IIEC also criticizes AIU's approach for ignoring the differences in size of DS-3 and DS-4 customers. Similarly, IIEC disagrees with Kroger that delivery voltage is the most accurate indicator of the cost to serve a customer. Thus, IIEC concludes that AIU fails to give consideration to the fact that customers with different demand sizes can impose different costs on the system. Finally, IIEC contends that there is no reason to assume that DS-3 and DS-4 customers have comparable unit demand costs. Under the circumstances, IIEC recommends that AIU's approach to the design of rates for the DS-3 and DS-4 classes in this proceeding be rejected.

d. Kroger Position

While AIU proposes a uniform Customer Charge and Transformation Charge between the DS-3 and DS-4 classes, AIU proposes a Distribution Delivery Charge for the DS-3 class that is notably greater than that proposed for the DS-4 class. Kroger is very troubled by this and believes that it is appropriate for the Distribution Delivery Charge for customers on the DS-3 and DS-4 rate schedules to be approximately equalized. To reach this objective, Kroger recommends that the Commission initiate steps to move these rate schedules closer together in this proceeding.

Table KCH-1 in Kroger Ex. 1.0 sets forth AIU's proposed Distribution Delivery Charges:

Utility Distribution Company Voltage	DS-3 Charge ($/kW)	DS-4 Charge ($/kW)
Ameren CILCO		
Primary Service	5.711	3.016
High Voltage Service	1.643	0.954
+100 kV Service	0.049	0.033
AmerenCIPS		
Primary Service	4.706	3.041
High Voltage Service	2.054	1.375
+100 kV Service	0.098	0.077
AmerenIP		
Primary Service	7.278	5.597
High Voltage Service	2.403	1.771
+100 kV Service	0.162	0.139

As seen in Table KCH-1, AIU's proposed DS-3 Distribution Delivery Charge for Primary Service is 30% greater than the proposed DS-4 counterpart in the AmerenIP territory. In the AmerenCIPS territory this difference is 55%, and in the AmerenCILCO territory, this difference is 89%. Kroger points out that this means that a Primary Service customer in the AmerenCILCO territory with a billing demand of 999 kW under DS-3 would pay a total Distribution Delivery Charge bill that is nearly 90% greater than an otherwise identical customer with a billing demand of 1,001 kW taking service under DS-4.

Kroger observes that although AIU proposes a larger percentage increase for DS-4 than DS-3, the two rates nevertheless would move further apart under AIU's proposal. Kroger recognizes that this statement may appear paradoxical, but insists that it is true. Kroger explains that this is because the Distribution Delivery Charge for the DS-3 class already exceeds that for the DS-4 class, and the proposed increase for the DS-4 class is not sufficient to catch up with the charge for the DS-3 class. Kroger offers an example based in AmerenCIPS' service area. For AmerenCIPS, Kroger states that the proposed overall rate increase for DS-3 is 12.43%, while for DS-4 it is 19.53% (excluding distribution tax). Yet Kroger calculates that the proposed increase for DS-3 is greater than DS-4 for each delivery voltage level, except Transmission Voltage Service. For instance, Kroger notes that the proposed increase for the DS-4-Primary Distribution Delivery Charge is only 5.59%. In contrast, Kroger continues, the proposed increase for the DS-3-Primary Distribution Delivery Charge is 14.47%. Kroger adds that for High Voltage Service, the proposed Distribution Delivery Charge increase for DS-3 exceeds that of DS-4.

Kroger maintains that the widely divergent Distribution Delivery Charges paid by DS-3 and DS-4 customers is not cost-justified. According to Kroger, the most important cost distinction for delivery service is the voltage at which customers take service. Kroger contends that this is a far more important distinction than whether a customer is above or below 1,000 kW of demand which is largely irrelevant insofar as per-kW delivery costs are concerned. Kroger states that AIU even admits that conceptually providing a kW of service to customers at a given voltage level costs the same whether the customer requires 150 kW or 2,000 kW. (See Ameren Ex. 16.0E at 39)

Kroger finds unpersuasive AIU's two arguments attempting to justify the different Distribution Delivery Charges for the DS-3 and DS-4 rate classes. AIU's first argument is that the difference is, at least in part, attributable to the recognition of DS-4 reactive power revenues as an offset to the DS-4 Distribution Delivery Charge. Kroger does not dispute the existence of the reactive power revenue offset, but contends that it is relatively too small to explain the disparity between the Distribution Delivery Charges for the DS-3 and DS-4 rate classes.

AIU's second argument pertains to the more consistent distribution of billing demand during the course of the year displayed by DS-4 customers relative to DS-3 customers. AIU asserts that this pattern of usage justifies a reduced unit demand charge for DS-4 relative to DS-3. While Kroger agrees that, mathematically, a customer whose billing demand is relatively constant throughout the year will produce more revenue than a customer with the identical annual peak demand, but who exhibits more variable billing demands throughout the course of the year, it does not necessarily follow that the demand charge for a class with more constant average usage should be lower than that of a class with more variable usage. To the extent that a class has more variable usage, Kroger contends that this fact is already captured in the billing determinant used to calculate the demand charge. Kroger insists that there is no need to make a further adjustment to account for it (as AIU does in Ameren Ex. 16.11E). Moreover, Kroger asserts that a class with more variable usage (e.g., DS-3) is likely to have greater demand diversity at the time the class NCP is measured, all other things being equal. As individual customers are billed for demand based on their individual peaks (which may not occur at the time of the class NCP), Kroger states that a class that exhibits variable demand patterns may very well warrant a lower demand charge relative to a class that exhibits a more constant demand pattern (but has less diversity at the time of the class NCP). Unless both diversity factors are taken account of (i.e., diversity of billing demand throughout the year and diversity of class demand at the time of class NCP), Kroger states that one can not conclude that a given group of customers warrants a lower demand charge relative to another group based on considering one aspect of diversity in isolation. For these reasons, Kroger contends that AIU's second rationale for a difference in DS-3 and DS-4 demand charges is not persuasive.

