Q. Please state your name, by whom you are employed and business address.

A. My name is Thomas J. Lord. I am employed by Teknecon Energy Risk Advisors, LLC (TERA). My business address is 1515 South Capital of Texas Highway, Austin, Texas 78746.

Q. What position do you hold with TERA?

A. I hold the position of Partner.

Q. Please describe your experience relevant to this testimony?

A. I have been involved, as a both consultant and employee, in the development and deployment of energy risk management systems. This experience includes direct responsibility for assessing, transacting, and managing speculative energy positions utilizing both physical and financial transactions. It also includes guidance for the creation of “best practice” risk policies, procedures and processes for investor-owned utilities and major consumers of electricity. An additional description of my industry experience and educational qualifications is attached.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to discuss the requisite internal skills necessary for Idaho Power Company (IPC) to assure price risk management capabilities for its customers, potential mitigation of speculative risks for Idaho Power affiliates due to contractual relationships with Idaho Power, and recommended actions to assure Idaho Power receives appropriate value and rewards from its affiliate relationships whenever Idaho Power receives transactional assistance or provides internal demand and supply information.

Q. Please summarize the scope of your testimony.

A. I will testify as to my understanding of Idaho Power’s ability to manage forward hedging of wholesale energy price risks. I will also testify as to my understanding of certain past practices and transactional patterns that have created or may have created value for Idaho Power affiliates without appropriate compensation to the regulated customers. Finally, I will recommend changes that Idaho Power should adopt to both contractual relationships with affiliates and internal practices that will improve business processes and risk/reward allocation between Idaho Power and its affiliates.

Q. IPC testimony (Gale prefiled direct testimony Case No. IPC-E-01-16, pg 4, line 12) indicates that long-term (time periods beyond 30 days in the future) hedging activities may not be performed by IPC in the future. In your opinion, is hedging an appropriate activity for a regulated utility to pursue on behalf of its customers to prudently manage the supply of energy to its customers?

A. Regulated utility customers implicitly depend upon the utility provider to make decisions to manage the cost of energy for their consumption. Wholesale energy market price fluctuations, due to internal supply excesses or shortfalls, make the risk of price changes for energy purchases or sales on behalf of the customers significant to individual customers. While hedging decisions are dependent upon a variety of considerations, the failure to make those decisions implicitly exposes the utility consumer to the equivalent of unmanaged speculation.

My opinion, therefore, is that a utility must possess the capabilities to determine whether the risk exposure of its customers to future price movements is, in the utility's best opinion, acceptable. The complete reliance upon spot pricing for open market transactions is, implicitly, a speculative decision to accept complete exposure to wholesale market price volatility. Only when a regulated utility has responsibly implemented the internal systems necessary to make and execute hedging, or price risk management determinations on behalf of its customers, can it remove this implicit speculative risk.

Q. Why isn’t the power cost adjustment an effective hedge against price movement?

A. A power cost adjustment (“PCA”) mechanism only acts to moderate the rate of change of customer prices by averaging price movements from one year and applying them to the next year’s customer rates. It does not, however, remove the risk of adverse price movements. Over time the PCA guarantees the customer will pay average cost of the market prices. The PCA does not remove customer exposure to systemic adverse price movements that are created by the variable nature of customer energy consumption patterns. Therefore, the PCA is not an effective hedging mechanism.

Q. What is an effective method of reducing customer exposure to price movements?

A. The only method of reducing customer exposure to wholesale price movements is to secure a source of energy which possesses, in some manner, an element of certainty concerning the price of the energy at time of delivery. In contrast, purchasing at “market price” at the time of delivery assures that the energy consumer will be a price taker at the time of purchase. In any wholesale market, a price taker is fully exposed to the ability of suppliers to extract value from the production of the good. In electricity, the wholesale market is perceived as inefficient and subject to the ability of suppliers to extract significant economic value for prompt delivery of energy.

It is possible that price risk management activities may result in higher consumer energy costs than relying on spot price purchases for all wholesale energy needs. However, the risk of unmoderated price movements and subsequent abrupt changes in annual prices may be unacceptable to many or all customers.

Previously, I discussed the implicit speculation accepted by the decision not to implement price risk management decisions. The possibility of resultant higher energy prices is the risk accepted from the reward of a smaller range of potential pricing outcomes that results from hedging activities. It is this reduction in the range of potential outcomes that reduces the risk of the utility consumer.

Therefore, I believe that captive customers should be provided some mechanism by which the customers can opt to be protected from wholesale market price volatility. Price risk management, or hedging, is the logical method of providing that mechanism.

