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BEFORE THE ARIZONA CORPORATION COMMISSION

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WILLIAM A. MUNDELL
Chairman
JIM IRVIN
Commissioner
MARC SPITZER
Commissioner

IN THE MATTER OF THE GENERIC PROCEEDINGS CONCERNING ELECTRIC RESTRUCTURING

Docket No. E-00000A-02-0051

STAFF'S NOTICE OF FILING STAFF REPORT

Staff hereby provides notice of filing it's Staff Report in the Generic Docket, as directed in the Procedural Order dated February 11, 2002.

The Staff Report is approximately 225 pages in length. Accordingly, while this Notice of Filing is being provided to the entire service list in Docket No. E-00000A-02-0051, Staff has not undertaken to provide a copy of the Staff Report along with this Notice. Rather, Staff will make the document available to interested parties in the following manners.

First, the Staff Report is being converted and will be posted to the Commission's website, no later than Monday, March 25, 2002. In addition, the Staff Report will be available, upon request, in either e-mailed version, CD-ROM version, or hard copy.

Requests for e-mail, CD-ROM, or hard copy version of the Staff Report should be submitted to:

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...

RESPECTFULLY SUBMITTED this 22nd day of March, 2002.

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Original and ten copies of the foregoing filed this 22nd day of March, 2002, with:

Docket Control
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1200 West Washington
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Copy of the foregoing Notice mailed this 22nd day of March, 2002, to:

All parties of record

Nancy Roe

STAFF REPORT

IN THE

GENERIC ELECTRIC RESTRUCTURING DOCKET

E-00000A-02-0051

MARCH 22, 2002

STAFF REPORT

IN THE

GENERIC ELECTRIC

RESTRUCTURING

DOCKET

E-00000A-02-0051

MARCH 22, 2002

TABLE OF CONTENTS

PAGE

I. Executive Summary 1

II. History of Retail Electric Competition in Arizona 3

III. Summary of Alternative State Approaches 9

III a. Lessons of the California Electricity Crisis 13

IV. Staff's Answers to the Commissioners' Questions 17

Staff Responses to the Questions attached to Chairman Mundell's 1st Letter dated January 14, 2002 17

Staff Responses to the Questions attached to Commissioner Spitzer's Letter dated January 22, 2002 46

Staff Responses to the Questions attached to Chairman Mundell's 2nd Letter dated January 30, 2002 52

Staff Responses To The Questions Attached To Commissioner Irvin's Letter Of February 7, 2002 58

V. Staff's Vision and Recommendations 64

Appendix One: Detailed Summary of Other States Experiences 70

Appendix Two: Staff's Summary of the Responses to the Commissioners' Questions 116

Chairman Mundell's Letter of January 14, 2002 117

Commissioner Spitzer's Letter of January 22, 2002 187

Chairman Mundell's Letter of January 30, 2002 205

Commissioner Irvin's Letter of February 7, 2002 217

I. Executive Summary

Between January 14, 2002 and February 7, 2002 each of the Commissioners docketed letters expressing their opinions and seeking information pertaining to the restructuring of Arizona's electric industry. These letters contained extensive lists of questions for which the Commissioners requested detailed answers from the interested parties. On January 22, 2002, the Hearing Division of the Arizona Corporation Commission ("Commission") issued a Procedural Order which opened a generic docket on electric restructuring (Docket No. E-00000A-02-0051) ("generic docket"). On February 11, 2002, the Hearing Division issued a Procedural Order directing the Utilities Division Staff ("Staff") to file its Staff Report on the generic docket by March 22, 2002.

Staff, with its consultant Synapse Energy Economics, Inc. ("Synapse"), has developed this Staff report in order to provide guidance to the Commission as it continues to manage the transition of Arizona's electric industry towards competition. This Staff Report contains:

- A brief review of the history of the restructuring process in Arizona.
- A summary of alternative approaches to restructuring that have been implemented in different states with a detailed state by state discussion included as an appendix.
- Staff's answers to the Commissioners' questions raised in the above mentioned letters. A statement of Staff's overall vision and recommendations.
- A summary of the parties' answers to the Commissioners' questions is included as an Appendix.

In developing its recommendations Staff has reviewed the experience other states have had regarding restructuring, the answers parties provided to the Commissioners' questions, and the current Retail Electric Restructuring Rules ("rules") and settlement agreements. While developing its answers to the Commissioners' questions, Staff reached certain conclusions regarding Arizona's transition to a competitive electric industry.

In Staff's opinion, competition may have highly desirable results. This is because Arizona is not a low-cost state. However, in order for there to be a significant likelihood of those desirable results actually occurring, it is necessary to modify the existing rules. Absent such modifications the Commission's goal of creating a vibrant competitive power market which would provide real benefits to Arizona's consumers, will likely not be realized. Staff believes that the Commission should go forward with restructuring at a proper and deliberate pace while making the necessary modifications to the current structure. Staff believes that the Commission's immediate focus should be on issues affecting the procurement of capacity to serve standard offer customers.

Specifically, Staff recommends that the following issues be addressed in the generic docket:

1) Market power and market monitoring. To what extent and in what way should the Commission be involved in monitoring market conditions and/or mitigating the development of market power for generation and transmission?

2) The competitive bidding process. In addition to the concerns about competitive bidding that APS has raised in its variance request, Staff is concerned that the current rules offer no guidance as to how the competitive bidding process will work.

3) Transfer and separation of assets. The stated reason for requiring utilities to transfer their generation assets was to eliminate market power in the wholesale generation market. The analysis in this Staff Report and the issues APS raised in its variance request indicate that market power will not be mitigated by the transfer of assets required by the Retail Competition Rules. Thus, going forward with the separation and transfer envisioned in the current rules is unwise in Staff's view. Staff recommends that other options be considered such as requiring the transfer of assets to a functionally (but not legally) separate entity within the utility.

4) Transmission constraints. Staff has identified serious transmission constraints in this Staff Report. Staff believes that the issues surrounding these constraints (and the resulting must run requirements) significantly impact the development of the wholesale market for power and should be addressed in the generic docket.

5) Adjustor mechanisms for standard offer service. At least one Arizona utility will be implementing an adjustor mechanism for its standard offer rates in the near future. In light of the problems with the development of a competitive wholesale market discussed in this Staff Report and in APS' request for a variance, Staff believes it would be appropriate to reassess the need for such an adjustor mechanism.

6) Shopping credits and unbundling generally. The adequacy of the shopping credit (the cost a customer would not pay to their UDC if they take generation service from a competitor) has been identified as being highly significant in the development of a competitive retail market. Staff is opposed to imposing artificially high shopping credits in order to give an artificial boost to competitors. However, the shopping credits and unbundled rates now in effect should be examined in order to determine whether they are set at levels that are artificially low.

II. History of Retail Electric Competition in Arizona

In the Spring of 1994, California published its "Blue Book" on competition in the electric utility industry, starting a trend in the United States leading to the evaluation by many states of the potential for competition in electric energy services. On May 20, 1994, the Arizona Corporation Commission established Docket No. U-0000-94-165 to investigate the introduction of retail electric competition.

Phase I: Information Gathering and Stakeholder Participation

As soon as the new docket was opened, the Commission Staff commenced the gathering of information and planning for the retail electric competition effort. Incorporated in the planning and information gathering process was an extensive schedule of stakeholder participation workshops, task forces, and working group meetings.

On September 7, 1994, an introductory retail electric competition workshop was held and a wide variety of interested parties and stakeholders were invited to attend. One hundred eighteen representatives from utilities, consumer organizations, other power suppliers, and others attended the workshop. The workshop was summarized in a Staff Report dated October 1994.

A series of nine working group and task force meetings were held in 1995, which addressed competition options, implementation of the options, and advantages and disadvantages of the options. Fifty-one groups were represented on task forces, which focused on system markets, regulatory issues, and energy efficiency and environmental issues. Members of the task forces included representatives from utilities, consumer organizations, other power suppliers, and others. This work was summarized in the "Report of the Working Group on Retail Electric Competition," dated October 5, 1995.

In February 1996, Staff issued a request for comments on how to implement retail electric competition in Arizona. Comments were filed by 31 parties on June 28, 1996. Commenters included consumer groups, Arizona utilities, other suppliers, and other parties. Staff prepared a summary of the comments in July 1996.

Phase II: Initial Rulemaking (1996)

During the summer of 1996, the Commission Staff took into consideration all of the input, comments and suggestions from the public process and commenced the drafting of proposed Retail Electric Competition Rules.

On August 12, 1996, a workshop was held to explore and obtain feedback on a small number of options developed from the comments about introducing retail electric competition. There were 130 workshop participants including representatives from utilities, consumer organizations, other power suppliers, and others. Staff summarized the workshop in a report dated August 19, 1996.

On August 28, 1996, Staff issued a request for comments on a proposed rule that was drafted after the August 12 workshop. The requests were sent out and comments were due September 12, 1996. Comments were provided by 30 utilities, consumer organizations, and others.

On September 18, 1996, a workshop was held to discuss a revised draft rule. Ninety individuals attended the workshop including representatives from utilities, consumer organizations, other power suppliers, and others.

On October 1, 1996, the Commission Staff circulated a final version of the proposed Retail Electric Competition rules. By Decision No. 59870 (October 10, 1996), the Commission voted to commence the formal rulemaking process and directed the Hearing Division to schedule public comment sessions in Phoenix, Tucson, Yuma, Flagstaff, and Kingman, Arizona. The public comment sessions were held on December 2, 3, and 4, 1996.

On December 26, 1996, the Commission approved Decision No. 59943, which adopted the Retail Electric Competition Rules, A.A.C. R14-2-1601 through 1616.

Phase III: 1997/1998 Working Groups

In the 1996 Retail Electric Competition Rules order, the Commission recognized that the initial rules were merely a starting point and that future rule amendments would need to be made in order to improve the rules package. With that in mind, the Commission ordered that a number of working groups be established in order to work out the details needed to prepare Arizona for the commencement of competition in 1999. Those working groups were:

- Stranded Cost Working Group
- Unbundled Services and Standard Offer Working group
- Reliability and Safety Working Group
- Independent System Operator & Spot Market Development Working group
- Legal Working Group
- Customer Selection Working Group

Each of the Working Groups included a broad array of participants representing all of the stakeholders expressing interest in retail electric competition. Many of the working groups established committees and subcommittees to address specific issues. With the exception of the Reliability and Safety Working Group, which started its work in 1996, all other working groups commenced meetings in early 1997 and finished their work, including final reports, recommendations, and suggested rule wording changes and additions, by year end 1997.

Phase IV: 1998 Rule Amendments & Proposed Settlements

During February 1998, the Hearing Division conducted hearings on generic stranded cost issues.

On June 22, 1998, the Commission issued Decision No. 60977, the Stranded Cost Order, in association with the Retail Electric Competition Rules. The order allowed Affected Utilities a choice of two options for stranded cost recovery: the Divestiture/Auction Methodology or the Transition Revenues Methodology.

During 1998, the Customer Education Working Group and the Low Income Working Group met and issued reports.

On August 10, 1998, the Commission adopted amended rules on an emergency basis (Decision No. 61071). The Commission accepted written comments on the rules and revisions through October 8, 1998, and held public comment hearings on October 7, 1998, in Phoenix, Arizona and on October 8, 1998, in Tucson, Arizona.

The Commission Staff negotiated with various utilities in the late summer and fall of 1998. On November 5, 1998, the Commission Staff entered settlement agreements with Arizona Public Service Company and Tucson Electric Power Company. On November 24, 1998, a Procedural Order set the matter for hearing. On November 25, 1998, the Commission established an expedited procedural schedule for evidentiary hearings on the settlement proposal, setting a December 3, 1998 hearing date.

On November 30, 1998, the Arizona Attorney General and the Residential Utility Consumer Office filed Petitions for Special Action with the Arizona Supreme Court, claiming that the hearing schedule did not allow enough time for other parties to prepare. On December 1, 1998, Vice Chief Justice Charles E. Jones issued an order staying the settlement proceedings and scheduled the matter for oral argument. On December 9, 1998, the parties withdrew the settlement agreements, making the Supreme Court proceeding moot.

On December 11, 1998, the Commission adopted the emergency rules on a permanent basis in Decision No. 61272.

On December 23, 1998, the Commission issued a CC&N to Eastern Competitive Solutions, Inc. (Decision No. 61302). On December 30, 1998, the Commission issued a CC&N to PG&E Energy Services, (Decision No. 61303). These were the first "Electric Service Providers" to receive CC&Ns under the Retail Electric Competition Rules.

On December 31, 1998, the Commission held an Open Meeting and issued Decision No. 61309, which denied numerous Applications for Rehearing of Decision No. 61272.

At midnight on December 31, 1998, the Retail Electric Competition Rules went into effect, opening Arizona to competition for electric services.

Phase V: 1999 Stay, Rule Amendments, and Settlements

On January 4, 1999, the Arizona Attorney General's Office and the Residential Utility Consumer Office filed a suggested procedural schedule for resolution of the remaining issues in the Retail Electric Competition Rules docket.

On January 5, 1999, the Commission voted to approve Decision No. 61311, which stayed the effectiveness of the Retail Electric Competition Rules and related decisions, including the Stranded Cost decision (Decision No. 60977). (Note: the Decision was signed and docketed on January 11, 1999.) The Commission directed the Hearing Division to solicit additional public comment about electric competition.

On January 6, 1999, the Chief Hearing Officer issued a Procedural Order that ordered all interested parties, including Staff and Affected Utilities, to file comments by January 20, 1999, on the following:

- What issues still need to be resolved in the electric industry restructuring;
- The order in which the issues should be resolved;
- The method (such as informal discussions by parties, hearings, combinations, etc.) and timing to resolve the issues identified; and
- Any agreements/disagreements/clarifications to the January 4, 1999, joint proposal by RUCO and the Attorney General of a procedural schedule.

The Commission asked the Attorney General's Office, RUCO, APS, and TEP to start new settlement discussions. In January 1999, a number of parties commenced settlement discussions with Arizona Public Service Company and Tucson Electric Power Company. The Commission Staff was not invited to participate in the settlement discussions.

On January 26, 1999, the Chief Hearing Officer issued a Procedural Order that ordered all interested parties to file no later than January 29, 1999, additional proposed changes to the Rules, including any proposals for additional rules. In addition, parties were ordered to list the rules that the parties agree need not be amended and to list modifications to the RUCO/Attorney General's January 4, 1999, proposal regarding a procedural schedule for hearings on stranded costs and unbundled tariff issues.

On February 5, 1999, and March 12, 1999, the Hearing Division issued draft notices of proposed rulemaking for consideration by the Commission.

On April 23, 1999, the Commission adopted modifications to the Retail Electric Competition Rules and ordered that the proposed rule amendments be forwarded to the Secretary of State and that public comment hearings be scheduled (Decision No. 61634).

On April 27, 1999, the Commission issued Decision No. 61677, which amended Decision No. 60977, the Stranded Cost decision. The decision also ordered the Hearing Division to issue a Procedural Order setting dates for consideration of stranded cost and unbundled tariffs for each Affected Utility.

The revised Retail Electric Competition Rules were published in the Arizona Administrative Register on May 14, 1999. Public comment sessions were scheduled and held in Phoenix on June 14, and 23, 1999, and in Tucson on June 17, and 21, 1999. Interested parties were ordered to file written comments to the revised rules no later than May 14, 1999, and to file responsive comments no later than June 4, 1999.

On May 18, 1999, Arizona Public Service Company filed for approval of a settlement agreement. The agreement was signed by APS, Arizonans for Electric Choice and Competition, the Arizona Community Action Association, and the Residential Utility Consumer Office. The Commission held six days of evidentiary hearings during July 1999. After the hearing, the hearing officer issued a proposed order, which was scheduled for Commission consideration at an Open Meeting. Various parties filed exceptions to the proposed order. The Commission held a daylong Open Meeting on the settlement on September 23, 1999. The Commission adopted modifications to the proposed order and then approved the order as modified in Decision No. 61973 on October 6, 1999.

On June 9, 1999, Tucson Electric Power Company filed for approval of a settlement agreement. The agreement was signed by TEP, Arizonans for Electric Choice and Competition, the Arizona Community Action Association, and the Residential Utility Consumer Office. The Commission held a three-day evidentiary hearing in Tucson in August of 1999. After the hearing, the hearing officer issued a proposed order, which was scheduled for Commission consideration at an Open Meeting. Various parties filed exceptions to the proposed order. The Commission considered the proposed order on November 30, 1999, at a daylong Open Meeting. The Commission adopted modifications to the proposed order and then approved the order as modified in Decision No. 62301.

During June and July 1999, Staff scheduled a number of workshops to address "technical issues" as requested by the Chief Hearing Officer. Those workshops were:

- Interconnection and Distributed Generation — June 28, 1999
- Metering Issues — July 1, 1999
- Load Profiling — July 12, 1999
- Direct Access Services Requests — July 13, 1999
- Metering: EDI Formats — July 16, 1999

On September 29, 1999, the Commission issued Decision No. 61969, which approved the revised Retail Electric Competition Rules. In the decision, the Commission ordered the establishment of the Process Standardization Working Group and set a deadline for creation of Standardized Operating Procedures to be used by all market participants.

Phase VI: 2000 Revisions to the Electric Competition Rules

The Process Standardization Working Group met regularly in late 1999, 2000, and 2001. The Working Group developed a number of recommendations that were designed to correct inconsistencies among the various rules and further define and clarify the intent of the rules.

On April 28, 2000, Commission Staff requested interested parties to file comments for clarifying revisions to the Retail Electric Competition Rules.

On July 5, 2000, the Commission Staff forwarded to the Commission proposed revisions to the rules. The Notice of Proposed Rulemaking was published in the Arizona Administrative Register on August 11, 2000. A public comment hearing was held on September 15, 2000. On October 10, 2000, in Decision No. 62924, the Commission approved the revised rules.

III. Summary of Alternative State Approaches

The 1990s: Growing Enthusiasm for Restructuring

About one half of the states in the United States embarked on the process of electric restructuring during the 1990s. There was a rising tide of enthusiasm for restructuring through 1999, and it seemed likely that other states would join in the process. At the Federal level, there was talk of mandating restructuring, and the Federal Energy Regulatory Commission (FERC) came to be increasingly committed to competition in wholesale electric markets and fair access to the transmission grid by independent power producers.

Reassessment in 2000/2001

In 2000/2001, however, the unexpected and severe California electricity crisis was dramatic proof of the dangers of embarking on restructuring in unfavorable circumstances and without a well-designed market structure. The wholesale electricity price increases in California and other regions, combined with delays in forming regional transmission organizations (RTOs), and difficulties in getting the retail market established for residential and small business customers, sobered up the enthusiasts, and led to a nationwide reassessment of restructuring.

Variety of State Responses

This survey is intended to document the responses of different states across the country to these developments. We have selected 15 states – some of which we have discussed in detail, others in a more summary or focused fashion. The states have been selected to show a variety of responses, and to attempt to explain why the responses have differed.

Some states had already established workably competitive wholesale markets with direct access by large business customers and even some residential and small business customers, and it is not surprising that most of them decided to stay the course. In our survey, Illinois, Maine, Ohio and Pennsylvania are in this group.

On the other hand, some states that had not yet embarked on restructuring, including Florida in our sample, decided to wait and see. Colorado, which is also in our sample, had already decided not to restructure. Others, including Vermont in our sample, had come close to restructuring, but have also decided to wait and see.

Of particular interest for states like Arizona that have gone some distance toward restructuring, but have not yet reached the point of no return, are those states that were in the process of restructuring, or were on the verge of restructuring. What have they done, and why?

We have picked one state, Texas, that has remained totally committed to restructuring, and opened up its retail market to competition on schedule on January 1, 2002. The Texas authorities believe that the experience of the first months of retail access is bearing out their optimism.

Few if any other states that are on the brink of restructuring have remained quite as sanguine about the prospects as has Texas. In our sample, Montana, New Mexico and Oregon have all delayed the process in one way or another, and retained the protection of utility regulation for an extended period. Two states – California itself and its neighbor Nevada – have completely abandoned restructuring, and one, Arkansas, which has already decided on a two-year delay, is considering a prolonged delay.

Lessons from the More Successful States

Broadly, certain lessons can be learned from those states that had already undergone electric restructuring – more or less successfully – before the California crisis erupted. In these states – including Illinois, Maine, Ohio and Pennsylvania in our sample – the wholesale market is functioning better in states with established regional ISOs, such as Maine and Pennsylvania. And even in these states, their ISOs and related power pools – NEPOOL and PJM respectively – have seen unjustifiably high prices at times, barriers to merchant power interconnection, and transmission pricing and congestion problems. In Illinois and Ohio, it is proving difficult to get the Midwest RTO off the ground and approved by FERC. This could result in shortfalls of supply or transmission inadequacy which could undermine competition and lead to unreasonable price increases.

In all of these four states, it is proving difficult to get retail competition established in the residential and small business market. There is considerable variation between different parts of each state, e.g., in Ohio, the northern Ohio service territories of Cleveland Electric Illuminating Company and Toledo Edison account for almost all the switching in the state. The utilities' high prices provide the motive, and the formation of large governmental aggregators provides the means. Governmental aggregation is made relatively easy in Ohio because it can be of the opt-out variety – customers in a municipal area are included unless they choose to opt out.

In Illinois, the Chicago area served by Commonwealth Edison Company (ComEd) accounts for most of the state's switching. Again, the motive is provided by ComEd's high rates. In Illinois, aggregation has not been a factor; rather, it seems that the sheer concentration of customers in Chicago makes it feasible for marketers to sign them up without incurring excessive acquisition costs.

In Maine, the legislation provides an alternative, indirect, means of bringing competition to small retail customers. Standard offer service is not part of the distribution utility's scope; it is put out to bid and awarded to competitive providers. Maine regards this approach as successful.

In Pennsylvania, the "poster child" for retail restructuring, the development of the small retail market is also very uneven. Pennsylvania's reputation was based on the adequacy of its "shopping credits" – the credit given by utilities to customers who no longer take generation service. The deduction of a relatively low exit fee for utility stranded costs, and the inclusion in the shopping credit of a retail adder to reflect alternative providers' retail overhead and marketing costs, are among the methods for increasing shopping credits. However, Pennsylvania's approach has not proved that much more successful in the face of market price increases than the approaches of other states. Fully 30% of the customers who had switched to the competitive market in Pennsylvania have returned to utility standard offer service in the past year or so.