Kroger observes that despite offering these two reasons to explain the difference in the Distribution Delivery Charges for the DS-3 and DS-4 rate classes, AIU also concedes that its two reasons can not explain all of the difference. According to Kroger, AIU suggests that imperfections in prior COSS may be responsible, at least in part. (See Ameren Ex. 16.1E at 7) AIU witness Jones, Kroger continues, also indicates agreement that DS-3 rates are too high relative to DS-4 rates. (See Ameren Ex. 40.0 Second Revised at 21) Kroger maintains that these statements by AIU as well as AIU's failure to remedy the problem on its own warrant action in this docket moving the DS-3 and DS-4 Distribution Delivery Charges closer together.

In response to Staff's concerns about the impact of load diversity on the cost of serving DS-3 and DS-4 customers, Kroger agrees that load diversity is a key determinant of distribution demand costs. Kroger points out, however, that the question at hand is how that diversity is best captured for the purpose of setting class rates. Rates are not set one individual at a time. Instead, the benefit of the diversity of an aggregation of customers is shared across the group. Kroger's concern is identifying the most appropriate grouping of customers.

Kroger also disagrees with Staff's opinion that customer size matters more than voltage level. For delivery services, Kroger contends that it is voltage that matters most. Kroger argues that there is no evidence presented in this case that the size of individual customer demands for DS-3 and DS-4 customers impacts the unit-cost-of-service for distribution demand. To the contrary, Kroger observes, AIU's COSS shows that DS-3 and DS-4 rates should be converging. According to Kroger, even Staff's discussion of distribution cost focuses on the role of load diversity, which is an entirely separate matter from customer size.

To address its concerns, Kroger suggests that the Distribution Delivery Charges for the DS-3 and DS-4 classes be converged for customers taking service at the same voltage within a given service territory, except for a minor difference to recognize DS-4 reactive power revenues as an offset to the DS-4 Distribution Delivery Charge. To reach this objective, Kroger recommends that the Commission initiate steps to move these rate schedules closer together over time. Specifically, in the current proceeding, Kroger recommends that this first step be implemented by removing 50% of the differential between the DS-3 and DS-4 Distribution Delivery Charges, with an adjustment to recognize DS-4 reactive power revenues. To the extent that the final approved revenue requirement is reduced, then the results for both rate schedules should be adjusted downward while retaining the targeted rate differential. The impact of adopting Kroger's proposal to remove 50% of the differential between the DS-3 and DS-4 Distribution Delivery Charges is presented in Kroger Ex. 1.4, using the combined DS-3/DS-4 revenue requirement proposed by AIU in this proceeding.

e. Commission Conclusion

The underlying concern with the DS-3 and DS-4 Distribution Delivery Charges is whether these rate classes are sufficiently similar to warrant similar charges. In response to concerns raised by Kroger in prior AIU delivery service rate cases and Commission direction that Kroger's concerns be at least considered, AIU has proposed a rate design for the DS-3 and DS-4 rate classes that it believes will eventually move them closer together. Kroger complains that AIU's proposal does not go far enough and recommends that the Commission go further in this proceeding in closing the gap between the rate classes. Staff and IIEC contend that AIU and Kroger are in error.

At the heart of Kroger's concerns is its position that it does not cost AIU any more to serve a DS-3 customer than a DS-4 customer when both are taking service at the same voltage. Customer demand, in Kroger's opinion, is irrelevant when determining the cost of delivering electricity. Kroger has made this argument in AIU's last two electric delivery service rate cases and in both instances the Commission has indicated that further information was needed before any determination could be made.

Additional information has been provided, but the Commission remains unconvinced that the changes sought by Kroger are warranted. Specifically, the Commission is not persuaded that voltage is the determining factor in cost causation when it comes to delivering electricity. While a factor, voltage is not the sole factor. The Commission continues to believe that customer size/demand plays a role in cost causation as well, as discussed by Staff and IIEC. Even if the Commission agreed with Kroger, it would be hesitant to adopt Kroger's proposal given the absence of any evidence on how it would impact AIU's other customers.

While AIU's class COSS may suggest that moving the DS-3 and DS-4 classes closer together is appropriate, the Commission is not willing to unquestionably rely on those results given the corrections that the Commission has made to AIU's electric COSS. Additionally, the Commission considers separating the DS-3 and DS-4 classes for cost allocation purposes inconsistent with the decision to combine the classes for rate design purposes. Absent compelling evidence that such a rate design is warranted, the Commission declines to adopt AIU's proposal.

The remaining rate design proposal for the DS-3 and DS-4 classes is that of Staff. While not perfect in addressing all of the concerns raised regarding these rate classes, the Commission finds Staff's proposal sufficient for purposes of this proceeding. Accordingly, Staff's proposal on this issue is adopted.

4. DS-5 Fixture and Distribution Delivery Charges

The DS-5 rate class provides customers with dusk-to-dawn, photo-cell controlled lighting service. The distribution charge does not include power and energy, transmission, or delivery service charges, which are separately stated. The distribution charge also does not include the cost of the fixtures, which may or may not be owned by AIU. A monthly Fixture Charge is assessed for street lights that are owned by AIU.

a. LGI Position

LGI pays for street lighting service under AIU's DS-5 rate. LGI claims that in AIU's last rate case, the Commission directed AIU to analyze the cost of lighting service in each utility's electric service area and develop cost based rates for lighting fixture charges. In this docket, LGI understands that AIU's pricing methodology is designed to move Fixture Charges for comparable lights for the three companies to a uniform level. LGI maintains that it is important that the lighting Fixture Charges be uniform across the companies since it is difficult for customers to understand why it costs twice as much for a streetlight fixture in AmerenIP's service area than it does for the same streetlight fixture located in AmerenCIPS' service area, especially where the service areas are literally across the street from each other.