Historically, regulated utility customers have depended upon their service provider and regulators to insulate them from wholesale energy markets, either by making long-term market purchases or by constructing generation assets. In the evolving deregulated wholesale energy markets, the forward energy prices will be the factor that determines the advisability of the “build versus buy” decision. The ability to analyze forward market prices and make the correct “build versus buy” decision is a fundamental component of the capability to provide price risk management services to regulated utility customers.

Q. What types of organizations possess these Price Risk Management skill sets?

A. The speculative activities pursued by Idaho Power affiliates revolve around exactly these skill sets. Speculative transactions that are not based on analysis of forward market prices, the underlying fundamental production costs of the marketplace and a perception of market supply/demand balances, are essentially decisions to place bets without justification for returns. I believe IdaCorp to be a fundamentally well managed organization that would not place its corporate well being at risk for unresearched “gambles.” Therefore, I believe that IdaCorp possesses these skill sets internally.

These skill sets are contained in affiliates of Idaho Power Company. The specific affiliates that I have identified are:

- IDACORP Energy Solutions, LP (“IES”)
- IdaWest

The second component of the skills necessary to provide price risk management services for regulated customers is the ability to calculate exposures to forward market price movements arising from a customer consumption pattern. It is my understanding that the existing computer hardware and software systems and supporting staff skills were transferred from IPC to IES under the IPC-IES services agreement. It is also my understanding that IdaCorp and IES portrayed to Staff and customers at workshops discussing the IPC-IES services agreement that these resources would still be utilized for regulated customer purposes after the transfer. The responses to staff data requests (see Exhibit 107) indicate that IES has implemented a number of “best practice” risk management practices. Therefore, I believe that IdaCorp’s subsidiaries, though possibly not within IPC, have created and possesses the skills necessary for this component of price risk management services.

The third component of price risk management is the creation of fundamentally sound internal policies, procedures and processes for the price risk management decision, market transaction execution and processing functions. I have been unable, at this time, to determine the complete nature of the IdaCorp policies and procedures and processes. However, I believe that the IPC policies, procedures, and processes that have been provided for my review prior to this testimony, are not sufficient to assure that IPC decisions to accept or reject long-term transactions for price risk management purposes – or for any other purpose – are made in a consistent and controlled manner. The lack of policies, procedures, and processes undermines any assertion by IPC that price risk management is or is not advisable for the regulated customers. An absence of these structures will inherently make price risk management less consistent and systematized, which frequently results in an internal perception that hedging activities are riskier than they may possibly be.

Q. What are the implications of the absence of certain “best practice” risk management systems for IPC?

A. This lack of structure also calls into question any prior decisions made by IPC because there is no clear basis for their decision-making. The determination of whether a transaction is advisable depends on three factors: 1) the current prices and implied volatility of prices in the forward market; 2) the net exposure of the risk position to price movements; and 3) the risk tolerance of the entity for which the price risk decision is being made. I acknowledge that there is a wide degree of latitude in what may comprise an acceptable decision based on these factors. I recommend that the Commission grant IdaCorp and IPC a significant amount of future discretion concerning the creation of mechanisms for supporting the price risk management decision.

Q. What structure do you recommend Idaho Power create to establish a clear basis for future decision-making?

A. I recommend that IPC be obligated to create adequate policies, procedures and process documents to show a well-grounded understanding of these price risk management factors. The ability to evaluate alternatives based on these policies and the capability to make well documented and consistent price risk management decisions are critical to facilitating appropriate regulatory prudency review of the Idaho Power’s wholesale energy purchases and sales. Failure to adequately implement policies, procedures, and documentation for risk management decisions will result in continued questions regarding the Company's ability to represent the best interest of its customers. The alternative could be the creation of alternative regulatory or market structures necessary to allow IPC customers the ability to make their own price risk management decisions. If such alternative structures were to be implemented, tariffs would need to be restructured in such a manner as to allow customers to make such decisions external to IPC purchasing practices while retaining the ability to rely upon IPC for the firm supply of energy at market prices. This could include implementing a service structure where customers could receive purely spot market priced energy on a load shaped time of use basis, thereby allowing the customer to access alternate suppliers for risk management products.

The documentation that I would expect IPC to implement in this regard are:

- A clearly stated risk management policy stating the IPC broad objectives for energy risk management (such as reduction in potential volatility of energy prices).

- The delegations of authority and responsibility within the IPC corporate structure to develop and implement risk management structures.
- A clearly stated method for determining the risk tolerance of IPC on behalf of its customers, and the metrics to be used in communicating that tolerance throughout the risk management and senior management organization.
- A clearly stated methodology, including assumptions and recognized areas of uncertainty, for determining the existing exposure to forward wholesale energy market price movements implicit in IPC's consumer sales obligations and generation resources. This methodology should include the ability to reflect exposure to the price risk on an hour-by-hour basis for a determined number of forward delivery months.
- A clearly stated series of procedures and processes for determining and executing hedge strategies and for maintaining and reporting wholesale market transaction

information under that strategy.

