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May 20, 1996

The Arizona Corporation Commission
1200 West Washington
Phoenix, Arizona 85007

Re: Docket Number U-0000-~~95~~ 94-165

Dear Commissioners:

Power Resource Managers, L.L.C. (PRM) is pleased to submit its reply to the Commission's questions dealing with the restructuring of the electric services industry in Arizona.

In its reply, PRM argues that retail competition can be introduced into Arizona on a very quick time frame, requiring only the unbundling of electric rates and the establishment of a power pool that posts the hourly purchase price of energy. This will result in an immediate downward pressure on electric rates. Other questions, such as the level of stranded investment recovery, or the ultimate market structure, can be deferred to a later date.

Electric retail services competition, in many ways, is already in Arizona. The creation of WEPEx in California allows Arizona customers an opportunity to begin retail wheeling, although in a limited fashion, on the same time frame as California retail customers. That is, there is no reason that an Arizona customer could not enter into a bilateral arrangement using financial instruments with a supplier that sold power into the California market. The transaction is not as clean as the California market, because of the lack of unbundled rates in Arizona, but competition is possible and will probably occur.

PRM believes that competition will result in a more efficient electric services industry in Arizona, with the state's ratepayers benefitting from lower energy rates.

PRM is willing to answer specific questions that the Commission may have in the future and we look forward to working with you as you embark upon this exciting and complicated investigation.

Respectfully,

David X. Kolk

David X. Kolk, Ph.D.

APPROVED: POWER RESOURCE MANAGERS, L.L.C.

Robert A. Montano

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Power Resource Managers, L.L.C.

Response to the Arizona Corporation Commission on Electric Industry Restructuring

Power Resource Managers, L.L.C. (PRM) is pleased to respond to the Arizona Corporate Commissions questions on Electric Industry Restructuring. PRM is a participant in the restructuring proceedings across the nation, including Arizona, New Mexico, California, New Hampshire, Vermont, Pennsylvania, Virginia and other states. PRM staff have testified before a number of state regulatory commissions. PRM is well qualified to provide testimony and comments on restructuring the Arizona electric services industry.

PRM favors introducing competition into the electric utility sector as quickly as possible.
PRM would like to make the following points in its initial response to the Commission:

THE DIFFERENT MODELS

There are currently three major models under discussion nationwide. These are:

The Bilateral Contracts Model
The POOLCO Model
The Pooling Model with Bilateral Contracts

In addition, there are several less known models, of which the *Community Access Model*, proposed by Towards Utility Rate Normalization, is perhaps the best known.

The Bilateral Contract Model

This model was originally proposed by Pacific Gas and Electric and Enron in the California proceedings. In this model, suppliers and customers contract with each other for capacity. In the bilateral contract model customers are responsible for negotiating contracts with the supplier of their choice. The system operator would provide some ancillary services, unless the customer choose to purchase them from some alternative supplier.

The customer is responsible for contracting with generation sources to meet his load at all times, or purchase energy from the system operator to serve load not met through bilateral contracts at the system operators cost, usually a high cost.

The system operator essentially acts as a facilitator, insuring contracted resources are dispatched to meet load, and with responsibility for insuring sufficient generation exists to meet all requirements. The system operator is also responsible for insuring non-discriminatory transmission access for all market participants.

A key point to recognize is that the system operator is not concerned about scheduling and dispatching in an economic order. Every generator notifies the system operator that it has load to meet and the operator attempts to accommodate the generators. Thus, a low-cost provider, without a bilateral contract, may not be dispatched, while high-cost producers that have secured bilateral contracts, will be dispatched to meet their contracted loads.

The Poolco Model

The Poolco model is an extension of the tight, or exclusive, power pools that exist in the eastern US and is similar to the industry structure that was put into place in the United Kingdom when the British government privatized the English electric system. Over time, this model has changed significantly, although there is still confusion between the Poolco model and the Pooling Model with Bilateral Contracts.

In the Poolco model, a tight or exclusive pool purchases all power from the region's generation facilities and then sells the energy to a local distribution company for resale to retail customers.

Each generator submits an hourly bid, identifying the amount of energy, the price and the delivery point. A system operator is responsible for the operation of the pool which then determines which resources are dispatched. The system operator is responsible for meeting load and maintaining reliability of supply. Load is met by scheduling resources in a least cost manner. The model uses a second-price, or Dutch auction to determine how much each successful bidder is paid for energy, that pays each bidder the price of the last resource dispatched by the pool operator, regardless of their bid price.

Many people have questioned the use of a second-price auction where all suppliers receive the same price, regardless of their bid costs. However, this is exactly how any competitive market works, with supply and demand working together to create a market clearing price that rewards the most efficient suppliers with the greatest level of profits, while just allowing the least efficient producers to remain in business until a new, more efficient supplier decides to enter the market, driving down costs and forcing the least efficient producer out of business.

Each retail purchaser takes delivery of energy through the pool and through the existing *local distribution company* (sometimes referred to as a local distribution utility), or LDC, exactly as customers currently do. The purchaser pays the distribution entity for energy at the pool price and then "trues-up" costs with their bilateral contracts supplier to realize final energy costs equal to the bilateral contract price. Because the cost that each customer pays the distribution entity is that of the highest price resource dispatched each hour, customers will be encouraged, through pricing, to enter into financial contracts with suppliers, such as contracts for differences. Customers that choose not to enter into financial contracts will pay the highest price.

The pool operator is responsible for establishing bidding procedures, taking hourly (or half-hourly) bids, determining which generation resources are scheduled each hour, insuring all ancillary services, such as automatic generation control, spinning reserves, etc., are satisfied and maintaining the reliability of the electricity system. The pool operator is responsible for acquiring necessary transmission. The pool operator is also responsible for billing all distribution systems for energy and paying all suppliers.

The system operator in the bilateral contracts models has a much smaller role than the pool operator in the POOLCO model. In the bilateral contracts model the system operator is only responsible for insuring any pooling imbalances are met and system reliability maintained, but does not participate in the actual decision of which resources are dispatched each hour.

In the bilateral model, as long as generation and load are perfectly balanced, there is no need for the pool operator, or system operator, to become involved in the transaction. However, because it is unlikely that all generators will exactly meet load on a real time basis, the pool operator is able to either buy or sell energy from suppliers to balance generation and load. A customer whose supplier fails to meet his commitments will either purchase power from the pool, at a high cost, arrange for backup supplies, or have his electricity supplies cut (this is obviously unlikely - more likely is that he will purchase power from the pool at the highest cost)..

A key difference between the POOLCO model and the bilateral contracts model is who faces the market risk. In the Poolco market, risk tends to be pushed to the supplier. A customer receives the benefits of his supply choice regardless of supplier performance. In the bilateral contracts model, the risk tends to be transferred to the customer, forcing him to mitigate risk through power contracts. The Poolco model also tends to have lower transactions cost for the consumer, since reliability, load-following and other ancillary services tend to be supplied by the pool at a cost less than any individual customer could realize.

All retail customers pay the hourly system incremental price, plus some fee for ancillary services. Retail customers also pay for use of the distribution and transmission systems

The Poolco model allows (indeed encourages) customers to enter into various forms of *financial settlement mechanisms*, or FSM's, the most common likely to be a *Contract for Differences*, or CFD. Under a CFD, the customer agrees to pay its CFD partner a set price for electricity, as an example, 2.0 cents per kWh. Once the contract is in place, the customer knows that the highest price he will pay is 2.0 cents for energy. All energy will continue to be delivered to the customer by the LDC. Retail customers will still receive a bill from the LDC that includes an energy price, in addition to all the other charges associated with the delivery of energy. The energy charge will be the total of the hourly amount of energy that he used at each hours cost. Each month the customer will compare the price that he paid the LDC for energy with his CFD. If the difference is positive, his supplier will rebate him for the difference. If energy prices was less than the CFD price, the customer owes his supplier the difference.