With three exceptions, LGI generally supports AIU's proposal regarding the DS-5 class in this docket. First, LGI asserts that the DS-5 class continues to subsidize the rates for other delivery service classes. Second, LGI complains that AmerenIP's lighting Fixture Charges continue to be significantly higher than the lighting Fixture Charges of AmerenCILCO and AmerenCIPS, without any cost justification. Third, while AIU supports its pricing principles in this case, LGI notes that AIU witness Jones testifies that there may be problems in applying the principle of setting DS-5 rates to achieve equalized class rates of return for each of the three electric systems in future rate cases.

Regarding its third exception, LGI states that Mr. Jones' issue arises as a result of the fact that the Fixture Charges for AmerenCIPS are significantly lower than the Fixture Charges for AmerenIP and AmerenCILCO. In fact, AmerenIP's Fixture Charge is about twice that of AmerenCIPS. So when the Fixture Charges become uniform among the three utilities, in order to meet the targeted revenue requirement for the DS-5 class and achieve equalized rates of return with the other AmerenCIPS DS classes, LGI asserts that any increases to the Fixture Charges for AmerenCIPS would have to be offset by decreases to the DS-5 Distribution Delivery Charge for AmerenCIPS. In other words, LGI states that it is possible in the future that the increase in Fixture Charges for AmerenCIPS would result in a near zero or negative Distribution Delivery Charge for AmerenCIPS.

LGI does not insist that uniformity be established in this proceeding. As long as AIU commits that it will continue to move DS-5 rates closer to equal rates of return in the next delivery service rate case, LGI will be satisfied until then. LGI wishes to withhold final judgment until having the opportunity to review the details of AIU's analysis in the next delivery service rate case.

b. AIU Position

For the DS-5 rate class, AIU took steps to create more uniformity among the Fixture Charges. AIU does not propose full uniformity at this time because it considers the rate changes to accomplish full uniformity too great. AIU constrained rates so that the change in rates results in a change of about $1 per fixture to the high pressure sodium 100 W fixture price. AIU states that it took those steps in response to LGI's concerns in this case, as well as the previous rate case.

Staff, however, contends that movement to more equal rates does not justify AIU's increased revenue allocation to the DS-5 class. AIU counters that Staff's approach does not provide sufficient weight to the lighting incremental cost study, ignores LGI's pleas that Fixture Charges be brought closer together, and does not adequately address the Commission's inquiries from AIU's prior rate order about moving Fixture Charges closer together. Movement toward uniform Fixture Charges across the three companies, using the incremental cost study as a guide, makes sense according to AIU because of outside vendors compete against its standard fixture offerings. Movement toward uniform Fixture Charges also makes sense, AIU adds, because there is no difference among the three companies in the incremental costs of providing a fixture.

Staff further claims that by not setting each individual company's DS-5 revenue allocation target at the level to achieve an equal return, AIU's method is arbitrary and unfair. In response, AIU asserts that its DS-5 revenue allocation approach is methodical, with the ultimate goal of recovering the cost of service at an equal return from the combined DS-5 classes of the three companies in a future case. The goal at this time, AIU explains, is to make progress toward uniform rates by easing AmerenIP rates lower and AmerenCIPS rates higher. Since each company is a single legal entity, AIU states that any revenue excess or deficiency still needs to remain within the individual utility, and should be absorbed by other rate classes.

Thus, by adopting its approach, AIU contends that the Commission would not be abandoning cost-based ratemaking. To the contrary, AIU argues, it would reflect the recognition that moving toward a uniform pricing approach that uses the incremental cost study as a guide, but ultimately constrained to the total embedded cost of service for all three utilities combined, is a sound policy choice.

c. Staff Position

Staff prefers its own rate design for the DS-5 lighting class over AIU's. Staff states that its approach would revise AIU's proposed lighting rates for each company on an equal percentage basis to conform to Staff's recommended revenue allocations for the lighting classes. Staff contends that its approach will best ensure that lighting customers only pay their fair share of system costs.

AIU argues that Staff's proposed lighting rates are flawed because they are derived from current DS-5 rates and therefore ignore the discussion of bringing Fixture Charges closer together. Staff responds that AIU is incorrect and asserts that the starting point for Staff's proposed DS-5 rates is AIU's proposed rate design which incorporates movement toward more equal charges. Staff adds, however, that such movement must be balanced with an allocation of the revenue requirement that is equitable to all rate classes. Staff asserts that its proposed revenue allocations are fair to all rate classes and its rate design for the lighting class is reasonable as well.

d. Commission Conclusion

The Commission recognizes that AIU is in a difficult situation in which it is working toward uniform lighting rates among the three electric utilities as encouraged by the Commission while at the same time trying to keep in mind the cost of service. At the outset, the Commission needs to clarify that it does not necessarily expect Fixture Charges to someday be identical across the three electric utilities. The directive that the Commission gave AIU in its last rate proceeding for its next (this) rate proceeding is "to address the possibility of moving the light fixture charges toward a more similar charge among AmerenCILCO, AmerenCIPS, and AmerenIP." (Docket Nos. 07-0585 et al (Cons.), Order at 359) The Commission does not want to give AIU the impression that it expects AIU to "force" identical Fixture Charges into the DS-5 tariffs even if legitimate cost of service reasons warrant different treatment. The direction given to AIU in its last rate proceeding is consistent with this message.

That being said, it appears to the Commission that AIU earnestly attempted to comply with the Commission's directive in the last rate proceeding. By considering both the results of its incremental COSS and embedded COSS, AIU appears to be trying to move the Fixture Charges closer to together while bearing cost of service in mind. The Commission recognizes that the numbers are apt to change after AIU reruns the COSS, but nevertheless finds the methodology reasonable for the DS-5 class for purposes of this proceeding. In contrast, it is not clear to the Commission how Staff's approach is designed to move the Fixture Charges closer. Accordingly, the Commission accepts AIU's position on this issue for purposes of this proceeding.

5. Combined Billing of Multiple Meters

a. IIEC Position

IIEC proposes a modification to AIU's Standards and Qualifications for Electric Service, so that combined billing of multiple meters, on the same or adjacent premises, would be permitted. Currently, the combined billing of multiple meters on the same or adjacent premises is not permitted, except for those customers having agreements with

AIU or having the benefit of tariff provisions permitting same prior to January 2, 2007. AmerenIP previously permitted such combined billing.