Optimism in Texas and Pessimism Elsewhere

Why did Texas go ahead on January 1? The authorities checked through the problems of California and decided that their own situation, and the structures that the legislature and commission had put in place, would prevent anything like that from happening in Texas. Perhaps the most significant differences are in the wholesale generation market. The Texas market benefits from having state control of its own independent system operator, and the state commission can accordingly develop consistent policies for the wholesale and retail markets. Texas prizes the isolation of its electric system, which protects it from being drawn into market crises in neighboring states. The ERCOT-ISO is encouraging the timely and adequate construction of new power plants and transmission lines, and there appears to be sufficient generation capacity.

The Texas legislation also favors the creation of a workably competitive wholesale market by requiring utilities to auction off 15% of their generation to competitive providers, and by limiting the ownership of generation assets by any one corporation to no more than 20% of the market.

Regarding the Texas retail market, it remains to be seen whether it develops for residential and small business customers as well as for large business customers. However, early signs are promising: a number of customers appear to be switching suppliers, and governmental aggregation has already succeeded in gaining a foothold in the market.

By contrast with Texas, Nevada, which had come close to allowing its two principal investor-owned utilities to divest their generation assets, abandoned its restructuring effort. The wholesale market simply wasn't ready for it. Similar considerations led to a successful effort by Montana to retain effective jurisdiction over the generation assets of Montana Power Company, even though those assets had already been divested to PPL Montana, a non-affiliated company. And in Virginia, fearing that loss of jurisdiction would result in higher prices – Virginia utilities having low embedded costs that would likely remain below the level of market prices – the Commission is trying to maintain jurisdiction by restricting transfers to utility generation divisions, not separate corporate entities.

Summary and Recommendations

In summary, there are very few states that can clearly demonstrate benefits from retail competition to date – and very few small customers have seen significant, lasting benefits. Experience has shown that there are risks associated with retail competition – risks of market power and increased electricity prices, risks associated with the loss of state regulatory jurisdiction, and even risks of electricity market failure. How states are responding to this changing situation depends as much on their views regarding markets versus regulation, as on the evidence provided by the experience to date. In looking at emerging competitive markets, state authorities seem to be able to see the glass as either half empty or half full.

Our foremost recommendation is that the risks must be carefully weighed against the potential benefits before taking irrevocable steps to restructure electric utilities. Restructuring should only be pursued if it can be demonstrated that the benefits outweigh the risks.

A smoothly functioning, well-designed, competitive wholesale electricity market is the most important condition necessary to reduce the risks and increase the potential benefits of retail competition. The appropriate design and structure of the retail market is also necessary to achieve the benefits of retail competition; including the design of the shopping credits, the availability of competitive marketers, and provisions for aggregation or competition to provide standard offer service. If these conditions are not in place, the risk may not be worth taking.

III a. Lessons of the California Electricity Crisis

California is not a model of what to do, it is an example of what *not* to do. Here, we list some of the electricity restructuring features and developments that resulted in the state's electricity crisis, and the lessons that can be learned.

1. Power Supply Shortages.

A tight power supply situation resulted in a malfunctioning of the poorly designed California ISO, and in opportunistic behavior by suppliers which enabled them to manipulate prices. Prices rose far above production costs.[1] Similar, though less extreme, price spikes have occurred in other parts of the country. If the supply of power becomes tight in the bulk power market, it is difficult to avoid extreme price spikes. This is perhaps the most widely applicable lesson of the California electricity crisis.

In California, demand was higher than expected, and supply was less than expected. On the supply side, hydroelectric generation was low, owing to low precipitation. Also, owing to environmental concerns, it has been difficult for generators or IPPs to site new plants in California, and for a long period, which ended only recently, no new plants were constructed in the state. Siting needs to be made consistent with demand growth, and someone needs to plan and build enough new capacity.[2]

There are features of a deregulated power supply market that can avoid or at least mitigate supply shortfalls. Some planning and/or pricing mechanisms are needed to ensure the adequate construction of new power plants and coordinated expansion of the transmission system.

The RTO may be the appropriate agency for planning and coordination. This is the view of Patrick H. Wood III, the FERC chairman. In a striking admission that generation markets need some kind of regional (and state) planning, he said recently, "The RTO is a recognition that the power business must be planned and operated regionally...The RTO ought to be the respected body that initiates regional planning by saying, 'In this large area we need these four projects to be built.' Then it becomes the states' responsibility." (BusinessWeek, March 4, 2002, p 30B) Wood also recognizes that price caps may be necessary to deal with price hikes; FERC responded slowly to the need for a price cap in the West in the wake of the California crisis, but finally imposed one.[3]

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[1] There is a dispute about whether or not supply was actually deficient in California, or whether the whole crisis was created by manipulative suppliers. Here, we assume that there was market manipulation, but that it would not have been so prevalent if supplies had not been at least somewhat tight (in the sense of capacity reserve margins being narrow) in the first place.

[2] Contributing to the California crisis was the way in which both California and the Pacific Northwest came to rely on power imports from each other in the late 1990s. When hydroelectric capability was reduced in 1990, while the regional economies were booming, a tight supply situation developed. Throughout, California relied upon power from the Southwest, and its increased dependence in 2000/2001 put pressure on the market in Arizona and the rest of the Southwest.

[3] Partial or regional price caps can distort the market or lead to gaming. It has been noted earlier that suppliers sold power to out-of-state marketers, who then resold it in-state. Another result of California-only price caps was that

California's chaotic regulatory structure probably contributed to the generation deficiency; investors in new generation capacity need a favorable return on investment with regulatory and market certainty. It is reported that belatedly several new plants are coming on-line, but there is no guarantee that the cycle may not repeat itself, with a glut of power followed by a shortage later.

2. ISO/RTO design.

The California crisis was exacerbated by poor design of the California ISO. The problems occurred in the functioning of the California Power Exchange's day-ahead market and the ISO's real time purchases (to make up, on an emergency basis, any remaining power shortfall on the day itself). For example, when prices rose in May and June 2000, the ISO capped the price of power, but this cap did not apply to the ISO's emergency purchases in the real-time market. The result was that suppliers withdrew power from the day-ahead market, forcing the ISO to purchase more and more "emergency" power at higher prices in the real-time market.[4] This aberration peaked on July 28, 2000, when fully 28 percent of load was met on the real-time market. But even in November and December 2000, the ISO was still declaring emergencies when the generating reserve margin was apparently around 40 percent.

FERC's ongoing task is to encourage the creation of more effective ISOs or RTOs. The West is lagging behind some other regions in this regard. Even in those regions that had a head start, because they already had tight power pools, ISOs are still undergoing evolution.

3. Market power.

The California experience of market manipulation – strategic withdrawal of capacity from the market and opportunistic pricing – shows that market power is an ever-present concern in deregulated bulk power supply markets, especially when supplies are tight. Wholesale markets need to be characterized by adequate supplies, as noted earlier. They also need to have a number of effective and independent suppliers and low barriers to entry by new generators.

4. Retail versus wholesale prices.

The combination of regulated low retail prices and high and volatile wholesale prices had two unintended effects. First, it made the retail market unprofitable for third-party suppliers. After some initial skirmishes in the retail market, they withdrew and concentrated on sales in the wholesale market.[5] The lesson is that if and when states wish to make the retail market attractive to suppliers, they need to allow a differential between wholesale and retail prices sufficient to

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power which might have been available in-state flowed out-of-state, period. There was a resulting loss of supply in California which contributed to make the market there tighter. These statements refer to price caps in general and should not be construed to indicate that Staff supports the price caps ultimately implemented by the FERC.

[4] There were other twists. One was that the ISO could purchase power from out-of-state at higher prices than it could pay to in-state suppliers. This resulted in "laundering" of power when suppliers sold it to out-of-state marketers who then resold it into the California market. Another maneuver was for generators with market power on the export side of a bottleneck to game the ISO's congestion pricing scheme by over-scheduling capacity. The ISO would then be forced to buy decremental generation, which the same generators would offer at low prices, enhancing their net revenues.

[5] Green power was an exception, owing to a special customer credit for green power.

cover retail marketing costs. Looked at from another perspective, states need to allow customers a sufficient shopping credit to make shopping pay.

Second, the rise in wholesale prices put extreme financial pressure on the distribution utilities, who could not pass the price increases on to their standard offer customers in the retail market. (When suppliers became afraid that the utilities would go bankrupt and not be able to pay, they withheld supplies. Their fears were justified: California's largest utility, Pacific Gas & Electric, filed for Chapter 11 bankruptcy protection from its creditors in April 2001.)

5. Demand-side inflexibility.

The protection that retail customers initially had against wholesale price increases in California made demand less responsive than it could have been. As retail markets develop and real-time pricing becomes more economical and widespread, energy conservation and load management are likely to mitigate supply shortfalls.

6. Poorly planned divestiture.

In California, utilities divested most of their power plants into an imperfectly competitive market. The retail market design favored standard offer service, and the utilities were required to purchase power for standard offer service on the Cal PX spot market. This was a recipe for disaster. Utilities were dependent on the PX for more than half of their purchases, contrasted with less than 20% in most other divestiture situations, like that in New England, where utilities rely for the most part on bilateral, long-term purchased power agreements. Limiting the utilities' ability to prudently purchase energy is never sound regulatory policy. It is especially imprudent when the utilities are forced to rely on an untested and flawed entity like the PX.

Utility divestiture of generation assets needs to be carefully planned. The California experience in this regard can be avoided by ensuring that the wholesale generation market is competitive before divestiture takes place, that divestiture itself contributes to the competitiveness of the market (e.g., by asset sales to several separate unaffiliated generators), and that Utilities are able to make better arrangements for utility buy-back of power for standard offer service, such as a mix of spot market purchases and contracts of different duration.

7. Natural gas dependence.

High gas prices and gas pipeline bottlenecks, allegedly exacerbated by market power in the gas market, contributed to California's electricity crisis. Perhaps there is over-dependence on natural gas among electricity generators in California, who use gas to generate more than half of their power.

The potential problem of lack of fuel diversity is difficult to avoid in deregulated markets; there is a tendency for most or all generators to build gas-fired plants. The solution could be for a regional entity such as the RTO to monitor this issue and provide incentives for fuel diversity.

8. <u>Clumsy and belated state intervention.</u>

State (and Federal) authorities were slow to respond to early warning signs of the California crisis. FERC finally responded by instituting region-wide price caps. However, California, through its Department of Water Resources, has now entered into long-term purchased power agreements (which its utilities had foolishly been prohibited from doing) at high prices, and is considering buying the transmission grid from the utilities to help them overcome their financial crisis.

9. <u>Stranded cost recovery.</u>

The mechanism by which the stranded cost recovery charge was set in California was defective. Instead of a fixed per-kWh charge on the rates for delivery service, the charge was variable. The higher the wholesale market price, the lower the charge, and the lower the wholesale market price, the higher the charge. This variation had the result of undermining the retail supply market, because suppliers who offered customers a fixed price never knew what revenue they would be getting on a net-of-stranded cost basis.

IV. Staff's Answers to the Commissioners' Questions

Staff Responses to the Questions attached to Chairman Mundell's 1st Letter dated January 14, 2002

I. Identification of Retail Electric Products and Services for Which Competition Could Bring Benefits

A. What are the possible goods and services traditionally provided by the electric utility for which retail competition is possible? You may address the following categories of goods and services:

1. generation, including baseload, intermediate and peaking power; green power; distributed generation; firm and nonfirm power; long- and short-term contracts; backup and coordination services.

The pro-competition view is that competition is possible for all generation services. According to this view, retail customers would be allowed to choose generation suppliers. Those suppliers would obtain some services, such as backup and coordination services, on the wholesale market, which would also be competitive.

Second thoughts have centered on the conditions that have to be in place if there is to be effective competition in an orderly generation market. In particular, a competitive retail market will only bring benefits to consumers if the *wholesale* generation market is effectively competitive. There must be a number of competitive suppliers, low barriers to access by new suppliers, adequate capacity and reserves, a well-functioning Regional Transmission Organization (RTO), and coordinated expansion of the transmission grid. Although in Arizona, the Commission has granted CC&Ns to a significant number of competitive suppliers of wholesale generation; transmission constraints (described below) may hinder their ability to bid to supply Arizona's more populated areas.

Concentration of generation ownership and control is now recognized as a key problem in the United Kingdom's restructuring efforts in the 1990s, and is the subject of numerous "market power" studies in the United States. It is difficult to apply standard antitrust law analysis to the electricity generation market because control of (and availability of) transmission is as important as control of generation. Thus, while Arizona may have a significant number of merchant generators, the incumbent utilities still may be able to exercise significant market power.

Another area of concern is the still-evolving RTO situation in the Southwest. The earliest projected operational date for WestConnect is late 2004. (Most of the states that have taken the lead in electricity restructuring, such as those in the Northeast, already had tight power pools that could form the basis for RTOs. Even in these states, RTOs have run into difficulties and are still evolving.)

Since the current Competition Rules require the utilities to purchase power for their standard offer customers from the competitive market, a well-functioning competitive wholesale market is necessary and may result in benefits for consumers even if retail competition never becomes widespread. Thus, Staff believes the Commission's focus should be on the development of a vibrant wholesale generation market.

On the retail side, even if large industrial and commercial customers are able to successfully gain access to alternative energy suppliers, smaller customers may not be able to do so. Risk-aversion and lack of information are factors here. From a supplier perspective, high customer acquisition costs, which have to include marketing, office infrastructure, etc., have proven to be a barrier to entry into the small-customer market in almost all states that have introduced retail competition. However, as noted above, since the current Competition Rules require the utilities to purchase power for their standard offer customers in a competitive manner, a well-functioning competitive wholesale market may result in benefits for consumers even if retail competition never becomes widespread.

Recent experience has shown that effective competition is very difficult to achieve during peak periods. When demand is close to available supply, generation suppliers possess potential market power, and have opportunities for profitable strategic withdrawal of capacity and overpricing. Given the price spikes in California and elsewhere, we know that market rules and regulations have to be structured to avoid opportunistic supplier behavior, and independent market monitoring is needed. There must be a large number of suppliers, and none with a large share of supply. Generally, adequacy of supply is essential -- plans or incentives for new plant and transmission construction are needed. In Arizona, the necessary incentives for new plant construction are apparently in place; however, plans or incentives to resolve transmission constraints are needed.

Distributed generation may be able to develop through competition, but will require intensive coordination with distribution utilities. Many commentators are concerned that the lack of a level playing field for distributed generation will require significant regulatory support for some time, as noted below.

2. distribution services, including ownership, construction, maintenance and repair of the physical lines; metering ownership, installation, reading and data analysis; and the process of planning for and negotiating with distributed generators.

It is generally agreed that the physical lines should be owned, constructed, maintained and repaired by regulated distribution utilities. (Utilities may outsource some of these services to competitive suppliers.)

Metering and billing cycle services may be competitively provided, according to the pro-competition view. However, we are not aware of any benefits that have been demonstrated to date from the several attempts to make the metering market competitive. The more fundamental issue of whether or not retail and wholesale generation are competitive should be resolved before addressing the complexities of a competitive metering market. Staff does not advocate foreclosing opportunities for competition in metering services; rather, Staff believes the Commission's focus on developing competition should be elsewhere (the wholesale generation market).

Regarding distributed generators, we believe that there should be significant reforms at both the wholesale and the retail level. On the wholesale level, the market needs to be able to recognize distributed generation resources and provide a means of compensating these resources for the benefits they provide to system reliability and the competitive bidding process. On a retail level, the distribution utility should provide appropriate incentives to distributed resources to reflect the benefits provided (enhanced local reliability and deferral of distribution system upgrades). The Commission would need to provide a regulated framework within which distributed generation could be fostered.

3. aggregation services, such as load profiling; load planning; customer services; data analysis; billing; generation planning; power supply acquisition; demand side management; energy efficiency and other services related to matching supply and demand.

We would draw a distinction between customer services (including billing cycle services), and coordination services related to matching supply and demand. As noted above, the pro-competition view is that customer services including billing cycle services can and should be competitively provided. Ultimately, a customer would pick one provider -- electric service provider (ESP) or retail supplier -- whom he or she would contract with and could pay for all services. (The provider would obtain distribution and perhaps metering services from the distribution utility, and would generate power or purchase it from the competitive wholesale market.) In some models (like Arizona's), however, the customer would get two separate bills -- one for distribution and customer services from the utility and one for energy from the energy services provider - or a consolidated bill from either entity.

Coordination services such as load profiling related to matching supply and demand need to be provided by the distribution utility and further coordinated on an inter-system basis by an entity such as A.I.S.A. or an RTO. The RTOs – even those that have evolved from highly cooperative pools – are still working out methods for how to address coordination services at the regional level. In the case of WestConnect and its predecessor, Desert STAR, there has been no attempt to address the details of retail competition because each participating state has its own vision ranging from no retail competition to various unique retail competition model for each state implemented at different points in time.

Second thoughts center, first, on the problem of planning a system that remains physically integrated, even when there are many participants. F.E.R.C. has recognized that RTOs need to influence or guide new generation construction and the expansion of the transmission grid, on a coordinated basis. This could be called "indicative planning" as opposed to rigid centralized planning.

Energy efficiency and demand-side management (DSM) are problematic both under restructuring and under the traditional regulatory regime. Asking utilities to fund DSM projects is essentially asking them to pay for a reduction in their business. This is true whether the market is competitive or not. Nevertheless promoting DSM is an important public policy goal. Vermont, which has not restructured its retail electric industry, has developed an independent efficiency utility to provide services to all customers of the state's vertically integrated electric utilities. Such a central, coordinated approach, with significant administrative cost savings, may be a model for other states.

B. For each good or service for which competition is possible, what are the possible benefits of competition for each good and service?

1. What are the potential price benefits?

The essential argument in favor of competition, as opposed to regulation, for any of these products is that prices will be lower because financial incentives favor efficient operations and aggressive pricing. Additionally, investments in generation resources that turn out poorly will no longer have to be supported by consumers – there is a shift in risk from consumers to merchant generators who are better equipped to deal with the risk.

Second thoughts center on two principal concerns. One is that, if the market is not fully competitive, prices may rise above competitive levels as a result of the exercise of market power. While this was always conceded to be a potential problem, the U.S. Department of Energy and others have found that market power is more prevalent than had been anticipated. In states such as Colorado and Arkansas that have commissioned market power studies, the finding that the wholesale generation market would not be competitive with the current utility ownership of most power plants has resulted in a delay in retail restructuring.

Another concern is based on the fundamental nature of the electricity system as an integrated system. Even some economists, such as Paul Joskow, who believe in electricity competition in principle, have acknowledged that "economies of scope" -- such as the ability to coordinate operations and system planning which we have referred to above -- may be strong enough to outweigh the efficiency gains from competition.[6]

The price benefits of competitive generation are likely to differ for different types of customers, with benefits being greatest for large customers and smallest (to the extent that they exist at all) for small customers.

Price impacts are likely to be different for states with low-price electricity than for high-priced states. Competitive generation markets are likely to lead to a leveling of rates in a region, so high-cost states are most likely to see prices going down, and low-cost states might see them increasing. A review of restructuring activities to date shows that states with high-cost power, such as California and states in the Northeast, have led the way in restructuring. Low power costs

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[6] Report in Arizona Daily Star, Tucson, February 1, 2002, of speech by Paul Joskow at Arizona State University.

have contributed to delays in restructuring in states like Colorado[7] and Arkansas, in addition to market power concerns.

2. Do the price benefits differ in the short-term and long-term?

Probably, yes. In the short term, price benefits will depend on the difference between regulated utility prices and market prices. The pro-competition view was that there would be some residual price benefit resulting from efficiency. It was also anticipated that there would be an orderly expansion of competitive supplies to match demand. In these circumstances, the price benefits would presumably increase gradually over time as the market became increasingly more efficient.

Second thoughts have resulted from the crises in California and the Mid-west, and less extreme price fluctuations in other parts of the country. Now, it is widely acknowledged that if supplies are tight, consumers can be gouged in the short term. There is the danger of a boom-and-bust cycle in which overproduction in one period leads to low prices and under investment for the next period, with the result that prices in the next period are high, there is over investment for the following period, and so on.

Another view is that the California crisis had nothing to do with supplies actually being tight but rather was the result of artificial supply restrictions (of both generation and transmission) created by some generators participating in the California market.

Currently, after a period of high prices and a plant building boom, construction plans may be cut back in response to oversupply, current economic conditions, and low prices. Market prices are likely to be quite low for the forthcoming period. However, without some kind of guidance by RTOs or other entities responsible for ensuring market stability, low prices could result in under-building of new capacity and raise the specter of a new round of price increases and even shortages down the road.

Shortages and price hikes could be mitigated by customer responses. Gradually, it is likely that demand will become more responsive to price changes, through real-time pricing and load management, but today most customers still have limited ability or incentive to respond to supply conditions.

Thus, one significant disadvantage of competitive generation markets is price volatility both in the long and short run. In addition, the potential to exercise market power is the greatest during times of short supply, so this risk is exacerbated by the cyclical effect. Thus, it is necessary for the Commission to ensure that adequate supply is and will be available and that market power concerns are addressed in order for restructuring to result in benefits to consumers. Possible solutions to these problems include planning and/or incentive pricing for adequate

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[7] Colorado may have low retail rates but it is a high cost transmission state because its load is located on one side of the Rockies and the generation is located on the other. This results in long transmission lines that are difficult to site and build thus yielding a high cost per mile. This is the reason that the Rocky Mountain reliability sub-region of WSCC has been reluctant to join any RTO because others do not want to share in their transmission cost due to a cost shift to other states.

generation and transmission capacity expansion, wholesale power market redesign, increases in the number of competitive suppliers, and selective price caps.

3. What are the potential non-price benefits?

The pro-competition view is that restructuring and competition will spur innovation, diversification, and new products, e.g., efficiency and load management services and advanced metering. Apart from the hopes for load management through real-time pricing, there seems to be little progress in this area so far. Customer choice is seen as an advantage in and of itself, provided that competitive providers come forward with a variety of service offerings. In some markets, competitive providers have not yet come forward.

