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SURREBUTTAL TESTIMONY

OF

RICHARD E. GOLDBERG

Submitted On Behalf

Of

AMEREN CORPORATION

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OF

RICHARD E. GOLDBERG

Q. Please state your name, title, and business address.

A. Richard E. Goldberg. I am a Principal of The Brattle Group, an economics consulting firm. My business address is 353 Sacramento Street, Suite 1140, San Francisco, CA 94111.

Q. Have you provided previous testimony in this proceeding?

A. No, I have not.

Q. Do you have prior testimony experience?

A. Yes. I have testified before the Federal Energy Regulatory Commission and in various state regulatory proceedings.

Q. What are your qualifications to provide testimony here today?

A. I co-manage The Brattle Group's consulting practice in Valuation and Risk Management for the energy industry. In this position, my main areas of focus have been risk management, power and gas trading, generation asset management, fuel procurement, and retail service design. I have 15 years of experience performing research for and consulting to energy companies and I have a Ph.D. in Physics from Stanford University. A more complete description of my qualifications can be found in Exhibit REG-1 of this testimony.

Q. What is the purpose of your testimony today?

A. I was asked by Ameren Corporation ("Ameren") to address Staff witness Michael McNally's statement that "[Ameren] has not quantified the effect that each alleged source of credit related savings … would have on the ultimate cost of purchased power or gas" [McNally Rebuttal p.2 lines 25-27] and to address Staff witness Eric Lounsberry's statement that "To the best of [his] knowledge" Ameren has not "attempted to quantify the claimed credit related benefit associated with having more suppliers and ISDA counterparties" [Lounsberry Rebuttal p. 10 lines 207-209]. These witnesses generally are responding to the analyses presented by Ameren witness Craig Nelson and his efforts to quantify credit savings to Illinois Power Company ("Illinois Power") in its purchased power and gas costs as a result of Ameren ownership. My testimony will provide the Illinois Commerce Commission ("Commission") with a quantification of the credit-related savings that Illinois Power can be expected to obtain under Ameren ownership due to Ameren's investment grade credit rating over the electricity and gas purchased costs that would be incurred under continued Dynegy Inc. ("Dynegy") ownership.

I: Overview

Q. How is your testimony organized?

A. I will first review three potential sources of credit related savings in electricity and gas purchased costs that a company can expect to receive from improving its credit rating to investment grade from below investment grade. Then I will address each source of savings in turn and quantify the specific level of savings that Illinois Power can be expected to achieve due to a change in credit rating from its current rating under Dynegy ownership to a rating closer to Ameren's current credit rating.

Q. What are the "alleged source[s] of credit related savings" that Staff witness McNally claims have not been quantified in his rebuttal testimony [McNally Rebuttal p.2 lines 25-27]?

A. Staff witness McNally is referring to credit related savings cited by Ameren witness Nelson in his rebuttal testimony. In that testimony, Mr. Nelson states that Ameren expects that under Dynegy ownership rather than under Ameren ownership, Illinois Power would face "higher commodity prices" due to "concern[s] about Illinois Power's creditworthiness", costly "prepayment/collateral requirements", and higher "power supply and gas costs" due to access to fewer suppliers [Nelson Rebuttal p. 2. line 38 – p. 3 line 50]. I agree with Mr. Nelson's observations.

Q. Are these the sources of credit related savings you will be quantifying in your testimony today?

A. Yes they are.

Q. Will you please explain why concerns about creditworthiness lead to increased electricity and gas purchase costs?

A. Certainly. When a company selling electricity or natural gas makes a sale to a company with a low credit rating, the seller faces two credit related financial risks: Firstly, the seller risks that the purchaser will go into default at a time when the sale contract has significant value. The risk of such default is an additional expected cost to the seller of doing business with a purchaser having a low credit rating that would not be borne by the seller had it instead sold the commodity to a purchaser without credit concerns. Clearly, sellers will need to demand a higher up-front price when dealing with such a counterparty to compensate themselves for this additional "mark-to-market credit cost". Since the risk of default is quite low for investment grade companies, this is an additional cost that typically only would apply to a non-investment grade company.[1]

Secondly, the seller risks that the purchaser will go into default and not make payments for commodity that has already been delivered to the purchaser. Clearly, sellers will demand that purchasers with low credit ratings make arrangements to secure payment for delivered commodity, either through pre-payment or by posting collateral adequate to cover any accounts receivable from the purchaser. These security arrangements are costly to the purchaser and provide an additional "accounts receivable credit cost" to purchasers of electricity and gas with low credit ratings. Again, since the risk of default is quite low for investment grade companies, this is an additional cost that typically only would apply to a non-investment grade company.