Figure 1 shows how CFD's work.:

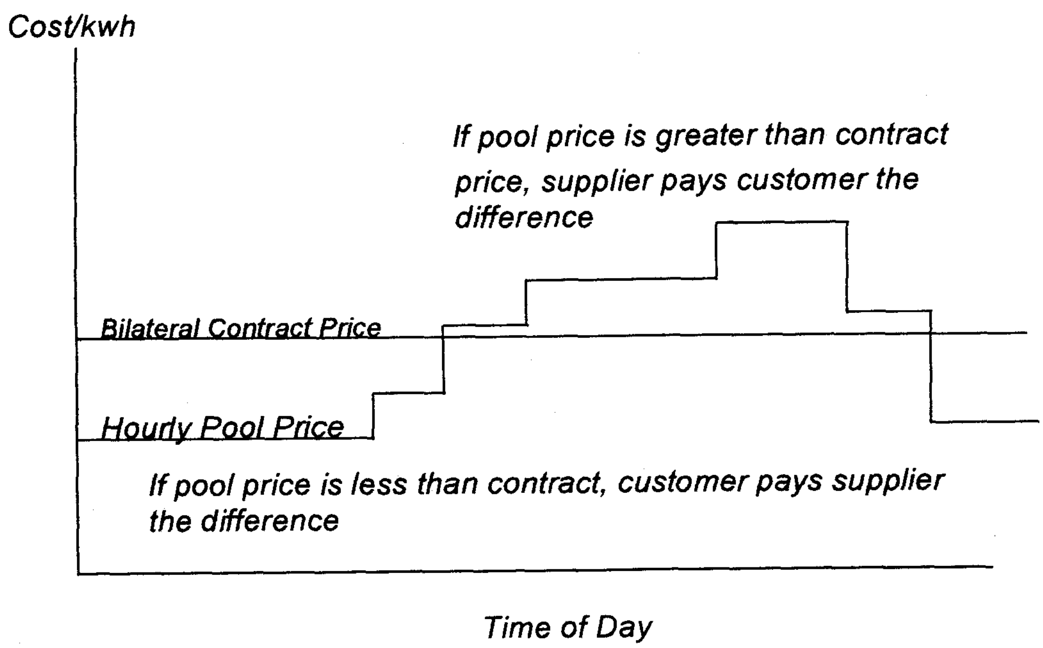

Figure 1: Contracts For Differences

A CFD is a relatively simple form of FSM. It guarantees that the customer pays only the price that he contracted to purchase energy for, while simultaneously creating a market for generators at known prices.

To illustrate how the CFD works, consider a contract between a customer and a generator at 2.5 cents per kWh. If the pool price in a given hour were 3.0 cents, the supplier would sell energy to the pool at 3.0 cents. The pool would then charge the LDC 3.0 cents, which would then bill the customer 3.0 cents. The customer would then send a bill for 0.5 cents (the difference between the pool price and the contract price) to the supplier. The net result of this transaction is that the supplier received his 2.5 cents and the customer paid 2.5 cents.

Now suppose that the pool price dropped to 2.0 cents. In this case, the supplier sells to the pool at 2.0 cents, the customer is charged 2.0 cents by the LDC and the generator bills the customer 0.5 cents. Again, the customer pays 2.5 cents and the generator receives 2.5 cents.

The existence of this type of contract leads to some interesting alternatives for both the generator and the retail customer. The customer has capped his price at 2.5 cents. However, there are ways that he can reduce his cost below 2.5 cents, by purchasing from other suppliers on a short-term basis. For example, another generator may wish to sell power during this example hour at 2.3 cents per kWh. In this case, the customer notifies his supplier that he does not wish to take deliveries this hour and instead purchases from the alternate, less expensive, generator. Or, if the pool price is less than 2.5 cents, the supplier may wish to meet his generation commitment through purchases from the pool and not generate.

In either case, the purchaser has guaranteed that he will not pay more than his bilateral contract with a supplier. But to lower his costs more requires that he actively participate in the day-to-day market. The generator also is dealing in the day-to-day market, with the goal of purchasing energy from other sources to meet his commitments at a lower cost.

CFD's are just one form of FSM's. FSM's provide customers the ability to lower their electricity bills strictly through financial transactions rather than face the problems associated with matching hourly loads with generation sources and acquiring the other necessary, ancillary services associated with the delivery of power. FSM's allow customers to enter into contracts for electricity without knowing, or caring, what sort of services are provided by the pool on their behalf. Also, the pool then guarantees the reliability of service, regardless of how the generator actually performs on an hourly basis. For example, suppose that the pool price jumps to 10 cents per kWh because of a transmission failure. The customer is indifferent to the price change, because he is protected by his bilateral contract. The supplier is also indifferent, if he can still deliver power to the pool. If however, the supplier is affected by the transmission line outage, and cannot deliver power to the pool, then he must pay the pool price to meet his energy commitments, unless he can purchase power from another supplier at less than the pool price to reduce his losses.

More sophisticated customers and generators will be using CFD's and other types of FSM's to protect against price fluctuations. For example, some market participants will be hedging electricity prices against natural gas prices, to protect themselves from changes in primary fuel prices.

A key outcome of the POOLCO model is that retail customers pay the highest hourly price of energy if they do not enter into power sales agreements with suppliers. It is up to the customer to take action to reduce his overall power supply costs.

The Pooling Model With Bilateral Contracts

The Pooling Model with Bilateral Contracts (PMBC) is the most general and flexible of the various proposed models. It has many of the attributes of the POOLCO model, such as an exclusive pool, while accommodating bilateral transactions between generators and suppliers. It is also the model that has been recommended for adoption by the California Public Utilities Commission to the state legislature (the WEPEx model).

In this model, each generator submits an hourly bid to the pool (or in the WEPEx model, the power exchange, or PX), identifying the amount of energy, the price and the delivery point. A system operator is responsible for the operation of the pool which then determines which resources are dispatched. The system operator is responsible for meeting load and maintaining reliability of supply. All bilateral contracts are first dispatched and then the remaining load is met by scheduling resources in a least cost manner. The model uses the same second-price, or Dutch auction, as the POOLCO model, that pays each bidder the price of the last resource dispatched by the pool operator.

Each retail purchaser takes delivery of energy through the pool and existing distribution company, exactly as customers currently do. The purchaser pays the distribution entity for energy at the pool price and then "trues-up" costs with their bilateral contracts supplier to realize final energy costs equal to the bilateral contract price. Because the cost that each customer pays the distribution entity is that of the highest price resource dispatched each hour, customers will be encouraged, through pricing, to enter into contracts with suppliers. Customers that choose not to enter into contracts will pay the highest price.

Suppliers can guarantee that their resource will be dispatched, by bidding a zero price into the pool, or they can bid their true incremental cost. In most cases, suppliers have a strong economic incentive to bid their true incremental cost. Suppliers would normally only enter a zero price if they had operating constraints that required that their resource be dispatched. For dispatchable resources with low incremental costs, the generator could determine hourly if he wanted to dispatch his generation or purchase energy at the pool price for delivery to his customers just by bidding the true resource incremental price. If the pool price is less than his incremental cost, he purchases from the pool and does not start his generation. If the pool price is greater than his cost, his generator is dispatched.

A pooling model that allows for bilateral contracts has several characteristics that make it attractive. These characteristics include:

Preserves, and may even enhance, system reliability;

Allows the greatest freedom of customer choice;

Recognizes the fallacy that energy can be transmitted from a designated supplier to a designated end-user;

Allows for the use of financial instruments to settle trades;

Presents a mechanism that allows for insuring dispatch of must-run resources;

Guarantees system average costs will decline;

Allows the greatest number of new entrants into the market by reducing transactions costs.

