BASIS OF PRESENTATION

Attached are a forecasted consolidated balance sheet and related forecasted consolidated statements of operations, cash flows, retained earnings and comprehensive income for the Ameren Illinois Company d/b/a Ameren Illinois ("AIC" or "the Company"), as of and for the year ending December 31, 2012. This financial forecast has been prepared by the Company and presented in accordance with the guidelines established in the March 1, 2009 AICPA Guide for Prospective Financial Information. The forecasted financial statements were prepared with the understanding that they will be used in connection with the filing for a general rate increase, and that they will be provided to the Illinois Commerce Commission ("ICC" or "Commission") as called for by Title 83, Section 285.7010 of the Illinois Administrative Code. The forecasted financial statements have been presented on a Federal Energy Regulatory Commission ("FERC") basis of accounting.

The forecasted financial statements contained herein present, to the best of management's knowledge and belief at the time this forecast was prepared, the Company's expected financial position, results of operations and cash flows as of and for the year ending December 31, 2012, assuming that current tariffed rates remain in effect through that time. This forecast also reflects management's judgment as of February 1, 2011, the date of preparation of this forecast, of expected conditions and the Company's expected course of action. The assumptions disclosed herein are those that management believes are significant to the forecast. There will be differences between the forecast and actual results because events and circumstances do not occur as expected and those differences may be material, which would cause these forecasted results not to be achieved.

SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

General

AIC is made up of the following historical Ameren subsidiaries:

• Central Illinois Public Service Company ("CIPS") operates a rate−regulated electric and natural gas transmission and distribution business, all in Illinois. Effective October 1, 2010, CIPS changed its name to AIC.

• Central Illinois Light Company ("CILCO") operated a rate−regulated electric and natural gas transmission and distribution business, all in Illinois.

• Illinois Power Company ("IPC") operated a rate−regulated electric and natural gas transmission and distribution business, all in Illinois.

On October 1, 2010, CIPS, CILCO and IPC completed the previously announced corporate reorganization. CILCO and IPC merged with and into CIPS, with CIPS as the surviving entity, pursuant to the terms of the agreement and plan of merger, dated as of April 13, 2010. Upon consummation of the merger, CIPS' name was changed to Ameren Illinois Company, or AIC, and the separate legal existence of CILCO and IPC terminated. The AIC Merger was accounted for as a transaction between entities under common control. In accordance with authoritative accounting guidance, assets and liabilities transferred between entities under common control were accounted for at the historical cost basis of the common parent, Ameren Corporation ("Ameren").

The Company is a wholly-owned subsidiary of Ameren. Ameren, headquartered in St. Louis, Missouri, is a public utility holding company under the Public Utility Holding Company Act of 2005, administered by the FERC. Ameren's primary assets are the common stock of its subsidiaries. Ameren's subsidiaries are separate, independent legal entities with separate businesses, assets and liabilities. Ameren's subsidiaries operate, as the case may be, rate-regulated electric generation, transmission and distribution businesses, rate-regulated natural gas transmission and distribution businesses, and merchant electric generation businesses in Missouri and Illinois.

The accompanying forecasted financial statements have been prepared using the accounting principles that the Company expects to use when preparing its actual 2012 financial statements.

Regulation
The Company is regulated by the ICC and FERC. In accordance with authoritative accounting guidance regarding accounting for the effects of certain types of regulation, the Company defers certain costs as assets pursuant to actions of our rate regulators or the expected ability to recover such costs in rates charged to customers. The Company also defers certain amounts as liabilities pursuant to actions of regulators or the expectation that such amounts will be returned to customers in future rates. Regulatory assets and liabilities are amortized consistent with the period of expected regulatory treatment.

Cash and Cash Equivalents
Cash and cash equivalents include cash on hand and temporary investments purchased with an original maturity of three months or less.

Allowance for Doubtful Accounts Receivable
The allowance for doubtful accounts represents our best estimate of accounts receivable that will ultimately be uncollectible. The allowance is calculated by applying estimated write-off factors to various classes of outstanding receivables, including unbilled revenue. The write-off factors used to estimate uncollectible accounts are based upon consideration of both historical collections experience and management's best estimate of future collections success given the existing and anticipated future collections environment.