In addition to these default-related costs of actual purchases, there is an additional cost that a purchaser with low credit rating faces: A gas or electric purchaser with a credit rating below investment grade will find that numerous potential counterparties are simply unwilling to sell to that purchaser in the first

[1] For example, a recent Standard and Poor's Special Report ["Corporate Defaults in 2003 Recede from Recent Highs", p. 4, (February 2004)] lists a historical default rate over 1 year of only 0.13% averaged over investment grade companies during the period from 1981-2003 while the corresponding default rate is over 30% averaged over companies in the CCC/C rating class – the historical default rate for companies in the CCC/C class is over 200 times greater than for investment grade companies.

place. Many energy companies have credit screens that will not allow their traders to conduct trades with counterparties below investment grade. Limited access to trading counterparties implies that the purchaser will pay a higher commodity price solely due to illiquidity. This "illiquidity credit cost" is a third credit related cost facing companies with low credit ratings.

Q. Why would Illinois Power face greater credit costs under Dynegy ownership than under Ameren ownership?

A. Prior to the press release on February 3, 2004, announcing Ameren's acquisition of Illinois Power, senior unsecured debt issued by Illinova (the Dynegy subsidiary that directly holds its ownership stake in Illinois Power) was rated at CCC+ by Standard & Poor's and at Caa2 by Moody's [S&P Monthly Bond Guide for month ending 1/31/04, p. 111, and Mergent Bond Record, January 2004, p. 118] – in both cases well below investment grade.[2] In contrast, at that time Ameren Corporation was rated at A3 by Moody's [Mergent Bond Record, January 2004, p. 84] – investment grade. Both Standard & Poor's and Moody's compute the average default probability over 1 year to be more than 200 times greater for companies in the range of Illinova's pre-announcement ratings than for investment grade companies [Standard & Poor's, "Corporate Defaults in 2003 Recede from Recent Highs", p. 4 (Feb. 2004), and Moody's "Default and Recovery Rates of Corporate Bond Issuers", Exhibits 20 and 31 (Feb. 2004)]. Hence, under Dynegy ownership Illinois Power will face substantial credit costs while under Ameren ownership Illinois Power is unlikely to face any credit costs.

Q. Would you please summarize your findings as to the additional credit related costs Illinois Power would incur under Dynegy ownership as compared to under Ameren ownership?

A. Using the base case estimate of 2007 electricity and gas purchase costs of $900 Million per year used by Ameren witness Nelson in his Exhibit 3.3, I find that under Dynegy ownership Illinois Power would incur roughly another $46 Million per year in credit related costs leading to total electricity and gas purchase costs of $946 Million. A breakdown of how my $46 Million per year estimate splits into components due to mark-to-market, accounts receivable, and illiquidity credit related costs is shown in Table REG-1 below.

Credit Cost Category	Credit Related Costs Under Dynegy Ownership
Mark-to-Market	$11.0 Million/yr
Accounts Receivable	$15.3 Million/yr
Illiquidity	$20.0 Million/yr
Total	$46.33 Million/yr

Table REG-1: Summary of Illinois Power credit related costs for purchased electricity and gas under Dynegy Ownership

II: Mark-to-Market Costs

Q. How can you quantify mark-to-market credit costs associated with electricity and gas purchases by a non-investment grade company?