4. Are there any other potential benefits (e.g., environmental, energy security, etc.)?

Renewable portfolio standards can be introduced in either a regulated utility system or a competitive generation market. Some have argued that green power offerings in a competitive market will help promote environmental improvements. There has been some limited success in the area of green power offerings, although most of these are from *existing*, rather than new, resources.

Arguably, issues of environment and energy security can be more easily dealt with in a planned, regulated industry than a competitive one but this is not necessarily so. The demand for competitively offered green power products is unlikely to address the complex and challenging environmental issues facing the electricity industry, and is not the most effective means of addressing these issues from a public policy perspective. Plant siting can be made conditional on meeting environmental standards in either a regulated or competitive system. But restrictions on plant siting might inhibit the competitive market, e.g. a showing of need is generally required in a regulated utility system but is not required for a merchant power facility.[8]

The pro-competition view suggested that regulatory burdens would be reduced by restructuring (e.g. there would be no need to deal with issues like stranded costs, periodic rate cases, etc.). Second thoughts have resulted from the complexity of restructuring, the experience of crisis management and re-regulation in some instances, and the recognition that even if restructuring ultimately brings benefits to consumers, a good deal of regulation will still be required to deal with the evolution of the marketplace and its institutions.

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[8] Environmental restrictions on plant siting should not inhibit the development of a competitive market as long as they are applied to all applicants consistently. The necessity of a showing of need may inhibit the development of competition, however. Competition is not necessarily inconsistent with environmental concerns. For instance, the automobile industry is highly competitive and yet today's automobiles are several times less polluting than those built in previous decades.

II. Determination of the Feasibility of Competition.

A. Are the product and geographic markets for the good or service conducive to effective competition or manipulation by a single entity? For example--

1. Are there economies of scale which make it most efficient for the service to be provided by a single company?

Staff believes that the magnitude of economies of scale for generation services are insufficient to undermine the argument for competitive generation.

Economies of scale do exist for both distribution and transmission services. Competition for these services would result in inefficient duplication of assets.

The metering technology that is currently employed for the vast majority of customers is characterized by economies of scale. New metering technology may not be subject to such scale economies and thus competition for metering services should be possible. However, there is little evidence that such competition will offer substantial benefits to consumers.

2. Are there economies of scope which make it most efficient for the service to be provided in a bundle with certain other services?

Clearly, the pro-competition view is (or was) that economies of scope were not a major factor in the electricity industry. As noted under I.B.1 above, economists have been having second thoughts on this subject. It is possible that the ability to coordinate operations and system planning which we have referred to above -- may be sufficiently strong to outweigh the efficiency gains in the generation market from unbundling and competition.

These same economies of scope may create problems of vertical market power in a deregulated marketplace. To the extent that there are advantages to jointly providing both generation and wires services (transmission and distribution), a utility that continues to provide generation may have advantages over competitive generation suppliers. Such potential for vertical market power also makes it essential that the relationships between affiliated generation and wire services companies be closely monitored.

B. Are or will there be a sufficient number of competitors in each potentially competitive market?

1. Is the product or service one which viable competitors will actually be interested in providing?

In the case of *wholesale* generation, it is clear that there are many companies that are interested in entering the market, provided the conditions are suitable. These conditions were discussed at the outset. They include the absence of incumbent suppliers that have dominant market shares, and the absence of barriers to entry, e.g. with regard to siting new power plants and getting access to transmission facilities.

The pro-competition view took it for granted that competitive suppliers would move into deregulated markets. Second thoughts, in light of the experience of a number of states that have provided retail access, are more refined. Conditions in the *retail* market for energy services have generally *not* been conducive to significant entry. Please see the response to the following question.

2. Is the cost of aggregating customers sufficiently small, relative to likely revenues, such that new suppliers will find it profitable to enter?

Large commercial and industrial customers, who can negotiate effectively with suppliers and whose loads are sufficient to attract supplier interest, have had significant success in moving to direct access (outside of Arizona). Residential and small commercial customers have had the opposite experience.

In the small customer market, the profitability of retail market entry has generally not been sufficient to overcome the acquisition and aggregation costs for new suppliers, who have had to compete with the incumbent utility or other designated standard offer provider. Few suppliers have entered the small retail market aggressively, and retail customers have tended to remain with standard offer service.

As noted above, much depends on the relative prices of standard offer and market suppliers. The general problem is that shopping credits have been inadequate to make competitive service attractive. Putting it another way, commissions have made every effort to keep standard offer service prices down, and this has made the market unattractive to alternative suppliers and has given customers little incentive to switch.

There is the possible exception of a few states such as Pennsylvania, where the shopping credit has been adequate -- or at least *was* adequate in comparison to wholesale prices when those prices were low. It is now being recognized that the shopping credit must be significantly higher than the wholesale energy price if it is to be sufficient to attract customers to the competitive market and provide suppliers a margin of profitability. First, it needs to take into account the (often low) load factor of small customers, i.e., needs to include a cost to account for peak period usage and installed generating capacity. Second, a retail adder is required to cover marketing and other retailing costs.[9]

Even in the states where retail competition has been deemed a success, stranded cost recovery has sometimes undermined customer migration to the competitive market. In Connecticut, for example, a stranded cost charge which is in effect an "exit fee" reduces the effective shopping credit.

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[9] A Connecticut ruling set the retail price of generation services "to include an adder to the wholesale cost of procuring generation to anticipate the retail expenses that will be experienced by competitive electric suppliers, thereby stimulating competition with the standard offer." Connecticut Department of Public Utility Control, Docket No. 99-03-35, *DPUC Determination of the United Illuminating Company's Standard Offer*, October 1, 1999. A study done for Staff of the Arkansas PSC estimated retailing costs at one cent per kWh, while Entergy's estimate was one quarter of one cent. Arkansas PSC *Progress Report to the General Assembly on the Development of Competition in Electric Markets and the Impact on Retail Customers*, Nov. 28, 2000.

There has been a marked tendency for the numbers of customers switching to competitive service to fluctuate according to market conditions. The "prodigal customer" situation results when customers switch to competitive suppliers when market prices are low, and switch back to standard offer service when market prices are high. At times during the past two years, market prices have been high relative to standard offer service, and large numbers of customers have returned to the utilities. In some cases, energy service providers facing high wholesale prices have exited the retail market and dropped customers, who have then defaulted to utility service. Now that prices have been falling in some areas, we can again expect more switching to the competitive market.

The failure of the competitive market to attract customers from standard offer service has led to other mechanisms to foster retail competition. In the natural gas industry in Georgia, the incumbent distribution utility, Atlanta Gas Light Company, was ordered to exit the retail gas supply business, with the result that customers had no choice but to switch. Significant difficulties have been experienced with alternative providers in Georgia, however, and it remains to be seen whether this approach should be imitated elsewhere.

In Maine, the license to provide standard offer service in each area has been put out to bid for the last two years. Since utilities had been ordered to exit the generation business, the market was open to competitive suppliers. This is not exactly *retail* competition in the sense of individual customers exercising their right to choose, but it could be called retail aggregation by commission order. According to the Maine commission, it has been a success, although the bids to provide standard offer service have been higher than anticipated when the Maine legislature authorized restructuring, and in some instances the commission refused to approve the initial winning bids.

Customer aggregation of other kinds, such as municipal aggregation, may provide a means for competition to reach the retail level.

3. Are there technical, legal, or other barriers to entry in the markets? For example:

a. Are there legal or technical barriers to the construction of the different types of generation plants by non-utilities?

In the wholesale generation markets, it is claimed that the incumbent utilities or RTOs have erected barriers to new construction through their control of suitable plant sites and the interconnection process for access to the transmission grid. While this may well be true, a large number of new merchant plants have been or are being built nationwide and in the Southwest.

The need for certificates for environmental compatibility (CECs) may be considered by some to be a legal barrier to entry. Staff does not agree with this view. As long as the requirements for CECs are applied consistently across all applicants they should be competitively neutral.

b. Is the cost of obtaining licenses, resources, knowledge and employees sufficiently small, relative to the expected revenues, such that new entrants will find the market attractive?

In the case of generation facilities, in which several large national and international firms have emerged, the costs appear to be small enough to make the market attractive. The pro-competition view was that the same would be true of retail market entry. Second thoughts have resulted from the experience of most states that the costs of retail market access -- including retail offices, marketing, etc. -- appear to have been too high to make entry profitable in competition with the incumbent distribution utility. As noted earlier, much depends on the relative prices of market supply and standard offer service.

C. Is it necessary for the product or service to be provided by a single regulated company to assure reliability and safety, or can multiple companies provide the service subject to reliability and safety rules?

Distribution service should be provided by a single company in each service territory. This is justified by two basic considerations. The first is that duplication of distribution infrastructure should be avoided in order to assure reasonable rates to consumers in a given service area. This principle is the foundation upon which service territory agreements between APS and SRP were founded. Until the territorial agreements were in affect, both APS and SRP were both rushing to build distribution facilities to connect the same domestic retail load in what at that time was rural Arizona, but today is known as the metropolitan Phoenix area. Secondly, for safety reasons, there can only be one operational authority for a radial distribution system.

If one parted interconnects its radial distribution system to another, then operational authority must be rendered to the party who has the transmission source for the radial system. The party without the transmission source would then pay for distribution service from the transmission system to the point of the distribution interconnection. Otherwise, the two parties could perform field switching that interconnects the common distribution system to multiple transmission sources thus pre-empting radial distribution service. This would expose distribution equipment to excessive fault duty and fuse and relay coordination problems. Power could flow in either direction on the distribution lines under such circumstances. Such a reliability and safety problem is exacerbated by many requests for new customer connections in areas such as Arizona that experience significant customer growth.

The pro-competition view suggests that wholesale generation and retail supply can be reliably and safely provided by multiple companies. However, system operation (dispatching, etc.) for purposes of reliability must be provided by a single entity in each control area. We believe the DesertSTAR/WestConnect process is aimed at providing centralized regional control.

Second thoughts regarding reliability and price stability in the wholesale generation market, center on the problems of coordinating long-term planning to match demand and supply. In its RTO proceedings, the FERC is attempting to deal with these issues by empowering the RTO to acquire and pay incentive prices for ancillary services like reserves, or the requirement that suppliers must have a capacity reserve margin over and above their levels of contracted loads. Installed capacity (ICAP) markets have been created in some regions. Much work still needs to be done to provide assurance that this approach will be effective. A January 2000 DOE report on outages in the electricity industry suggests that – absent additional reliability measures – a restructured electricity industry has the potential to result in deterioration of reliability.

D. For customers, is the cost associated with learning how to shop and actually shopping sufficiently small, relative to the expected benefits, that customers would want to shop.

The pro-competition view ignored this issue, assuming that customers would be eager and willing to shop for a good deal or for innovative services. However, states had doubts about customers' ability and willingness to shop, and put standard offer service in place to provide customers with a reliable and reasonably priced fallback for electricity as an essential service. In practice, the continuation of full utility service by the incumbent utility, including standard offer service at favorable prices negotiated by state commissions, has thus far proved fatal to retail competition for residential and small commercial customers in most states.

In addition, many small customers do not have the time, wherewithal, or interest to shop for a product that never captured much of their attention in the first place.

These points further support Staff's contention that the Commission's focus should be on the development of a competitive wholesale market.

III. Relationship of the Current Regulatory Regime to Competition

A. For each potentially competitive product or service, how does current state and federal regulation foster or inhibit (a) retail competition and (b) wholesale competition?

The pro-competition view was that it would be feasible to foster both retail and wholesale competition. On second thoughts, however, it seems that neither state nor Federal regulators had fully appreciated how radically the electricity market would have to be changed if it was to become fully competitive.

In the *retail* market, the standard offer alternative has been so convenient for customers, and the potential rewards of leaving it so meager, that few customers have been willing to take the leap. Thus, the incumbent utility monopoly has remained in place. Large commercial and industrial customers have been a partial exception: some have had the expertise and size to make it worth their while to shop around and achieve savings on their electricity bills, and many energy service providers have found the business profitable.

The record of retail competition to date suggests that the Commission should retain standard offer utility service, particularly for residential and small business customers, for the time being. We believe the burden of proof is clearly on those who propose changing this approach to encourage retail competition. They should demonstrate the benefits, but Staff does not believe they can.

The risks of continuing along the path toward retail competition are mostly in the *wholesale* market, to which we now turn. Staff believes the evidence points to price volatility and a potential recurrence of instability in the regional wholesale market.

The path towards competition would involve a drastic change to decades of integrated utility operation and planning. Traditionally, the whole purpose of integrated utility planning was that the utility would reliably serve all retail loads in its territory. It followed that the utility built a mix of generating plants designed to match the loads in the territory and have a reserve margin for purposes of reliability.

In the traditional model, no other supplier could come close to equaling the incumbent utility's capability, especially if the utility continued to build (as it is, or was, required to do) new capacity to match load growth. A new entrant could find that customer demands were already fully met, and in any event would probably need to acquire ancillary services such as back-up or replacement power from the market, and the markets for those services too might be dominated by the utility.

To overcome the utility's historical advantage as the dominant supplier in its service territory, it may be necessary to take radical steps such as requiring the break-up and divestiture of utility generation assets.[10] Alternatively, if a method is found to relieve Arizona's transmission constraints such a radical step may not be necessary.

The Federal Energy Regulatory Commission is only gradually coming to grips with the two principal features that are needed to make a wholesale generation market workably competitive and reliable. The first is willingness and ability to root out horizontal *market power* by breaking up suppliers and removing barriers to entry. The antitrust law is not well designed to prevent market power in cases that do not involve mergers, e.g., where an industry is being deregulated, but this is where FERC and states need to be proactive. A determination needs to be made in advance of restructuring that generation entities will not have significant market power when they are deregulated. This requires that there be a significant number of participants in the market and that barriers to entry need to be low.

In some instances, where market power cannot be eliminated because there are load pockets or shortages during peak load periods, FERC needs to mitigate the effects of market power. As noted earlier, measures could include the use of bid or price caps, congestion management systems, and/or providing for some kind of incentive pricing for transmission upgrades and ancillary services.

The second principal feature that must be put in place under the aegis of FERC before the generation market can be competitive is a well-designed RTO that can effectively monitor the wholesale markets, monitor and control transmission, price transmission services fairly and in such a manner as to broaden the market, design the expansion of the transmission system in

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[10] However, Arizona Public Service's proposed transfer of its non-nuclear generation in one block to an affiliate may delay effective competition indefinitely both because it retains generation in an affiliate, PWEC, and because PWEC would likely have market power in the service territory. It would still have that power if it were spun off.

coordination with power plant construction to avoid bottlenecks and supply disruptions, and ensure non-discriminatory transmission access to new generators.

B. How can the Commission protect Arizona customers from the risks of competition while promoting competition?

The pro-competition view was that the level of risk in competitive electricity markets would be acceptable. Second thoughts focus on the functioning -- or malfunctioning -- of wholesale markets. The egregious example is of course California, but wholesale markets in other areas like New England and the Mid-Atlantic states have also had above-cost prices, and at times extremely high prices. The primary responsibility for structuring and monitoring wholesale markets rests with F.E.R.C. Allowing (or requiring) Arizona utilities to transfer their generation assets to an affiliate that will not be subject to the Commission's jurisdiction entails significant risk. Without a vibrant wholesale market, consumers are unlikely to receive any benefit from such a transfer.

Staff believes that if the Commission wishes to promote retail competition, it should actively work with other parties to create an effective RTO under the aegis of FERC.

C. How have the interim rate reductions for customers receiving standard service affected the ability or desire of generation suppliers to compete in Arizona retail markets?

In Arizona, as in most other states, standard service has been made so attractive -- in comparison to high market prices in 2000/2001 -- that it has been difficult for third party suppliers to win customers, given that customer acquisition costs are quite high. If wholesale prices continue to decline, the competitive retail market will become more profitable.

D. Do Commission policies or legal requirements ensuring that utilities recover investments from ratepayers affect the prospects for competition in any market for which competition otherwise would be possible?

The pro-competition view was that, provided stranded costs such as uneconomic investments in power plants are recovered equally from all retail distribution (wires) customers as part of the distribution (wires) charge, regardless of who their supplier might be, such cost recovery should not in principle affect the prospects for supply competition. The same should apply to retail supply costs such as marketing and office infrastructure that might be eligible for stranded cost recovery.

Second thoughts focus on the fact that, if utilities are allowed to recover substantial generation and retail supply costs through a wires charge, the result is to squeeze the residual energy supply charge on which the shopping credit is based. That is, the recovery of stranded generation costs may allow for shopping credits that are artificially low. In most of the states that have introduced retail access, this problem has occurred, and has had the effect of discouraging competitors from entering the market. If and when stranded cost recovery ends, the retail market could become more attractive.

E. Does continuing utility control of depreciated generation assets affect the ability of competing suppliers to enter retail markets?

The answer to this question depends, first, on whether utility embedded generation costs are higher or lower than market prices. Regulated electricity prices in Arizona appear to be somewhat higher than those in neighboring states. This suggests that utility assets are not giving the utilities an advantage in the market at the present time and that new generators should be able to compete successfully.

However, there are certain caveats. First, this situation could change over time, if natural gas prices faced by new generators escalate above the coal costs of utility coal-fired capacity.

Secondly, as noted in response to the previous question, utility stranded cost recovery mechanisms may reduce or eliminate the margin that competitors can work with. Third, if the utility or any other generator has control of a diversified generation portfolio (including base-load, intermediate and peaking units, geographically dispersed) it may have an advantage over competitors, and it may deny them access to ancillary services like back-up or reserve power that they may need.

F. How does current Commission regulation promote or deter the ability of (1) renewables, (2) distributed generation, and (3) energy efficiency and demand side management to compete with traditional generation resources?

The Commission's Environmental Portfolio Standard (EPS) acts to promote the use of renewable energy sources such as solar. Without the EPS, it is doubtful that these sources of generation could compete (based on cost) with traditional generation sources.

In order for distributed generation to become a significant source of generation, interconnection standards and processes need to be established.

Over the years, the Commission has approved various cost recovery mechanisms and other procedures for demand-side management (DSM) as an incentive for utilities to consider cost-effective DSM instead of additional supply sources.

G. What are the risks of moving to a regime of retail competition for each product or service and what are the methods for managing those risks?

The pro-competition view assumed that generators would have the appropriate incentive to add enough capacity (and not too much), and that whoever was responsible for transmission system operations and expansion would develop adequate facilities to accommodate the new generators. This was expected to ensure adequate supplies.

However, experience shows that the principal risks of moving to retail competition are manipulation or disruption of the *wholesale* electricity market. Manipulation has resulted from the exercise of market power and disruption from the market mechanism failures such as those that occurred in California. Recent experience has demonstrated that competitive generation markets are also likely to result in greater price volatility, creating significant risks for customers.

The methods for managing or avoiding the risk of market manipulation include avoiding excessive market power by means of ensuring that there are an adequate number of generators, reducing barriers to generator access such as transmission constraints, and creating an effective ISO or RTO. And it seems there should be features such as an installed capacity market for the construction of sufficient new generation, and a general planning and coordination role for regional organizations such as RTOs. We propose the term "indicative planning" based on incentives as contrasted with rigid centralized planning.

H. If the current regime is not conducive to retail competition for a particular product or service, what actions should the Commission take to promote its success in the future? Specifically --

1. Should the Commission require existing utilities to procure particular products or services from unaffiliated competitors?

The premise of this question is that existing utilities are (and remain for the time being) the principal *retail* suppliers, and therefore dominate the demand side of the wholesale market. To the extent they are required to purchase increasing portions of their energy requirements from unaffiliated suppliers, this should be conducive to creating a more competitive wholesale market over time, which in turn is supportive of a competitive retail market.

However, APS has said -- and we believe this is correct -- that the regional wholesale market is too thin and volatile to make it desirable for utilities to be required to depend on large new power purchases from unaffiliated suppliers at this time. It is important to note that this is true partly because of APS's proposal to transfer *all* of its non-nuclear generation assets to one affiliated entity. Another factor contributing to the thinness of the wholesale market is the significant transmission constraints around Arizona's major load centers.

We do not believe that APS's solution to the problem of inadequate competitive supplies -- the transfer of generation to its affiliate and repurchase of power from it under a Purchased Power Agreement that will not be under ACC jurisdiction -- is conducive to competition, nor will it in our opinion result in fair regulated retail rates.

2. Are utilities taking steps that will make competition more difficult down the road (e.g., retail marketing, internal restructuring, entering into agreements to avoid customer self generation)? If so, identify those steps and how the Commission should proceed.

The principal step that utilities (sometimes through affiliates) are taking that will militate against competition in both the retail and wholesale markets is to plan to enhance their generation supplies under the assumption that they have a lock on retail customers. APS, for example, is currently in the process of adding at least $1 billion of new generation capacity. Of course, APS is obligated to take this step so long as it has a duty to serve most or all of its retail customers with reasonably priced and reliable power. But the problem is that the larger the APS or PWEC generation system becomes, the less room there is for new suppliers to compete successfully in the market.

3. Are utilities entering into long-term contracts with existing customers? If so, how do they affect prospects for future retail competition? Should the Commission allow them?

This should not be an issue in Arizona because all special contracts approved by the Commission have clauses that provide for termination of the contract if the customer chooses to go with a competitive supplier. The Retail Electric Competition Rules allow exceptions for time-of-use rates, interruptible rates, or self-generation deferral rates.

4. Should the Commission consider instituting competition for billing and metering services even if retail generation competition is premature?

We are reluctant to recommend a piecemeal approach in which billing and metering services are made competitive before generation, which is the big-ticket item. Furthermore, it may be wiser to deal first with generation, rather than introducing the complexity of billing and metering services at this time.

However, if and when the Commission institutes effective retail competition for generation, customers should be able to purchase packages of services including billing and perhaps metering. In other words, if the goal is a thoroughgoing competitive model, customers should at some point in time be able to enter into contracts with qualified suppliers and marketers and no longer contract with the distribution utility. The role of the distribution utility would be focused on delivering electricity, i.e., providing wires service, under contract with suppliers and under regulation by the Commission.

IV. Retail Generation Competition

A. Regarding each identifiable generation product --

1. Identify with particularity any defects in the wholesale market structure affecting Arizona.

We see two major defects in Arizona's current wholesale market structure. One is that incumbent utilities have large shares of the generation (and transmission) market and, if that market is restructured, they would likely be in a position to exercise market power, by raising prices above competitive levels and/or discouraging new entrants. In such a situation the incumbent utilities would be reluctant to work towards relieving the transmission constraints that enhance their market power. Second, transmission constraints limit generator access to Arizona load centers.