Materials and Supplies
Materials and supplies are recorded at the lower of cost or market. Cost is determined using the average-cost method. Materials and supplies are capitalized as inventory when purchased and then expensed or capitalized as plant assets when installed, as appropriate.

Property and Plant
We capitalize the cost of additions to and betterments of units of property and plant. The cost includes labor, material, applicable taxes and overhead. An allowance for funds used during construction, as discussed specifically below, is also capitalized as a cost of our rate-regulated assets. Maintenance expenditures are expensed as incurred. When units of depreciable property are retired, the original costs, less salvage values, are charged to accumulated depreciation. Asset removal costs accrued by our rate-regulated operations that do not constitute legal obligations are classified as a regulatory liability.

Depreciation

Depreciation is provided over the estimated lives of the various classes of depreciable property by applying composite rates on a straight-line basis to the cost basis of such property. The Company's provision for depreciation (combined historical CIPS, CILCO, and IPC) in 2010, 2009, 2008 and 2007 generally ranged from 3% to 4% of the weighted average depreciable cost.

Allowance for Funds Used During Construction ("AFUDC")

In our rate-regulated operations, we capitalize the allowance for funds used during construction, or the cost of borrowed funds and the cost of equity funds (preferred and common stockholders' equity) applicable to rate-regulated construction expenditures, as is the utility industry accounting practice.

Allowance for funds used during construction does not represent a current source of cash funds. This accounting practice offsets the effect on earnings of the cost of financing current construction, and it treats such financing costs in the same manner as construction charges for labor and materials. Under accepted ratemaking practice, cash recovery of allowance for funds used during construction and other construction costs occurs when completed projects are placed in service and reflected in customer rates.

The cost of AFUDC debt and equity included in the forecasted financial statements was 3.39% and 5.26%, respectively.

Goodwill and Intangible Assets

Goodwill represents the excess of the purchase price of an acquisition over the fair value of the net assets acquired. The Company's goodwill relates to Ameren's acquisition of IPC in 2004 and the acquisition of CILCO in 2003. The Company's last annual goodwill impairment test was performed as of October 31, 2010 and did not result in impairment. We do not expect impairment indicators will develop before 2012 and accordingly, no goodwill and intangible asset impairments have been assumed in the forecasted financial statements.

Impairment of Long-lived Assets

We evaluate long-lived assets classified as held and used for impairment when events or changes in circumstances indicate that the carrying value of such assets may not be recoverable. Whether impairment has occurred is determined by comparing the estimated undiscounted cash flows attributable to the assets with the carrying value of the assets. If the carrying value exceeds the undiscounted cash flows, we recognize an impairment charge equal to the carrying value of the assets in excess of estimated fair value. In the period in which we determine an asset meets the held for sale criteria, we record an impairment charge to the extent the book value exceeds its fair value less cost to sell. We do not expect impairment indicators will develop before 2012 and accordingly, no long-lived impairments have been assumed in the forecasted financial statements.

Environmental Costs

Liabilities for environmental costs are recorded on an undiscounted basis when it is probable that a liability has been incurred and the amount of the liability can be reasonably estimated. Environmental liabilities included in the financial statements include all known exposures at the time of preparation. Estimated environmental expenditures are regularly reviewed and updated. Costs are expensed or deferred as a regulatory asset when it is expected that the costs will be recovered from customers in future rates.

Unamortized Debt Discount, Premium, and Expense

Discount, premium, and expense associated with long-term debt are amortized over the lives of the related issues.

Revenue
The Company records operating revenue for electric or natural gas service when it is delivered to customers. We accrue an estimate of electric and natural gas revenues for service rendered but unbilled at the end of each accounting period.