Q. What is your understanding of the relationship between IES and Idaho Power?

A. My understanding, prior to the filing of testimony by Idaho Power, was that the Company had transferred its trading and risk management operations to IES under an Electric Supply Management Services Agreement ("Agreement"). In return for that transfer Idaho Power has an obligation to pay IES approximately $4.8 million per year, which is closely equivalent to 100% of the cost of those operations in the most recent rate proceeding for Idaho Power. This transfer between IPC and IES allows IES to participate in the speculative market, and allows the IdaCorp family of companies to retain transactional and risk management skills. Keeping these skill sets within IdaCorp is a benefit to both the Company and the regulated customers.

It is my understanding that the retention of skill sets was a critical component of the rationale for approving the Agreement. I believe that the transfer of transactional and risk management skill sets to IES without retaining access to those skill sets significantly diminishes Idaho Power's ability to function effectively in deregulated wholesale energy markets. Since Idaho Power will be compelled to participate in those markets due to the fluctuations in generating capabilities of hydroelectric generation resources, effective participation in the wholesale energy market will be critical to Idaho Power’s regulated customers.

Q. What is your understanding of the current services provided for Idaho Power by IES?

A. In keeping with the understanding expressed above, IES is participating in the near, medium, and long-term markets at the Idaho Power interconnections to the regional markets. Furthermore, IES is gaining insights into the market behavior, expected direction of price movement, and the implied market volatility expected by the trading community. Speculative trading necessitates a significant investment in risk management infrastructure and skills. I believe it was assumed that IES would make these investments to protect its speculative positions, while educating Idaho Power in the process. Because of the $4.8 million dollar cost paid by Idaho Power to IES, it seems rational Idaho Power should receive constant advice and education from IES. My understanding is that Idaho Power would be able to utilize the IES risk management staff to act on behalf of the regulated customers in fashion similar to what they did while Idaho Power had the information and systems necessary to make prudent decisions on behalf of the regulated customers.

However, from the testimony of witness Gale in the Commission Case No. IPC-E-01-16 (pg 4 line 12) and Case Nos. IPC-E-7/11 Hoyd (pg 14 line 4), it appears that IES may adopt a more restricted view of these responsibilities under the Agreement. The testimony indicates that the support provided by IES may be restricted to the real time and day-ahead management of the Idaho Power physical deliveries of energy, the "assurance that system resources are managed to the benefit of the customers," and the provision of certain limited audit information.

Idaho Power should clearly indicate whether it intends to rely on IES for longer-term price risk management. If my interpretation of the Gale and Andersen testimony is correct, the remaining resources do not appear sufficient for the exercise of prudent actions by Idaho Power within the wholesale power market on behalf of the regulated customers without the skill sets provided by IES.

Q. Do you believe that the current interactions between Idaho Power and IES provide instances where the risks and rewards are shifted between IPC and IES are without appropriate customer compensation?

A. Yes. IES has received certain benefits from the relationship that have, or could have allowed, IES to transact with lower risk and to shift certain transactional costs to Idaho Power and its customers. The specific areas of concern are:

- Prior knowledge of market liquidity
- Credit risks
- Pricing formulae
- Regulatory authorities necessary for IES to participate in the wholesale energy market
- Access to generation optionality

Each of these areas will be discussed separately in the following testimony.

My fundamental premise is that Idaho Power cannot reduce the risks of IES trading activities without transferring a benefit to IES that is unavailable to other market participants, while at the same time reducing the ability of Idaho Power Company customers to achieve the most competitive market pricing for needed resources. Without transaction specific data, any estimation of whether IES executed transactions to implement some of the benefits, and the degree to which IES was successful in profiting from these benefits, would be highly subjective. However, the fact that such activities could take place without adequate customer compensation, is only an element of the consumer cost. As discussed later, an increased open market transaction costs can arise from market perception of inter-affiliate advantage. Other benefits relating to the reduction of internal transaction or operating costs, such as reduction in credit risks, could be determined from the cost of securing such benefits from the open market.

Q. Would it be beneficial for the Idaho Public Utility Commission to create formalized rules for the interaction of IES and Idaho Power?

A. No. Any regulatory action that transfers risk and reward between two entities, be it utility and consumer or utility and affiliate, creates a transaction that can be modeled using financial analysis tools. Companies acting in speculative wholesale energy markets should have resources to examine and disassemble financial components to determine the most profitable actions and extract maximum benefit from the regulatory transaction. Frequently, regulatory Staff do not have the training or resources to perform such analysis.