Third, we believe that the ISO/RTO arrangements at this time are inadequately developed to ensure an open, competitive, and stable wholesale market. The cure lies primarily with the

FERC, which is attempting to move forward on these matters. The development of WestConnect under the aegis of FERC will be critical in this respect.

In light of these three defects, we believe it would be prudent for the Commission to wait before requiring jurisdictional utilities to place substantial reliance on the wholesale generation market.

2. Are there an adequate number of competitors to sell in Arizona to make the product sufficiently competitive? How many sellers are there?

There are at least seven generators now operating in Arizona that are not affiliated with any Arizona utilities. An additional five generators are currently constructing plants. Notwithstanding new merchant power plant construction, incumbent utilities appear to be in a position to exercise market power in the wholesale generation market, especially for generation products required during peak periods. This is because of the significant transmission constraints in Arizona.

For retail products, there are no competitors currently operating in Arizona.

3. How have mergers and consolidations in the industry affected the competitiveness of the product in the region at the wholesale and retail levels?

Mergers and consolidations have not been a major factor in the Arizona or Southwest market.

4. Are competitors building new generation able to price their generation at rates competitive with existing generation?

In some areas of the country, such as the Northeast and (belatedly) California, the answer has generally been "yes", and a great deal of new generation construction has taken place.

Today, however, with falling wholesale market prices, the prospects for new power plant construction are changing. Although market prices will likely be sufficient to cover operating costs, they may not be sufficient to provide a reasonable return on investment. We believe there are delays or cancellations of some projects. However, merchant power producers are better able to answer this question.

5. How has the Independent System Administrator affected the success of (a) retail competition and (b) wholesale competition?

We believe the A.I.S.A. has developed protocols and tariffs for retail customers who directly access third-party suppliers. Presumably, the role of the A.I.S.A. will in time be absorbed into that of a regional RTO, and retail and wholesale protocols and tariffs will be complementary. Meanwhile, at least until recently, market prices have been so high relative to standard offer prices that little direct access has taken place.

B. Regarding the transmission and distribution infrastructure necessary to support competition for each identifiable generation product --

1. Are there transmission constraints inside or outside Arizona that currently impede the ability of competitors to reach Arizona customers during any seasons of the year or times of the day?

There are transmission constraints both inside and outside Arizona that currently impede competitors reaching Arizona customers during summer peak hours. These constraints were reported in Staff's Biennial Transmission Assessment revised July 2001 and adopted by the Commission. The report established that three geographical load zones (Phoenix, Tucson and Yuma) are transmission import constrained at peak load conditions. Generation internal to these load zones "must run" at peak load conditions to avoid system overloads and voltage problems for outage of critical lines. Thus, merchant generators, which may be more cost-effective than generation available locally, are precluded from bidding to serve these areas during peak hours. Similarly, new generation capacity under construction and interconnecting at the Palo Verde commercial hub will be constrained by existing 500 kV transmission lines interconnected at the hub. Firm regional transmission capacity for competitive Electric Service Providers to import power to Arizona retail customers is also very limited and only available on selected transmission paths.

Two additional transmission constraints have been identified since Staff's Biennial Transmission Assessment was completed. Both constraints were revealed during Arizona Power Plant and Transmission Line Siting Committee hearings for two new projects. Testimony given during the Toltec Power Plant hearings (Case #112) established that the newly completed Reliant Desert Basin Power Plant could not deliver its full capacity to SRP in the Phoenix area because of 115 kV and 230 kV transmission system constraints between the plant and the Phoenix load zone. Similarly, testimony during Case #111 siting a TEP 345 kV transmission line and Citizens Communications 115 kV transmission line to serve Nogales and Santa Cruz County revealed another transmission constraint. Citizens Communications presented a load forecast that indicated that as early as summer peak 2003 the load in Santa Cruz County may exceed the delivery capability of the existing 155 kV line serving the area. Even with the proposed new transmission line to Nogales, continuity of service to customers is of concern in case of the outage of the new line.

2. What plans are in place to relieve transmission constraints?

A new 500 kV line from the Palo Verde hub to the new Southwest Valley switching station has been approved in Line Siting Case #115. That line is under construction for a Summer 2003 completion. Until that line is in service, local Phoenix area generation must run during peak hours. (And thus, merchant generators located outside of the Phoenix-area cannot bid to supply Phoenix during peak hours.) APS revealed in Case #115 that tripping schemes must also be activated by APS and SRP to drop load for a line outage or local generator outage during local peak load conditions until the new line is in service.

Pinnacle West Energy Corporation is a partner in expanding generation at the West Phoenix Power Plant. Similarly, SRP is expanding its Kyrene Power Plant and Santan Power

Plant. All three projects are internal to the transmission import constrained Phoenix load zone. During the past year, two additional 500 kV transmission lines have been announced for 2006 and 2008 that will help relieve the transmission import constraint for this area: a Palo Verde to Southeast Valley Switching Station line and a Palo Verde to Table Mesa line.

APS has planned a new 230 kV line from Gila Bend to Yuma by 2006. This line will eliminate the transmission import constraint for the Yuma area. In addition, a new Yuma area generation project has been proposed by York and Welton Mohawk Irrigation and Drainage District for 2004. The generation project is active in the state siting process as Case #114.

TEP has proposed several Transmission line enhancements that improve the Tucson area transmission constraints. Sierra Southwest Transmission has proposed a new 230 kV line from the Apache generating station to a new switchyard called Winchester interconnecting with TEP's 345 kV line between Greenlee and Vail. Several transmission options remain under study by the Central Arizona Transmission Study (CATS) that will impact delivery to Tucson and southeastern Arizona.

In addition to the three new Palo Verde transmission lines identified above, Staff has conditioned Duke's Arlington Valley II Power Plant with the upgrade of the Palo Verde to Kyrene and Palo Verde to North Gila 500 kV lines. A number of other Palo Verde line projects have been discussed but applications for Certificates of Environmental Compatibility (CEC) have not yet been filed with the Commission. Public Service Company of New Mexico (PNM) still has a transmission line from Palo Verde to Mexico under study through CATS. The PNM line is active in a federal Environmental Impact Assessment (EIS) and Presidential Permit process with the US Department of Energy as the lead agency. There has been recent discussion of upgrading the existing Palo Verde to Devers line and building a second Palo Verde to Devers 500 kV line. Similarly, a merchant transmission project to build a 500 kV line from Gila Bend to North Gila in conjunction with other transmission enhancements in California continues to seek a funding source.

The newly declared Nogales transmission import constrained area remains unresolved at present. Citizens Communications filed several alternative fixes in its most recent ten year plan with the Commission. Citizens Communications has committed to completing its study of those options and notifying the Commission of its selected plan of action by midyear.

3. How long will it take to relieve any existing transmission constraints and what factors are affecting and will affect prospects for relief?

Phoenix-area 500 kV transmission additions in the 2003 through 2006 time period coupled with new power plants and expansions internal to the constrained area should be sufficient to reduce dependence upon older, more costly, and higher polluting local generation through about 2008. However, Staff has yet to see transmission solutions proposed for the Phoenix area that will eliminate the transmission import constraints in the long term. Since two of the three new 500 kV lines from Palo Verde must still go through the rigors of a state line siting process, there remains some risk of public opposition for the new lines.

The Tucson transmission import area faces the same line siting risks as the Phoenix area. In fact the environmental community and public at large have already been very vocal regarding a variety of transmission projects in Central and Southern Arizona. Nevertheless, there appear to be sufficient transmission options under investigation to assure the Tucson import constraint will get resolved within the next few years.

The Yuma transmission import constrained area appears to have several competing line solutions moving forward towards a 2004 resolution. New proposed merchant generation in the local area may also offer a remedy as early as 2004. It is premature to judge how quickly the Nogales constrained area will be resolved until Citizens Communications identifies its proposed solution.

Resolution of transmission constraints at the Palo Verde hub are the most difficult to project. Except for the new 500 kV lines proposed by Arizona transmission providers, all other transmission improvements remain very speculative and lack any definitive funding sponsor, specific scope or well-defined, in-service date. Most of these proposed 500 kV transmission projects improving the Arizona / California transfer capability will require Arizona line siting approval. At best, these projects are likely to formally emerge in the last half of this decade.

4. Are the owners of constrained transmission facilities, or holders of transmission rights, able to use their control to affect market prices?

Yes, transmission owners and holders of transmission rights can exercise market control and affect market price in a variety of ways.

In the case of transmission import constrained load zones, local generation must run during peak periods to avoid transmission system problems. When local must-run generators are old and are of a fuel source and technology that yields high operating and maintenance costs, then relying on these must-run generators can result in higher system incremental costs for energy purchases than would have occurred had there been ample transmission capacity. Such market power is further exacerbated when a single company or affiliates of a common company own both the transmission and local generation. By placing obligations on new competitive Electric Service Providers (ESP) to share in the cost of must-run generation, an incumbent utility can cause the energy prices for competitive customers to be elevated in some instances above the shopping credit level at which the incumbent serves standard offer customers.

Market control and pricing effects in the case of a commercial hub such as Palo Verde that is constrained by transmission capacity take a somewhat different form. By there not being sufficient transmission available to reliably deliver all of the output of all units connected to the hub, there is an effect of stranding some of the connected generation capacity. This has a dual effect on prices. It first can cause the interconnected power plants to primarily compete to a floor price within the hub and to offer non-firm energy where firm energy would otherwise be available. If the interconnected transmission providers are able to purchase and deliver all the energy that they need for their local consumers, then they are satisfied. However, the constraint also protects higher pricing of energy from other plants owned by affiliates of the transmission providers because the hub units cannot compete with them due to delivery constraints. Secondly, transmission constraints at a hub can cause the bidding price for transmission rights to be elevated due to transmission congestion. Arizona does not yet have such a transmission congestion pricing mechanism but proposes such a pricing mechanism when its proposed Regional Transmission Organization (RTO), WestConnect, becomes operational. The California Independent System Operator already has such a transmission pricing mechanism in place for lines from Palo Verde to California. If a company has both a power plant affiliate and a transmission provider affiliate interconnected at such a hub, then they can certainly leverage the price of energy production versus the price of energy delivery.

5. Are these transmission owners currently doing things that will allow them to exert more or less control in the future? If so, please detail.

It is Staff's opinion that Arizona transmission owners have over the past year made significant progress in planning and announcing new transmission additions to resolve perceived market power via transmission constraints within Arizona. While it will take a number of years for these new lines to be sited and constructed, there is certainly a good faith demonstration of Arizona utilities' commitment to respond favorably on a forward looking basis. The recent transition from a Desert STAR RTO to a WestConnect RTO is also reflective of a commitment to have an RTO with the authority to build transmission lines if others do not.

6. Will the transmission system be adequate prospectively (e.g., in the next 5, 10, 15, 20 years) to deliver power from new generation plants?

FERC anticipates that a regional RTO will in time be the entity responsible for ensuring the adequacy of transmission capability in the Southwest or West. FERC has suggested that some form of incentive ratemaking could be used to encourage appropriate transmission upgrades identified through an RTO planning process. The process of getting an overall "indicative planning" and incentive pricing structure in place will likely take several years.

Staff is not in a position to accurately assess the adequacy of planned transmission system enhancements filed with the Commission as of January 31, 2002. Such an assessment will be rendered upon completion of a second ACC biennial transmission assessment that will commence in April. However, Staff's preliminary opinion is that Arizona transmission adequacy for new generating plants will likely be achieved in the last half of this decade.

7. Is the natural gas pipeline infrastructure adequate to support all proposed new gas-fired generation plants? How many plants can it support?

The natural gas infrastructure in Arizona at this time largely consists of El Paso Natural Gas Company's (El Paso) northern and southern interstate pipeline systems and associated laterals. The Transwestern pipeline in northern Arizona also serves a small amount of Arizona's natural gas needs. Currently there are no appreciable instate natural gas production, natural gas storage, or liquid natural gas facilities in Arizona. Therefore, natural gas consumers in Arizona, whether residential or power generating in nature, rely on the on-going flow of natural gas on the interstate pipeline system to meet their service needs.

There is a general uncertainty regarding pipeline capacity availability for shippers on the El Paso pipeline system. The rights, obligations, and needs of shippers and El Paso are being disputed in a number of proceedings at the Federal Energy Regulatory Commission (FERC). At this time it is unclear how or when the disputes regarding pipeline capacity will be resolved. However, it is clear at this time that during periods of high demand, the El Paso system is unable to fully meet the needs of its existing shippers. During periods of relatively low demand on the interstate pipeline system, it appears that the system is generally able to meet the needs of its shippers. This situation exists at a time when few of the new natural gas-fired generating units are yet operational. As additional gas-fired generating units come on-line in Arizona and other southwestern states that utilize the same pipeline systems, the inability of the existing pipeline system to serve all customer demands will become increasingly apparent.

El Paso has failed to address the growing demands for natural gas transportation in Arizona and the Southwest. New generating facilities appear to be relying on a number of possible sources of pipeline capacity for their facilities, including: use of existing contract rights, acquiring released pipeline capacity from other shippers, purchasing rights on new pipelines or pipeline expansions, and swapping of gas supplies on different pipeline systems. In the long term, market players are likely to build additional pipeline capacity and/or natural gas storage capacity to serve additional demand for natural gas in Arizona and the Southwest. However, it is unclear at this time how well the availability of additional pipeline capacity in the future will coincide with the additional natural gas demand of the new generating facilities in the next few years. The on-going uncertainty regarding existing shippers rights on the El Paso system has made it difficult for both shippers and potential capacity expansion developers to accurately gauge what the demand/need is for additional capacity. Most new gas-fired generating units in Arizona are located near El Paso's southern pipeline system, and this is likely to be the area of greatest concern regarding the shortfall of interstate pipeline capacity, although several recently announced pipeline projects may at least partially address the shortfall.

8. Does the transmission and distribution system facilitate or deter --

a. the development of renewable energy technologies?

Current transmission and distribution system structures deter the development of renewable energy technologies in three significant ways. First, on the local level, the small size and often remote locations of renewable generators mean that they are not directly connected to the regional bulk power system and often have to pay a distribution utility tariff in addition to the regional transmission tariff. Second, interconnection procedures in many regions do not provide streamlined procedures for interconnecting small generation units that have virtually no impact on the bulk power system. Third, the wholesale markets administered through tight power pools do not accommodate the small size and often intermittent production output associated with most renewable generation, such as wind, hydro, and solar. Until these barriers are addressed and a level playing field is created, renewable generation technologies will be at a competitive disadvantage.

b. the development of distributed generation?

The same issues discussed above regarding renewable generation also apply to distributed generation. In addition, local distribution utilities have difficulty integrating and accommodating the power flows of distributed generation that may operate only during peak load periods. One solution to this difficulty is to require the distribution utility to purchase, through bids, distributed generation resources that it then operates.

c. the development of demand-side management and energy efficiency?

Although integrated resource planning in the 1990s quantified the significant benefits that energy efficiency, conservation, and load management can provide to distribution and transmission systems, there are very few mechanisms developed that capture these benefits. As mentioned earlier, Vermont has implemented a statewide efficiency utility that is supported through a systems benefit, or wires, charge. Alternatively, the RTO entity could provide incentives for demand-side programs based on the benefits to the bulk power system; however, the RTO may not be in a position to offer incentives for the distribution system benefits associated with DSM measures.

C. Regarding competitive bidding --

1. Identify with particularity any adverse consequences that would result from Commission approval of a substantial variance to the electric competition rules that require competitive bidding for 50% of the electric supply for standard offer customers, starting in 2003. Specifically:

a. How would retail customers be affected?

Assuming that most retail customers remain standard offer customers for the time being, APS and other utilities will remain the principal *retail* suppliers, and therefore represent most of the demand for power in Arizona. Given current market conditions and the inherent difficulties of competing in the retail market, Staff believes that it is unlikely that ESPs will attain a significant number of customers in the near future, with or without a variance to the 50% requirement. Thus, any effect on retail consumers would come through standard offer rates. A variance to the 50% requirement in isolation would not affect standard offer rates. However, if the variance is accompanied by the transfer of assets to an affiliate and a long-term purchase power agreement between the affiliate and the utility, standard offer rates may be adversely affected. Staff's consultant Synapse will address the specifics of the possible effects of APS' proposed purchase power agreement in the testimony currently due March 29, 2002.

b. How would retail generation competition be affected?

Given current market conditions and the inherent difficulties of competing in the retail market, Staff believes that it is unlikely that ESPs will attain a significant number of customers in the near future, with or without a variance to the 50% requirement. Any effect on retail providers of generation would be felt through the variance's effect on the wholesale market.

Staff believes that the effects of variances to the Commission's 50% requirement on retail customers should be examined further in a subsequent proceeding.

c. How would wholesale generation competition be affected?

Wholesale generation competition would be delayed by a variance from the competitive acquisition requirement. However, if, as APS argues, the wholesale market is too thin and volatile to support a 50% competitive bid requirement, whatever the reason, delay would be advisable in terms of stability of pricing and reliability of supply. Such a delay need not set the required amount of generation to be purchased from a competitive bidding process at 0%. If a variance were granted that required a realistic amount of competitive bidding, the wholesale generation market would not be adversely affected.

2. Are sufficient competitors available for an effective bidding process for 50% of standard offer service? A higher or lower percentage?

We are inclined to agree with APS that the market is too thin to support an effective bidding process for 50% of standard offer. It is important to note that this is partly because the utilities' own share of the generation market are so large. Also, transmission constraints existent in Arizona inhibit the development of competitive bidding.

3. Can retail competition develop if current rules are modified to allow a utility to procure all of its generation for standard service from an affiliated company?

No. If utilities continue to retain most of their retail customers under standard offer service, and they procure all of their generation from an affiliated company, utility control of the wholesale market will likely retard wholesale competition and, indirectly, retail competition.

The answer to this question would be different to the extent wholesale prices are low -- and are expected to remain low – and ESPs find it profitable to enter the retail market (and feasible, given transmission constraints) and retail customers migrate to the competitive market in large numbers. Arrangements for standard offer supply would become less central in these circumstances.

4. How would retail competition be affected by other deviations to the competitive bid rules? Be specific about the changes in the rules and their consequences.

As stated above, the competitive bid rules have only an indirect effect on the prospects for retail competition. Staff's proposed alternative to APS' variance request will be discussed in detail in Staff's testimony due March 29, 2002.

5. Instead of entertaining individual requests for substantial variances to the competitive bid requirements, should the Commission proceed on a generic basis to modify the rules for competitive bidding?

Yes. Staff believes that it would be appropriate at this time to suspend the implementation of some provisions of the Electric Competition Rules on a generic basis. This suspension should last only long enough to address the issues laid out in the recommendations section of this report.

6. If the Commission would change the 50% bidding requirement for standard offer service, are there other specific measures the Commission can take to promote retail competition?

Staff believes that the primary measures the Commission should take in the near future to *promote* retail competition relate to the mitigation or elimination of barriers to entry in the Arizona *wholesale* market. Staff does not believe that the 50% bidding requirement was ever meant to promote retail competition. Its purpose was to foster the development of wholesale competition. Staff believes that the Commission's focus should be on the development of a vibrant competitive wholesale market, by encouraging transmission system enhancement, the implementation of WestConnect, and appropriate siting of new merchant power plants.

D. Regarding the pricing of power supply contract rates --

1. Identify any advantages that would result if the Commission approved a long-term supply contract for standard offer customers that was based solely on cost-based rates. (Your answer should define "long term" as compared with "short term" contract.)

Standard offer supplied under a long-term supply contract, one with a term of at least five years, can be compared with two standards -- competitively-determined generation prices and Commission-regulated generation rates. Compared with competitively determined prices, the advantage of a long-term supply contract for standard offer customers would lie in price stability -- it would provide insurance against market price volatility and would probably reduce the risk of power supply shortfalls. However, it would not bring the supposed efficiency and innovation benefits of the competitive market.

One draw back of PPAs is that they fall under FERCs jurisdiction. It is unlikely that FERC would scrutinize the implementation of the PPA as closely as the Commission would in terms of its consistency with the interests of Arizona retail customers.

Among the key features that has to be addressed in determining whether a PPA has appropriate provisions are the provision for allocating capacity and costs between wholesale and APS retail generation sales by PWCC/ PWEC (e.g., would the revenues from out-of-state sales be credited back to retail customers as they are under Commission regulation?). There is also a potential problem of excess capacity (e.g., is there any limit to the amount of capacity on which carrying costs would be charged to APS retail customers?). Also, is there a procedure to ensure that the *mix* of capacity used to supply retail customers is appropriate? These are just three of the difficult problems that could arise if the Commission were to lose its jurisdiction over APS's generation assets.

2. What if the contracts are based solely on market-based rates?

In this case, PPAs would not provide insurance against market price fluctuations. Basing contracts on market-based rates can transfer wholesale market volatility directly to retail customers, as occurred in San Diego during the summer and fall of 2000.

And to the extent a PPA gives the utility affiliate an advantage in the wholesale market, prices in that market would likely be higher than they would be under either a more competitive regime, or under cost-based rates.

3. Describe how FERC's new approach for analyzing the ability of sellers with market rate authority to exercise market power affects generation companies selling into Arizona.

FERC's new "pivotal" test is a useful addition to the other tests, such as HHI, that it has used in the past. The pivotal test provides for a more detailed analysis of opportunities to exercise market power based on temporal changes in the daily bidding and dispatch of the market system. Rather than a hypothetical opportunity based on an HHI rating, the pivotal test looks at particular market situations and a particular entity's market position at those times. Thus, a relatively small entity that does not generally have market power may be found to have market power under specific circumstances. Since this test expands the scope of analysis, it is likely that more generators selling into Arizona will be found to have more opportunities to exercise market power.

4.Does the Commission have the ability to assure that approval of a long-term contract would protect ratepayers receiving standard offer service as well as foster competition?

No. It seems that a long-term contract of the type proposed by APS, coupled with transfer of generation assets to an affiliate, would inherently have the effect of raising standard offer prices above current regulated rates, and of retarding competition in the wholesale (and thus the retail) markets.