IIEC asserts that AIU's current policy has several adverse implications for larger customers. Among the implications, IIEC asserts, is the fact that it creates more customer accounts than are necessary and increases AIU's customer charge revenue. IIEC adds that it reduces the beneficial impact of diversity in separately metered loads of a single customer in a single location on the Distribution Delivery Charge. The current tariff provisions, IIEC continues, also effectively create a barrier to the development of combined heat and power ("CHP") installations under certain circumstances.

With regard CHP installations, IIEC explains that industrial customers with a number of processes under one account proposing to construct a CHP or cogeneration plant on an adjacent site would be required to treat the CHP plant as a separate account from the remainder of the customer's load served by the CHP facility. According to IIEC, such a customer would not be able to enjoy the benefit of using the output of its CHP plant to reduce the amount of electricity delivered to other production facilities in the same plant, but on adjacent premises. IIEC further asserts that to the extent the power generated by the CHP unit is cheaper than power available in the market, the owner would not be able to replace the more expensive power with the cheaper CHP unit power at its adjacent facilities. IIEC also contends that AIU's policy becomes a barrier to CHP development if AIU begins collecting the PURA tax through a cent per kWh charge. Under such circumstances, the customer would pay the full PURA tax on all of the separate accounts at its plant without offset for the power generated by the CHP plant. If the generator output is not included within the same account as the plant load, IIEC complains that the customer would pay the PURA tax on the full plant load even though the net effect of the new generator is to reduce the amount of energy the utility needs to deliver to the customer for its entire manufacturing plant or possibly to the utility system as a whole.

While IIEC acknowledges that CHP units have still been developed in AIU's service territory, IIEC argues that that fact does not address the fundamental problem with AIU's policy, which discourages CHP units on a going-forward basis. IIEC also maintains that spending significant sums to reconfigure electrical distribution systems to accommodate a new CHP plant is not a satisfactory solution to the problem. Customers of this kind, IIEC contends, should not be forced to expend large sums of capital on reconfiguring electrical distribution systems in order to provide a source of power and energy that is a preferred source of power and energy for Illinois, when a simple change to AIU's tariffs will accommodate the construction of the CHP unit without such expenditures. IIEC references Section 16-115D(h) of the Act in support of its assertion that Illinois law encourages CHP installations.

IIEC finds little reassurance in AIU's statement that its tariffs allow 40 kW and over cogenerators to reduce their Distribution Delivery Charge through net metering. IIEC points out that under Section 16-107.5 of the Act, net metering is not available to generating units with a rated capacity greater than 2,000 kW. IIEC asserts that eligible units are relatively small, and would be hardly comparable to the CHP or other cogeneration units that may be built by a large manufacturing customer to serve the load at its manufacturing facility, which may be much larger than 2,000 kW of electrical demand. Furthermore, IIEC points out that AIU has also apparently overlooked the provisions of the net metering legislation which limits the applicability of the law to retail customers owning or operating a “solar, wind or other renewable electrical generating facility.” (220 ILCS 5/16-107.5(b)) The Act further defines “renewable generating facility” to mean a facility powered by “solar electric energy, wind, dedicated crop for energy generation, anaerobic digestion of livestock or food processing waste, fuel cells or micro turbines powered by renewable fuels, or hydroelectric energies.” (Id.) IIEC asserts that a large cogenerating unit at a steel manufacturing facility, for example, fueled by something like coke oven gas or fuels other than those mentioned, would not benefit from AIU's net metering tariffs.

To the extent that a customer seeks other benefits associated with distributed generation, AIU notes that Rider QF provides two different compensation options that provide the customer with a fair market value for the output of its generating unit. IIEC observes, however, that this applies only to the energy value of the generating unit, and does not address the recovery of delivery service costs generally, or the PURA tax specifically from these customers, without giving them credit for their cogeneration.

In response to AIU's billing determinants argument, IIEC asserts that AIU fails to recognize that if the CHP facility were simply located on the customer’s premises, behind the meter, the reduction in billing demands would be the same whether the CHP unit was located on or adjacent to the customer’s premises. IIEC states that locating a CHP facility on an adjacent property rather than on its main plant property may be due to circumstances largely beyond the customer’s control (e.g., a bisecting roadway), and it should not be penalized simply due to such circumstances.

Lastly, AIU argues that IIEC has not proposed any specific tariff language to be reviewed by the Commission. IIEC points out that its recommendation is that AIU be required to change its policy. Presumably, if the Commission follows IIEC’s recommendation, AIU would present the tariff language necessary to accomplish that change in policy. IIEC also notes that until recently, AmerenIP had provisions in its Standard Terms and Conditions which addressed IIEC’s concerns. IIEC does not believe it would be difficult for AIU to develop, or simply modify and reuse, the prior language to achieve the change in policy directed by the Commission.

b. AIU Position

In response to IIEC's concerns, AIU recognizes that the existence of more than one service point results in a corresponding increase in the number of Customer Charges assessed on the customer. What IIEC fails to consider, AIU counters, is that for customers metered at primary voltage or greater, a substantial portion of the cost basis for the Customer Charge is for the current and/or potential transformers used to meter the customer. Since metering has been unbundled, the Commission has directed that current and potential transformers associated with metering remain part of the utility's responsibility. AIU states that customers are assessed a monthly Customer Charge in lieu of a lump sum payment predominantly to pay for the current and/or potential metering facilities. According to AIU, the added revenue offsets the added cost.