A. Mark-to-market credit costs can be quantified by estimating the likelihood of loss on electricity and gas purchase contracts and multiplying that by the expected

[2] In addition, Illinois Power's senior unsecured debt rating was Caa1 according to Moody's prior to the announcement of the transaction [Moody's Rating Action, 2/4/04]. Thus, Illinois Power and Illinova

value that the contract would have for the seller in the case of default.[3] The likelihood of loss for any particular counterparty can be estimated from the company's bond ratings and is equal to the probability of default multiplied by one minus the expected recovery rate.[4] Market forward price and volatility data can be used to calculate the expected value to the seller of the contract under default.[5]

Q. Have you done this calculation for the case of Illinois Power?

A. Yes, I have.

Q. What were your results?

A. I find that sellers of electricity and gas to Illinois Power would face mark-to-market credit costs of $11.0 Million per year more under Dynegy ownership than under Ameren ownership.

To carry out this calculation I made the assumption that Illinois Power would contract for its electricity and gas needs at least one year in advance in the forward markets[6] and used a monthly electricity and gas purchase amount of $75

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were in essentially the same credit position.

[3] This relies on the standard assumption that the default probability is uncorrelated with the commodity price outcome. See J. Hull, "Options, Futures, and Other Derivative Securites" Second Edition, p. 456-458, Prentice Hall, 1993 for further discussion on the appropriateness of making this assumption.

[4] Both Standard & Poor's and Moody's regularly publish statistics on the cumulative probability of default over various time horizons versus company rating. Moody's also includes statistics on the expected recovery rates over various time horizons for senior unsecured debt versus company rating. Estimates of credit losses, therefore, can be presented as the product of historical default probability and loss severity for senior unsecured debt (which is simply one minus the recovery rate for senior unsecured debt) See "Ratings Performance 2003", Standard & Poor's, February 2004, p. 13 and "Default & Recovery Rates of Corporate Bond Issuers", Moody's, January 2004, pp. 15-16.

[5] The value of a forward contract is equal to roughly zero at the time of contracting since the forward price is equal to the (risk neutral) expected value of commodity deliveries. However, the contract is likely to have non-zero value at any later time due to the movement of market forward prices. Volatility data summarizes the range of potential forward price movements and, hence, describes the expected contract value under default.

[6] Note that Ameren witness Nelson states that "Ameren's position" is for "Illinois Power to enter into long-term supply arrangements for a significant portion of its commodity supply" [Nelson Rebuttal p.

Million[7]. I then estimated the mark-to-market credit cost for each month of deliveries one year away as the sum over intervening months of the likelihood of loss times the expected contract value to the seller under purchaser default.

The likelihood of loss is equal to the probability of default multiplied by one minus the recovery rate. For the probability of default I used the Standard & Poor's default probability of 30.85% over the following year for CCC/C rated companies ["Ratings Performance 2003", Standard & Poor's, February 2004, p. 13][8] and for the recovery rate I used Moody's recovery rate of 28.4% over the following year for Caa-Ca rated companies ["Default & Recovery Rates of Corporate Bond Issuers", Moody's, January 2004, p 15]. These values imply a probability of loss equal to 22.1% over the year or 1.84% for each month of the year.

The expected seller loss under default on a contract to deliver one-month's worth of commodity one year forward is the sum of the values of 12 at-the-money European put options on the one year away forward price expiring serially in each intervening month.[9] I used Black's formula[10] to value these put options which

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2 lines 34-36]. Repeating my calculations for longer time horizons led to larger results so the one year time horizon can be considered a conservative assumption.

[7] $75 Million per month represents the $900 Million annual electricity and gas purchase cost estimated for 2007 by Ameren witness Nelson in his base case [Nelson Rebuttal p. 8 lines 168-170] divided by 12.

[8] For comparison, Moody's default probability over 1 year for Caa-C rated companies was equal to 36.84% when averaged over the period from 1994-2003 and equal to 23.49% when averaged over the period from 1983-2003 ["Default & Recovery Rates of Corporate Bond Issuers", Moody's, January 2004, p 26].