V. Industry Events External to Arizona

A. Describe in detail developments you believe will occur in both the wholesale and retail competitive electric generation markets nationally and in Arizona over the next 12 months, 24 months, 36 months, 48 months and 60 months.

Nationally, the move to retail competition is slowing down in some states (such as New Mexico, Arkansas and Montana), and it is being reversed in some cases (such as California and

Nevada). In other cases (such as Texas), legislatures and commissions have decided to stay the course.

At FERC, the pressure is on to fix transmission access, pricing and expansion issues. FERC is also adding emphasis to the market monitoring roles that ISOs and RTOs perform. It is fair to say, though, that with all the parties involved in any particular regional situation, this is going to be a long (several year) and evolving process. In the West, FERC has to assess WestConnect and decide whether an RTO is needed for the whole West (the WSCC area) or whether smaller regional RTOs are adequate.

B. Is there anything the Commission should do to continue to avoid California's retail electric competition experience? Please be specific.

The Commission should not move precipitately to make customers or utilities dependent on a wholesale market -- ***especially a spot market*** -- that may not yet be competitive, and may not yet include an ISO or RTO that is capable of providing effective monitoring and oversight. Rather, the Commission should work with FERC and others to ensure that Arizona's ISO/RTO arrangements are satisfactory before considering releasing utility generation into that market.

See the "Lessons of the ***California*** Experience" section of this report.

C. Does the Enron bankruptcy have any lesson for retail electric competition in Arizona?

Yes. Reliance upon unregulated generation companies with little or no responsibility to Arizona customers can create significant risks. The means to reduce these risks is to require supplier certification, including financial disclosure, performance bonds, etc. Even with all these provisions in place, however, ***some*** risks may remain. In Maine, Enron was one of the largest retail suppliers. Maine commissioner William Nugent, currently NARUC President, has reported that Enron's customers avoided serious fallout.[11] Part of the reason, however, was the good luck that market prices were lower than Enron's contract prices when the company failed.

As Commissioner Nugent has explained, from the customer standpoint, a supplier failure is a heads you don't win, tails you lose situation. Enron customers in Maine are being held to above-market prices under their ***contracts*** with Enron. If, however, when Enron had failed, contract prices had been below-market, customers would have had to pay higher market prices and would have been left with a worthless claim for compensation as unsecured creditors of Enron.

The Enron collapse left many ***customers*** without an energy service provider. It is accordingly essential to have in place a provider of last resort with a clear obligation to accept, on reaseonable terms, customers of failed suppliers. Also, this underscores the importance of energy service provider licensing criteria, including a showing of financial and technical capability and the posting of a bond if necessary. It must be admitted, though, that even with the

[11] Comments of the Hon. William M. Nugent, before the U.S. Senate Committee on Energy and Natural Resources, *The Effect of Enron Disintegration on Electricity Markets*, January 29, 2002. Available on the N.A.R.U.C. website.

best financial criteria, Enron would still have appeared to be qualified and would not have had its license revoked.

D. How will FERC's RTO initiative affect the realization of effective retail generation competition in Arizona?

A competitive wholesale market is a precondition for a competitive retail market. FERC's RTO initiative is intended to make the wholesale market more competitive; to the extent that it succeeds in doing so, the retail competition option becomes more realistic. At this time, it is not clear when FERC-approved RTO arrangements in the Southwest or West will be in place.

E. Do you anticipate changes in federal utility statutes to affect the jurisdiction of the Commission and its ability to foster retail competition in Arizona? Please detail.

No. Our understanding is that the administration and Congress have pulled back from the kind of legislation that would force states to adopt retail competition. And FERC appears to be willing to defer to states in their efforts to restructure their retail markets. However, recent FERC activities regarding interconnection standards, commercial business practices and market design and federal legislation pending regarding transmission siting, net metering, and distributed generation objectives show that states must remain vigilant regarding preemption of states' rights in these arenas.

VI. System Security

A. Are there compelling reasons to be concerned about security for electric generation facilities since the Sept. 11, 2001 tragedy? Please include discussion of interconnection at a central location such as Palo Verde/ Hassayampa.

Nuclear power plants have been identified as a high security risk, especially since September 11, 2001. Such high-profile facilities are attractive terrorist targets. Critical electric facilities such as the Palo Verde/ Hassayampa interconnection could therefore also be at risk. Such facilities would be tempting targets for terrorists whether Arizona moves forward with restructuring or not.

There is an electric industry Critical Infrastructure Protection Working Group (CIPWG) under NERC that interfaces with a variety of federal agencies dealing with national security concerns of exercising due diligence in protecting and managing both our critical physical and cyber assets.

Staff has taken a very cautious position regarding such system security matters during siting of new generation facilities. In fact, Staff has advocated that it would be prudent to limit additional expansion at the Palo Verde hub and additional interconnections with transmission lines out of the hub until an assessment of special reliability provisions appropriate for large commercial hubs is performed. In fact, a condition was placed on the Palo Verde to Southwest Valley 500 kV line applicants, APS and SRP, in line siting Case # 115, to work with Staff in performing that assessment. The CIPWG issued a report in June 2001 entitled "An Approach to

Action for The Electricity Sector" in which it advocates action organized around a four-tier model: avoidance, assurance, detection, and recovery. The principles of avoidance and recovery should be the core elements that shape the pending Arizona assessment for large commercial hubs.

B. Does transferring ownership of generation facilities out from traditional Commission jurisdiction have any potential negative security consequences?

Staff does not believe that there are any potential negative security consequences of IPP ownership of plants as opposed to utility ownership. Transfer of existing utility generating assets to affiliates or other corporations is not viewed as having adverse physical security consequences. That is because all generators remain under FERC jurisdiction as Exempt Wholesale Generators (EWG) and must comply with NERC reliability criteria. Staff has also taken steps to assure that those same provisions are required of new merchant plants going through the state siting process.

C. What if ownership after transfer results in a foreign corporation eventually controlling Arizona's generation?

Foreign corporations own and control a large number of U.S. businesses, including utilities such as PacifiCorp owned by ScottishPower and facilities in the northeast owned by National Grid. There do not appear to be any security consequences resulting from ownership or control of Arizona's generation by a foreign corporation.

D. Does such a transfer to a non-Arizona entity potentially impact security issues for Arizona?

No.

E. Are there any positive security aspects to transferring electric generation out from Commission traditional regulation to a foreign corporation?

No.

F. Provide specific examples to support your answers.

Some specific examples **have** been provided in responses to questions A and C.

VII. Vision

A. Please provide your vision for how viable competitive wholesale <u>and</u> retail electric markets will (or will not) develop in Arizona. Please be specific regarding dates, the development process, and measures for determining at various stages how successful the process has been.

Staff's response to this **question** is contained in the Staff Recommendations section of this report.

Staff Responses to the Questions attached to Commissioner Spitzer's Letter dated January 22, 2002

1. In a vertically integrated utility model, what incentives (regulatory, financial and ratemaking) exist for the expanded use of renewable energies?

In the simplest terms, in a vertically integrated utility model the incentives to expand the use of renewable energy exist in the form of approved generation plants that qualify for rate base treatment. If a renewable generator is easier to site and easier to include in rate base than a fossil-fueled plant, then the utility will favor the renewable generator even if its production costs are higher.

In many states, there are standards or goals (some voluntary, some mandatory) for expanding the use of renewable resources. To the extent that these standards and goals can only be met through the addition of new renewable generation units, then an incentive is in place that will encourage the expanded use of renewable resources.

There are currently only a few explicit incentives for use of renewables in the vertically integrated utility model. Some of the most commonly adopted explicit incentives in the nation are portfolio standards for renewables, system benefits charges, and renewable energy funds.

However, the Commission, in Decision No. 57589, the Commission's 1991 Integrated Resource Planning decision, found that environmental costs and other externalities must be considered by resource planners in making informed decisions about new electric energy resources and services. The Commission established a Task Force to identify and quantify environmental costs and externalities. The Externalities Task Force met during 1992 and published the "Report of the Externalities Task Force" in December 1992 (Docket No. U-0000-92-035). For the purposes of the Commission's efforts, an externality was considered an impact on society not accounted for by the producers or consumers of electricity in the course of production or consumption of electricity.

In compliance with Commission Decision No. 58237, the Commission established the Externalities Prioritization Working Group, which met in 1993 and early 1994. The report and recommendations of the Working Group were published in March 1994 (Docket No. R-0000-93-099).

In 1994, Staff commenced development of draft rule amendments to include externalities in the Commission's Resource Planning rules (R14-2-701 through 705). Later in 1994, after California published its Blue Book on Restructuring and Arizona decided to move toward consideration of electric competition, the rule-making effort ended. The Commission later suspended portions of the Resource Planning rules.

If Arizona were to decide to continue with a vertically integrated utility model, the externality effort could be included in Resource Planning rules. Alternatively, the Power Plant and Transmission Line Siting Committee could use externalities as a way to evaluate potential power plants before making recommendations on Certificates of Environmental Compatibility. Since many renewables are generally less environmentally damaging than conventional, fossil fuel generators, the consideration of externalities could act as an incentive for renewables.

2. In a competitive electric market model, what incentives exist for the expanded use of renewable energies?

There are two commonly mentioned "incentives" for the development of renewable energy resources in a competitive market: special retail products and renewable portfolio standards.

Special retail products refer to efforts by retail competitive suppliers to market products specifically tailored to consumer preferences. For example, Green Mountain Energy Resources (GMER) provided three distinct products to California consumers: a 60%, 75%, and 90% renewable-based retail electric service. As consumers signed up, GMER committed to expand its contracts with renewable energy generators to maintain the advertised percentage of renewables.

Another approach to special retail products is a disclosure label that states, among other information, the resource mix of fuels that were purchased by the retail supplier. The thought is that consumers may want to switch to a supplier who provides a greater percentage of renewable resources in its fuel mix, thereby encouraging the development of renewable resources.

The second general incentive program for renewable resources is a renewable portfolio standard (RPS). Enacted either through state legislation or by commission rule, an RPS requires each retail supplier to have a minimum percentage of renewable resources in each product that it provides to consumers. Some RPS programs, such as the Environmental Portfolio Standard in Arizona, also mandate a specific percentage of "new" renewables or specific types of renewables. Maine, Massachusetts, and Connecticut have adopted RPS programs as part of their restructuring legislation. Portfolio standards can be an effective incentive, particularly if <u>all electricity providers</u> are held to the <u>same</u> portfolio standard requirements.

There are also some federal and state tax credits that are available. One potential incentive would be the standardization of distributed generation interconnection procedures and agreements. Simplification of procedures and streamlining of interconnection hurdles could significantly improve the potential for new renewables development. Net metering (or net billing) laws or rules would encourage customers to buy and install renewables on their own property. Renewable leasing programs or lease-to-buy programs would allow customers to utilize renewable systems even if the customer did not have the capital to install his/her own system.

3. In a vertically integrated utility model, what disincentives (regulatory, financial and ratemaking) exist for the expanded use of renewable energies?

One disincentive for expanding the use of renewable resources in the traditional model is the generally higher production costs currently associated with many renewable energy resources. In a regulatory climate that focuses on just low cost, the higher prices of renewable energy resources will often act to exclude them from consideration. While there are well-documented case studies to the effect that traditional low-cost resources are receiving significant subsidies or cause significant collateral cost impacts that are shifted to society as a whole (such as air pollution), traditional regulatory and ratemaking policies tend to discount or completely ignore these "societal costs."

There are financial disincentives for cooperatives that might be interested in incorporating renewables in their generation mix. Since cooperatives rely on RUS and CFC for financing, which require the least-cost generation resources, renewables that are more expensive than fossil fuel generators do not even get considered.

4. In a competitive electric market utility model, what disincentives exist for the expanded use of renewable energies?

In a competitive electric market model, the lowest delivered cost per kWh is the driving force in decisions to add new generators. If renewables appear, in the short run, to be more expensive, they will not be considered, even though over the long-run, when considering potential fuel cost increases or fuel availability risks, the renewables may be a better long run choice. Many renewables are very capital intensive, but have little, if any, ongoing fuel costs. (The wind and sun are free.) On the other hand, many conventional generators, such as gas turbines, have extremely low capital costs, but also have the potential for extremely high-cost fuel impacts over time.

5. During Arizona's period of reliance on the vertically integrated utility model, what renewable energy programs were enacted in Arizona?

Arizona Public Service Company and Tucson Electric Power Company led the state in renewables efforts. Both companies developed and installed a number of solar demonstration projects. APS developed the Solar Testing and Research (STAR) Center in Tempe, which has tested dozens of different types of solar technologies and packaged products.

6. Since Arizona's adoption of a competitive electric market model, what renewable energy programs have been enacted in Arizona?

The three largest Arizona electric utilities (APS, SRP, and TEP) have all instituted "green pricing" programs to assist in obtaining funding for new renewables.

Since the Commission's Retail Electric Competition rules were passed in 1996, each of the three major utilities have installed large photovoltaic arrays to produce electricity. SRP and TEP have both installed landfill gas generators, and APS has been trying to sign a contract with other landfill gas developers.

These efforts are in response to Arizona's Environmental Portfolio Standard requirements.

7. Under the vertically integrated utility model, what incentives exist to build newer plants that are less damaging to the environment to replace older, dirtier plants?

Very few incentives exist. Least-cost dispatch has always been the key in a vertically integrated utility model. Rate-basing of plants by the state regulatory commission provides the financial incentive for building new facilities. The commission may be able to mandate the construction of cleaner new plants, or at least can agree to rate-basing of those newer, cleaner plants. The new plants may render the older facilities uneconomic, but a further financial incentive may be needed, namely an agreement by the commission to allow continued recovery of any remaining depreciated book value of the older facilities.

8. Under the competitive electric market model, what incentives exist to build newer plants that are less damaging to the environment to replace older, dirtier plants?

Very few incentives exist. Similar to the response to Question #2 above, special retail products or a portfolio standard -- in this case related to low pollution or minimal environmental impact specifically – could provide an incentive.

Although some would say that the next generation plants will be more efficient and cleaner than the older plants, this isn't necessarily true. At the same time that a dozen or more gas-fired turbine plants are being built or proposed in Arizona, Tucson Electric proposes to build two new coal plants. It is entirely possible that the two new plants could partly or completely displace older, simple cycle gas plants that are "cleaner" than the new coal plants, at least in terms of the volume of air pollutants. There are no explicit incentives for "clean" plants, only incentives for the operator who can operate his plant at a lower cost than his competitors.

9. Under the vertically integrated utility model, what disincentives (regulatory, financial and ratemaking) exist to build newer plants that are less damaging to the environment to replace older, dirtier plants?

If older, dirtier plants are already receiving cost recovery in rate base, and there is uncertainty about the rate-basing of new facilities that may constitute "excess capacity," a utility would have a financial disincentive to build the newer facilities without a green light from the legislature or commission. Likewise, if reliance on energy from newer plants involved departure from least-cost dispatch, a utility would have a financial disincentive, unless it received regulatory approval.

If older, dirtier plants are still operational and the plants' fixed costs have essentially been "paid off," they can still continue to operate and compete against newer, cleaner plants that need to charge prices to reflect fixed costs, variable costs, today's financing costs, and a competitive profit margin. In a state, such as Arizona, where the older plants have such an advantage, new competitors will not voluntarily install any pollution improvement if it will make their electricity less competitive.

10. Under the competitive electric market model, what disincentives exist to build newer plants that are less damaging to the environment to replace older, dirtier plants?

The disincentive is that the owners of the existing, dirtier plants, which may already be fully depreciated, will have no reason to build newer, cleaner plants, unless those plants are significantly less costly to operate than the older plants of their competitors. Since the environmental costs of the older, dirtier plants are not paid directly by the plant operators, ***as far as the operator is concerned, those environmental costs don't exist.*** Since price is king in the competitive model, any pollution-reducing extra costs would be seen by plant operators as making their product more costly, and, therefore, less competitive.

11. During Arizona's period of reliance on the vertically integrated utility model, what emphasis did the Commission place on pollution control measures in Certificates of Environmental Compatibility?

Many of the records of line siting cases prior to 1992 are not complete, or in some cases not available. However, it appears that the Commission used an approach similar to that included in Decision No. 55477, dated March 18, 1987, for TEP's Unit #4 at Springerville. In that decision, the Commission included the following condition:

> (i.) that pursuant to the provisions of ARS §40-360.06, the Applicant comply with all applicable air and water pollution control standards and regulations, and with all applicable ordinances, master plans and regulations of the State of Arizona, and of any county or incorporated city or town with jurisdiction in the premises.

a. What is the most stringent pollution control measure placed on a CEC during Arizona's reliance on the vertically integrated utility model?

Although many of the records of the early line siting cases are either incomplete or non-existent, it appears that the CEC for Cholla Unit #5 (Case # 46), Decision No. 50559, dated January 9, 1980, may be one of the most stringent in terms of explicit pollution control measures. Included in the CEC were six conditions:

- "That the Applicant monitor visibility during construction of the additional generating unit and after commencement of operation of the new generating unit, . . . "
- "That any water quality chemical analysis performed by the Applicant on domestic water in the vicinity of Cholla 5 be forwarded to the Department of Health Services."
- "That timely archaeological investigations of proposed road alignments, . . . be made . . .."
- "That the Applicant monitor the water levels of the Hugo Meadow area . . .. "
- "That radiological monitoring and analysis of coal piles, ash and ash ponds for Cholla 5 be performed by the Applicant . . ."
- "That a water management plan of reasonable practicability, designed to minimize impacts on the ground water resource, be developed by the Applicant and that the plan be acceptable to the Arizona Water Commission."

12. Since Arizona's adoption of a competitive electric market model, what emphasis has the Commission placed on pollution control measures in Certificates of Environmental Compatibility?

a. What is the most stringent pollution control measure placed on a CEC since Arizona's adoption of a de-regulated utility model?

There are two power plants that are the most stringent in terms of pollution control: Santan (Case #105) and Arlington Valley II (Case #117). Each have a LAER requirement. Of the two, Santan is probably the most stringent, because of its location within a non-attainment area and proximity to a large number of homes.

b. What is the likelihood that that measure would have been placed on a similar CEC in a vertically integrated utility model?

Extremely high likelihood. In fact, for Santan, even though SRP is considered by some to be in the "competitive" model, because it was not required by the Legislature to divest its power plants, one could argue that SRP is really a vertically integrated utility operating in a "competitive" environment.

13. During Arizona's period of reliance on the vertically integrated utility model, what amount of excess generating capacity existed in Arizona?

Excess generating capacity existed in Arizona from the late 1980s into the mid-1990s. For an example, TEP installed its Springerville Unit 2 in 1990, but the Commission did not find the last part of it to be used and useful for ratepayers until 1996.

14. Since Arizona's adoption of a competitive electric market model, what amount of excess generating capacity existed in Arizona?

As the Commission started to consider adopting electric competition in the mid-1990s, the utilities became reluctant to build new generation because of the uncertainty of the amount of load that they would actually be serving and no guarantee that the Commission would allow cost recovery of the power plants.

Staff Responses to the Questions attached to Chairman Mundell's 2nd Letter dated January 30, 2002

I. Corporate Structure and Affiliate Relations

1. If the U.S. Congress repeals the Public Utility Holding Company Act of 1935 ("PUHCA" or "Act") PUHCA –

a. what regulatory protections would be lost for Arizona consumers?

b. what would be the risks for Arizona consumers?

c. for any identifiable risks, are the risks reduced or increased under competitive retail regime?

(a), (b), and (c) If the Congress repeals the PUHCA, then serious regulatory protections would be lost for Arizona consumers. The PUHCA was enacted in 1935 as a response to abusive interstate electric and natural gas holding companies, reportedly ten layers deep in some instances. By 1932, three groups controlled 45% of electricity generated in the United States. Many factors led to this concentration of electricity production, the economics of a declining average cost technology not the least among them. The PUHCA broke up the large interstate firms into intrastate firms that could be more effectively regulated by state regulators. Provisions for exemption allowed for a utility that operated interstate but within contiguous states.

The essential problem with complete repeal of the PUHCA is that it currently affords a significant source of federal protections and preventative measures unique to the energy industry, in addition to the general protections under anti-trust law. The risks for Arizona consumers include a loss of federal protection and oversight. In response to this loss, the State would probably face a seriously difficult time of replicating the protections because of interstate commerce clause protections afforded the utilities.

Risks to Arizona consumers of regulated services would most likely increase under competition because competition creates increased possibilities for abuse in regulated vs. unregulated subsidization, impairment of regulated assets by unregulated activities, and other cross effects. Complete repeal of the PUHCA would probably result in increased concentration of the energy industry. Concentration would clearly translate directly into decreased ability of state regulators to regulate. The decreased ability would include obvious problems such as access to books and records, application of state law to multistate companies, ability to appropriately allocate multi-jurisdictional costs to intrastate rates, and less obvious but real problems such as loss of local control.

An alternative to repealing the PUHCA would be to transfer PUHCA powers to the Federal Energy Regulatory Commission; though that transfer would lose the weight of the power of the Securities and Exchange Committee behind the regulatory power, enforcement in particular. The benefit of the transfer would be assignment of powers to a body that is more closely affiliated with the industry it regulates and most likely better understands it, particularly in its engineering aspects.

2. What is the extent of the Commission's authority to protect retail consumers from any potential adverse consequences resulting from multistate companies operating in either wholesale or retail markets in the state?

The Commission's authority to protect retail consumers from potentially adverse consequences from multistate holding companies depends on federal limits on state power to regulate under the U.S. Constitution. There are two main sources of limitations -- federal preemption under the Supremacy Clause, and the restraints on state regulatory power imposed by the Commerce Clause.[12] Below we highlight the two main sources of federal preemption: Federal Power Act preemption and PUHCA preemption. We then briefly discuss the limits on state regulation posed by the Commerce Clause.

A. Federal Power Act Preemption

While a state may set rates for retail transactions, it may not set rates for wholesale transactions. Narragansett Elec. Co. v. Burke, 119 R.I. 559, 381 A.2d 1358 (1977), cert. denied, 435 U.S. 972 (1978). The task of setting wholesale rates belongs to the Federal Energy Regulatory Commission (FERC). The rates set by FERC can either be preemptive or nonpreemptive. When the transaction is nonpreemptive, the courts have recognized the authority of states to limit a utility's ability to recover FERC-approved rates. When the wholesale transaction is preemptive, FERC approval of the wholesale rate preempts the States from taking any action that limits the pass through of the wholesale costs. The crucial differences between the two lines of cases involve the factual circumstances of the transactions.