AIU also agrees with IIEC that its policy may diminish a possible reduction in the Distribution Delivery Charge for the customer if it was allowed to combine all service points for billing purposes. AIU asserts, however, that IIEC fails to recognize that AIU's tariffs already provide generators with the ability to mitigate their Distribution Delivery Charges. AIU explains that under Section 16-107.5 of the Act, non-residential customers with generators with a name plate capacity rating in excess of 40 kW are assessed delivery service charges based on a "gross" method, where the amount of generation is not allowed to serve as an offset to delivery service charges. Those customers operating on-site generators with capacities under 40 kW are allowed to offset distribution charges. Under Rider QF, however, a customer with a CHP facility with output that exceeds the load at a service point for the entire month would avoid Distribution Delivery Charges, even though facilities were designed and built to ensure adequate distribution capacity is available to serve the customer in the event their generation facility became unavailable for any period of time. AIU states that this practice has been in place for several years, and pre-dates the establishment of net-metering in Illinois.

Essentially, AIU continues, the energy and demand associated with load are registered by the meter, in a manner inclusive only to the extent required beyond what is provided by the generator. AIU allows all customers with facilities up to 1 megawatt to avail themselves of this benefit pursuant to longstanding tariff policies. Beyond that point, AIU requires that generation be separately metered. Further, AIU states that the customer must interconnect the generator directly to the system, or else they can not receive the load off-setting benefits of the Rider QF option, described above. Customers that choose to have AIU run a separate distribution line to the facility will be required to have the interconnected facilities metered after installation of the load-serving line segment.

Additionally, to the extent a customer is metered at the generator, and assessed a delivery service change for all customer load, AIU notes that under the current Rider QF, the customer may choose to be compensated under a fixed or variable rate. AIU states that such compensation will provide some level of total bill offset, even providing compensation in excess of supply charges assessed in certain circumstances. Thus, between net metering and its established policy for onsite generation for Rider QF customers, AIU believes that it allows for significant flexibility for large customers pursuing on site generation supply options. AIU asserts that any expansion of these options to include additional aggregation of metering data for billing purposes is not cost-based, and ultimately would increase the cost responsibility borne by other customers.

Moreover, AIU states that Section 16-107.5 provides that non-residential customers taking service under a net-metering election at a level greater than 40 kW are required to pay distribution charges and taxes for their delivered power. AIU maintains that the policy implications of this legislative prerogative would bode against the revision of Rider QF policies in a manner that would further reduce delivery service and other charges, such as taxes and energy efficiency rider revenues.

With regard to IIEC's concerns over CHP installations, AIU reiterates that current tariff provisions allow customers a reasonable opportunity to achieve the same end that IIEC advocates. For customers that do not qualify, or elect to receive service pursuant to Rider NM - Net Metering Service, Rider QF provides two compensation options for customers that produce more power than they use: fixed-price and variable-price compensation. AIU states that both compensation methods reflect a fair market value for the qualifying facility output. AIU adds that customers that are unhappy with the Rider QF options may take their power output directly to MISO and register their generator as a resource. In AIU's view, customers have both physical and financial options that allow them to effectively reduce their electricity costs using their CHP facility.

From a broader policy perspective, AIU notes that its tariff provisions related to metering and cogeneration are tailored to comply with applicable laws and regulations, as well to avoid unnecessary subsidization from other customer classes. AIU believes that removing any undue barriers to supply options, including self-supply by means of distributed generation, is a goal worthy of consideration. AIU states that its current policy, however, of allowing one meter per service point more closely aligns distribution service cost recovery with those who cause the cost. Measurement of energy on a per service point basis, AIU continues, is a foundational step to associating energy consumption costs with the facilities and customer behind the delivery point.

Finally, AIU states that its billing determinants have not been reviewed in order to determine the impact of implementing IIEC’s proposal. AIU points out that there is at least one large CHP facility which recently began operating in AmerenIP's service area. A change to the metering policy would effectively reduce the billing demands shown in the test year billing determinants, and thus reduce AmerenIP’s expected revenue. AIU adds that the prices to other customers would need to be increased to recover the authorized revenue requirement. Because no party has performed such analysis, AIU maintains that IIEC’s recommendation should be rejected. Additionally, AIU indicates that any new tariff language would need to be developed and reviewed in the same way that other tariff changes were reviewed in this case. Since the IIEC has not proposed any such tariff language for review by parties in this docket, AIU states that there is nothing for the Commission to review.

c. Commission Conclusion

Having considered the record, the Commission finds merit in IIEC's position. Despite AIU's arguments to the contrary, the Commission is persuaded that combined billing of multiple meters, on the same or adjacent premises, should be permitted. AmerenIP apparently even allowed combined billing until relatively recently. AIU's reliance on Section 16-107.5 of the Act is misplaced, as it is not even applicable to the situation at hand. Similarly, Rider QF, while applicable to CHP and other cogeneration facilities, is not relevant to the question of combined billing.

To the extent that the current tariff provisions impede the development of industrial cogeneration projects, the Commission views the elimination of such hindrances as a side effect of permitting combined billing. If the practicality of combined billing also facilitates cogeneration projects that are consistent with Illinois policy, the Commission considers that outcome fortuitous and encourages customers to take advantage of such opportunities.

While the Commission finds that combined billing is appropriate, the Commission is hesitant to direct AIU to prepare tariffs allowing such as part of its compliance tariff filing at the conclusion of this proceeding. Determining language implementing combined billing may not be as straightforward as IIEC suggests. Therefore, to avoid any complications associated with AIU's final tariffs as well as any unforeseen rate or rate design problems, the Commission refrains from directing AIU to implement combined billing in this proceeding. Instead the Commission directs AIU to work with IIEC, Staff, and any other interested parties to develop tariffs addressing the concerns of those involved. Whether tariffs permitting combined billing of multiple meters, on the same or adjacent premises, can be agreed upon or not, AIU should include such tariff provisions with its next electric rate case filings. If the tariff language is not agreed upon, interested parties are free to litigate the issues. Those objecting to AIU's language, however, should submit alternative language for the Commission's consideration.