The system operator is only concerned about system reliability, dispatching available resources in least-cost order, subject to system constraints, after accommodating all market participants that have entered into bilateral contracts, if possible. A key point to recognize is that the system operator is not concerned with minimizing cost, per se. It is the responsibility of the retail consumer to protect himself, through the use of bilateral agreements (either bilateral contracts or FSM's), to find the least-cost resources available. But by establishing dispatch requirements, such as dispatching in least-cost order according to hourly bids from generators, within system constraints, the pool is guaranteed that the average hourly cost is minimized.

Notice that the responsibilities of the system operator are greater in the PMBC than any of the other models. The system operator is responsible for accommodating all bilateral contracts, insuring that all remaining load is met through the economic dispatch of resources that are bid into the pool, all accounting and payment functions between the various participants, and operation of the transmission system.

The PMBC allows customers the greatest choice in which generators they contract with. Customers can contract with least-cost suppliers, with "green" generators, or any mix of suppliers that they choose. No generator is precluded from the market, assuming that they can either interconnect or acquire transmission to the pool.

The pool recognizes the physical constraints that exist within an interconnected grid. No generator can designate energy for delivery to a particular customer. Instead, the generator can deliver to the pool on behalf of his retail customers, who receive the benefits of their contractual choices.

The PMBC allows the use of a wide range of FSM's that use the hourly pool price as a means of settling contracts. In effect, the PMBC separates the physical operation of the pool from the financial transactions between suppliers and customers. There is no societal value for a generator to be forced to generate power that can be produced less expensively by another party that desires to generate at a given, known, price. The PMBC gives the appropriate price signal, and then minimizes transaction costs by automatically finding the least cost generators and allowing high priced generators to make a rational decision on how they will meet their hourly contractual obligations to their retail customers. Most importantly, the risk of non-performance is transferred to the supplier, away from the customer who will never know, nor care (except in the case of "green," or environmentally friendly, generation) if his supplier is generating. No customer will ever be interrupted due to a failure of his, or any other, supplier to perform -- only financial performance will be affected.

Through bidding procedures the pool also guarantees that generation resources that cannot be varied on an hourly basis, or must-run, will be dispatched. This will require a zero bid into the pool by the operators of the must-run resources. It is possible, that if there is too much must-run generation, that at some times the pool incremental cost will be zero. However, most of the time, the incremental cost will be greater than zero, and the owners of must-run resources will receive a positive, but small, price for their energy. This is exactly how the current market values must-run resources in the non-firm market, by having a low off-peak price for must-rum generation.

The pool guarantees that system average costs will decline. High-priced generation will not be dispatched into the pool. If the average pool price is greater than the cost that new generators can deliver to the pool, new generation will be constructed and replace higher priced resources in the pool. The pool will value low incremental cost, dispatchable resources more than non-dispatchable resources.

Many of the comments above concerning the desirability of the PMBC are subject to an important caveat -- no entity has sufficient market power to manipulate hourly pool prices. A PMBC minimizes, but does not eliminate, the possible negative effects of market power. For this reason, regulatory bodies, such as FERC, appear to support the concept of an *Independent System Operator*, or ISO, responsible for operating and dispatching system generation and overseeing use of the transmission lines. The PMBC allows the greatest number of potential entries into the pool by establishing relatively small entrance costs and minimal transactions cost. Anyone can bid into the pool each hour. If the supplier does not perform, it pays a penalty, the cost of the resources necessary to replace his generation, but his customers are not harmed unless he has insufficient funds to pay them the difference between his contract price and the pool price. Thus, customers will demand performance bonds or other forms of proof of financial strength, or take their chances that a supplier is unable to pay them monthly. However, the PMBC does not require any extreme measures on the part of potential generators to deliver to the pool. This will encourage entrepreneurs to develop new generation for delivery to the pool, helping mitigate market power.

A Physical and Financial Market

The PMBC separates the market for electricity into two separate and distinct markets. These two separate markets are a physical market for electricity and a financial market. The pool operator is responsible for the physical market, while customers and suppliers are responsible for the financial market.

The physical market is relatively easy to understand. Each potential supplier bids his power into the pool. The pool operator decides if it wishes to schedule and dispatch it each hour, based upon least-cost protocols and operating constraints. Because the pool operator is responsible for the reliability of the pool, it will pay whatever is necessary to secure the needed hourly supplier. The pool operator is not concerned about cost, per se, although least-cost dispatch protocols, subject to system constraints, will encourage it to operate in an efficient manner. But the priority of the pool operator is maintaining physical deliveries of power to the consumers.

The pool will provide energy to customers. But the price of energy is not the total price that the retail customer pays for electricity service. In addition to energy costs, a customer will pay for transmission, distribution, ancillary services, public programs charges and, possibly, a stranded investment charge to help utilities recoup investment in generation resources that is uneconomic or unnecessary in a competitive environment. Thus, the energy charge is just one of the components of the total energy bill that the customer will pay.

How the Models Compare

An interesting aspect of the three models, the bilateral contracts, POOLCO and PMBC, is that they all tend to converge to the same price and encourage the same behavior on the part of consumers. That is, under all three models, participants will ultimately behave in the same fashion, with regard to cost and ability to schedule and dispatch generation. While participants and intervenors across the country have argued over which is the appropriate model, close examination shows that all three models result in exactly the same long-run equilibrium position.

The reason that the models result in the same behavior is that retail customers that choose not to enter into bilateral contracts will pay the pool price in the POOLCO and PMBC models. But the pool price is the highest hourly price of energy. Thus, retail customers will be forced into bilateral contracts in order to lower their cost of supply. As soon as retail customers realize that any bilateral arrangement, either through the use of bilateral contracts or FSM's, will reduce their hourly energy prices, the behavior of customers becomes the same in all models, with customers shopping for the best price.

Generators will also attempt to minimize their hourly cost of delivering energy to satisfy their supply obligations. Bilateral suppliers will attempt to lower their cost of meeting their obligations by purchasing from the pool each hour, if the pool price is lower than their (average) incremental cost of generation. This will result in generators acting as through they are dealing in a pooling environment, even in the bilateral contracts model.

The only significant difference between the three models is that the POOLCO and PMBC models tend to have lower transaction costs as compared to the bilateral contracts model. There is no reason that debate over what type of model should be used in the industry should be allowed to slow down the pace of restructuring. (A further discussion of the comparability of the different models is given by Hogan in the January 1, 1995 issue of *Public Utility Fortnightly*).

TURN's Municipal Choice Model

One of the less widely-known models is the TURN model of municipal choice. This model encourages municipalities to develop their own municipal utilities by taking advantage of the unbundling of services from existing utilities, without requiring the costly process of municipal condemnation. The existing utility serving a municipality continues to provide transmission, distribution, control area services and customer service, such as meter reading and billing. The municipal entity contracts with suppliers for generation resources. Savings are the difference between what the municipality was paying for power supplies versus what the same supply would cost with contracted generation.

In effect, municipalities act as aggregators on behalf of their customers. Aggregators will schedule and dispatch generation to meet the normal variations in energy use each day through the existing control area operator. No entity uses exactly the same amount of power each hour. Electricity use varies every minute as lights and office or manufacturing equipment is turned on or off or operated at different rates. Balancing generation and load, while maintaining sufficient reserves to meet unanticipated demands can be a costly service. Aggregators will insure that these services are provided, either by purchasing them from the control area operator or contracting with other entities if it is more cost effective.

Competition in the electric services sector means that some customers, primarily the large users and those that use power during the evening hours, could see reduced energy bills. Small customers will have difficulty reducing their bill. This is because generators do not, or cannot, deal directly with small customers, primarily due to the lack of time-of-use metering equipment. Also, depending upon the way that the state legislature deals with franchise payments, it is possible that franchise payments could initially drop as new suppliers begin serving customers within existing franchise territories, reducing sales and revenues of existing utilities. By aggregating the load of many of its small customers, a municipality can deal with suppliers and negotiate new, lower costs for its residents, while preserving or increasing its current franchise receipts.