Purchased Gas and Power Rate-adjustment Mechanisms
The Company has various rate-adjustment mechanisms in place that provide for the recovery of purchased natural gas and purchased power costs. In the Company's retail natural gas utility jurisdictions, changes in natural gas costs are generally reflected in billings to their natural gas utility customers through clauses in purchased-gas-adjustment tariffs (‘‘PGAs’’). The difference between actual natural gas costs and costs billed to customers in a given period are deferred and included in Regulatory Assets or Regulatory Liabilities on the Company's balance sheet. The deferred amounts are either billed or refunded to natural gas utility customers in a subsequent period.

In the Company's retail electric utility jurisdictions, changes in purchased power costs are generally reflected in billings to their electric utility customers through pass-through rate-adjustment clauses. The difference between actual purchased power costs and costs billed to customers in a given period are deferred and included in Regulatory Assets or Regulatory Liabilities on the Company's balance sheet. The deferred amounts are either billed or refunded to electric utility customers in a subsequent period.

Accounting for Midwest Independent Transmission System Operator, Inc. (‘‘MISO’’) Transactions
MISO-related purchase and sale transactions are recorded by the Company using settlement information provided by MISO. These purchase and sale transactions are accounted for on a net hourly position. We record net purchases in a single hour in Operating Expenses—Purchased Power and net sales in a single hour in Operating Revenues—Electric in our statement of operations. On occasion, prior period transactions will be resettled outside the routine settlement process because of a change in MISO’s tariff or a material interpretation thereof. In these cases, the Company recognizes expenses associated with resettlements once the resettlement is probable and the resettlement amount can be estimated. AIC recognizes revenues associated with resettlements in accordance with authoritative guidance on revenue recognition.

Excise Taxes
Excise taxes imposed on us are reflected on Illinois natural gas customer bills. They are recorded gross in Operating Revenues and Operating Expenses—Taxes Other Than Income Taxes on the statement of income. Excise taxes reflected on Illinois electric customer bills are imposed on the consumer and are therefore not included in revenues and expenses. They are recorded as tax collections payable and included in Taxes Accrued on the balance sheet.

Income Taxes
We use an asset and liability approach for the financial accounting and reporting of income taxes, in accordance with authoritative accounting guidance. Deferred tax assets and liabilities are recognized for transactions that are treated differently for financial reporting and income tax return purposes. These deferred tax assets and liabilities are calculated based on statutory tax

rates. We recognize that regulators may reduce future revenues for deferred tax liabilities initially recorded at rates in excess of the current statutory rate. Therefore, reductions in the deferred tax liability, which were recorded because of decreases in the statutory rate, were credited to a regulatory liability. A regulatory asset has been established to recognize the probable future recovery in rates of future income taxes resulting principally from the reversal of allowance for funds used during construction, that is, equity and temporary differences related to property and plant acquired before 1976 that were unrecognized temporary differences prior to the adoption of the authoritative accounting provisions for income taxes. Investment tax credits used on tax returns for prior years have been deferred for book purposes; the credits are being amortized over the useful lives of the related investment. Deferred income taxes were recorded on the temporary difference represented by the deferred investment tax credits and a corresponding regulatory liability. This recognizes the expected reduction in rate revenue for future lower income taxes associated with the amortization of the investment tax credits.

The Company and other Ameren subsidiaries are parties to a tax sharing agreement with Ameren that provides for the allocation of consolidated tax liabilities. The tax sharing agreement provides that each party is allocated an amount of tax similar to that which would be owed had the party been separately subject to tax. Any net benefit attributable to the parent is reallocated to other members. That allocation is treated as a contribution of capital to the party receiving the benefit.

Asset Retirement Obligations
Authoritative accounting guidance requires us to record the estimated fair value of legal obligations associated with the retirement of tangible long-lived assets in the period in which the liabilities are incurred and to capitalize a corresponding amount as part of the book value of the related long-lived asset. In subsequent periods, we are required to make adjustments to asset retirement obligations (‘‘AROs’’) based on changes in the estimated fair values of the obligations.