The first line of cases establishes the general principle that the wisdom of a retail utility's decision to make the wholesale purchase is subject to state review. See Kentucky West Virginia Gas Co. v. Pa. Pub. Util. Comm'n, 837 F.2d 600, 609 (3d Cir. 1988) (citing the "long standing notion that a State Commission may legitimately inquire into whether the retailer prudently chose to pay the FERC-approved wholesale rate of one source, as opposed to the lower rate of another source"); Pike County Light & Power Co. v. Pa. Pub. Util. Comm'n, 77 Pa. Commw. 268, 273-74, 465 A.2d 735, 737-38 (1983) (similar holding).

The second line of cases involves "trapped costs." Under the concept of trapped costs, a state may not disallow costs associated with the purchase under a FERC-approved rate where the disallowance results in "trapped costs." Cost trapping interferes with FERC regulation and therefore is preempted under the Supremacy Clause of the U.S. Constitution. "Trapped costs" occur under specific circumstances. Although the Supreme Court has not defined the phrase explicitly, its decisions indicate that a "trapped cost" occurs when (1) FERC issues a decision requiring the purchasing utility to take a particular action, while (2) the state sets the utility's

[12] The Supremacy Clause provides that federal laws shall be "the supreme law of the land." Article VI, cl. 2. The Commerce Clause of the United States Constitution provides that Congress may "regulate Commerce with foreign Nations, and among the several States." Article I, sec. 8, cl. 3.

rates as if the utility had made a different choice. See Mississippi Power & Light v. Mississippi ex rel. Moore, 487 U.S. 354 (1988)(holding that where FERC issued an order allocating a specific portion of the costly Grand Gulf nuclear plant to a utility, the state could not regulate the utility as if it had bought a lesser portion); Nantahala Power & Light v. Thornburg, 476 U.S. 953 (1986) (holding that FERC order allocating a portion of a low-cost hydroelectric plant to a utility preempted the state from treating the utility as if it were entitled to a higher portion of the hydropower than FERC had assigned).

B. PUHCA Preemption

PUHCA may preempt states from inquiring into a utility's purchase of nonpower goods and services from an affiliate. In Ohio Power Company v. FERC, 954 F.2d 779 (D.C. Cir. 1992), cert. denied, 498 U.S. 73 (1992), the U.S. Court of Appeals for the D.C. Circuit found that approval by the SEC of a sale of goods and services from a non-utility affiliate to a utility affiliate of a registered holding company precluded FERC from inquiring into the reasonableness of the utility affiliate's decision to make the purchase. Applying the same reasoning, a court could find that a state commission is preempted from reviewing a utility's decision to purchase from an affiliate.

C. Commerce Clause

While the Commerce Clause provides affirmative authority to the U.S. Congress to regulate interstate commerce, it also acts as limitation on the power of the States to regulate interstate commerce. This feature is sometimes referred to as the "negative" or the "dormant" Commerce Clause. The primary concern of the dormant Commerce Clause is to ensure that buyers and sellers have access to a national market in which they are able to transact business with out-of-state buyers and sellers free from undue interference by the states. The negative Commerce Clause protects this national market against state statutes that protect a state's own economy from out-of-state competition and inconsistent state statutes that create obstacles to national competition.

As a general rule, state regulation must not unduly burden interstate commerce. When states encroach on matters requiring federal uniformity or pass laws unduly burdening interstate commerce, courts will step in and invalidate those laws. While courts generally invalidate protectionist state legislation, the courts also are mindful of the states' inherent police powers to enact legislation to promote the health and safety of their citizens.

There is ample legal authority for the proposition that states have significant powers to regulate public utilities. The Supreme Court has noted that "the regulation of utilities is one of the most important of the functions traditionally associated with the police power of the States." Arkansas Electric Coop. Corp. v. Arkansas Pub. Serv. Comm'n, 461 U.S. 375, 377 (1983). To some degree, most every state regulates utility service, rates and structure, such as affiliate relations, financing, and ownership.

The reach of state regulation of holding company behavior may be subject to challenge under the dormant Commerce Clause. In Wisconsin, for example, a utility holding company is now challenging a state utility holding company statute as in violation of the Commerce Clause. Alliant Energy Corp. v. Bie, No. 00-C-611-S (7th Cir., Jan. 17, 2002)(holding, in case involving utility challenge to state holding company regulation under the Commerce Clause, that utility has standing to sue to prohibit enforcement of state law).

3. How would the existence of effective retail competition in Arizona affect your responses to Questions 1 and 2 above?

Effective retail competition, if it existed, would ameliorate some of the risks posed by repeal of PUHCA and federal limits on state regulation. However, customer risks would remain because retail competition involves only certain aspects of utility service, such as sales of power, and not other services which remain regulated and which will remain regulated for the foreseeable future. For example, the utility will continue to retain monopoly control over the delivery of power and perhaps other services, such as billing and metering. Utility customers will remain vulnerable to holding company abuses arising out of their control over services that continue to be monopolized and regulated. While those abuses might be diminished through effective franchise competition, they would not be eliminated by effective retail competition focusing on power sales.

4. What is the extent of any impact of effective federal or state regulation to protect Arizona wholesale and retail consumers, if a holding company is (a) registered or (b) "exempt" under PUHCA?

"Exempt holding companies" are not really "exempt" from the Public Utility Holding Company Act. They are conditionally exempt from specific provisions from which the SEC explicitly exempts them. As a practical matter, the SEC has exempted exempt holding companies from all provisions of the Act except the pre-acquisition review provisions of Sections 9 and 10.[13] Therefore, as a practical matter, an "exempt holding company" is free from SEC regulation until it seeks to acquire another public utility, or until the SEC finds the exemption detrimental to the public interest.

As a result, the primary regulation of an exempt holding company falls to the state with jurisdiction over the public utility subsidiaries of the holding company. Whether and the extent to which a state's regulation extends to utility holding company behavior in addition to the public utility is a matter of state law.

[13] The condition on a continued exemption is the "unless and except" clause of PUHCA Section 3(a), which says an exemption is available "...unless and except insofar as [the SEC] finds the exemption detrimental to the public interest or the interest of investors or consumers ..." Section 3(c) also allows the Commission to revoke an exemption if it "finds that the circumstances which gave rise to the issuance of such order no longer exists."

On the other hand, if a holding company is a registered holding company (RHC) under PUHCA, it is subject to the following three major categories of PUHCA regulation:

1. Diversification Restrictions

2. Interaffiliate Transaction Regulation

3. Financial Practices Regulation

II. Questions Specifically for Retail Suppliers as Defined Above

Staff is not a retail supplier.

III. Divestiture or Corporate Separation

14. How would the divestiture or transfer of assets of vertically integrated utilities now serving Arizona affect the Commission's regulatory authority over the divested entities? What controls or limitations might the Commission place on divestiture or transfer of assets to limit any loss of authority over the divested assets?

Staff understands that, as a general matter, the divestiture or transfer of assets of vertically integrated utilities would result in loss of jurisdiction by the Commission over the divested entities and a loss of jurisdiction over wholesale contracts between the utility and the divested entity.

The transfer of assets to a functionally separated division of the utility within the same corporation, as provided for by the Virginia commission, would not appear to result in a loss of jurisdiction by the Commission.

15. How would the divestiture or transfer of assets of vertically integrated utilities now serving Arizona affect federal jurisdiction under the FERC and the SEC over the divested entities?

Staff understands that, as a general matter, the divestiture or transfer of assets of vertically integrated utilities would result in FERC jurisdiction over the divested entities and over wholesale contracts between the utility and the divested entity.

The transfer of assets to a functionally separated division of the utility within the same corporation, as provided for by the Virginia commission, would not appear to result in FERC jurisdiction over the divested entities or over arrangements between the utility division and the functionally separated division.

16. How would the potential effects of divestiture or transfer of assets on Commission authority differ under a competitive retail regime than under a monopoly regime?

Staff understands that, from a legal standpoint, divestiture or transfer of assets would result in a loss of Commission jurisdiction over the divested or transferred assets and on wholesale agreements between the utility and the new owner of the assets. This would seem to be the case, regardless of whether the retail regime was competitive or still a monopoly.

The Commission would have jurisdiction over retail agreements between the new owner of the assets and retail customers in Arizona. From a strict legal standpoint, however, it is possible that FERC could claim jurisdiction in these circumstances. In practice, however, it appears that FERC has enough on its hands regulating the wholesale market and is leaving the state commissions with authority with respect to retail contracts and arrangements.

17. How would a requirement that company services, such as generation services, be offered only through a separate corporate affiliate affect the Commission's regulatory authority and any risks identified in response to the questions above?

As noted in response to the previous question, it appears that *retail* services offered by a separate corporate affiliate would in practice remain under Commission jurisdiction.

18. For any risks resulting from a divestiture requirement or a requirement that competitive services be offered through a separate affiliate, how might those risks be eliminated or reduced? Specifically –

a. What actions might the Arizona Commission take?

If the Commission is concerned that it would (or might) lose jurisdiction over the affiliate in the case of divestiture or transfer to a separate corporate entity, transfer of the assets to a division that is functionally but not structurally separated from the utility would seem to avoid this risk. Eliminating or postponing the transfer also would mitigate these risks.

b. Are there actions that the Commission might encourage the FERC or the SEC to take to maintain adequate oversight for the protection of ratepayers?

It is probably reasonable to assume that, as in other states, FERC would not in practice interfere with Commission provisions such as consumer protection provisions imposed on retail suppliers. With this assumption, the area where the FERC should be encouraged to maintain adequate oversight is the wholesale market. The actions that are necessary to protect ratepayers include the development of an effective regional ISO or RTO, and the strict enforcement of measures to ensure that new generators are able to access the grid without barriers to entry and that the wholesale market is workably competitive. FERC needs to take steps to mitigate market power, as well as scrutinizing proposed mergers very closely.

Staff Responses To The Questions Attached To Commissioner Irvin's Letter Of February 7, 2002

I. Arizona Independent Scheduling Administrator

1. Please address whether Arizona's Constitution prohibits the Commission from giving up any authority with respect to the pricing of services by public service corporations which occur solely within the state.

Arizona's Constitution states that the Commission "shall have full power to, and shall, prescribe just and reasonable ... rates and charges...." Arizona Constitution Article XV, § 3. Arizona law does not expressly address whether, and to what extent, the Commission may refrain from exercising this authority. However, it could be argued that the Commission's plenary and exclusive ratemaking authority includes the power to choose to refrain from acting in appropriate circumstances.

Whatever the precise legal answer to this question, it is clear that the line between state and federal jurisdiction shifts and becomes obscured by retail competition. A state embarking on retail restructuring is taking the significant risk of greater loss of jurisdiction than it may have anticipated or desired.

2. Should Arizona be willing to let the federal government take over pricing jurisdiction (market-based rates) for all retail transactions which occur in the state, or is this an inevitable (and proper) result of opening retail markets to competition?

It would be inappropriate and outside of FERC's jurisdiction for it to assert jurisdiction over all aspects of retail transactions. FERC would not have jurisdiction over the pricing of *distribution* services in a competitive retail energy market. FERC would have jurisdiction over wholesale energy sales and transmission services in interstate commerce.

Divestiture, as a practical matter, will result in loss of Commission jurisdiction because it changes the focus of energy sales from retail to wholesale. Loss of jurisdiction is one of the greatest disadvantages and risks of moving to retail competition, and should be weighed carefully by the Commission. One thing is clear: the state can decide whether and when it wishes to allow restructuring and to take this risk.

3. Can Arizona's UDCs modify their tariffs with the FERC to conform with AISA protocols so that retail transactions can still take place without the AISA? How many times has the AISA been used to resolve disputes over transmission issues to date?

The AISA has been used zero times to resolve disputes over transmission issues. If there is no AISA, it appears that some filing at FERC would be necessary to modify the Affected Utilities' OATTs that refer to AISA protocols. However, whether FERC would approve modifications to the OATTs with similar protocols without an AISA is speculative. FERC may require the Affected Utilities to adopt a pro forma OATT in compliance with FERC Order 888 without any Arizona specific provisions. Furthermore, until our Commission has had an opportunity to review any prospective OATT filings by the Affected Utilities, it is premature to conclude that our Commission could support OATT filings incorporating AISA-like protocols without AISA independent oversight.

II. <u>Retail Electric Competition Rules ("Rules"); Markets</u>

4. If the majority of market participants intend to market electricity only to industrial, large commercial and load-serving ESP entities, should retail markets be limited by load size to allow those entities with true bargaining power to negotiate Direct Access?

Many of the states that have introduced direct access have phased it in by size of customer. There are several reasons for this. One, as the question notes, is that larger customers have more bargaining power; they have the resources and the financial incentive to thoroughly investigate market alternatives.

Two, larger customers have had the greatest interest in switching to an open market for electricity, the last of their inputs that is still regulated. It is the perception in the business community that deregulation is a feature that favors industrial location in a state. (However, botched deregulation like that in California affects industrial location negatively.)

Three, from a logistical standpoint, it is easier to implement, and if necessary modify, retail wheeling protocols for hundreds of large customers, than for thousands or tens of thousands of customers of all sizes. One reason is that large customers already have advanced meters or can economically acquire them, but such meters are not yet economical for most small customers.

Four, we now know how difficult it is to create a market structure that succeeds in fostering ESP entry to the small-customer market or provides small customers with sufficient incentive to shop for electricity. Rather than shooting for near-term direct access by small customers, it might be preferable to create a competitive alternative such as standard offer that is put out to competitive bid. As noted earlier, this alternative appears *de facto* to be within state jurisdiction.

However, there is an important risk associated with allowing only large customers to participate in a competitive retail market. Suppliers have a strong preference for customers with high load factors (i.e., a large baseload usage and a small peaking usage). By separating out the large customers, the small customers' load factors are lower than they would be if seen as a package with the large customers, and thus smaller customers might become even less attractive to suppliers. One example of how this might play out is in standard offer services, where a supplier might charge higher rates for a group of customers with fewer customers, fewer energy requirements, and a lower combined load factor. Another example of how this might play out is with municipal aggregation, where the aggregator would have to pay higher prices for a smaller group of customers with a lower load factor.

Thus, at this time, Staff does not advocate limiting participation in the retail market based on customer size.

5. What will be a UDC's primary functions in a competitive market?

Delivery of electricity over distribution lines would be a UDC's primary function. Also, ownership and construction of transmission lines, under RTO operation and planning. Most probably retail metering too, at least for the time being. And, as we suggest, the provision of some kind of bundled service such as standard offer or default service for small retail customers, assuming it is premature at this stage to force such customers onto the competitive market. UDCs should also play a role in supporting the development of distributed generation.

6. Is it important to first establish functional wholesale markets before creating robust retail markets in electric generation? If so, why? If not, why?

Yes. The reason is that a competitive retail market provides retail customers direct access to the wholesale market. If that market malfunctions, as it did in California, retail customers would be at risk. They would be vulnerable to price volatility, bulk power supply disruption, and supplier failure. A functional wholesale market can also be a means of preventing or mitigating vertical and horizontal market power.

7. When price caps are lifted for the majority of Arizona consumers, what assurances do we have that volatility in the market (for both natural gas and electricity) will not result in unstable or inflated rates? Will the generation price of electricity fluctuate with the price of natural gas?

Until such time as a well-functioning bulk power market structure is established, there can be no assurance of price stability or supply reliability. Such a market structure would include an effective RTO (with authority over a large region) which is able to deal with congestion problems and peak period pricing, and assure adequacy of generation and transmission capacity. The RTO would have to have sufficient authority to coordinate planning and/or pricing of generation and transmission to avoid supply disruptions in the future.

Yes, the generation price is likely to fluctuate with the price of natural gas. An orderly, competitive gas market would contribute to electricity price stability. So would fuel diversification by electricity generators.

Price volatility and inflation are significant risks associated with a competitive electricity market – even a market that is well-designed and sufficiently competitive. The Commission should ensure that the alleged advantages of competition are worth the disadvantages associated with these risks.

8. Should there be a provision added to R14-2-1606(B) which would allow/limit a UDC to contract for wholesale power in three or five year intervals?

We do not see any advantages to such a provision, while there are likely to be several important risks. It is risky to provide specific limits of this kind on the way a UDC provides for its power supplies.

Rather than place regulatory limits on a UDC, the Commission should require a filing by the UDC that would describe its plans for providing energy to its remaining retail customers (those who have not switched to direct access), including flexibility to handle uncertainties, and the avoidance of unnecessary risks. The UDC might, for example, enter into contracts of different lengths and with staggered termination dates, as well as other arrangements to deal with demands that turn out to be greater or less than now anticipated.

9. What are the real benefits to residential consumers and small businesses in retail competition, other than consumer choice? Will IPPs market their power directly to retail customers, or are their efforts mainly focused on selling power to wholesale customers?

Experience to date suggests that retail competition offers very few benefits to small customers, if any. Thus far, the small-customer retail market has been disappointing to both customers and suppliers in most states. Residential customers have remained on standard offer service, and few suppliers have marketed aggressively among small customers. This outcome was to some extent inevitable – the potential benefits are inherently quite small. It has also been partly the result of market design: the primary objective of legislators and commissions has been the protection of small customers (by guaranteeing favorable standard offer service), rather than fostering competition.

10. Currently, is residential choice a real option? If not now, when?

Residential choice is probably *not* a real option at the present time, given the lack of suppliers willing to service small customers.

It is conceivable that the small customer market could open up in time, and bring some benefits to those customers. Factors that could favor customer choice include the development of lower-cost advanced meters and interactive load controls for small customers, and greater seasonal and daily variations in wholesale market prices, which could together make real-time pricing economical. Another factor could be the development of customer aggregation, which would reduce customer acquisition costs for marketers. These developments might emerge in the next five to ten years; although there is also a considerable risk that they might not.

A negative factor that is currently inhibiting retail competition is the malfunctioning of wholesale power supply markets. California is the obvious example, but market power has also raised prices in states with more mature wholesale markets like those in New England, and in the mid-Atlantic states in the PJM pool. And in the Mid-West and elsewhere, there have been price spikes.

11. What provisions, if any, are necessary to effectuate a gradual replacement of those existing plants in Arizona which are older, more polluting and less efficient than the newer combined cycle plants currently being built?

Experience to date suggests that existing power plants are likely to be very valuable in a competitive market, and Independent Power Producers are going to be unwilling to retire them. Several older fossil-fired steam plants have been sold to IPPs at high prices, suggesting that (a) they are considered very valuable in a competitive market, and (b) the owners intend to operate them for a considerable period. These existing plants (whose construction costs are sunk and who already have permitted sites and access to transmission lines) will make it difficult for new entrants to compete on economic grounds. Once new, efficient gas plants are financed, permitted and constructed, they may be able to displace some of the generation of the highly-inefficient, older plants. But even this is not guaranteed – it depends upon the operating economics of the existing power plants (in particular, the efficiency and the fuel costs).

Also, if the older, less-efficient plants are on the wrong side of a transmission constraint and thus "must run" during peak hours (as is the case in the Phoenix area) it will be difficult for newer, more-efficient plants to replace them. Thus, the elimination of transmission constraints may be necessary if we are going to depend on competitive forces to retire older, less-efficient plants.

Under continued integrated utility planning, the Commission has more scope to influence the retirement of more polluting and less efficient plants and the construction of newer, cleaner, more efficient plants. The utilities could be given favorable regulatory treatment, e.g. by allowing rapid depreciation of old plant and providing an assurance that the companies would not have to take write-offs; and the assurance of rapid rate-basing of new facilities and their reflection in rates. Under a deregulation scenario, the Commission would presumably have little authority to effect the replacement of existing power plants.

12. What are the long-term effects of divestiture for APS? How does the Commission guard against a PG&E situation, where the distribution company declares bankruptcy after profits have flowed to its parent holding company?

The divestiture of generation assets creates substantial risks with considerable disadvantages. First and foremost, the Commission will not have jurisdiction over the sale and pricing of wholesale generation from those assets. This, in turn, increases the risks associated with price inflation, price volatility, and horizontal market power problems.

Divestiture is a double-edged sword. On one hand, it is necessary to ensure a sufficiently competitive electricity market and to eliminate problems with vertical market power. On the other hand, it creates risks associated with loss of regulatory jurisdiction and potential horizontal market power. If the divestiture option is chosen, it should be done in a way that minimizes these risks and makes for a sufficiently competitive market. For example, generation assets should not be divested to any companies with any affiliation with the local UDC. Divestiture should only occur when other conditions for a workably competitive market are in place, such as an effective, competitive wholesale electricity market.

With regard to PG&E's experience, divestiture to a non-affiliated company, and perhaps even transfer to an affiliate, shrinks the distribution company's asset base and therefore reduces the financial cushion in the event of financial distress. However, the best safeguard of distribution company solvency is the creation of a sound business and regulatory model. The California utilities' financial distress resulted from a foolish combination of fixed retail prices and volatile wholesale prices. Arizona should avoid that combination, and spare distribution utilities the risk of financial distress.

V. Staff's Vision and Recommendations

Staff Vision

Even if electric industry restructuring can be a good thing in principle, there is now widespread recognition that it is not easy to get the details right in practice. Indeed, the risk of making mistakes in the restructuring process seems to be so serious that regulators in some states are now rethinking the whole enterprise. Meanwhile, in other states, retail competition is continuing to evolve. In these circumstances, Staff's responses to the questions raised by the Chairman, are designed to provide the Commission with a brief statement of the late-1990s *pro-competition view*, and Staff's tentative assessment of regulators' *second thoughts* in light of the California crisis, high wholesale electricity prices in many parts of the country, and the spotty record of customer switching.

We believe it is important to keep certain basic economic principles in mind. Continued regulation is desirable for those services that are natural monopolies, i.e., in which economies of scale or scope are so strong that it is more efficient to have only one supplier provide the services. This was the traditional view of the whole electricity industry -- economists and regulators thought it most efficient for one utility to operate and plan the whole package of electricity services on a coordinated basis in each state-approved service territory.