[9] The expected value to the seller under default is equal to the expected difference between the forward price when the contract is signed and the forward price at the time of default where the expected value only includes cases where the forward price at the time of default is below the contract price (so that the contract is a net liability to the defaulting purchaser). An at-the-money European put option on the forward price will likewise pay off any positive difference between the forward price at the time the contract is signed and the forward price at expiration so its value is identical to the expected value to the seller under default in that month.

required an estimate of the forward price volatility for each intervening month. I estimated the volatility of the forward price for monthly deliveries one year away during each intervening month of the year by fitting broker quotes[11] for monthly volatilities of Cinergy power using a 2-factor volatility function.[12]

I multiplied the put option value in each intervening month by the probability of loss for that month and summed the results to get the expected default cost associated with monthly deliveries one year away. The result was an expected default cost to the seller of $0.91 Million for each month's deliveries which implies a cost of $11.0 Million per year.

Further details of these calculations are presented in Exhibit REG-2 and my workpapers to this testimony.

Q. Are you aware of any examples where price quotes to non-investment grade companies have reflected a credit adder to forward prices?

A. Yes. In April 2002 Nevada Power Company ("NPC") had its bond rating downgraded following a regulatory disallowance. After that downgrade, NPC's risk manager told me that they had been informed by one of their neighboring utilities that they would be required to pay a $3/MWh credit adder to any forward prices.

Q. Are you aware of other examples where non-investment grade companies have incurred costs related to mark-to-market credit issues?

[10] F. Black, "The Pricing of Commodity Contracts", Journal of Financial Economics, 3 (March 1976) pp. 167-179.

[11] I used the average of bid and ask implied volatilities shown for Cinergy options on the option pricing sheet sent by ICAP on the close of business of July 20, 2004.

[12] See EPRI Technical Brief "Forward Curve Dynamics and Asset Valuation" [EPRI TB-108991, October 1997] for a discussion of this standard 2-factor volatility function.

A. Yes. The State of New Jersey auctions off its retail load in slices to be served by bidders to an auction. In the Master Agreement for fixed price bids ("New Jersey BGS-FP Supplier Master Agreement") there are provisions that require any non-investment grade suppliers to provide collateral to cover their entire mark-to-market exposure on their load obligation. In other words, if a bidder is below investment grade, it needs to post cash or a letter of credit to cover any difference between forward prices at the time the auction is completed (the "mark") and current forward prices:

> "At the time the auction is completed, the MtM credit exposure for each BGS-FP Supplier shall be equal to zero. Subsequently, the differences between the available Forward Market Prices on the valuation date and the "mark" prices for the corresponding Billing Months will be used to calculate the daily exposures for each BGS-FP Supplier. The total MtM credit exposure will be equal to 1.1 times the sum of the MtM credit exposures for each Billing Month."
>
> [New Jersey BGS-FP Supplier Master Agreement, p. 42, Article 6.5]

> "If at any time and from time to time during the term of this Agreement, the Total Exposure Amount exceeds the BGS-FP Supplier's or Guarantor's credit limit, then the Company on any Business Day, may request that BGS-FP Supplier provide cash or letter of credit in an acceptable form … in an amount equal to the Margin (less any Margin posted by the BGS-FP Supplier and held by the Company pursuant to this Agreement or any other agreement(s) between the Company and the BGS-FP Supplier for the provision of BGS Supply).
>
> [New Jersey BGS-FP Supplier Master Agreement, p. 45, Article 6.7]

Such posting of collateral is costly to such companies and represents another example of below investment grade companies incurring substantial cost to alleviate credit concerns about potential default when their obligations are liabilities to them.

<u>III: Accounts Receivable Costs</u>

Q. How can you quantify accounts receivable credit costs for a non-investment grade electricity or gas purchaser?

A. Accounts receivable credit costs can be measured as the incremental cost to the purchaser of arranging for pre-payment of electricity or gas purchases rather than making payment after delivery as is standard commercial practice in electricity and gas markets.

Q. Have you done this calculation for the case of Illinois Power?

A. Yes, I have.

Q. What were your results?

A. I find that Illinois Power would face accounts receivable credit costs of $15.3 Million more per year under Dynegy ownership than under Ameren ownership.