Corresponding increases in asset book values are depreciated over the remaining useful life of the related asset. Uncertainties as to the probability, timing, or amount of cash flows associated with AROs affect our estimates of fair value. CIPS and IPC have recorded AROs for the disposal of certain transformers. Asset removal costs accrued by our rate-regulated operations that do not constitute legal obligations are classified as a regulatory liability. The financial statements do not assume changes to underlying ARO cost estimates during the forecast period.

Derivative Financial Instruments
We account for derivative financial instruments and measure their fair value in accordance with authoritative accounting guidance. The identification and classification of a derivative and the fair value of such derivative must be determined. We determine whether to exclude the fair value of certain derivatives from valuation under the normal purchase and normal sales provisions of authoritative accounting guidance based upon our intent and ability to physically deliver commodities purchased and sold. For derivatives not excluded from valuation, the resulting gains and losses qualify for regulatory deferral and are classified as regulatory assets or liabilities. Fair value of our derivatives are measured in accordance with authoritative accounting guidance, which provides a fair value hierarchy that prioritizes inputs to valuation techniques. We use valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs. When we do not have observable inputs, we use certain assumptions that market participants would use in pricing the asset or liability, including assumptions about risks inherent in the inputs to the valuation. Our valuations also reflect our own assessment of counterparty default risk, using the best internal and external information available.

Benefit Plan Accounting
Based on actuarial calculations, we accrue costs of providing future employee benefits in accordance with authoritative accounting guidance regarding benefit plans. Our ultimate selection of the discount rate, health care trend rate, and expected rate of return on pension and other postretirement benefit plan assets is based on our consistent application of assumption setting methodologies and our review of available historical, current, and projected rates, as applicable.

Accounting Changes and Other Matters
The following is a summary of recently adopted authoritative accounting guidance as well as guidance issued but not yet adopted that could impact the Company. The financial statements incorporate the application of generally accepted accounting principles effective as of the date of the financial statement preparation and those that will become effective during the forecast period. The forecast does not include consideration of accounting standards that could become effective prior to or during 2012, but have not currently been finalized.

Variable-Interest Entities
In June 2009, the FASB issued amended authoritative guidance that significantly changes the consolidation rules for variable-interest entities (‘‘VIEs’’). The guidance requires an enterprise to qualitatively assess the determination of the primary beneficiary of a VIE based on whether the entity (1) has the power to direct matters that most significantly affect the activities of the VIE and (2) has the obligation to absorb losses or the right to receive benefits of the VIE that could potentially be significant to the VIE. Further, the guidance requires an ongoing reconsideration of the primary beneficiary. It also amends the events that trigger a reassessment of whether an entity is a VIE. The adoption of this guidance, effective for us as of January 1, 2010, did not have an impact on our results of operations, financial position, or liquidity.

Disclosures About Fair Value Measurements
In January 2010, the FASB issued amended authoritative guidance regarding fair value measurements. This guidance requires disclosures regarding significant transfers into and out of Level 1 and Level 2 fair value measurements. It also requires information on purchases, sales, issuances, and settlements on a gross basis in the reconciliation of Level 3 fair value measurements. Further, the FASB clarified guidance regarding the level of disaggregation, inputs, and valuation techniques. This guidance was effective for us in the first quarter of 2010, with the exception of guidance applicable to detailed Level 3 reconciliation disclosures, which will be effective for us in the first quarter of 2011. The adoption of this guidance will not have a material impact on our results of operations, financial position, or liquidity because it provides enhanced disclosure requirements only. These disclosures have not been presented in the forecasted financial statements or related footnotes.

SUMMARY OF PRINCIPAL FORECAST ASSUMPTIONS

Electric Revenue
Forecasted electric revenues were primarily determined by applying the Company’s current (November 2010 rehearing order) delivery service rates and rate structure to forecasted deliveries of electricity to customers, plus the cost of power delivered, as well as other miscellaneous charges.

Forecasted deliveries, including changes due to customer growth and conservation, were determined using internally developed models that consider various factors, including historical, trend and regression analysis. The residential sales modeling is done using a statistically adjusted end use model approach which also incorporates economic and market variables. Sales models for the remaining customer classes were determined using econometric models that consider economic and market variables.