Municipalities can combine, or aggregate, the electric load of many different customers to get a desirable load shape. Contracting for power supplies requires knowledge of the many different facets of the electricity market, including such things as transmission availability, the price of electricity form various sources in the region, the type and operating characteristics of generation sources offered by different entities and price trends of primary fuels, such as coal, natural gas and petroleum products.

Aggregators do this by finding entities that have excess generation or non-utility generators that need a load. Aggregators also buy and sell electricity on the economy energy market, a nationwide market that all generators deal in to reduce their hourly costs. Also, many suppliers attempt to sell off-peak energy from generation sources that must operate at night if they will be used the next day. Many operators hope to just be able to recoup fuel costs to minimize the losses associated with having to run the unit to make it available the next day. Each hour, aggregators compare the cost of power from various generation sources in the region to the cost of power purchased under bilateral contracts. If energy is available at a lower cost, and the contract permits it, aggregators purchase the energy for their clients, further reducing their costs.

The municipality can also take advantage of proposed changes in the electric services industry to begin receiving the benefits of a municipal utility without having to go through the difficult and costly process of acquiring transmission, distribution and the necessary customer service infrastructure. As an aggregator, the municipality can contract on behalf of its residents for electricity at reduced rates, sharing the savings in electricity costs between the residents and itself. Thus the municipality can help both reduce the cost of electricity to its residents and find a new revenue source.

The TURN model compliments the other three models. Regardless of which model is ultimately adopted by the Commission, the TURN model can be used by municipal agencies to reduce costs to its residential and smaller commercial customers.

<u>Summary of the Models</u>

1. The choice of which of the three major models (POOLCO, Bilateral Contracts or the Pooling Model with Bilateral Contracts, or WEPEx model) is the appropriate model for a restructured Arizona electric services industry is not of overwhelming importance. All three models tend to led to the same behavior by consumers and suppliers;

2. Retail competition can begin immediately with little or no impact on the financial structure of the utilities if Arizona utilities unbundle rates, while requiring the control area operator to acquire energy in a least-cost manner, posting hourly prices;

3. Many of the participants in this proceeding fail to recognize that a competitive market will be primarily a financial, rather than a physical, market for electricity, even if a bilateral contracts model is ultimately adopted by the Commission. Customers will be able to take advantage of financial mechanisms to participate in retail wheeling opportunities without informing their local utility or even changing their current service arrangements;

4. All the proposed industry models for a restructured electric services industry break the link between a utility's obligation to provide energy to consumers and move this function to a different entity;

5. Because of the financial structure of the new marketplace, suppliers should be able to offer to supply customers with energy regardless of their location or the firmness of power.

There appears to be a confusion among many people nationwide about the way in which a restructured market for electricity will operate. There seems to be a prevalent belief that utilities will continue to supply energy to customers, and be responsible for the reliability of supply, in a competitive marketplace, rather than seeing this function passed on to another entity.

Many people appear to believe that the competitive market for electricity will look very much like today's market, with the primary difference being utilities and generators will compete to supply power an a bilateral basis to individual customers, rather than service territories. Instead, utilities will be supplying energy to some sort of a pool in competition with all other suppliers. The exact structure of the pool depends upon which model is ultimately adopted by the Commission. But the link between consumer needs and utility supply obligations has been broken in all the proposed models for the new utility industry.

Existing utilities will not need to acquire new energy sources unless retail prices are high enough to encourage the construction (or acquisition) of new resources. This will be a business decision, based upon the utility's belief about future price and costs conditions, rather than a regulatory decision.

PRM, while arguing that the Pooling Model with Bilateral Contracts (PMBC) is the most appropriate for Arizona and the rest of the southwestern United States, does not believe that the Commission should become bogged down in the details at this time. All of the major models currently being discussed, result in essentially the same outcome insofar as consumer options and behavior. The PMBC does tends to minimize transactions costs to consumers in comparison to the bilateral contracts model.

PRM urges the Commission to require utilities to unbundle rates immediately and begin posting their hourly incremental price in a manner accessible to all participants. This will allow retail customers to begin taking advantage of retail competition immediately, through FSM's, with no significant impact on utility finances. Once retail competition for at least the energy component of electric service begins, consumers will see some downward pressure on rates. This is also the appropriate time for continued discussions on stranded investment, exit fees and market structure.

PRM does not believe that utilities should oppose unbundling of rates. Utilities will not even be aware of any agreements for energy entered into by their retail customers. There will be no effect on the utilities financial position. Indeed, utilities should be willing to accept energy in a least-cost manner, regardless of what entity is supplying the energy to the control area. Unbundling can only help provide information to customers, while reducing their costs, while not affecting Arizona's utilities in any manner.

It is in this context that PRM offers its response to the following questions.

A1. Affected Utilities. *Which utilities should open their markets to competition?*

All Arizona utilities should allow their customers the opportunity to lower their costs.

A2. Scope of Restructuring

a. How much of the utilities' markets should be opened to competition?
b. Which consumers should be allowed to shop around for power and energy?
c. Should utility customers served under existing contracts be eligible to participate in the competitive market prior to expiration of the existing contracts?
d. If divestiture were undertaken, how should it be accomplished?

If the pooling model with bilateral contracts (PMBC) model or the Poolco model is adopted, or if retail rates are unbundled, in a pooling environment, it will be impossible to keep any customer from participating in retail wheeling if he so desires. This is because most transactions will be financial, rather than physical, transactions.

As an example, if a retail customer enters into a CFD with a supplier, it does not need to inform its franchised utility of the transaction. The supplier sells energy to the pool, the pool operator charges the LDC each hours price, the LDC charges the customer, and the customer then reconciles accounts with its supplier. Nowhere does the customer need to inform its LDC that it has made a financial transaction with a new supplier. The LDC or pool operator have no need to know of the customers financial arrangements.

In the same manner, just because a customer has a special contract with a utility, it does not mean that he cannot enter into various FSM's with suppliers - it just means that his price cap is somewhat different than all other customers that have not entered into special contracts.

Divestiture

PRM believes that utility divestiture should be handled in the context of the restructuring process as a whole. PRM does not believe that utilities should be broken into component parts unless something in particular is to be accomplished. In this case, divestiture should be considered a way of reducing the potential amount of stranded investment.

PRM believes that the utilities claims of stranded investment costs could be lowered if utilities were forced to correctly value all facets of their operations. Utilities claim stranded investment and attempt to recover from ratepayers when the market value of assets is less than remaining debt on the asset. But utilities are attempting to appropriate for shareholders the difference between market value and debt whenever market value is greater than debt. Divestiture makes sense only as a way of balancing both the overvalued and undervalued resources. This issue is addressed more fully in PRM's response to question A9.

If divestiture were undertaken, all utility resources should be auctioned to all bidders when possible. For example, not all entities are qualified to assume responsibility for nuclear facilities. The utility would have the option to match any bids for any of its resources and only the difference between the auction amount and existing debt, in total, would be considered stranded investment.

A3. Terms of Restructuring

a. When should competition start?

b. If competition is in the form of a pilot or phase-in, how long should the pilot or phases run? Please describe the phases of a phase-in. Please consider that many larger customers of utilities are currently under contract and may not be allowed to shop around until those contracts expire.

c. If competition is in the form of a pilot, how can the term of the pilot be set so as to avoid discouraging long term contracts signed under the pilot?

Competition should begin as soon as feasible. Again note that PRM argues that establishment of a pool, with posted hourly prices and minimal unbundling of rates is all that is necessary to begin at least some level of retail competition, resulting in lower prices for consumers.