By contrast, restructuring should be considered for those services that can be competitively provided. When it promulgated its *Electric Competition Rules* in 1996-2000, the Commission believed that electricity generation and retail customer services could fall in this category. However, for there to be vigorous competition in the supply of these services, it was always understood that regulatory oversight would still be needed to mitigate market power (both for generation and transmission), prevent barriers to entry for new competitors, and continue to use antitrust measures to avoid the formation of monopolies. Absent this oversight, formerly regulated utilities might be able to become deregulated monopolies, or new generation companies could establish dominant positions.

During the past two years, it also became clear that a failure to structure wholesale and retail markets appropriately could result in price volatility and even market failure. And it became evident that, even without instability in the wholesale market, it would prove difficult to profitably serve retail customers.

In light of the events of the past two years, the Commission is now reviewing its earlier decisions about which services can be competitively provided. The general requirement for a workably competitive market is that suppliers must not be able to exercise significant market power. This requirement will be satisfied to the extent that a significant number of strong competitive firms find it profitable to participate in the market, and/or barriers to entry into the market are low, and buyers have effective means to accept or reject supplier bids.

In applying this test – which electricity markets can be workably competitive? – Certain observations can be made in light of the experiences of the past two years:

1) Retail electric competition is only feasible if and when there is a smoothly functioning *wholesale* market to which retail customers can gain access.

2) Acquisition of retail customers – especially small customers – can be costly.

3) The starting point of restructuring is that each incumbent vertically-integrated utility *already* has in place a full array of generation resources with which it can reliably and economically provide all retail customer needs in its service territory. Its established local position can make it difficult for new entrants to compete on equal terms. Furthermore, vigorous antitrust enforcement is needed to avoid the subsequent formation of local or regional monopolies.

4) The peculiar nature of the electric industry makes it prone to boom-and-bust cycles.[14] To smooth these cycles and ensure reliability and price stability in the wholesale electricity market, some kind of coordinated system planning (e.g. by regional transmission organizations) is still required, with a favorable regulatory climate and appropriate pricing incentives for investment in generation capacity and transmission system expansion. "Indicative planning" might be an appropriate label.[15]

Now that the risks of proceeding toward electric restructuring are known, especially the instability of wholesale markets, the difficulty of designing market mechanisms that work well, and the reluctance of both customers and suppliers to enter the small retail market, it is appropriate to reframe the issue of electricity regulation versus competition. While it is too soon to assess the <u>long-term</u> benefits and risks of electric competition, we think the burden has shifted onto those who would advocate near-term electric industry restructuring to show that the risks are worth taking. Briefly stated, Staff supports competition where appropriate. In this instance, while Staff believes the Commission should continue to transition towards competition, Staff would advocate that the Commission take the time to ensure that the current rules and agreements will truly result in a vibrant competitive market. In doing so, Staff believes that the Commission should take actions that protect the development of *competition*, not that protect the interests of individual *competitors*.

<u>Staff Recommendations</u>

Through the Retail Electric Competition Rules, which were developed from 1996 through 2000, the Commission set Arizona on a path toward retail competition. That path was confirmed

[14] New generation takes a relatively long time to plan, permit, site, and construct, which makes it difficult for suppliers to respond quickly to price signals. Transmission expansion needs to be coordinated with new generation. Many electricity services are necessities, and demand is inelastic. There can be needle peaks during periods of extreme weather conditions, but electricity cannot be stored for future use. Because electricity is transmitted and distributed through an integrated network, it is not easy to isolate instability -- the whole regional system needs to work together smoothly.

[15] This term was coined by the French government in the period after World War II, to distinguish its approach from more rigid centralized planning.

and modified in the settlement agreements approved by the Commission for APS and TEP. The pace is rapid, and there is concern that the conditions for a competitive wholesale market, on which a competitive retail market would depend, may not yet be in place. Specifically, APS does not believe that the wholesale market can reliably supply 50% of the power needed for standard offer service, as anticipated and required in the APS Settlement Agreement, and Retail Electric Competition Rules.

APS has proposed an alternative to obtaining power in the competitive wholesale market. It has proposed to transfer its generation assets to an affiliate company and enter into a long-term Purchased Power Agreement with that affiliate to supply the power APS needs for standard offer service. This is a significant change in direction, compared with what the Commission had in mind. It is a recognition that a competitive wholesale market, on which Staff believes the Electric Competition Rules and settlement agreements were premised, does not yet exist.

Meanwhile, in light of the California energy crisis and other problems, certain western states are having second thoughts about retail competition, and are canceling or delaying restructuring. Chairman Mundell, in his letter of January 14, 2002, asked "whether circumstances have changed enough to compel a different pace or path." Staff would like to take this opportunity to present its proposed answer to this question.

First, regarding the *path*, the events of the past two years have revealed unexpected and serious risks along the path to electric restructuring. The events that have occurred around the nation have added to the growing body of evidence that competition in retail electric markets is going to take a long time to get established. For all but large industrial customers, the evidence to date suggests that the vast majority of customers prefer the safety of utility standard offer service to the uncertainties of the competitive market. Even some large industrial customers on special contracts with at least a portion of their rates based on market prices have renegotiated those contracts to have fixed prices. The rise in wholesale prices in 2000/2001 resulted in Electric Service Providers returning customers to standard offer service. And with high wholesale prices, many electric service providers couldn't compete with Standard Offer Service and withdrew from the market.

Turning to wholesale electric markets, it is no news to say that the experience thus far has been unexpectedly rocky, with prices significantly higher than costs in most if not all regions, not to mention extreme price spikes and shortages in some areas. Market structures are still evolving, and the development of ISOs and RTOs is in its early stages in most regions. There have been widespread allegations of abuses of market power by generators, even in regions with relatively well-structured ISOs. Transmission system planning and expansion are lagging behind need in some areas. And a boom-and-bust cycle may be emerging in the merchant power business -- after the experience of high prices and shortages in 2000/2001, prices have been falling. The consequent delay or cancellation of construction plans could result in another period of shortages down the road.

Wholesale competition is a precondition for retail competition. Also, given that the current rules envision utilities serving their standard offer customers through purchases in the competitive wholsale market (whether through a bid process or otherwise), a vibrant competitive wholesale market can benefit Arizona's consumers whether retail competition ever develops or not. However, it is not clear that FERC and the regional RTO arrangements are yet up to the task of ensuring that structures are in place to properly price transmission services and ensure the orderly expansion of the transmission system. The AISA was never intended to address issues affecting the competitive wholesale market.

In considering the following recommendations, Staff has been guided by the following four principles:

1. Staff continues to believe that retail electric competition may be appropriate. Although Staff will identify several deficiencies with the details of the existing rules, Staff believes that these rules, with amendments, may yet form the framework for an appropriate transition to competition.

2. Staff must give due consideration to actual and emerging national, regional and state developments regarding the wholesale and retail markets. In other words, managing Arizona's transition to a competitive market must be reality based.

3. Staff must consider what is in the best interest of Arizona's consumers while affirming that we support a properly functioning competitive market. In doing so Staff recognizes that competition potentially could afford three principal benefits to Arizona's consumers: price, choice, and innovation. Staff believes that, if the Commission chooses to remain committed to competition, the Commission should structure the transition to maximize these three potential benefits and to recognize an appropriate balance between them. Specifically, Staff does not believe that price benefits should be sacrificed in order to encourage consumer choice.

4. Since the current Competition Rules require the utilities to purchase power for their standard offer customers in a competitive manner, a well functioning competitive wholesale market is necessary and may result in benefits for consumers even if retail competition never becomes widespread.

As the Commission seeks to manage the transition from a regulated monopoly environment to a competitive environment, in Staff's view, it is desirable to protect the development of a properly functioning competitive market place. Thus, Staff is interested in protecting competition not competitors. Therefore, Staff recommends that all transfer and separation of utilities' assets be stayed pending the completion of the generic docket. Staff supports a properly functioning competitive market. Such a market is likely to have significant benefits for Arizona. However, there are problems with the current Retail Electric Competition Rules, and the settlement agreements that support them, that need to be addressed in the generic docket. It would be unwise to move forward now without first attempting to resolve these problems. Resolving the problems of the current rules through the generic docket will be Staff's highest priority.

Staff believes that the issues that need to be addressed in the generic docket are the following:

1) Market power and market monitoring. The question is this: To what extent and in what way should the Commission be involved in monitoring market conditions and/or mitigating the development of market power for generation and transmission? Staff does not believe that vibrant competition will develop without some Commission oversight. Staff is aware that there are serious jurisdictional issues here that need to be addressed.

2) The competitive bidding process. I n addition to the concerns about competitive bidding that APS has raised in its variance request, Staff is concerned that the current rules offer no guidance as to how the competitive bidding process will work. Staff will not support placing California style restrictions on how the bidding process works. Staff is committed to a bidding process that provides utilities wide latitude in making prudent purchases on behalf of their standard offer customers. However, the current rules offer no guidance whatsoever on what constitutes a competitive bidding process. Some definition of the process is necessary.

3) Transfer and separation of assets. The stated reason for requiring utilities to transfer their generation assets was to eliminate market power in the wholesale generation market. The analysis in this Staff Report and the issues APS raised in its variance request indicate that market power will not be mitigated by the transfer of assets required by the Retail Competition Rules. Allowing utilities to transfer all of their assets to affiliates which then engage in less than arms-length transactions with the affiliates will not encourage the development of a vibrant competitive wholesale or retail market. With the generation assets in the affiliates' control, the assets they will be outside of the Commission's jurisdiction and will fall under FERC's aegis. Thus, allowing such separation will potentially put Arizona's retail electric rates under the jurisdiction of the FERC. The FERC is unlikely to take an active interest in Arizona's retail rates, thus the market power of incumbent utilities is likely to go unmitigated.

Thus, going forward with the separation and transfer envisioned in the current rules is unwise in Staff's view. Staff recommends that other options be considered such as requiring the transfer of assets to a functionally (but not legally) separate entity within the utility. Virginia has required such a separation. Transfer of assets to a functionally separate entity may allow for the same benefits as transfer to an affiliate without the corresponding loss of Commission jurisdiction. An alternative (but not necessarily mutually exclusive) option is to allow or require the sale or transfer of generation assets to non-affiliated companies in a much more gradual manner than envisioned by the existing rules. These and other options should be examined in depth during the course of the generic docket.

4) Transmission constraints. Staff has identified serious transmission constraints in this Staff Report. Staff believes that the issues surrounding these constraints (and the resulting must run requirements) significantly impact the development of the wholesale market for power and should be addressed in the generic docket.

5) Adjustor mechanisms for standard offer service. At least one Arizona utility will be implementing an adjustor mechanism for its standard offer rates in the near future. In light of the problems with the development of a competitive wholesale market discussed in this

Staff Report and in APS' request for a variance, Staff believes it would be appropriate to reassess the need for such an adjustor mechanism.

6) Shopping credits and unbundling generally. The adequacy of the shopping credit (the cost a customer would not pay to their UDC if they take generation service from a competitor) has been identified as being highly significant in the development of a competitive retail market. Staff is opposed to imposing artificially high shopping credits in order to give an artificial boost to competitors. However, the shopping credits and unbundled rates now in effect, such as they are, should be examined in order to determine whether they are set at levels that are artificially low.

Appendix One: Detailed Summary of Other States Experiences

Arkansas

Summary

Arkansas is a good example of a state that was moving in a deliberate manner toward retail competition until 2000/2001, but then decided -- in light of the California situation as well as local considerations -- to delay restructuring for two years. In 2001/2002, further delay or even repeal of the restructuring legislation is under discussion.

Among the local considerations that contributed toward the decision to delay restructuring were the following. First, Arkansas enjoys relatively low power costs, and there was the fear that in a competitive regional electricity market, prices might rise. Second, the region's utilities, who are members of the Southwest Power Pool (SPP) are moving slowly in their compliance with FERC directives to form an RTO.

In a nutshell, with the wholesale market unready for retail competition, the Arkansas Public Service Commission and state legislators decided in 2000/2001 that Arkansas need not be in a hurry to embark on the complex procedure of opening up the retail market to direct access. In 2001/2002 the debate has gone further than merely delaying restructuring; now the PSC has become skeptical, and the whole endeavor is under review.

Profile of State Electricity Situation

The principal electric utility company in Arkansas is Entergy Arkansas, Inc., a subsidiary of Entergy, Inc., which, through subsidiaries, dominates the electricity industry across the middle south from east Texas through Louisiana and Arkansas to Mississippi. It has joined the Southern Company, which abuts Entergy to the east, in the Southeastern Electric Reliability Council.

The other electric utilities operating in the state have relatively small pieces of the market -- Southwest Electric Power Co. (SWEPCO, a Central & Southwest subsidiary), Oklahoma Gas & Electric, a number of rural electric cooperatives, and a couple of municipal systems.

The generation system is quite diversified, with coal-fired, natural gas-fired and nuclear generators. In the past, the most controversial issue was the FERC allocation of a large share of the costly Grand Gulf nuclear generating station to Arkansas. This gave rise to potential stranded or unrecoverable fixed costs.

The Arkansas Public Service Commission (PSC) is the state's regulatory agency.

Restructuring Legislation and Regulation

Act 1556, the Electric Consumer Choice Act of 1999, was signed into law on April 15, 1999, and provided the basis for restructuring in Arkansas. Act 1556 mandated retail open access (ROA) no sooner than January 1, 2002, and no later than June 30, 2003, the exact date to be set by the PSC. Those dates gave the PSC a timeframe to work with in preparing the industry and its customers for restructuring.

Before and after the passage of Act 1556, the Arkansas PSC conducted proceedings to investigate restructuring issues such as Entergy's stranded cost problem. The statute has provisions for stranded cost recovery. For those customers who remained on standard offer service from their incumbent utility, rates would be frozen for one year. If, however, the utility seeks to recover stranded costs, its standard offer rates would be frozen for three years. Utilities were required to file functionally unbundled tariffs showing, at a minimum, generation, transmission, distribution and customer service components. Other provisions related to such matters as licensing of suppliers and aggregators, competitive metering and billing, and customer protection.

Concerns over the structure of the power market and the possible exercise of market power in a deregulated wholesale power market have been addressed by the PSC. In Docket No. 00-048-R concerning market power, opened in February 2000, utilities were required to file market power studies. If a company was found to possess market power, it would have to file a market power mitigation plan. Mitigation plans may include such measures as price caps, transitional standard offers, generation sale through long-term contracts, and asset divestiture.

Delays in the Restructuring Schedule in 2000/2001

The statute requires the PSC to submit annual progress reports to the state's legislature, the General Assembly. In 2000, the PSC conducted a proceeding in which interested parties could address these issues before the submission of its first annual report. The report was titled *Progress Report to the General Assembly on the Development of Competition in Electric Markets and the Impact on Retail Customers*, and was submitted November 28, 2000.

The questions addressed in the proceeding and reported to the legislature focused primarily on the state and region, and included forecasts of generation prices. The PSC also noted that it had "closely followed developments in other regions of the country including, but not limited to, the problems encountered in some parts of the California markets as well as other states in the West and the Northeast, the price fluctuations in the natural gas markets, and developments regarding RTO issues." (p. ii)

The PSC developed a two-part "readiness" test for retail competition: (1) was there a market structure that was ready for competition, and (2) would competition result in net public benefits? The PSC convened a hearing on October 11, 2000, in which it noted that many of the parties believed that the statutory timeframe was too tight. The PSC came to the conclusion that the schedule "would not provide sufficient time to allow the development of market structures that could support a competitive, fully functioning retail market for electricity, and would not provide a reasonable opportunity for all consumers to realize net benefits from competition." (p.ii)

Regarding the development of the wholesale market, the PSC was not convinced that the region would have a comprehensive and effectively functioning RTO in time for retail access in

2002/2003. Yet, "The Commission is convinced that a workably competitive wholesale generation market is a prerequisite to the effective functioning of retail generation competition." (p. 17)

The electricity providers were supporting the efforts of the Southwest Power Pool (SPP) to form an RTO, which was then expected to be operational by the end of 2001. However, Entergy was planning to establish a for-profit Transco, which would have to enter into an operating agreement with the RTO. Furthermore, the Entergy system's operating agreement would have to be modified. And finally, OG&E, SWEPCO and Empire District Electric would not commit to joining the RTO unless certain conditions were met. "It is simply not reasonable to expect that all of these tasks will have been completed and that the RTO/Transco will be fully functional within the timeframe currently contemplated by Act 1556." (p. 18)

The PSC did not think Arkansas would run the same risk of high prices and power emergencies as California, because conditions in Arkansas were different. It was easier to site new power plants in Arkansas, and in fact a number of plants were under construction or are planned. The formation of an effective RTO should "encourage expansion of the transmission system." (p 21) But the PSC was still concerned: "However, there are still significant transmission issues that must be addressed and market power mitigation and enforcement remedies that must be established as a prerequisite for an effective competitive marketplace that could produce net benefits." (p. 21)

Regarding the benefits to customers, Staff consultants made a forecast "that customers would pay higher generation costs under competition than under continued regulation for the foreseeable future." (p. 3) Some parties pointed out that entry into the Arkansas generation market was easier than in California, that there would be no mandatory purchase of power through a power exchange, and that the standard service package for small customers would mitigate price volatility. (p. 6) They also disagreed with the magnitude of the retail adder estimated in the Staff study, the mark-up of retail over wholesale power costs. The consultants estimated one cent per kWh, compared with Entergy's estimate of a quarter of one cent (pp. 15-16). The PSC was, however, clearly influenced by the views of the Staff consultants.

In summary, the PSC concluded that retail competition was not expected to meet either of its "readiness" tests in the 2002/2003 timeframe. A Joint Agreement was negotiated between the parties. Pursuant to that agreement, the PSC recommended to the General Assembly that ROA be delayed to no sooner than October 1, 2003, and no later than October 1, 2005, with the PSC being authorized to set a date within this range.

Three other points are of interest in the Arkansas PSC's November 2000 *Progress Report*. One is that the PSC continued to believe that it was appropriate to plan for retail competition, and that "the statutory framework embodied in Act 1556 is an appropriate one to transition from regulated to competitive electric generation service." (p. iv) Moreover, "Most of the parties agreed that wholesale competition can provide some but not all of the benefits that consumers will realize when ROA is implemented." The PSC cited the Staff's view that "Over time, wholesale competition should provide lower costs and greater efficiency. Retail competition can offer pricing options, source options, and payment in-service options." (p.7)

The second point is that the PSC recognized how important it was to give market participants a framework within which they could make their planning decisions. "A reasonable implementation window needs to exist as a target date for purposes of providing investment and planning direction to the market participants, both regulated and non-regulated. If they have not already done so, the electric utilities must now make decisions regarding acquisition of additional generation capacity. Transition plans need to be developed and large customers have equivalent energy planning decisions to make." (p. iv)

The third point is a background political point about the process by which the recommendations to the legislature were negotiated. The recommendation was able to receive near-unanimous support, because it left the basic framework of restructuring intact, and restricted itself to a matter of timing.

Increased Skepticism in 2001/2002 Regarding Restructuring

During 2001, the PSC was obviously concerned about the on-going electricity crisis in California. It issued an (undated) 7-page document on its website, *What Happened in California, or Why Arkansas is not California*. It identified the factors that resulted in the market failure in California, and concluded that none of those factors applied to Arkansas. However, it is clear from the issuance of this document that the PSC was finding itself in a defensive posture on the issue of electricity restructuring.

In its defense of the Arkansas situation, the PSC made the following points. First, there is no official power exchange planned for Arkansas, nor is there a mandate for the utilities to sell power into or buy power from the spot market. There is likely to be a high proportion of stable, long-term bilateral contracts (as is the case in most states). Second, the price freeze period is short and default standard service will respond to market prices. Third, demand growth in Arkansas is increasing modestly, supply resources are increasing, and plant siting is not overly difficult, all of which should avoid a constricted supply and demand situation.

The PSC had this to say about market power. "Dealing with the exercise of market power is a problem we share with California, or any other state that moves to competitive generation markets." (p. 7) However, the PSC believes it has broad statutory authority to deal with market power. (The PSC does not make it clear how its authority would prevail over federal jurisdiction in the wholesale market.)

This document represents the PSC's last defense of retail open access. Its conclusion was that, "As we learn from the experience of other states, Arkansas can move ahead confidently, knowing that the California mistakes will not recur here." (p. 7)

The PSC submitted its second annual progress report to the General Assembly on December 20, 2001, titled *Report to the General Assembly Pursuant to Act 324 of 2001 on the Development of a Competitive Electric Market and Possible Impact on Consumers*. The PSC noted that Act 1556 had been amended by Act 324 of 2001, as a result of the recommendations made by the PSC in its first progress report. The date for initiating retail competition had been changed to not earlier than October 1, 2003, but the PSC may delay competition in one-year increments until not later than October 1, 2005.

In Docket No. 00-190-U, the PSC had entered an order on July 6, 2001, asking interested parties to comment on forecast prices under competition compared to continued regulation, and on anticipated market readiness. Before introducing retail open access, Act 324 provided that the PSC would have to find that there would be "net price benefits for customers, particularly residential and small business" (a more restrictive provision than the earlier "net public benefits"), and that "the wholesale market was ready for retail competition." (more pointed than the earlier "market structure" requirement). (p. i)

Applying these more precise tests, the PSC was much more skeptical in its assessment of the prospects for retail open access than it had been a year earlier. "Based on information submitted in Docket No. 00-190-U, and the status of activities at the Federal Energy Regulatory Commission ("FERC"), the Commission believes that continued movement towards retail competition in Arkansas is not in the public interest." (p.i) The PSC recommended "one of two viable statutory modifications:"

The first option would be the complete suspension of the current statute for a considerable period of time, perhaps going out to 2010 or 2012. The second option would be a repeal of the laws related to retail open access." (p. ii)

There are several considerations that led to this recommendation. No doubt the first was that the atmosphere in the General Assembly had changed, as evidenced by the tightening of the pre-conditions for retail competition. The second was that the tenor of the debate in the PSC hearing room had changed even more. It was no longer a matter of "let's just stick to the issue of schedule." Now, the substantive issue of restructuring itself was the center of the discussion. However, some parties, such as Entergy, while agreeing that a further delay was necessary, opposed an outright repeal of Act 1556.