6. Rate Limiter

Both the DS-3 and DS-4 rate classes currently contain rate limiter provisions that ensure the monthly charges for the sum of Distribution Delivery and Transformation Charges are limited to no more than a set ¢/kWh value if 20% or less of the customer's annual usage occurs in the summer months of June through September. The limiter value is presently 1.953 ¢/kWh for AmerenCILCO, 2.223 ¢/kWh for AmerenCIPS, and 2.613¢/kWh for AmerenIP. The limiter values do not differ between the DS-3 and DS-4 rate classes. The rate limiter provisions were implemented through the Order in Docket No. 07-0165. At that same time, DS-3 and DS-4 Distribution Delivery Charges were increased to maintain revenue neutrality.

a. GFA Position

AIU proposes to constrain the increase in delivery service rates to 23.5% for AmerenCILCO, 19.5% for AmerenCIPS, and 21.8% for AmerenIP. GFA complains, however, that AIU has proposed higher increases to the rate limiters than are proposed for the respective rate classes. GFA argues that AIU's proposal in this proceeding disproportionately impacts grain companies. According to GFA, at least one grain company will experience a delivery service rate increase as high as 42%. GFA recommends that the rate limiters be constrained by the same percentage as the constraints that are applicable to the respective rate classes. GFA contends that this approach more closely tracks the approach taken by the Commission in AIU's previous rate proceeding, Docket Nos. 07-0585 et al (Cons.), where the Commission approved an across-the-board increase to the rate limiters, thereby treating the rate limiter customers the same as other customers.

GFA acknowledges that both the Commission and AIU have recognized the need to reduce and eliminate the rate limiters at the appropriate time, but maintains that now is not the time. GFA contends that the time to consider eliminating the rate limiters is when AIU files a rate case based on a class COSS, and proposes a fully cost-based rate design. While AIU filed a class COSS in this proceeding, GFA states that AIU deviated from it in designing its proposed rates. GFA adds that various parties have advocated differing allocators in this case as well (e.g. CP vs. NCP). Until the Commission has reviewed and determined the appropriate allocators to be used in a full class COSS rate case, with due consideration of seasonal rates, GFA asserts that it will not be known whether and to what extent rates are fully cost justified. Without that knowledge, GFA contends that the Commission will not know in which direction and to what degree rates should be adjusted to eliminate the rate limiters.

b. AIU Position

AIU proposes to retain the rate limiter provision, but increase the limiter ¢/kWh amounts to a level so that the total dollar rate limitation effect is approximately the same under proposed rates as it is under present rates. AIU proposes to set the limiter value at 3, 3, and 4¢/kWh for AmerenCILCO, AmerenCIPS and AmerenIP customers, respectively. Upon learning the final revenue requirement, AIU states that it will need to recalculate the rate limiter values as part of developing the final rates in these cases.

GFA, on the other hand, proposes to limit the increase to the ¢/kWh rate limiter at the same level as the class average increase. AIU opposes GFA's proposal and argues that an adjustment to the rate limiter by an amount only equal to the class average increase would not allow for the eventual reduction or elimination of the provision, but instead would further increase the subsidy provided to eligible customers. AIU adds that applying its method for conforming rates to the final revenue requirement by decreasing the DS-3 Distribution Delivery Charges (and holding the other charges as proposed) will place downward pressure on the ¢/kWh rate limiter values, which is a benefit to GFA.

c. Staff Position

Staff supports AIU's approach to the rate limiters in this proceeding. Staff observes that AIU's proposals in this case include constraints on revenue increases for individual rate classes as well as continued efforts to limit adverse impacts for large non-summer users in the DS-3 and DS-4 classes. Staff therefore believes that it would be consistent with these efforts to maintain the rate limiters. Also, consistent with the Commission's past pronouncement that the rate limiters are temporary, Staff notes that AIU's proposal facilitates the future elimination of the rate limiters and placement of the larger customers currently under the rate limiter under the same tariffs that apply to other DS-3 and DS-4 customers.

d. IIEC Position

IIEC does not oppose the continuation of the rate limiters in this case, as it has proposed rate moderation/mitigation measures of its own. IIEC notes, however, the apparent inconsistency between AIU's support for the rate limiters for the benefit of grain drying customers, but apparent lack of concern for other large customers. Without the continuation of the rate limiters, IIEC understands that some of AIU's grain drying customers would experience delivery service rate increases as high as 42%. IIEC states that this must be contrasted with increases in delivery service rates as large as 1,000% for some of AIU's largest customers who do not happen to be grain dryers. IIEC views this disparity as further support for its position that AIU has been trying to shift costs away from smaller customers for public relations and political reasons.

e. Commission Conclusion

All of the parties agree that now is not the time to eliminate the rate limiters. The only issue in dispute is how to modify the existing rate limiters to reflect the change in electric delivery service rates. AIU proposes to increase the limiter ¢/kWh amounts to a level so that the total dollar rate limitation effect is approximately the same under the new rates as it is under present rates. GFA recommends that the rate limiters be constrained by the same percentage as the constraints that are applicable to the respective rate classes.

Having considered the arguments, the Commission finds AIU's proposal more in tune with the ultimate goal of eliminating the rate limiters. Specifically, AIU's proposal takes steps toward that goal while GFA's proposal essentially maintains the status quo. While GFA talks about eliminating the rate limiters, its proposal as well as the "conditions" that it believes are necessary before doing so seem geared more toward delaying elimination of the rate limiters. GFA seems to suggest that the Commission must have an undisputed class COSS underlying strictly cost based rates before it can eliminate the rate limiters. Such a scenario would be very rare.

Because it finds AIU's proposal a step toward the goal of someday eliminating the rate limiters, the Commission adopts it for purposes of this proceeding. The

Commission agrees with AIU that upon learning the final revenue requirement, AIU will need to recalculate the rate limiter values as part of developing the final rates in these cases. That is why the Commission is approving AIU's methodology and not the specific ¢/kWh amounts AIU identified in its testimony.