PRM does not believe a pilot or phase-in is necessary. If the Commission decides to adopt any of the three models, system reliability will continue to be in the hands of the existing control area operator. There will be little, if any, effect on the way utilities currently operate. The only difference will be the manner in which retail customers enter into various FSM's with suppliers.

Customers with existing contracts should be allowed to participate in retail wheeling in conjunction with their existing contracts. That is, even customers that have special contracts should have their rates unbundled. They can then enter into FSM's to lower their costs. The utility will be indifferent to the financial transaction, assuming that it even knows it occurred.

A4. Services Available on a Competitive Basis. *Which services should be available in a competitive marketplace?*

> *Distributed energy services at market based rates (serving multiple consumers located in proximity, and not requiring transmission service from others); this is distinct from on-site generation for just one consumer.*

Central station generation services at market based rates (generation serving one or more consumers located at a distance from consumers and requiring transmission service)

Other services described in Sections A5, A6, A7 and A8.

Other services (please describe).

PRM believes that all services should be provided on a competitive basis. How these services are coordinated depends upon which of the different models the Commission ultimately decides upon.

A5. Necessary Services. *Utilities and perhaps other parties will have to address the services listed below. Please indicate how these services should be offered, measured (metered), and priced on an unbundled basis.*

Distribution service
Transmission service
Supplemental generation service
Imbalance service (including accounting for losses)
back-up (stand-by services)
voltage control
other ancillary services necessary for maintaining system reliability
scheduling of suppliers and demands
repairs/consumer complaints
other necessary services -- please describe

PRM would argue that how these various services are offered and priced depends upon the type of model that is ultimately adopted by the Commission. Because PRM believes that a PMBC is the most appropriate model for Arizona, it will answer the question in this context.

The existing Arizona utilities should ultimately be required to functionally organize themselves into at least a distribution company, generation company and transmission company.

The distribution company would be responsible for providing customer service functions, including distribution services, metering, meter reading, responding to interruption of service complaints, new customer hook-ups and billing.

The distribution company would also be able to provide energy efficiency services, to the extent that the Commission determines that a utility should offer these services in competition with the supply-side resources.

The role of the transmission company is to operate the existing transmission resources of the utility. Service would be provided on a non-discriminatory basis at a regulated rate of return.

The generation company would operate existing generation resources of the utility and bid this generation into the pool. The utility would receive market prices for its energy, but no rate of return should be guaranteed.

All other functions would be moved from the utility to the pool operator. The utility would no longer have an obligation to acquire or bid generation into the pool. This does not mean that the utility could not acquire new generation, but it would be an economic, rather than regulatory decision and the utility is at risk for the financial performance of the new generation asset.

The pool operator assumes responsibility for system reliability and adequacy of supply. This includes providing ancillary services, although it will purchase these services from suppliers under a bidding system. In effect, the pool assumes responsibility for operating the supply portion of the electric system, while the utility is one possible supplier.

Under the PMBC, there are no imbalance services. The customer has entered into a FSM with a supplier that bids his power into the pool. The pool pays him only for energy delivered to the pool. How the supplier and customer settle accounts is between them, not the pool. In fact, the pool will not know what type of arrangement exists between retail customers and suppliers. Only the customer and supplier are concerned about imbalances, because it affects their financial performance. But the pool is only concerned about insuring that load is met, regardless of cost.

A6. Market Center Services. *The market may benefit from the services listed below. Please indicate how these services should be offered and priced.*

Title transfer
Transaction confirmation
Establishing credit standards
Invoicing
Dispatching of transmission/generation
Exchanges/swaps
interruption notification
Imbalance trades

Which of these services will be offered depends upon which model is ultimately decided upon by the Commission and the structure of the existing utilities. If the existing utilities functionally reorganize themselves into a distribution company, transmission company and generation company, with a pool operator responsible for scheduling and dispatching of the generation resources bid into the pool, most of these services will be provided automatically and will be priced on a pro rata basis. How consumers then attempt to minimize costs is then their choice.

For example, invoicing and interruption notification will continue to be done by the distribution entity. Transaction confirmation between the pool, the generators and the LDC, dispatching of transmission/generation will be done by the pool operator, which can charge a fee to cover costs that will be spread among all consumers (sometimes referred to as an *uplift fee*). The LDC will bill the customer for energy delivered. Assuming that a PMBC or POOLCO type market is adopted by the Commission, there will be no imbalances, as the pool and the LDC will charge all consumers the hourly energy price, regardless of what type of financial arrangements exist between customers and suppliers. The customer and supplier to settle accounts between them based upon metering and billing data normally furnished by the pool to its generators and the LDC to the retail customers..

A7. Spot Market Services. *The market may benefit from the services listed below. Please indicate how these services should be offered and priced.*

Electronic bulletin boards for spot transactions/prices
Power pooling services
Coordination with futures/options markets.

In the PMBC or POOLCO models there is no spot market for power. This is because generators bid into the pool and all successful bidders receive the same price, regardless of their bid. There is a short-term market, where the generator attempts to sell energy across some short time period, perhaps a day, hoping that the price that he receives over that time period is greater than the average of the hourly prices that he would have received if he had sold his energy into the pool.

There will be a great deal of coordination between the futures market and the pool - however, it will be coordinated by customers that are using the pool price, which is an hourly or half-hourly price, and the monthly futures market. Customers will purchase contracts through the NYMEX exchange and then use this as a hedging mechanism against the pool price.

The primary role that the pool serves is to establish a market for energy on a hourly basis and then provide information to all participants as to what prices are. The model should not be expanded past this.

A8. Transmission Service. *For a competitive market to work, utilities owning transmission facilities* *must provide transmission service. Please indicate how the following objectives would be met:*

service must be provided consistent with FERC tariffs.

utilities must accept power delivered to their transmission systems by other suppliers and offer wheeling services comparable to services they provide to themselves.

all sellers supplying consumers must have interconnection agreements with owners of necessary transmission facilities

PRM believes that all transmission should be charged on a postage stamp basis, with necessary transmission expansions charged to all consumers in the region on a mills/KWH basis. New generators, who choose to locate outside the control area, or in areas where transmission expansions are necessary, should pay all costs associated with interconnecting their generation facilities to the grid.

PRM's proposal treats each portion of the existing transmission system differently. The transmission system is divided into three distinct components: (1) radial lines outside the grid, (2) the bulk power system within the grid, and (3) the distribution system. PRM recognizes that in many areas, lower voltage facilities are an integral part of the bulk power system and would need to be treated as part of the transmission system.

The ownership and control of existing radial lines remains with the existing owners. Use of the lines would be determined in accordance with FERC policy or membership in regional transmission groups. There would thus be no changes in radial transmission line ownership or use under the pool from current rules and regulations.

The distribution companies would continue to receive payment for their current investment in distribution facilities. The operation, maintenance and expansion of the distribution grid will also remain the responsibility of the distribution companies.

The operation of the bulk transmission system will be turned over to an *independent system operator*, or ISO, responsible for operating, dispatching and maintaining the reliability of the bulk transmission system.

The ISO would have authority over the physical operation of the transmission system, which includes maintaining system reliability, providing the suppliers with access to all parts of the transmission system (including system expansions, if necessary), and operating and maintaining the system. Each supplier is responsible for obtaining access to the transmission system, and participating in establishing and following joint planning procedures for the system.

In effect, the ISO designates the transmission system as a common carrier, providing service to all entities to meet load requirements at the same cost per KWH, regardless of which entitiy actually owed the transmission facility.

The ISO will also assume responsibility for the reliability and expansion of the transmission system. This includes determining when, and where, new transmission expansions are necessary. In effect, the ISO will decide if a transmission expansion is necessary to lower average costs to the pool. If an expansion is necessary, then all participants will benefit from it because system average costs will decline. If average costs do not decline, then there was no need for the expansion.