Therefore, it can be more efficient and effective in certain instances for regulatory agencies to adopt objective-based criteria that sets forth policies, objectives, and goals. The responsibility for the creation of specific procedures and processes to respond to these objectives is most appropriately left to the Company or group of employees responsible for daily management of the targeted activities. The regulatory agency then reviews the specific procedures and processes to assure their compliance with the objectives. It is frequently more tenable for the regulatory agency to perform the necessary review than to be involved in the micromanagement of financial concepts.

I have noted previously certain basic “best practice” risk management structures that should be implemented by IPC. My recommendation is that the Commission develop, preferably in consultation with IPC, the acceptable objective for the IPC risk management policy – reduction of price volatility or the management of prices to a “not to exceed” level, for example – and a complete listing of the types of metrics and reports that are expected to be available to the Commission Staff on an annual basis as the foundation for prudency reviews.

I have also recommended that Idaho Power be given the charge to develop price risk management procedures and processes based on basic policies and objectives. That is to allow IPC's discretion in developing these metrics, in coordination with Commission Staff, to best utilize IPC's existing skill sets. This structure is most likely to create the necessary alignment of responsibility and authority to achieve the Commission's goals.

Q. What is your understanding of the current pricing for transactions between Idaho Power and IES?

A. My understanding is that the pricing of transactions beyond the next delivery day is done at the purchase price. It appears, from Company testimony (IPC-E-01-16, Gale, pg 4- line 15, "all wholesale transaction between Idaho Power and IES will be at market prices" and Gale pg 18 line 2) that no transactions are done directly between Idaho Power and IES for periods beyond next day delivery. IES offers to act as a broker for all such transactions. I have been unable to determine whether IES charges a brokerage fee for arranging such transactions or if such a fee is charged, it is in keeping with normal brokerage fees charged in the industry.

For day ahead and real time pricing, IES uses a “representative” market price based on either Mid-C (the Mid-Columbia wholesale market trading hub in Washington state) or Palo Verde (the California-Nevada border wholesale market trading hub) market prices. The pricing is based on the market prices for those points, not the actual transaction costs of IES for securing or selling the power.

Any difference between the purchase price and the representative market price, or transmission arbitrage obtained or lost by IES, is retained on the speculative book. Pricing differential and transmission arbitrage opportunities are addressed in subsequent portions of my testimony.

Q. What are the trading risks or opportunities that could be experienced by IES in the management of Idaho Power service obligations under the Agreement?

A. The manner in which IES interprets the relationship between Idaho Power and IES significantly constrains the risks under the Agreement while retaining a significant number of the advantages.

In regards to the short term (real-time and day-ahead), Idaho Power represents the largest market participant for firm energy transactions for power at the interconnections of Idaho Power with other regional market participants. IES, by managing the transaction flow, can assure that Idaho Power and IES are not simultaneously attempting to complete transactions in periods of limited liquidity. In addition, if IES perceives that liquidity at certain pricing locations is constrained, then IES may anticipate that IPC purchases will have the impact of moving wholesale market prices in a specific direction.

While this may not impact the pricing at the representative pricing points, it may have a noticeable impact on the Idaho border prices. If IES believes its actions on behalf of Idaho Power could shift the local prices noticeably from the representative prices, IES has the opportunity to create lower risk returns.

For example, if IES determines that IPC will require an additional 500 MW per hour of on-peak power three days in the future in a market where the maximum size of on-peak energy trading over the last week was 150 MW per hour, then IES may anticipate that prices could move higher. By purchasing block power for future periods in anticipation of this demand, IES may be able to position itself to capture returns due to increased market knowledge. This practice has occurred frequently enough in commodity markets to develop a name “front running” and to necessitate Commodity Futures Trading Commission regulations to prohibit this behavior by commodity brokers.

With regard to the long-term markets, IES again has knowledge prior to all other market participants of upcoming Idaho Power market activity. Information given to me indicates that IES is provided and has participated in load forecasting and other activities that define the energy purchasing and sales exposure of Idaho Power. In addition, the audit requests submitted and responded to in this proceeding indicate that IES operates whatever risk position tracking software is utilized by Idaho Power to manage its wholesale market position. I am concerned about the existence, or lack thereof, of software security or firewalls to segregate Idaho Power information from IES.