X. FINDINGS AND ORDERING PARAGRAPHS

The Commission, having given due consideration to the entire record herein and being fully advised in the premises, is of the opinion and finds that:

(1) AmerenCILCO, AmerenCIPS, and AmerenIP are Illinois corporations engaged in the distribution and sale of electricity and natural gas to the public in Illinois, and are public utilities as defined in Section 3-105 of the Act;

(2) the Commission has jurisdiction over the parties hereto and the subject matter herein;

(3) the recitals of fact and conclusions of law reached in the prefatory portion of this Order are supported by the evidence of record, and are hereby adopted as findings of fact and conclusions of law; Appendix A attached hereto provides supporting calculations for those portions of this Order concerning AmerenCILCO's electric operations; Appendix B attached hereto provides supporting calculations for those portions of this Order concerning AmerenCIPS' electric operations; Appendix C attached hereto provides supporting calculations for those portions of this Order concerning AmerenIP's electric operations; Appendix D attached hereto provides supporting calculations for those portions of this Order concerning AmerenCILCO's gas operations; Appendix E attached hereto provides supporting calculations for those portions of this Order concerning AmerenCIPS' gas operations; and Appendix F attached hereto provides supporting calculations for those portions of this Order concerning AmerenIP's gas operations;

(4) the test year for the determination of the rates herein found to be just and reasonable should be the 12 months ending December 31, 2008, as adjusted; such test year is appropriate for purposes of this proceeding;

(5) for purposes of this proceeding, the net original cost rate base for AmerenCILCO’s electric delivery service operations for the test year ending December 31, 2008, as adjusted, is $275,015,000;

(6) for purposes of this proceeding, the net original cost rate base for AmerenCIPS’ electric delivery service operations for the test year ending December 31, 2008, as adjusted, is $452,066,000;

(7) for purposes of this proceeding, the net original cost rate base for AmerenIP’s electric delivery service operations for the test year ending December 31, 2008, as adjusted, is $1,290,963,000;

(8) for purposes of this proceeding, the net original cost rate base for AmerenCILCO's gas delivery service operations for the test year ending December 31, 2008, as adjusted, is $160,082,000;

(9) for purposes of this proceeding, the net original cost rate base for AmerenCIPS' gas delivery service operations for the test year ending December 31, 2008, as adjusted, is $165,512,000;

(10) for purposes of this proceeding, the net original cost rate base for AmerenIP's gas delivery service operations for the test year ending December 31, 2008, as adjusted, is $435,480,000;

(11) a just and reasonable return which AmerenCILCO should be allowed to earn on its net original cost electric delivery service rate base is 8.05%; this rate of return incorporates a return on common equity of 9.9%;

(12) a just and reasonable return which AmerenCIPS should be allowed to earn on its net original cost electric delivery service rate base is 8.02%; this rate of return incorporates a return on common equity of 10.06%;

(13) a just and reasonable return which AmerenIP should be allowed to earn on its net original cost electric delivery service rate base is 8.97%; this rate of return incorporates a return on common equity of 10.26%;

(14) a just and reasonable return which AmerenCILCO should be allowed to earn on its net original cost gas delivery service rate base is 7.83%; this rate of return incorporates a return on common equity of 9.4%;

(15) a just and reasonable return which AmerenCIPS should be allowed to earn on its net original cost gas delivery service rate base is 7.59%; this rate of return incorporates a return on common equity of 9.19%;

(16) a just and reasonable return which AmerenIP should be allowed to earn on its net original cost gas delivery service rate base is 8.59%; this rate of return incorporates a return on common equity of 9.4%;

(17) the rate of return for AmerenCILCO set forth in Finding (11) results in base rate electric delivery service operating revenues of $117,625,000 and net annual operating income of $22,138,000 based on the test year approved herein;

(18) the rate of return for AmerenCIPS set forth in Finding (12) results in base rate electric delivery service operating revenues of $235,899,000 and net annual operating income of $36,255,000 based on the test year approved herein;

(19) the rate of return for AmerenIP set forth in Finding (13) results in base rate electric delivery service operating revenues of $450,412,000 and net annual operating income of $115,798,000 based on the test year approved herein;

(20) the rate of return for AmerenCILCO set forth in Finding (14) results in base rate gas delivery service operating revenues of $65,825,000 and net annual operating income of $12,535,000 based on the test year approved herein;

(21) the rate of return for AmerenCIPS set forth in Finding (15) results in base rate gas delivery service operating revenues of $70,199,000 and net annual operating income of $12,562,000 based on the test year approved herein;

(22) the rate of return for AmerenIP set forth in Finding (16) results in base rate gas delivery service operating revenues of $156,590,000 and net annual operating income of $37,482,000 based on the test year approved herein;

(23) the electric delivery service rates AmerenCILCO, AmerenCIPS, and AmerenIP which are presently in effect are insufficient to generate the operating income necessary to permit each company the opportunity to earn a fair and reasonable return on net original cost rate base; these rates should be permanently canceled and annulled;

(24) the gas delivery service rates of AmerenCILCO, AmerenCIPS, and AmerenIP which are presently in effect are inappropriate and generate operating income in excess of the amount necessary to permit the company the opportunity to earn a fair and reasonable return on net original cost rate base: these rates should be permanently canceled and annulled;

(25) the specific rates proposed by AmerenCILCO, AmerenCIPS, and AmerenIP in its respective initial filings do not reflect various determinations made in this Order regarding revenue requirement, cost of service allocations, and rate design; the proposed rates of each company should be permanently canceled and annulled consistent with the findings herein;

(26) AmerenCILCO should be authorized to place into effect tariff sheets designed to produce annual base rate electric delivery service revenues of

$117,625,000, which represents an increase of $1,416,000 or 1.22%; such revenues, in addition to other tariffed revenues, will provide AmerenCILCO with an opportunity to earn the rate of return set forth in Finding (11) above; based on the record in this proceeding, this return is fair and reasonable for AmerenCILCO;

(27) AmerenCIPS should be authorized to place into effect tariff sheets designed to produce annual base rate electric delivery service revenues of $235,899,000, which represents an increase of $16,611,000 or 7.75%; such revenues, in addition to other tariffed revenues, will provide AmerenCIPS with an opportunity to earn the rate of return set forth in Finding (12) above; based on the record in this proceeding, this return is fair and reasonable for AmerenCIPS;