Of course, should any merchant facility wish to construct transmission to interconnect to the grid, then they are welcome to construct a line themselves and pay for it, and then charge other participants for the right to use this line.

PRM argues that in a pooling environment with bilateral contracts, the question of access is almost moot. It is not the customer that will be hurt, or helped, by access. It is the supplier that has entered into an agreement to sell energy at some price. If the supplier locates on a constrained path, then it will be curtailed and its costs of meeting its obligations will increase, either by paying the incremental pool price to meet his obligations or paying for dispatch costs for dispatching in non-least-cost order. Eventually, if the necessary path is overly constrained, the generator will be unable to stay in business. Or, the generator could decide to pay for the necessary system reinforcements.

In either case, the supplier is the entity that takes responsibility for relieving any system constraints, not the consumer. Only when the ISO determines that the reduction in system average cost is sufficient to pay for any increases in transmission costs are new bulk power lines constructed.

The above is one of the two reasons PRM is opposed to congestion pricing schemes. The other is that in a world of financial settlement mechanisms, that are settled outside the scope of the system operator, congestion pricing becomes a non-issue. As an example, suppose a customer in Phoenix entered into a FSM with PacifiCorp. As long as PacifiCorp can deliver to the pool, anywhere, it will be able to determine if it wants to bid power to the pool. The customer takes energy from the pool. Then the customer and PacifiCorp settle their FSM outside the scope of the pool operator. How will the pool operator know that PacifiCorp, through the use of financial arrangements, "delivered" energy across a constrained path to a Phoenix customer to satisfy his supply commitments?

A9. Recovery of Stranded Investment*. Please indicate how the recovery (if any) of stranded investment should be accomplished. Address each of the following issues:*

a. The definition of stranded investment.

b. The fraction of stranded investment which should be recovered.

c. How the Commission will determine the amount of stranded investment, taking into account: revenues under traditional tariffed rates (or existing special contracts); actual utility revenues from customers who obtain discounted rates or obtain service from others; increases in net revenues from wholesale sales and additional retail sales, including the effects of price elasticity of demand; increases in the value of assets due to new pricing or competition; mitigation of stranded investment; and other factors.

d. Preliminary estimates of the magnitude of stranded investment (please provide supporting analyses).

e. The proper ratemaking treatment of negative stranded investment.

f. From whom stranded investment should be recovered.

g. The mechanism for recovery of stranded investment.

h. The time period over which stranded investment is to be recovered.

I. How utilities can mitigate stranded investment.

Stranded assets will be limited to generation resources that have an incremental cost in excess of the market cost of energy. Until the Commission determines what type of market will replace the current monopoly market for electricity, it is not possible to determine what the market price will be. That is, if the Commission determines that a bilateral contracts model is the appropriate model, there may not be a benchmark price that one could use to determine the market cost. If the Commission decides upon a pooling model, the pool's hourly incremental price would be the market price that could be used to determine which resources were uneconomic.

Also, too high a cost for stranded investment could encourage greater amounts of self-generation or prompt industry (with jobs and tax base) to leave for an area with a better business environment

Obviously, identification of stranded costs and possible recovery of stranded costs is an issue of extreme importance in the transition to a competitive market. However, PRM believes that it is important to develop a market structure that can be used to value stranded investment, if any, prior to debates about which, if any, resources are uneconomic.

Stranded investment, according to the Federal Energy Regulatory Commission's definition, is: "the difference between (1) the utility's bundled, regulated rates less its marginal costs; and (2) the amount it actually recovers from the departing customer in transmission, distribution and other charges."

Investor-owned utilities (IOUs) are concerned that they will not recover as much as $200 billion in investments nationwide in generation, transmission and other investments that were made to provide electric services to their ratepayers under the regulated industry structure. IOUs are (rightfully) concerned that ratepayers will attempt to bypass payments for investments in generation resources that are not economic in today's generation market. Instead, retail customers would opt to take service from new generation sources that are less expensive. Customers remaining on the existing IOU's grid would be required to pay higher costs to reimburse the IOU for investments made to provide electric services to all customers, or the shareholders of the IOUs would be responsible for some, or all, of the stranded investment.

There have been several different proposals for calculating stranded investment. One proposal, submitted to the California Public Utilities Commission (CPUC) by Recon Research, proposes to allow an auction of all generation assets, without requiring the utility to actually accept the bid price. In effect, this allows a market valuation of the existing generation assets of a utility. If the utility believes that the market overvalues its generation assets relative to book value, the utility can sell the asset. If it believes that the market undervalues its assets, then it can keep the asset. But, the total value of all bids determines the market price of generation and stranded investment becomes the difference between the bid price and book value.

Another proposal suggests selling the existing transmission system at market rates to offset any generation asset's stranded investment. This proposal was bitterly contested by all public power utilities that had made significant investments in transmission resources.

The proposal put forth by the Edison Electric Institute (EEI) on behalf of many of its members in FERC Docket RM94-7-000 (Recovery of Stranded Costs by Public Utilities and Transmitting Utilities), requires an annual ex-ante forecast of stranded investment and an ex-post true up, based upon market costs. In effect, a utility would identify what portion of its generation assets are non-competitive at forecasted market rates. A cost per kilowatt hour or kilowatt would be assessed on all customers during the year. To the extent market prices were greater than forecast, reducing the amount of the utilities' uneconomic investment, stranded investment would decline and rates for the following year would also decline. If market rates were less than forecast, uneconomic investment would increase, and the utility would increase its cost recovery the following year.

For example, assume that the authorized revenues associated with utility-owned generation this year yield an average cost of 5.5¢ per KWH compared to a market value of 3.0¢/KWH. (The relevant authorized revenues per KWH, 5.5¢/KWH in this example, can be determined from the existing electric service ratemaking techniques mechanism.) The transition cost this year associated with utility generation is then equal to 5.5¢/KWH (the "authorized revenue") minus the market value for this electricity (3.0¢/KWH) times the quantity supplied. That is, the actual transition cost of utility generation this year (under the stated assumptions) is equal to 2.5¢/KWH times the number of KWH of electricity supplied from utility generation. Precisely the same type of calculation defines the transition costs associated with utility generation in each future period in which these facilities are in operation.

Given the long-lived nature of utility investments in generating capacity and long-term contractual commitments of QFs and other power and fuel suppliers, the strandable or so-called uneconomic costs associated with power produced or resold by a utility is most easily conceptualized as a future stream of potential revenue shortfalls that can be calculated on an ongoing basis as time goes by based on actual realizations of market prices for electricity and revenues authorized pursuant to current regulatory commitments. This method is referred to as the "Realized" Transition Cost computation procedure.

In effect, the EEI proposal would allow one hundred percent cost recovery of all generation investment over a long time period. The effects of competition would be limited to minor reductions in annual energy costs.

However, the EEI proposal does allow for a utility and its customers to negotiate a one-time payment freeing the customer from all future stranded investment obligations. The EEI proposal also does not address how expansions of existing service would be treated. That is, if a firm expanded its operations, or otherwise added load within a service territory, does the marginal load have a stranded investment obligation? What if a firm left one area and relocated to another. Does this mean that it has incurred a stranded investment? It is PRM's belief that these are negotiable questions between a utility and its retail customers.

IOUs have proposed several ways to avoid the possibility of either remaining ratepayers or shareholders from absorbing stranded investment. The first, and most popular, proposal is through the creation of a competitive transition charge (CTC). The CTC would ensure that all customers taking electric services would continue to pay for their use of transmission and distribution services, ancillary services and stranded investment costs. Only the marginal cost of electricity, or the energy costs, could be reduced until after all stranded investments were recovered.