Forecasted deliveries assumed the following cooling degree days (CDD) and heating degree days (HDD) on a billing month basis.

Rate Zone 1	CDD = 1,199	HDD = 5,017
Rate Zone 1 - ME	CDD = 1,647	HDD = 4,415
Rate Zone 2	CDD = 1,061	HDD = 5,649
Rate Zone 3	CDD = 1,260	HDD = 4,956

This represents the average of actual weather at a base temperature of 65 degrees Fahrenheit for the 10 year period from 2000-2009.

The customer base forecast has taken into account the recent economic slowdown and its effects on customer usage and payment trends. There are expected load additions from some large commercial and industrial customers, based on assumed customer plant openings, which have been taken into consideration in the forecast.

Based on the above volume assumptions, AIC forecasted deliveries to customers are 38.6 million MWh for 2012.

Revenues not associated with delivery volumes were determined primarily from historical factors or the number of customers. These revenues consist primarily of late fees, pole attachment revenue and other rental revenue.

Wholesale distribution revenues are assumed to increase by $9.4 million annually, to an annualized rate of approximately $19.6 million per year, effective March 2011.

Gas Revenues

Forecasted gas revenues were primarily determined by applying the Company’s current (November 2010 rehearing order) delivery service rates and rate structure to forecasted deliveries of gas to customers, plus the cost of gas delivered, as well as other miscellaneous charges.

Forecasted sales for the residential class, including changes due to customer growth and conservation, were determined using statistically adjusted end use model approach, which considers various factors, including historical data, trend, weather and economic and market variables. Forecasted sales for the remaining revenue classes and forecasted customer counts for all revenue classes except residential class were determined using various economic models.

Forecasted deliveries assumed heating degree days (HDD) on a billing month basis:

Rate Zone 1	HDD = 5,017
Rate Zone 1 – ME	HDD = 4,415
Rate Zone 2	HDD = 5,649
Rate Zone 3	HDD = 4,956

This represents the average of actual weather at a base temperature of 65 degrees Fahrenheit for the 10 year period from 2000 – 2009.

Based on the above volume assumptions, AIC forecasted deliveries to customers on a weather normalized billing month basis are 160.7 million DekaTherms for 2012.

Revenues not associated with delivery volumes were determined primarily from historical factors or the number of customers. Revenues for large customers with special contracts were based on a combination of historical and projected data.

No significant changes to the customer base have been assumed. The forecast has taken into account the recent economic slowdown and its effects on customer usage and payment trends.

Cost of Electricity

The forecasted cost of purchased power for sales to customers includes the cost of energy, capacity costs, market settlements, renewable energy credits, and other miscellaneous charges. The forecast also assumes the cost of purchased power is recovered as incurred and therefore, no over/under recovery is projected.

The cost of energy, capacity and renewable energy credits are generally based on current contracts in place or anticipated to be entered into in the future.

The market settlements and other miscellaneous charges are generally based on a combination of historical and projected data.

Forecasted purchased volumes include an estimate for line losses. This estimate is based on historical experience and is estimated at 5% annually.

The cost of power purchased for sales to customers is passed on directly to customers with no mark-up. Therefore, while a change in the forecast of purchased power costs may have a significant effect on revenue and the cost of power, it would not have a direct impact on the Company’s forecast of income. Indirectly, changes in the cost of purchased power impacts customer deliveries and the forecast of other costs, especially bad debt expense.

Cost of Gas

The forecasted cost of gas purchased for sales to customers includes natural gas commodity costs and non-commodity costs, along with changes in underground storage inventory. The forecast assumes the cost of gas purchased for sales to customers is recovered as incurred, and therefore, no over/under recovery is projected.

Non-commodity costs, primarily pipeline transportation and storage demand charges, were generally based on contractual volumes and rates in place as of August 2010. No material changes are expected in these contracts for the forecast period.

Forecasted commodity costs were based on the product of forecasted purchase volumes and forecasted gas purchase costs.

Forecasted purchase volumes include lost and unaccounted for gas. The forecast includes an unaccounted for gas loss rate of between 0.5% and 1.5% of forecasted retail deliveries, which is consistent with the actual loss rate experienced in recent years.