Without these firewalls, IES has access to Idaho Power’s intended market activities and consequently has an advantage that no other participants in the Idaho wholesale power market possess – the understanding of when IES’s speculative position would be in conflict with future actions that Idaho Power would be expected to assume in the market. For example, a speculator in wholesale power would understand that Idaho Power may at times buy and other times sell. This participant must be concerned that any speculative position would be impacted by Idaho Power activities. If a speculator purchased power for June, only to have Idaho Power soon thereafter determine it had excess power for the upcoming June and therefore need to sell power for that period, the likely result would be that the speculative position would lose money without other market actions.

Therefore, knowledge of risk exposure and transaction decisions of Idaho Power prior to other market participants reduces IES's speculative risks in the Idaho region. However, Idaho Power customers receive no benefits from the risk reduction experienced by IES.

Q. Do you believe that hedging activity by IPC could reduce the benefit to IES of access to IPC risk positions?

A. Yes. Actions by IPC to reduce its wholesale market price risk are, by their nature, intended to reduce IPC's need to transact in the sport market. This reduction should, in aggregate, reduce IPC's competition for short-term market liquidity. Energy commodity markets generally experience their highest volatility, and therefore most rapid price changes, in the delivery month. Prior hedging of risk, by reducing

IPC’s delivery month activities, could reduce IES’s knowledge advantage in the marketplace.

Q. If Idaho Power Company’s purchasing practices changed from entering into transactions for time periods beyond thirty days to a practice of entering into transactions for periods of less than thirty days, do you believe it would create opportunities for IES to benefit from lower risk transactions?

A. Yes, I do believe this could create speculative opportunities for IES at lower risk than that of other speculative market participants. As discussed above, knowledge of the activities of organizations with significant market positions allows lower risk trading. Any potential change to increase IPC’s exposure to delivery month prices increases IES’s knowledge advantage during the period of time when that advantage has the potential to create greatest leverage.

Q. How would this occur?

A. In this case IES would receive, through its assistance in load forecasting to Idaho Power, knowledge of Idaho Power’s need to purchase or sell energy in the wholesale market for forward periods for high, normal, and low water flow scenarios as well as high, normal, and low demand scenarios. With this information, IES has a forecast of the likelihood that Idaho Power will have purchasing or sales transactions during a delivery month. IES can assess the likely market liquidity during that period, estimate the Idaho Power impact on market liquidity during that period, and make appropriate speculative transactions to take advantage of the likely market price direction during that period.

This is not to imply that IES, by the nature of this information, is guaranteed profitable trading activities. Abnormal and abrupt conditions can occur, plant outages may take place, and market pressures from interconnected markets –such as California – may overwhelm the market balance of the Idaho region. I am not implying that IES is gaining perfect market knowledge. However, IES is gaining better market knowledge than other participants in the region. This knowledge reduces the risks of speculative activities. It does not appear that the Idaho Power regulated customers have been compensated for that risk reduction in any manner.

Without access to all transactions by IES and IPC, information as to whether IES was securing speculative positions to have risk exposures in opposition to IPC, cannot be determined. Without specific transaction level information for both the operational and non-operational books as to what the price movements were from the IES transaction date until the delivery date, I can not estimate the magnitude of IES potential gains from this knowledge. However, it is simple to note that a $10/MWhr movement for a 100 MW exposure for any given week is $80,000 ($10/MWH *100MW * 80 on-peak hours). The price movements experienced during the later portion of the PCA year under review in this proceeding were, at times, orders of magnitude greater. I believe that this is ample evidence that opportunities did exist for IES to make substantial profits from the prior knowledge of Idaho Power purchasing requirements.

Q. What additional benefits do you believe IdaCorp and its affiliates received from Idaho Power during last years PCA?

A. IES received its FERC power marketing license on April 27, 2001. Prior to that time, IES was not legally authorized to trade wholesale power. IPC responses to staff data request (see Exhibit 107) indicate that all transactions on IES's behalf were actually entered into by Idaho Power. This implies that all counterparty credit risk for IES speculative transactions was actually assumed by Idaho Power. The open market cost of such credit enhancement is normally between 1-2% of the notional amount, i.e., the total value of the transaction as determined by multiplying all volumes for the life of the agreement by the current pricing under the agreement. This is a cost of doing business that IES avoided by receiving free credit enhancement by the regulated customers.

In addition, IES was allowed to enter the market months earlier than it could have otherwise, giving IES access to the market volatility of the west during 2000/2001. Prior to receiving its power marketer certificate authority from the Federal Energy Regulatory Commission, it was unlawful for IES to enter into wholesale energy market transactions as a principal. Without Idaho Power standing behind all IES transactions, IES would not have received any profits prior to April 2001. In addition, IES was also allowed to build name recognition in the market place months earlier and will likely be considered part of Idaho Power for several months into the future, extending its credit advantage.