Standard industry practice for electricity and gas purchases requires payment by the 20th of the month following delivery.[13] Prepayment prior to each month's deliveries requires each month's payments to be made roughly 50 days[14] earlier than would otherwise be required. Since the weighted cost of capital represents the average earnings expected from company funds, it is the appropriate opportunity cost to use for computing the cost of tying up funds for prepayment requirements.

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[13] See, for example, the WSPP Master Agreement [WSPP Master p. 20B Articles 9.1-9.2] or the EEI Master Agreement [EEI Master p. 17 Article 6.2]. Natural gas forward contracts typically require payment on either the 20th or 25th of the month following deliveries. (For example, the "Base Contract for the Sale and Purchase of Natural Gas" provided by the North American Energy Standards Board has a default payment date of on the 25th of the month following deliveries.)

[14] The 50 day estimate is based on assuming roughly 30 days per month. In fact, prepayments usually need to take place a few days before the start of the month (and, as noted in the prior footnote, gas contracts often allow payment as late as the 25th of the following month) so 50 days is a conservative estimate of the number of days of lost earnings.

Using a monthly electricity and gas purchase amount of $75 Million[15] and a cost of capital of 12.43% [Nelson Rebuttal p.7 line 159 – p. 8 line 165] leads to an annual accounts receivable cost of roughly $15.3 Million or 1.7% of annual electricity and gas purchase costs.[16]

Q. Have any such accounts receivable costs ever been approved by another regulatory commission?

A. Yes. The Federal Energy Regulatory Commission ("FERC") explicitly ordered that the California ISO pay suppliers a mitigated market clearing price that included an adder of "10 percent to the market clearing price … to reflect credit uncertainty" from "the real risk of non-payment in California" in the days following the bankruptcy proceedings of the California Power Exchange [FERC Order on June 19, 2001 in Docket EL00-95-031 et al., p. 35].

At the time of that FERC order, Moody's was rating the State of California (whose Department of Water and Power was the main power buyer at the time for California load) at a much higher rating than they were rating Illinova at the time of the announcement that Ameren was planning to acquire Illinois Power.[17]

In spite of the higher credit rating given to California, using the FERC's calculation of accounts receivable cost to estimate the savings under Ameren

[15] $75 Million per month represents the $900 Million annual electricity and gas purchase cost estimated for 2007 by Ameren witness Nelson in his base case [Nelson Rebuttal p. 8 lines 168-170] divided by 12.

[16] Each monthly prepayment of roughly $75 Million loses 50 days (roughly 14% of a year) of earnings at 12.43%/yr. This implies a loss of $1.28 Million of earnings for each monthly payment. Over a year this adds up to $15.3 Million which is equal to 1.7% of the $900 Million annual electricity and gas purchase cost.

[17] Just prior to the promulgation of the order (June 19, 2001) Moody's downgraded the rating of the State of California's general obligation bonds to Aa3 [Moody's Rating Update, May 15, 2001].

ownership of Illinois Power would lead to much higher estimated savings than I calculated above. Using FERC's approach (and adjusting down from their 75 day payment lag cited by the FERC in their decision to the 50 day payment lag considered here) leads to an estimate of $60 Million per year in accounts receivable costs.[18] In other words, based on FERC's 10% risk premium used in California, power purchases by Ameren instead of IP would save Illinois customers $60 million in costs related to accounts-receivable risks.

Q. Are you aware whether Illinois Power under Dynegy ownership has prepaid for gas purchases in response to suppliers' demands for adequate credit assurance?

A. Yes. In Docket 04-0476 before this Commission, Illinois Power has provided a a lead-lag study report prepared by Navigant Consulting that states that "IP, on account of its creditworthiness situation, had to pre-pay for the majority of its supplies of natural gas during the test year." [Docket 04-0476, WP-B8a, July 23, 2004, p. 10]. In my experience companies that are below investment grade often need to post collateral (e.g., prepay for supplies) before other parties will transact with them. This statement provides further evidence that Dynegy ownership translates to a prepayment obligation for IP.

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[18] $60 Million = $900 Million * 10% * (50 days/75 days).