Forecasted gas purchased costs were determined by utilizing forward market pricing, adjusted for applicable basis differentials and existing hedge positions.

The cost of gas purchased for sales to customers is passed on directly to customers at the Company's actual cost, without any mark-up, through the purchased gas adjustment mechanism. A gas uncollectible charge is applied to recover the uncollectible related to gas supply.

Operations and Maintenance Costs
Forecasted operations and maintenance costs reflect a return to normal expected levels compared to levels experienced in 2009 and 2010, which were subjected to cost reduction strategies due to the economic environment and rate levels. The discussion below summarizes the key assumptions utilized in the determination of operations and maintenance costs in the forecasted financial statements.

Labor: The number of employees is projected to increase by 2% or 69 employees in calendar year 2012, as compared to 2011.

Union employee wage increases were based on existing union contracts which cover the forecast period. The contract stipulates an average 3.25% increase, the majority of which is effective in July of each year.

Non-union wages were forecast to increase 4.0% annually for calendar year 2011 and 2012, over 2010 levels. Non-union wages are primarily effective in April of each year.

Bad Debt: The provision for bad debt, including non-service revenue, was forecast at approximately $38 million per year. The amount projected to be allowed in rates is approximately $31 million per year, with the $7 million per difference accounted for as a regulatory asset, in accordance with the Illinois bad debt tracker.

Other Costs: Operating and maintenance costs are forecast through a detailed bottoms-up budgeting process. Unless specifically determined otherwise, this process assumed, as a default, a 2.0% annual rate of inflation for 2012. For certain supplies including meters, transformers, polyethylene pipe, aluminum, copper and other energy delivery materials, budgeters were provided specific price escalation factors, to be used in the development of project based budgets.

Pension and Post Retirement Expense: Assumptions used to determine net periodic benefit cost for the year ending December 31, 2012 were consistent with those used in the February 2011 actuarial valuation and included the following:

	Pension	OPEB
- Discount rate	5.25%	5.25%
- Expected return on plan assets	8.00%	7.75%
- Rate of compensation increase	3.50%	3.50%
- Initial health care cost trend rate	N/A	6.00%
- Ultimate health care cost rate	N/A	5.00%
- Year ultimate reached	N/A	2013

Qualified pension expenses, prior to any capitalization and excluding the effects of purchase accounting, are forecast to be $30.1 million in 2011 and $31.7 million in 2012. Non-qualified pension expenses are forecast to be $0.6 million per year. Post retirement benefit expenses, prior to any capitalization and excluding the effects of purchase accounting, are forecast to be $17.7 million in 2011 and $11.8 million in 2012. Additionally, a certain percentage of Ameren Services Company ("AMS") pension and post retirement expenses are allocated to AIC.

The Ameren Illinois forecast includes annual cash contributions of $30.1 million in 2011 and $31.7 million in 2012 for pension and $118.9 million in 2011 and $14.8 million in 2012 for OPEB. These amounts will vary based on actual investment performance, changes in interest rates, any pertinent change in government regulations, and other assumption changes.

The effect of changes in actuarial assumptions after February 2011, have not been included in this forecast and could be material.

The table below reflects the sensitivity of the Company's pension and post retirement benefits obligation and expense to changes in key assumptions (in millions).

	Obligation	Expense
- 0.25% decrease in discount rate (Pension)	$101	$0
- 0.25% increase in salary scale (Pension)	$13	$2
- 0.25% decrease in discount rate (OPEB)	$29	$0
- 0.25% increase in salary scale (OPEB)	$0	$0
- 1.00% increase in annual medical trend	$31	$2
- 1.00% decrease in annual medical trend	($29)	($2)

Merger Cost Savings
Merger costs and savings, both capital and O&M, as identified by the merger integration project team and presented to AIC leadership in December 2010, have been included in the forecast. O&M costs in 2011 and 2012 required to achieve the merger savings are treated as regulatory assets in the forecast, with 4 year amortization beginning in 2012. O&M savings as a result of the merger are estimated to be $1.4 million in 2011 and $4.0 million in 2012.