Q. Do you believe there are opportunities for IES to obtain minimal or risk-free profits under the IPC-IES pricing methodology?

A. Yes, opportunities could exist under the

Agreement. In the area of real-time and day-ahead power purchases for Idaho Power by IES, a strong possibility exists for transmission arbitrage under the contract pricing. Arbitrage is an instance where a discrepancy between two different pricing points exists such that a transaction can be entered into to capture the difference as a profit without risk.

My understanding is that transmission services are transferred to IES at cost. In addition, power purchased at the Idaho border for Idaho Power by IES is transferred based on the representative market locations - not the border price. Since the transportation price is known, it is possible for IES to determine whether Idaho border prices are less than the representative market price plus transmission. If there is a differential, IES collects that differential as a profit. This profit is risk-free and is not shared with the customers.

For example, if for the next day deliveries of energy the Mid-C wholesale energy market is transacting at a value of $100/MWhr and the price of wholesale energy at the Idaho border with Washington State is $98/MWhr, an arbitrage opportunity would exist under the pricing formula. As currently utilized, the formula would price energy at the border at a price equal to the Mid-C price plus approximately $1.25/MWHr of transmission costs – or $101.25/MWhr. Purchasing energy delivered at the border could occur at a cost of $98/MWhr without requiring any purchase at Mid-C. The difference between the price under the formula - $101.25/MWhr – and the market price - $98/MWhr – would be retained by IES and would have required no risk by IES on the transaction.

Another area of potential rewards to IES that is not solely dependant upon the contract pricing mechanism is the creation of speculative positions in anticipation of Idaho Power open market transactions. If IES, through its participation in load forecasting and management of Idaho Power's risk position information, has knowledge that Idaho Power will have the need for significant day-ahead and real-time purchases, IES can enter into speculative transactions that reflect Idaho Power's future needs. For example, if IES has knowledge that Idaho Power will require significant energy purchases for on-peak periods during the next week, IES can take speculative positions to purchase power during that delivery period prior to the execution of the power purchase for Idaho Power. While it is possible that weather or other conditions will remove that need, IES actions will be made with knowledge:

- of the projected buying or sales needs of the largest firm energy market participant at the interconnections of Idaho Power with other regional market participants,
- that IES will know before any other market participant if those needs shift,
- that IES will view all market transaction structures of Idaho Power, and
- that if IES sells power to Idaho Power at values above the IES purchase price, IES will receive a benefit.

Q. Can there be additional costs to Idaho Power customers from the IES relationship?

A. Yes. If the other market participants that might transact with Idaho Power perceive that Idaho Power, either explicitly or implicitly, favors IES in its transactions, then there is a significant risk that these market participants may decide to withdraw from the business of providing energy to Idaho Power. Another central premise of deregulated markets is that an open and freely contested market is necessary for efficient market pricing. If the Idaho Power-IES relationship reduces the willingness of third parties to participate actively in the wholesale market for energy at the border of the IPC system, inefficient pricing may occur. This inefficiency may occur during any time period – real-time to multi-year forward periods – that the market lacks an adequate number of participants. These inefficiencies reduce market liquidity and increase prices. Since Idaho Power's regulated customers are paying market prices, they will pay more as a result of decreased liquidity.

Several of my recommendations have dealt with the access to internal Idaho Power data by IES prior to other market participants. While the major reason for my recommendations have been to reduce IES's ability to decrease its own risk on speculative transactions in relation to other market participants, the potential reduction in market liquidity and the negative impact on Idaho Power customers if the market loses participants should not be ignored.

Q. Are there additional possible benefits that IES may receive from its relationship that current audit information may be unable to identify?

A. I believe there are additional risk reducing or risk transferring transactions that would be impossible to identify without access to all trading information for IdaCorp and its affiliates. I am not stating such transactions have or have not occurred, only that information necessary to make a determination is not available at this time.

The transaction types referred to above relate to the nature of generation assets as a real option transaction. Generation facilities, in financial engineering terms, constitute a series of options that can be exercised on an hourly, daily, weekly, or monthly basis. Since the generation owner has the right but not the obligation to utilize the generation asset, in financial engineering terms this would be considered owning the option of being “long”.

The owner of an option has the ability, using financial formulae such as the Black-Scholes option model, to determine the efficient hedge ratio for sales of production against the option to produce output. Financial theory can illustrate that the constant readjustment of this efficient hedging ratio has the effect of allowing risk-free monitization of the production optionality. The only residual risk is that market price movement, or volatility, will not occur and the cost of acquiring the option, the fixed carrying costs of the asset, will not be recovered.