(28) AmerenIP should be authorized to place into effect tariff sheets designed to produce annual base rate electric delivery service revenues of $450,412,000, which represents an increase of $13,535,000 or 3.1%; such revenues, in addition to other tariffed revenues, will provide AmerenIP with an opportunity to earn the rate of return set forth in Finding (13) above; based on the record in this proceeding, this return is fair and reasonable for AmerenIP;

(29) AmerenCILCO should be authorized to place into effect tariff sheets designed to produce annual base rate gas delivery service revenues of $65,825,000, which represents a decrease of $9,253,000 or 12.32%; such revenues, in addition to other tariffed revenues, will provide AmerenCILCO with an opportunity to earn the rate of return set forth in Finding (14) above; based on the record in this proceeding, this return is fair and reasonable for AmerenCILCO;

(30) AmerenCIPS should be authorized to place into effect tariff sheets designed to produce annual base rate gas delivery service revenues of $70,199,000, which represents a decrease of $2,976,000 or 4.07%; such revenues, in addition to other tariffed revenues, will provide AmerenCIPS with an opportunity to earn the rate of return set forth in Finding (15) above; based on the record in this proceeding, this return is fair and reasonable for AmerenCIPS;

(31) AmerenIP should be authorized to place into effect tariff sheets designed to produce annual base rate gas delivery service revenues of $156,590,000, which represents a decrease of $14,601,000 or 8.53%; such revenues, in addition to other tariffed revenues, will provide AmerenIP with an opportunity to earn the rate of return set forth in Finding (16) above; based on the record in this proceeding, this return is fair and reasonable for AmerenIP;

(32) determinations regarding cost of service, interclass revenue allocations, rate design, and tariff terms and conditions, as are contained in the prefatory portion of this Order, are reasonable for purposes of this proceeding; the tariffs filed by AmerenCILCO, AmerenCIPS, and AmerenIP should incorporate the rates and rate design set forth and referred to herein;

(33) the new tariff sheets authorized to be filed by this Order shall reflect an effective date not less than five working days after the date of filing, with the tariff sheets to be corrected within that time period if necessary, except as is otherwise required by Section 9-201(b) of the Act as amended; and

(34) all motions, petitions, objections, and other matters in this proceeding which remain unresolved should be disposed of consistent with the conclusions herein.

IT IS THEREFORE ORDERED by the Illinois Commerce Commission that the tariff sheets at issue in these dockets and presently in effect for electric delivery service rendered by Central Illinois Light Company d/b/a AmerenCILCO, Central Illinois Public Service Company d/b/a AmerenCIPS, and Illinois Power Company d/b/a AmerenIP are hereby permanently canceled and annulled effective at such time as the new electric delivery service tariff sheets approved herein become effective by virtue of this Order.

IT IS FURTHER ORDERED that the proposed tariffs seeking a general increase in electric delivery service rates, filed by Central Illinois Light Company d/b/a AmerenCILCO, Central Illinois Public Service Company d/b/a AmerenCIPS, and Illinois Power Company d/b/a AmerenIP on June 5, 2009 are permanently canceled and annulled.

IT IS FURTHER ORDERED that the tariff sheets at issue in these dockets and presently in effect for gas delivery service rendered by Central Illinois Light Company d/b/a AmerenCILCO, Central Illinois Public Service Company d/b/a AmerenCIPS, and Illinois Power Company d/b/a AmerenIP are hereby permanently canceled and annulled effective at such time as the new gas delivery service tariff sheets approved herein become effective by virtue of this Order.

IT IS FURTHER ORDERED that the proposed tariffs seeking a general increase in gas delivery service rates, filed by Central Illinois Light Company d/b/a AmerenCILCO, Central Illinois Public Service Company d/b/a AmerenCIPS, and Illinois Power Company d/b/a AmerenIP on June 5, 2009, are permanently canceled and annulled.

IT IS FURTHER ORDERED that Central Illinois Light Company d/b/a AmerenCILCO is authorized to file new tariff sheets with supporting workpapers in accordance with Findings (26), (32), and (33) of this Order, applicable to electric delivery service furnished on and after the effective date of said tariff sheets.

IT IS FURTHER ORDERED that Central Illinois Public Service Company d/b/a AmerenCIPS is authorized to file new tariff sheets with supporting workpapers in accordance with Findings (27), (32), and (33) of this Order, applicable to electric delivery service furnished on and after the effective date of said tariff sheets.

IT IS FURTHER ORDERED that Illinois Power Company d/b/a AmerenIP is authorized to file new tariff sheets with supporting workpapers in accordance with Findings (28), (32), and (33) of this Order, applicable to electric delivery service furnished on and after the effective date of said tariff sheets.

IT IS FURTHER ORDERED that Central Illinois Light Company d/b/a AmerenCILCO is authorized to file new tariff sheets with supporting workpapers in accordance with Findings (29), (32), and (33) of this Order, applicable to gas delivery service furnished on and after the effective date of said tariff sheets.

IT IS FURTHER ORDERED that Central Illinois Public Service Company d/b/a AmerenCIPS is authorized to file new tariff sheets with supporting workpapers in accordance with Findings (30), (32), and (33) of this Order, applicable to gas delivery service furnished on and after the effective date of said tariff sheets.

IT IS FURTHER ORDERED that Illinois Power Company d/b/a AmerenIP is authorized to file new tariff sheets with supporting workpapers in accordance with Findings (31), (32), and (33) of this Order, applicable to gas delivery service furnished on and after the effective date of said tariff sheets.

IT IS FURTHER ORDERED that all motions, petitions, objections, and other matters in this proceeding which remain unresolved are disposed of consistent with the conclusions herein.

IT IS FURTHER ORDERED that subject to the provisions of Section 10-113 of the Act and 83 Ill. Adm. Code 200.880, this Order is final; it is not subject to the Administrative Review Law.

By order of the Commission this 29th day of April, 2010.

(SIGNED) MANUEL FLORES

Acting Chairman