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<u>IV: Illiquidity Costs</u>

Q. How can you quantify illiquidity credit costs for a non-investment grade electricity or gas purchaser?

A. To get a rough estimate of the increase in costs a non-investment grade purchaser or electricity or gas would face, one can compare the cost increases seen in electricity and gas markets in going from highly liquid instruments to more illiquid ones. An illiquid instrument is an instrument that has very few parties interested in trading it and so the cost increases associated with illiquid instruments can be used as a surrogate measure of the costs associated with having few counterparties willing to trade with a non-investment grade electricity or gas purchaser.

Power and gas traders regularly find that when they try to purchase or sell a product that is outside of the usual trading products (e.g., other than on-peak, off-peak, or all-hours firm power at a major trading hub for electricity) they face additional illiquidity costs. Examples of this in electricity include the relatively higher costs to purchase super-peak hour electricity versus peak hour contracts (higher, that is, than would be expected based on historical price ratios between super peak and peak hours), the higher costs to purchase option contracts far from "at-the-money", and the lower prices associated with the sale of unit-contingent power than those associated with firm power.

The common understanding of these cost increases is that there are fewer counterparties interested and willing to trade the illiquid instruments as they are less easily hedged. Hence, additional margin is required to entice counterparties to transact. The increase in costs seen in transacting such instruments is likely to be similar to the increase in costs seen by a non-investment grade company whose credit risk is not easily hedged. Hence the scale of margins seen on these types of instruments can serve as a surrogate measure of illiquidity credit costs.

Q. Have you performed an estimate of the level of illiquidity cost Illinois Power is likely to incur under Dynegy ownership?

A. Yes, I have.

Q. What were your results?

A. I find that Illinois Power would face illiquidity credit costs of roughly $20 Million more per year under Dynegy ownership than under Ameren ownership.

To estimate the increase in costs due to illiquidity, I have examined bid-ask spreads for forward electricity sales into Cinergy. The higher the market liquidity the lower the typical bid-ask spreads. I have used daily screen-prints taken from ICE by Ameren staff during the last Rider MVI data collection period and computed average bid-ask spreads by contract during that period. I find that highly liquid near-term months typically have a bid-ask spread of at or below \$1/MWh while more illiquid longer term months reach a bid-ask spread of up to \$3/MWh. In other words, bid-ask spreads increased by about \$2/MWh in going from highly liquid to more illiquid products. If, as is usually assumed, we consider the midpoint price to be the true "market price" then one half of the bid-ask spread would represent the increase in purchase costs due to illiquidity. In other words, about \$1/MWh would be the increase in purchase costs in going from the highly liquid contracts to the more illiquid ones. As the calendar year contracts were priced at roughly \$45/MWh, \$1/MWh represents an illiquidity premium of 2.2%. Applying this premium to \$900 Million in annual electricity and gas purchases leads to an estimated illiquidity cost of roughly \$20 Million per year.

Further details of these calculations are presented in Exhibit REG-3 and my workpapers to this testimony.

Q. Can you provide any evidence that acquisition by Ameren will increase the number of counterparties willing to trade with Illinois Power?

A. Yes. As noted by Staff witness Lounsberry, after Ameren acquired Central Illinois Lighting Company ("CILCO"), CILCO had "more gas suppliers and ISDA counterparties" that would trade with it [Lounsberry Rebuttal, p. 10, lines 198-202].

<u>V: Summary and Conclusions</u>

Q. Can you please summarize your findings?

A. Yes. I have described three sources of additional credit related costs associated with having below investment grade credit ratings. These sources of savings are the same as those previously identified by Ameren. Those costs are: Mark-to-Market costs, Accounts Receivable costs, and Illiquidity costs. Table REG-1 above summarizes my calculations of how much additional credit related costs Illinois Power would incur in their purchase of electricity and gas under Dynegy ownership as opposed to under Ameren ownership. As shown in the table, I find that ownership by Ameren will lead to a decrease in electricity and gas credit related costs of $46 Million each year.

Q. Does this conclude your surrebuttal testimony?

A. Yes, it does.