However, in the case of Idaho Power and IES, the fixed carrying costs of the generation assets are recovered through regulated rates. If, and I stress that to my knowledge the information necessary to perform the analysis has not been made available to either myself or IPUC Staff, IES were to transact knowing that Idaho Power generation assets would have excess power to sell in the future, it could be possible for IES to utilize those assets to form the basis for this type of transaction. This type of trading would serve to reduce the risk of IES while providing potentially profitable trading activities.

Q. What might be the appropriate relationship between IES and Idaho Power?

A. I believe that the definition of appropriate or inappropriate relationships depends upon the alignment of economic interests between Idaho Power and IES. For example, I believe that IES possesses significant market knowledge that would be very beneficial to the regulated customers if they can access it in a nondiscriminatory manner.

One way to assure that Idaho Power regulated customers receive that benefit would be for IES and Idaho Power to adopt a corporate policy that, within the acceptable risk tolerance for regulated customers, IES and Idaho Power would always share congruent market views in the region. For example, if IES believes that it is in its best interest to own speculative positions in power for the next June, Idaho Power would assure that it has minimized, to the extent feasible, its exposure to upward price movements for the same period. In this manner, Idaho Power would receive the benefit of IES's market knowledge and counsel on appropriate prudent risk management decisions.

In addition, a mechanism for assuring an allocation of transactions entered into during periods of inadequate liquidity could be created. For example, if IPC has requested IES to broker a wholesale transaction to buy energy for a period in which IES is also attempting to purchase energy, an allocation of percentages of requested volumes might be made in instances where total desired volumes cannot be contracted for at the requested prices. In this manner, IPC customers could be assured that IES does not gain an advantage by preferring its own transaction needs over those of the customers.

Q. What alternative measure could be required if their practices are not adopted?

A. I believe that a failure to adopt "best practice" risk management systems by IPC and a failure to structure the interrelationship between IPC and its affiliates may necessitate Commission action to assure customer protection. As noted previously, those actions could encompass imposition of innovative tariff structures. Other potential actions to assure customer protection could include a complete severance of all transactional and informational ties between IPC and any affiliates, a requirement for transfer of all risk management and execution actions to a third party supplier, or the resumption of forced customer access to the profits obtained by IPC affiliates in the wholesale market. I believe that some or all of these measures may be counterproductive to the long term interests of both Idacorp and its regulated customers. However, a failure to appropriate and effectively manage IPC's price risk and its affiliate relationships would be adequate justification for Commission exploration of alternative measures to protect the regulated customer's interests.

Q.   Staff has recommended that IES be compensated at the lower of IES's actual cost of purchasing power for consumption or the market price of energy at the "representative price" under the IPC-IES agreement at time of consumption for purchases for Idaho Power regulated customers. Staff has also recommended that

Idaho Power be compensated at the higher of IES’s actual cost of revenues for sale or the market price of energy at the time of delivery of sales of power by Idaho Power. Do you agree with these recommendations?

A. Yes, the IPUC Staff has identified one of the potential flaws in transfer pricing mechanisms – the ability to create risk arbitrage between two locations. Under the current pricing system, IES has the opportunity to determine whether power purchased at the IPC interconnections with other transmission systems is priced at a different value than that represented under the IPC-IES contract price of Mid-C market price plus the tariff costs of transmission to the IPC system from that point.

If the cost of wholesale power at the IPC border is less than the IPC-IES reference price for real-time or day-ahead power, the difference is retained by IES. However, IES has taken no risk to obtain that value. Rather, that value is implicit in the IPC customer load and physical assets. Prior to implementation of the pricing structure of this Agreement, risk-free trades were passed on to the ratepayers for their benefit. As such, I agree with Staff that the existing pricing structure under the IPC-IES contract should be modified to assure that the risk-free arbitrage is captured as a customer benefit.

I believe that transfer-pricing mechanisms, in general, are a flawed business structure. Because open market prices are dynamic and a transfer-pricing mechanism requires a more static viewpoint, potential arbitrage of the transfer price for one party’s benefit will always occur. In organizational structures where inter-departmental cost flows have no overall impact on shareholder value, these inefficiencies may not be fatal. However, in this instance, where inefficiencies may either lead to regulated customer subsidization of non-regulated profits or to non-regulated activities supporting regulated customer costs, the use of transfer pricing becomes problematic.

The Staff position recognizes the fundamental concern of transfer pricing between two organizations with differing economic incentives by allocating all risks to one entity and all potential reward to another. While the Staff position clarifies the situation, it is not a sustainable relationship because there would be no economic benefit to IES.