The electric utility would unbundle its rates into various components: transmission and distribution costs, ancillary services (in some proposals) and stranded investment costs. Each of these components would remain regulated. Energy costs would be unregulated and competitors could attempt to sell energy at rates less than the utility. All customers would pay the same unit costs for each of the regulated components, ensuring full recovery of all stranded investment costs.

PRM does not believe that utilities should be allowed to automatically recover one hundred percent of stranded investment. That is, PRM proposes that some proportion of stranded investment, say 50 to 75 percent as has proposed in New Hampshire, can be recovered if a utility decides to remain a fully vertically integrated utility, while if the utility agrees to a market evaluation of all its assets, it should sell the assets and become a local distribution company. Any residual "loss" could form the bias for a wires charge.

If the Commission decides that stranded costs exist, there will be several problems in collecting stranded costs from customers. For example, can the Commission impose a transition fee that all customers will pay, even customers that choose to leave the area? Have all customers agreed to assume a debt to their local utility for investments made by the utility? If a residential customer were to move to another state, is he/she obligated to pay an exit fee to his/her local utility? Will utilities reduce the transition fee to some customers as a means of competing for large commercial and industrial loads? Does a new customer moving into the region that takes energy from an alternative supplier pay a stranded investment charge, even though the argument is that stranded investment payments are made to allow a utility to recover investments made on a customer's behalf? What investment has a utility made on behalf of a new customer or the additional load of an existing customer?

PRM does not believe that full recovery of stranded investment from customers is a viable option. More importantly, PRM is not convinced that the stranded investment problem is as great as many utilities claim. For example, if a utility has a depreciated power plant and a non-depreciated facility, is the stranded investment the difference between the incremental cost of the non-depreciated facility and the market price of energy? What justification for collection of stranded investment exists when the utility will still own a depreciated generation facility that has a market value in excess of its book value, that is not counted against the uneconomic value of the uneconomic generation facility?

PRM proposes a mock auction process, as originally proposed by Recon Research in the California proceedings and Green Mountain Power in Vermont, as the appropriate way to determine stranded investment. All the generation assets of a utility are put up for bid. A utility can decide which, if any, bids, it wants to match. If the utility does not match the bid for one of its assets, the asset is sold and the proceeds used to write down the non-depreciated portion of the utility's assets. If the bid price is greater than the book value, the difference is used to buy down the book value of other generation facilities. On the other hand, a real auction is currently taking place in the utility industry as utilities are merging and being taken over by others according to the market value of their generation and transmission assets in relation to the utility stock price.

If the Commission does determine that stranded investment exists and that utilities are entitled to recover some amount of money for stranded investment, then it is important that the utilities are not allowed to waive stranded investment fees as a marketing tool.

PRM believes that the time period for collecting any stranded investment charges should be limited to a relatively short time period, for example, 3 to not to exceed 5 years.

The responsibility for any stranded investment should be allocated to the various stakeholders on the basis of total energy use. However, PRM does not believe that utilities should be allowed to recover one hundred percent of claimed stranded investment because this will essentially allow utilities to recover twice for some investments.

Utilities have traditionally received a higher return on investment than other industries to encourage investment. Now that the electric services industry faces competition, some utilities are claiming that they should be allowed to recover all their investment from the ratepayer, without crediting them for the above average rates-of-return enjoyed by stockholders in the past. If stranded investment does indeed exist, then only a portion, approximately 50 to 70 percent, should be allowed to be recovered.

A10. Recovery of Costs of Commission-Mandated Utility Low Income, DSM, Environmental, Renewables and Nuclear Power Plant Decommissioning Programs ("Mandated Programs").

a. How shall costs of mandated programs be recovered from participants in the competitive market?
b. How shall the magnitude of costs of mandated programs be determined?

PRM believes that low income programs should be paid for by the general government as a tax funded function. There is no reason to justify high energy users paying a greater proportion of costs for social programs.

Any of these programs could continue to be funded for some transition period through the collection of a non-by-passable fee charged to users of the distribution system. The fee would initially be set to cover the current costs of existing programs, which would be maintained and administered by the distribution company.

PRM does not believe however, that the debate on how to continue these programs should be used as a means of slowing down the deregulation process. The existing program can remain in effect during the transition period to a different funding process.

Programs, such as encouragement of renewable resources, nuclear decommissioning programs and energy efficiency programs can be financed originally by a surcharge on energy sales. The surcharge should be set high enough to cover the costs of the existing programs. Money collected by the distribution system to administer the program should continue to be overseen by the distribution utility and the state PUC, which currently has jurisdiction over these programs. Ultimately, however, these programs have no appropriate place in a competitive electric industry and should be administered by the state government if they are determined to be desirable.

PRM believes that a goal of restructuring should be to transfer risk, either economic or environmental, to the generators. If a generator chooses to sell coal- or petroleum-fired generation that is impacted by environmental regulations, the costs should be passed on to the generator, not underwritten by the ratepayers.

The current debate on restructuring the electric utility industry leaves much to be desired when discussing the role of energy efficiency and protection of the environment. The debate has centered primarily upon means to reduce the cost of a kilowatt-hour of electricity. As the Natural Resources Defense Council and the Union of Concerned Scientists have pointed out (among many), current proposals to protect energy efficiency and internalize the costs of environmental damage have all centered around voluntary contributions and green pricing proposals. The three major California investor-owned utilities have all argued that they alone should not be charged with funding social and environmental programs, while non-utility generators and out-of-state competitors are freed from the additional costs imposed by energy efficiency programs.

Arizona's utilities have invested significant resources in the pursuit of energy efficiency and protection of the environment. However, these investments could be jeopardized if the industry restructuring results in a loss of the municipal industrial load through a flexible pool, resulting in higher costs for the remaining customers. Pressure to keep rates below those of potential competitors will force the utilities to begin cutting costs; eventually, the energy efficiency and environmental programs will be affected. Additionally, there will be pressure to reduce or eliminate funding for research and development of new alternative generation technologies.

Even if a utility were able to compete in the marketplace successfully, competitive pressures will force a re-evaluation of the types of programs being offered by the utility to its customers.

It is necessary to build into the restructuring debate a method for providing cost effective energy efficiency programs that account for the environmental externalities associated with generation. In other words, industry restructuring should not be used as an excuse to allow ignoring the negative environmental externalities associated with power generation, either by importing less expensive, greater polluting power from outside Arizona that does not internalize environmental costs, or allowing Arizona utilities to discontinue current cost-effective energy efficiency programs that are both beneficial to the customer and have positive environmental effects. Nor should competition be used as an excuse to abandon development of renewable resource alternatives that promise to have a substantial positive benefit on both the regional economy and the environment. On the other hand, Arizona utilities should not be placed on an unequal footing with potential competitors by imposing constraints upon them that others, such as out-of-state generators, are free to bypass.

It should also be clear that the non-exclusive pool proposed by PRM allows green pricing for those willing to pay for it. If a non-polluting generator can sign contracts with retail or wholesale customers in the pool, the green generator can bid a zero price into the pool and be assured that its resource will be dispatched. The customer will know that its choice of a non-polluting generation alternative reduces the environmental damage caused by aggregate power generation.

PRM has favored the establishment of an Environmental Benefit Set-Aside Fund (EBSA), as originally proposed by the California Municipal Utilities in the California proceedings. This fund would be available to utilities serving a retail load to fund energy efficiency, and the research and development of renewable energy alternatives and certain social programs. The EBSA would initially be set to collect the same amount of moneys as is currently spent by the state's utilities on resource efficiency and alternative generation technologies

The following are some of the justifications for establishing the EBSA concurrently with the beginning of the industry restructuring program.

1. Under the Commission's guidelines for industry restructuring, cost shifting between classes is prohibited. Thus, all customers should see a reduction (albeit slight in many cases) in energy costs. Establishment of the EBSA at the time the rate is deregulated should be transparent to most customers.