Depreciation
The provision for depreciation and amortization, expressed as an annual percentage of the original cost of depreciable property, was on average 3.2% for calendar year 2012.

Depreciation expense is based on the average estimate life of depreciable property and weighted average depreciation rates, for AIC combined, based on a prior depreciation study previously approved by the Commission in Docket 07-0585 (Cons.). Forecasted depreciation expense also includes dismantling costs, net of salvage, as incurred at the time of the dismantling activity.

Taxes Other than Income Taxes
The Ad Valorem tax forecast is developed based on a review of historical data. The forecast for 2012 property taxes payable in 2013 assumes a 3.0% increase over 2011 levels.

Payroll taxes were estimated based on statutory rates in place as of the forecast date, and applied to estimated applicable earnings,

Income Taxes
Income tax expense was forecast by applying the current federal and state statutory income tax rates of 35% and 9.5%, respectively, to forecasted pre-tax income, tax liabilities and assets, after adjusting for forecasted permanent items. Deferred taxes are calculated within the model for book-tax depreciation differences and other identifiable book-tax differences.

The forecast includes the effects of new legislation regarding bonus depreciation signed into law in December 2010. The new legislation allows for a 100 percent bonus depreciation in 2011 and a 50 percent bonus depreciation in 2012 for qualifying capital additions. Generally, the legislation applies to capital projects placed in service with a useful life of less than 20 years. Additionally, greater than 10 percent of the total cost of the project is required to be incurred in the current year placed in service.

The forecast also includes the effects of new tax legislation enacted by the Illinois legislature and signed into law in January 2011. As a result of the new legislation, the Illinois state corporate income tax rate increased from 7.3% to 9.5%.

Interest Income and Expense
Interest expense includes a) interest on long-term debt, b) amortization of debt issuance costs, c) interest and fees associated with short-term borrowings and lines of credit, and d) interest expense related to customer deposits, budget plan customers, employee deferred compensation balances, and over-collected electric and gas costs.

For fixed rate long-term debt, interest expense was forecast by applying the stated interest rate to the principal amount of each series of currently outstanding first-mortgage bonds.

The cost of short term debt is based on the sum of the Blue Chip Financial Forecast of LIBOR (1.8%) plus the AIC's current spread over LIBOR in their bank facility (2.05). The resulting cost of 3.85% is the cost of short-term debt for the 2012 capital structure.

Long-Term Debt
The forecast includes the maturity of $150 million in long term debt in June 2011. Based on the AIC forecasted cash position, the Company is expected to repay the maturing debt out of available cash.

The forecast includes the issuance of $150 million in long term debt in October 2012. The forecasted interest rate on the new long term debt was determined to be 5.44% based on 10 year treasury rates and AIC credit spread.

Dividends
The Company has forecasted annual dividends paid to Ameren of $326 million and $291 million dollars in 2011 and 2012, respectively. The level of dividend payments is reflective of increased cash availability within the forecast period as a result of changes in certain income tax legislation, discussed previously. These dividends will assist the Ameren parent in covering a portion of the estimated dividends paid to Ameren common shareholders during 2011 and 2012.

Capital Expenditures
Capital expenditures were forecasted as follows for calendar 2012 ($ in millions and including AFUDC):

Electric Distribution system	$228.4
Gas Distribution system	$ 78.5
Electric Transmission system	$156.4
Total Capital	$463.3

The capital expenditure forecast above represents the 2012 budgeted capital plan as approved by the AIC board of directors.

Accounts Receivable, Less Allowance
Accounts receivable balances were forecasted using an average of 29 days of revenue outstanding.

Accounts Payable
Accounts payable were forecasted using an average of 18 days of total spend.

Derivative Instruments
The Company has recorded derivative asset and liabilities in the forecasted financial statements at fair value. The fair value has been determined utilizing internal fair value assumptions at the date of forecast preparation and have not been adjusted to reflect future changes in prices throughout the forecast period.