I recommend one of two solutions to this problem: either IES must create an internal resource set that trades the Idaho Power real-time and day-ahead obligations without communication with the IES speculative trading activities or Idaho Power should determine whether outsource real-time and day-ahead transaction and risk management could be obtained for less than the $4.8 million dollar per year cost charged by IES. In the first case the result would be very similar to the relationship in place prior to implementation of the Agreement, with IES maintaining a regulated and non-regulated trading group. In the second case, the information flow would cease to the speculative group.

Since Idaho Power audit request response (see Exhibit 107) indicates that no long-term hedging is undertaken by IES on IPC's behalf except at the RMC's direction, either change would only need to impact the real-time and day-ahead trading.

In addition, since IES and other affiliates of Idaho Power are speculative market competitors with Idaho Power for market liquidity, I recommend that, in the interest of assuring equitable market rules, the Commission consider ordering:

1. Any IES Staff in contact with Idaho Power risk management position reports, load forecasting and risk decision analytics be precluded from discussing such information with any person who is

engaged in or who has contact with persons engaged in IES speculative activities; and

2. All Idaho Power risk position, load forecasting and risk decision analytics information be maintained in a secure information system to which IES Staff members can gain access only by specific written permission from Idaho Power Staff ; and

3. No Idaho Power Staff engaged in supporting or making risk management decisions be allowed to hold a position of financial responsibility in IES;

4. Idaho Power must act to obtain market pricing information, market liquidity information and to execute trades for risk management purposes while treating IES as a third-party competitor; and

5. All conversations between Idaho Power risk management Staff and IES Staff must occur on telephone lines possessing recording capabilities and all tapes must be maintained until after the final determination of a Power Cost Adjustment

or similar cost recovery proceeding for the period of time pertaining to the conversations has been entered and is no longer subject to appeal; and

6. No members of the Ida-West or other IdaCorp purely merchant subsidiaries be allowed access to any IPC customer, market forecast, load forecast or risk management information.

The first five conditions should be met for as long as the IES-Idaho Power contract is in effect. The sixth condition should be a prerequisite for any IdaCorp merchant activities that are not in whole or part designed to provide services for the IPC regulated customers under Commission regulation.

Q. You have recommended that Idaho Power be required to develop price risk management policies, procedures and processes for submission to the Commission. Why is it more appropriate for Idaho Power to develop these procedures than it would be for the Commission?

A. TERA has been involved in many engagements devoted to assisting investor owned utilities, municipal utilities and energy consumers in developing price risk management policies, procedures and processes. While there is significant literature describing industry “best practices” in this area, the reality is that no single “off the shelf” control framework is correct for any entity. The best practice for any organization differs depending on internal Staff skills; the ability to implement and utilize complex software systems and the cost versus benefits of said systems for specific applications; the wholesale power market that is being accessed; the liquidity, variety and sophistication of trading products available in that market; and the desire of the organization to utilize personnel or computer resources to provide certain data flow management and security functions. This matrix of varying abilities, needs and resource allocation decisions can not be managed externally, as would be the case if the IPUC imposed price risk management policies, procedures and processes upon Idaho Power. Therefore, I believe that the only organization that can appropriately determine Idaho Power’s best practice price risk management policies, procedures and processes is Idaho Power.

However, it is possible for an external party to review an organization’s policies, procedures and processes to perform a “gap” analysis to assure that adequate safeguards are in place. I do believe that it is appropriate for the Commission to request that the price risk management policies, procedures and processes of Idaho Power be submitted for review and comment. In this manner, the regulated customers are assured that the entity responsible for oversight of Idaho Power actions on their behalf has agreed that Idaho Power has implemented the appropriate controls, allocated adequate resources and will provide the information necessary for legislated regulatory oversight.

I believe that Idaho Power should be offered significant latitude and discretion in the drafting and implementation of price risk management systems. The Company is best positioned to know its strengths and weaknesses. Development and review of the price risk management system should be a collaborative, rather than confrontational, process. However, certain fundamental issues need to be addressed to assure that the Idaho Power implementation decisions reflect the understandings reached by Idaho Power, IPUC Staff and Idaho Power customers during the refinement of the Idaho Power – IES contract. These issues include:

- differentiation of IES and Idaho Power data,
- protection of Idaho Power customers from

IES arbitrage opportunities,

- consistency of Idaho Power analysis and actions, and
- access of Idaho Power to IES skill sets

My opinion is that, in this manner, the fair and equitable guidelines for prudent price risk management actions by Idaho Power can be achieved. Furthermore, that subsequent PCA discussions can be based upon responses to Idaho Power internal management systems rather than concern over fundamental questions concerning the relationship between Idaho Power and its affiliates.

Q. Does this conclude your testimony?

A. Yes