2. The implementation of restructuring has put increasing pressure on utilities to critically examine the costs associated with energy efficiency and environmental programs. Many of these programs that have positive societal benefits, but do not generate revenue for their sponsoring utility will be cut. A source of funds earmarked for energy efficiency will maintain funding for a short-time period.

3. Currently, most alternative fuel generation technologies are not cost-effective if priced on a cents/KWH basis and compared with fossil-fuel-fired facilities (even

including the 15 mill/KWH subsidy offered under the National Energy Policy Act), if the social costs of pollution are ignored. Yet within the last few decades, the cost of renewable resources has been reduced by at least an order of magnitude, and within a decade may be very cost-effective when compared to traditional fossil fuel fired generation technologies. An EBSA would allow funding of research in some key areas of renewable energy technology, providing a promise of new, cleaner energy technologies in the future.

A flat payment per KWH is not necessarily the fairest method of raising funds, having the effect of shifting costs (on a proportional basis) from low load factor customers to high load factor customers. That is, residential and small commercial customers will be paying less for some reduction in pollution levels than industrial customers. Residential and small commercial customers tend to use power more intensively when the environmental costs are highest, such as summer afternoons.

PRM's proposal for establishing an environmental benefit set-aside fund is:

1. The EBSA would initially be set between 2 and 3 mills per KWH, adjusted annually in accordance with price changes in primary fuel costs.

2. The local distribution company (LDC) collects the moneys raised by the EBSA as part of its rate structure.

3. The LDC spends these funds on programs that meet at least one of the following criteria:
   a. reduction of any negative effects of electricity generation on the environment;
   b. cost-effectiveness within an integrated resource planning framework; and,
   c. reduction of electricity costs to customers.

4. Some portion (roughly 33 to 50 percent) of the money collected would be set aside for continuing research and development and pilot projects for renewable and alternative energy technologies.

The funds would be collected and administered by the LDC.

Note that if the Poolco or PMBC model is adopted by the Commission, the utilities obligation to insure adequate generation resources are available to meet load will be moved to the pool. Utilities will determine which generation and energy efficiency programs that they wish to implement on the basis of economics.

A11.Encouragement of Renewables

a. How shall renewables be encouraged in a competitive environment? Please discuss such mechanisms as a requirement that x percent of energy sold in the competitive market must come from solar resources.

b. How could progress in encouraging renewables be measured?

c. How could a renewables program be enforced by the Commission?

PRM does not believe that the Commission should attempt to legislate the type of resources that are bid into the pool. If renewables are cost-effective, either now or when primary fuel prices begin to increase, then they will be bid into the pool and dispatched. Also, the pool already contains a mechanism for allowing green resources to be bid into the pool, if consumers can be convinced to purchase them.

Most renewable resources are not currently cost effective, (even when including the 15 mill/kwh payment from the Department of Energy under the Energy Policy Act). A competitive market will provide the necessary incentives to encourage development of cost-effective renewable and distributed generation resources.

A12. Pooling of Generation and Centralized Dispatch of Generation or Transmission

a. Should pooling of generation or centralized dispatch of generation or transmission be mandatory or voluntary?
b. What technical requirements will be necessary to ensure reliable and efficient use of generation and transmission resources. Please propose specific requirements if possible.

PRM has proposed the PMBC as the appropriate choice of models for restructuring the Arizona electric services industry. This model requires an exclusive pool for generation dispatch. Therefore, PRM argues that the pool should be mandatory, with transmission resources controlled by the pool operator. There is no need to impose additional technical requirements on the pool operator that are not already in place to insure economic and reliable operation of the generation and transmission resources in the region.

A13. Non-Public Service Corporations. *How shall non-public service corporations, such as municipal utilities be involved in a competitive market? For example, the service territories of Arizona utilities not regulated by the Commission may not be open to competition and Arizona utilities not regulated by the Commission may not be able to compete for sales in the service territories of the utilities identified in Section A1. Alternatively, an Arizona utility not regulated by the Commission may voluntarily participate in a competitive program if it makes its service territory available to competing sellers and if it agrees to all of the requirements of the Commission's competitive program.*

This question presupposes a particuliar model structure for the future Arizona utilities.

This is also a concern more about reciprocity than competition. Because the Commission does not have jurisdiction over the municipal utilities in the state, there is no need to slow down the restructuring process while the municipal utilities decide what they will do.

A more germaine point is - who cares? In a competitive marketplace, the more sellers available, the greater the downward pressure on prices. Allowing municpal utilities to compete through FSM's for sales in other parts of Arizona outside their service territory will drive down prices. The downward pressure on prices will bring forth a cry for more competition by their customers.

But again, if the PMBC is adopted by the Commission, there is no way that anyone will know if the municipalities are selling energy to customers through the use of FSM's.

A14. Conditions for Returning to Utility Service after the Conclusion of a Pilot Project. *If a pilot were adopted, please indicate what conditions are appropriate for returning to utility service after the conclusion of the pilot.*

If the pilot was based upon a PMBC or Poolco model, there would be no conditions, because the utility would not even know which of its customers participated in the pilot through FSM's.

A15. Conditions for Returning to Utility Service. *Please indicate what conditions (if any) are appropriate for returning to utility service if a competitive market is on-going.*

If the Commission adopted a PMBC or Poolco model, the utility would not have an obligation to serve, hence the customer would always take service from the pool and settle accounts through a FSM. Hence, this question is meaningless in the context of a PMBC or Poolco model.

A16. Administrative Requirements

a. A utility may require consumers obtaining generation from another entity to adhere to reasonable scheduling notification requirements, accept reasonable delivery points, adhere to reasonable metering requirements, and accept reasonable remote control requirements for interruptions or other purposes. Please specify what you would consider reasonable.

b. How should the utilities identified in Section A1 notify their customers of the adoption of a competitive program by the Commission?

PRM believes that this question presupposes the type of model that will be implemented. The question assumes a bilateral contracts model, or that customers are actually attempting to take power delivery from a supplier. In the PMBC, customers would deal primarily in financial instruments and the question becomes irrelevant.

PRM does believe that utilities have an obligation to attempt to inform customers that a competitive program has been adopted by the Commission. The information could be passed by means of bill stuffers and the same information means that the utilities currently use to inform customers of new programs.

A17. Impacts on Other Utility Customers. *Please indicate how adverse impacts on rates or service quality for utility customers not participating in the competitive market could be minimized.*

PRM has argued that there would not be negative effects on non-participating customers if rates are correctly unbundled. Currently, through special rate discounts and economic incentive rates offered by utilities, some large customers are benefitting from economic competition. Customers that are not offered these special rates do suffer from rate shifts. Competition will eliminate this bias, allowing all customers to benefits, although probably not to the same degree.

A18. Reporting Requirements for All Sellers of Electricity to End Users. *Please indicate what reporting requirements (to the Commission) are appropriate and who should file reports.*

The only reporting requirement should be by the pool operator, indicating which suppliers are consistently not meeting their generation bid. The Commission will not be able to police FSM's, since by their nature they will be transparent to oversight.

PRM suggests that the Commission issue a set of guidelines to consumers that suggest what safeguards consumers should identify when entering into FSM's - such as bonding requirements on the seller.

A19. Certificates of Convenience and Necessity. *Please comment on whether competitive sellers who supply electricity to an end user must obtain a Certificate of Convenience and Necessity from the Commission (unless the seller already has an applicable Certificate). Please describe whether any conditions on the certificate would be necessary.*

PRM suggests that aggregators be required to post a bond equal to some portion of their annual purchases on behalf of a group of customers. Suppliers that bid into the pool have a financial incentive to meet their obligations, as do those that enter into a bilateral contract. However, entities that deal in FSM's only cannot be overseen by the Commission - any contract breach will be between the seller and his retail customer.