The PSC Staff submitted ten-year price forecasts, for each utility, comparing competition with continued regulation. For all utility areas except OG&E (which has a relatively small service territory in Arkansas), generation rates would be higher under competition throughout the period, the Staff study concluded. For Entergy, the utility with by far the largest service territory in the state, the cumulative change would be 13.4% higher than regulated rates. This was despite the fact that generation capacity was expected to be adequate, and transmission systems were not expected to pose problems. The PSC saw "no anticipated qualitative benefits" to offset the price increases. (p. 15)

The PSC found that, "Perhaps the most critical key to the development of a workably competitive wholesale market is adequate, non-discriminatory access to the transmission network. Such success is largely dependent on FERC activity regarding RTOs. However, issues that will be crucial in determining whether or not this wholesale market plan will be effective and beneficial to retail consumers include: the price of access and the effect of federal pricing policies on retail customers in Arkansas; the policies surrounding non-discriminatory mechanisms for management of congestion at certain points on the transmission network; and the appropriate cost recovery treatment of additions to the transmission network." (pp. 12-13) Only one of the participants in the proceedings (SWEPCO) believed that a FERC-approved and operational RTO would exist in time to support ROA in Arkansas by October 2003. (p. 7)

The PSC concluded that, "The direction the electric industry will ultimately take regarding retail markets is certainly not clear...Several surrounding states have only begun initial inquiries into whether to restructure the electric industry within their borders, while others have conclusively determined not to move forward anytime in the near future. In this part of the country, only Texas is continuing to move towards ROA...The ERCOT portion of Texas is still moving to ROA, even though the start date for Entergy and SWEPCO in the eastern portion of the state has moved from January 1, 2002, to September 2002." (p. 11)

The PSC's overall assessment of retail competition was negative. "To date, no state has implemented an entirely successful retail competition model. Every state, including Pennsylvania and Texas, that has implemented electric competition has experienced various combinations of price increases, price volatility, and operational problems. Some model may eventually prove to be workable and beneficial; however, there are strong indications that existing models will likely be changed in significant ways." (p. 15)

The General Assembly holds sessions every other year, and its next scheduled session is in 2003. Unless it meets in special session, presumably the fate of Act 1556 will remain in the balance during 2002.

<u>California</u>

The California commission voted to end direct access by retail customers in September 2001. It is not our intention to describe the California restructuring model, which is quite complex, in great detail. Rather, with hindsight, we describe briefly some of the features of the California model that contributed to the state's electricity crisis of 2000-2001. In other words, we are using California as an example of what *not* to do.

1. <u>Power Supply Shortages</u>.

A tight power supply situation resulted in a malfunctioning of the poorly-designed California ISO, and in opportunistic behavior by suppliers which enabled them to manipulate prices. Prices rose far above production costs.[16] Similar, though less extreme, price spikes have occurred in other parts of the country. If the supply of power becomes tight in the bulk power market, it is difficult to avoid extreme price spikes. This is perhaps the most widely applicable lesson of the California electricity crisis.

In the intensity of debate in California over the transition to a new market structure, and the design of that structure, participants took their eye off the ball. They failed to keep abreast of

[16] There is a dispute about whether or not supply was actually deficient in California, or whether the whole crisis was created by manipulative suppliers. Here, we acknowledge that there was market manipulation, but that it would not have been so prevalent or have had such dramatic effects if supplies had not been at least somewhat tight (in the sense of capacity reserve margins being narrow) in the first place.

the state's economic boom, with its implications for high electricity demand. The construction of new generation plant, and the upgrading of the transmission system, failed to keep up with demand. Another factor on the supply side was that hydroelectric generation was low, owing to low precipitation.

The California crisis has reminded the electric industry and its regulators of something that they all took for granted under the regulated utility regime -- that power plant siting and construction needs to made consistent with demand growth, and somebody needs to plan and build enough new capacity.[17] One way to avoid supply shortages is to revert to regulated, integrated utility operations and planning. Utility planning has generally been able to avoid supply shortfalls. And if, occasionally, supplies are tight, utility regulation is reasonably well designed to avoid excessive price spikes and to ration supplies for short periods.

A balance between supply and demand is more difficult to achieve in a deregulated wholesale generation market. There is a tendency for a boom-and-bust cycle to develop. However, there are features of a deregulated power supply market that can avoid or at least mitigate supply shortfalls. Some planning and/or pricing mechanisms are needed to ensure the adequate construction of new power plants.

The coordinated expansion of the transmission system, in step with generation, is also necessary. The California crisis revealed transmission problems -- Northern California was unable to import enough power on Path 15 from Southern California.

The RTO may be the appropriate agency for planning and coordination. This is the view of Patrick H. Wood III, the new FERC chairman. In a striking admission that generation markets need some kind of regional (and state) planning, he said recently, "The RTO is a recognition that the power business must be planned and operated regionally...The RTO ought to be the respected body that initiates regional planning by saying, 'In this large area we need these four projects to be built.' Then it becomes the states' responsibility." (Business Week, March 4, 2002, p.30B) Wood also recognizes that price caps may be necessary to deal with price hikes; FERC responded slowly to the need for a price cap in the West in the wake of the California crisis, but finally imposed one.[18]

California's chaotic regulatory structure probably contributed to the generation deficiency; investors in new generation capacity preferregulatory and market certainty. It is reported that belatedly several new plants are coming on line, but absent the kind of foresight that FERC Chairman Wood is talking about, there is no guarantee that the cycle may not repeat itself, with a glut of power followed by a shortage later.

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[17] Contributing to the California crisis was the way in which both California and the Pacific Northwest came to rely on power imports from each other in the late 1990s, while neither area was planning to supply the needed exports. When hydroelectric capability was reduced in 1990, and the regional economies were booming, a tight supply situation developed. Throughout, California relied upon power from the Southwest, and its increased dependence in 2000/2001 put pressure on the market in Arizona and the rest of the Southwest.

[18] Partial or regional price caps can distort the market or lead to gaming. It has been noted earlier that suppliers sold power to out-of-state marketers, who then resold it in-state. Another result of California-only price caps was that power which might have been available in-state flowed out-of-state, period. There was a resulting loss of supply in California which contributed to make the market there tighter.

2. ISO/RTO and Power Exchange Design.

The California crisis was exacerbated by poor design of the California ISO. The problems occurred in the functioning of the California Power Exchange's day-ahead market and the ISO's real time purchases (to make up, on an emergency basis, any remaining power shortfall on the day itself). For example, when prices rose in May and June 2000, the ISO capped the price of power, but this cap did not apply to the ISO's emergency purchases in the real-time market. The result was that suppliers withdrew power from the day-ahead market, forcing the ISO to purchase more and more "emergency" power at higher prices in the real-time market.[19] This aberration peaked on July 28, 2000, when fully 28 percent of load was met on the real-time market. But even in November and December 2000, the ISO was still declaring emergencies when the generating reserve margin was apparently around 40 percent.

It is an ongoing task, under the aegis of FERC, to encourage the creation of more effective ISOs or RTOs. The West is lagging behind some other regions in this regard. Even in those regions that had a head start because they already had tight power pools, ISOs are still undergoing evolution.

3. Market power.

The California experience of market manipulation – strategic withdrawal of capacity from the market and opportunistic pricing – shows that market power is an ever-present concern in deregulated bulk power supply markets, especially when supplies are tight. Wholesale markets need to be characterized by adequate supplies, as noted earlier. They also need to have a number of effective and independent suppliers with no one supplier large enough to be able to manipulate prices, and low barriers to entry by new generators.

4. Retail versus wholesale prices.

The combination of regulated low retail prices and high and volatile wholesale prices had two unintended effects. First, it made the retail market unprofitable for third-party suppliers. After some initial skirmishes in the retail market, they withdrew and concentrated on sales in the wholesale market.[20] The lesson is that if and when states wish to make the retail market attractive to suppliers, they need to allow a differential between wholesale and retail prices sufficient to cover retail marketing costs. Looked at from the customer perspective, states need to allow customers a sufficient shopping credit to make it worthwhile for them to shop around for more efficient suppliers.

Second, the rise in wholesale prices put extreme financial pressure on the distribution utilities, which were not allowed under the California rules to pass the price increases on to their

[19] There were other twists. One was that the ISO could purchase power from out-of-state at higher prices than it could pay to in-state suppliers. This resulted in "laundering" of power when suppliers sold it to out-of-state marketers who then resold it into the California market. Another maneuver was for generators with market power on the export side of a bottleneck to game the ISO's congestion pricing scheme by over-scheduling capacity. The ISO would then be forced to buy decremental generation, which the same generators would offer at low prices, enhancing their net revenues.

[20] Green power was an exception, owing to a special customer credit for green power.

standard offer customers in the retail market. (When suppliers became afraid that the utilities would go bankrupt and not be able to pay, they withheld supplies. Their fears were justified: California's largest utility, Pacific Gas & Electric, filed for Chapter 11 bankruptcy protection from its creditors in April 2001.) Southern California Edison narrowly avoided bankruptcy.

5. Demand-side inflexibility.

The protection that retail customers initially had against wholesale price increases in California made demand less responsive than it could have been. As retail markets develop and real-time pricing becomes more economical and widespread, energy conservation and load management are likely to mitigate supply shortfalls.

6. Poorly planned divestiture.

In California, utilities divested most of their power plants into an imperfectly competitive market. The retail market design favored standard offer service, and the utilities were required to purchase power for standard offer service on the California Power Exchange (PX) spot market. This was a recipe for disaster. Utilities were dependent on the PX for more than half of their purchases, contrasted with less than 20% in most other divestiture situations, like that in New England, where utilities rely for the most part on bilateral, long-term purchased power agreements for their standard offer requirements.

Utility divestiture of generation assets needs to be carefully planned. The California experience in this regard can be avoided by ensuring that the wholesale generation market has adequate supplies and is potentially competitive before divestiture takes place, and that divestiture itself contributes to the competitiveness of the market (e.g., by asset sales to several separate unaffiliated generators). Also, by making better arrangements for utility buy-back of power for standard offer service, including longer-term bilateral contracts.

7. Natural gas dependence.

High gas prices and gas pipeline bottlenecks, allegedly exacerbated by market power in the gas market, contributed to California's electricity crisis. Perhaps there is over-dependence on natural gas among electricity generators in California, who use gas to generate more than half of their power.

The potential problem of lack of fuel diversity is difficult to avoid in deregulated markets; there is a tendency for most or all generators to build gas-fired plants. The solution could be for a regional entity such as the RTO to monitor this issue and provide incentives for fuel diversity.

8. Clumsy and belated state intervention.

State (and federal) authorities were slow to respond to early warning signs of the California crisis. FERC finally responded by instituting region-wide price caps. However, California, through its Department of Water Resources, has now entered into long-term purchased power agreements (which its utilities had foolishly been prohibited from doing themselves) at high prices.

9. Stranded cost recovery mechanism.

The mechanism by which the stranded cost recovery charge was set in California was defective. Instead of a fixed per-kWh charge on the rates for delivery service, the charge was variable. The higher the wholesale market price, the lower the charge, and the lower the wholesale market price, the higher the charge. This variation had the result of undermining the retail supply market, because suppliers who offered customers a fixed price never knew what revenue they would be getting on a net-of-stranded cost basis.

Colorado

Colorado considered electricity restructuring in 1998 and 1999. The legislature passed, and the governor signed into law, SB 152 which established the Colorado Electric Advisory Panel to study and report on whether restructuring would be in the interests of Colorado consumers and the state as a whole. The Panel consisted of 29 representatives of the industry and its stakeholders, including consumer and business organizations.

The Panel retained Stone & Webster Management Consultants to study the situation, including the impact of restructuring on retail prices, the likelihood of utility stranded costs, and the likely effects of potential market power. Stone & Webster noted that, "Colorado has had relatively low generation costs and, therefore, fairly low retail electricity rates relative to other states." Against this background of relatively low regulated utility rates, the study's conclusions were devastating as far as the prospects for restructuring were concerned:

> -- Restructuring the electric industry in Colorado will likely lead to an increase in retail electricity rates throughout the state...
>
> -- Restructuring the electric industry in Colorado will likely lead to significant stranded benefits (negative stranded costs)...
>
> -- (Public Service Company of Colorado) controls nearly two-thirds of the utility-controlled generating capacity in the state. In the short term, it will possess market power, and be able to raise prices...[21]

In its report to the legislature and the governor in November 1999, a majority of 17 of the 29 members of the Electric Advisory Panel opposed restructuring. Among their reasons were the following:

> -- Colorado's rates are relatively low and are likely to increase with restructuring.
>
> -- Public Service Company of Colorado is likely to possess market power in Colorado.

[21] Stone & Webster report to Colorado Electric Advisory Panel, 1999, pages ES-1 to ES-2.

-- Before implementing restructuring, a competitive wholesale market should develop in the region.

-- Utility customers have a legitimate claim over "stranded benefits."

-- Restructuring will expose customers to greater cost, reliability, and service risks.

The minority of 12 panelists raised a number of general arguments in favor of restructuring. These included references to the national trend towards customer choice, and the belief that competition produces lower rates, customer choice, new investment, new products and innovation.

Whether or not the points made by the minority might have been valid in other circumstances, they were not persuasive when weighed against the Colorado-specific findings of Stone & Webster. Needless to say, the Colorado legislature did not decide to restructure the state's electric industry.

Florida

Florida was still moving in the direction of electric restructuring during 2000, and to a lesser extent 2001. In September 2000, the staff of the Florida Public Service Commission issued a report that was skeptical about restructuring, although not opposed to it. In a review of what it called "the 24 pioneer states," it found that "policy makers should lower expectations about competition substantially reducing retail rates in the short term. Moreover, few states have undertaken vigorous evaluations to see if the benefits of competition are being realized."[22]

The PSC staff is also concerned about the potential for the exercise of electric market power in Florida. "Market power in the wholesale generation market is a major concern in Florida due to two factors. First, Florida is a peninsula and has limited transmission lines between it and its neighboring states, allowing imports of only 8% of needed power...The second factor is that two incumbent utilities serve over half the load in the state. The potential for either or both of these utilities to exercise market power currently exists."[23]

A number of years ago, the Florida Energy Broker was established by the state's utilities to create a computerized system for trading hourly non-firm or "economy" electric energy. This system was extended to merchant power producers in 1995. There have also been a number of longer-term power contracts between different entities. However, according to the PSC, "wholesale sales in Florida continue to be a relatively small portion of investor-owned utilities' sales and are predominantly conducted between Florida's utilities."[24]

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[22] Florida Public Service Commission, Key Aspects of Electric Restructuring and Their Relevance for Florida's Electricity Market, September 2000.
[23] Florida PSC, Market Power in a Transitioning Electric Industry, March 2001.
[24] PSC, States' Electric Restructuring Activities Update, 1999.

In December 2001, a report by the Florida Energy 2020 Study Commission recommended a further move toward a competitive *wholesale* electric market. It did not recommend retail market restructuring -- the commission chairman noted that, "Until you restructure wholesale, which will bring more players on the field, you can't have real retail restructuring."[25] The commission proposed that merchant power producers should be encouraged to build power plants in the state. Some merchant power producers have succeeded in building plants in Florida, but they face serious obstacles under Florida's stringent Power Plant Siting Act.

During the past few months, however, legislative interest in restructuring appears to have waned, and it is no longer a high priority. Governor Bush was already reported to have lost interest in restructuring during 2001 after the California crisis and the collapse of Enron. The electricity market in Florida is regarded as being in reasonably good shape, with relatively low and stable prices and adequate capacity.

During 2001, there were collaborative efforts to form a statewide RTO, GridFlorida, and the Florida Public Service Commission approved the transfer of transmission control to that entity by the state's three main electric utilities. Meanwhile, however, FERC was of course pushing for a larger regional RTO. The result has been a stalemate in which the Grid Florida endeavor has been put on hold.

Illinois

Summary

In contrast to some other states like Maine and Pennsylvania that were also among the first wave of states to embark on electric restructuring, Illinois' restructuring experience is regarded as unsuccessful so far by many of its participants, particularly customers and competitive electricity providers. This negative assessment is clearly reflected in the third Chairman's Roundtable Report issued by Illinois Commerce Commission Chairman Richard Mathias in November 2001.[26]

Retail competition in Illinois is being phased-in, with large industrial and commercial customers being eligible in October 1999, other industrial and commercial customers during 2000, and residential customers in May 2002. However, after an initial period of competitive activity, the migration of customers to the competitive market and the entry of competitive electricity suppliers to that market have stalled out. One customer representative cited "a limited number of suppliers, transmission constraints, and the continuation of utility/affiliate supply purchase agreements as an indication that the 'only thing (we) are doing differently today is shifting money around to differently named players in the same affiliated group.'" (Roundtable Report, p. 6) The market in Commonwealth Edison's service territory is a partial exception --

[25] The sources for this quote and other Florida news over the past year are press and trade reports reproduced in Restructuring Weekly.

[26] Report of Chairman's Fall 2001 Roundtable Discussions Re: Implementation of the Electric Service Customer Choice and Rate Relief Law of 1997. This report is available on the Illinois Commerce Commission's website in a section containing reports, etc., by Chairman Mathias.

relatively high ComEd prices and the concentration of customers in Chicago have made this market more attractive to alternative providers.

The chairman concluded that, "This Roundtable marked the first time that no participant would even argue that Illinois is experiencing robust competition or the robust development of competition." (Roundtable Report, p. 5) Although there has been no dramatic market failure like California's, the Illinois experience is disappointing and suggests the whole restructuring effort in that state may not have been worthwhile. What lessons can be learned from this experience?

It appears that a number of features of Illinois restructuring are not conducive to electric competition. First, some utilities "locked up" their "most attractive" industrial and commercial customers before the market opened in 1999. (Roundtable Report, p. 5) Second, most of the competitive providers that have entered the market are actually affiliates of incumbent utilities, and customer groups voiced concerns "that the future could subject them to the market power of incumbent utilities and their affiliates in a non-competitive environment." (Roundtable Report, p. 2) Third, Roundtable participants stated that "retail competition would not develop without robust wholesale competition." (Report, p. 2) But the wholesale market is not structured to create robust competition -- transmission constraints have been an obstacle to market transactions, no RTO is yet in place to supervise the pricing of transmission services and tariffs, and there is no framework for much-needed transmission construction. There is also insufficient investment in new power plants. The result has been a tight supply situation, particularly during peak periods.

Considering the concentration of generation in the hands of utilities and their affiliates, coupled with transmission constraints, the commission had earlier concluded: "Probabilities are high that Illinois will have a number of partially isolated markets, each with a resident, unregulated, potentially monopolistic firm -- the utility's affiliate -- poised to dominate it."[27]

Relatively few competitive providers have entered the market, and small customers have not found their offerings attractive. Competitive providers are frustrated with the high cost of retail customer acquisition in Illinois. For instance, start-up costs include: renting office space, buying supplies and equipment, hiring personnel, retail marketing costs, commission certification costs, and the costs of participating in proceedings before the commission. (Fall 2000 Roundtable Report, p. 38) There is a requirement for a "wet signature" before a customer can be switched, and a marketer needs to have a door-to-door sales force to sign up small customers, an expense that is not justified, considering how small the potential revenue is.

The Illinois Commerce Commission finds itself in the difficult position of having diminished --indeed "severely limited" -- jurisdictional authority to deal with the range of problems that are being encountered. The authority of FERC tends to increase when a state restructures, but the Illinois Commerce Commission chairman's experience is that FERC has been "very timid in implementing corrective initiatives." Roundtable participants complained about the "splintered nature of governmental regulatory authority," and one participant said that there was such uncertainty about the extent of the commission's authority under the new law that the commission should undertake a legal analysis of the matter. (Roundtable Report, p. 15)

[27] Illinois Commerce Commission, Assessment of Retail and Wholesale Market Competition in the Illinois Electric Industry, April 2001, p.16.

Rather than take the risk of entering into contracts with independent power producers in a tight and fragmented wholesale market, Illinois customers who are eligible to shop for power have mostly stayed with utility standard offer service.

Looking ahead to January 2005, when customers are switched from current regulated standard offer rates to market-based pricing, forecasts differ. Incumbent utilities and alternative providers forecast a smooth transition, but customer representatives do not share this optimism. In the previous Roundtable, everyone had already agreed that "the liquidity of the Illinois *wholesale* market for electricity must increase to ensure that the Illinois *retail* electric market will be viable at the end of the mandatory transition period." (Fall 2000 Roundtable Report, p. 32, emphasis added) Some participants believe there is a risk that the wholesale market might fail, unless the supply situation improves by 2005, and there is even discussion of the possibility of a "perfect storm" like the one that hit California.

Restructuring Legislation and Regulation

The Electric Service Customer Choice and Rate Relief Act of 1997 (HB 362) provided for a phase-in of retail competition by size and type of customer, beginning with large industrial and commercial customers in October 1999, extending to all industrial and commercial customers by December 31, 2000, and to residential customers in May 2002. Metering services as well as generation are being opened to competition, and the commission will conduct investigations in the future to determine whether further services, such as the whole bundle of metering and billing services, should be made competitive.

Utilities continue to provide standard offer service at rates that were set at the last rate case, less reductions required in the Act. Rates will be fixed during the transition period, which ends on January 1, 2005. Affiliate suppliers may use the name and logo of the utility, but are prohibited from joint marketing.

Competitive suppliers have to be certified by the commission, and must provide a performance bond and proof of technical, managerial and financial capability. A "wet signature" is required on a contract between the customer and the competitive supplier, who must notify the utility. The customer may get one bill (from the generation supplier), or two bills -- one for generation and one for distribution service.

Those customers who choose a competitive provider must pay the utility a competitive transition charge to enable the utility to recoup stranded costs. The competitive transition charge continues to December 31, 2006. The period may be extended to December 31, 2008, except in the case of ComEd.

The Act applies primarily to investor-owned utilities. Electric cooperatives and municipal utilities are not required to allow their customers to switch suppliers, but they may do so if they wish.

The Act did not require divestiture or structural separation of competitive activities from regulated utility activities. However, after January 1, 2003, the commission may require separation, and this step is under consideration.

Electricity Market Profile

There are six major utilities in Illinois, of which Commonwealth Edison is the largest. The electric grid is connected with neighboring Midwestern states. The utilities have been members of the Mid-American Interconnected Network (MAIN) reliability council, and have been split over whether to join the Midwest ISO (MISO) or the Alliance RTO. Describing the Midwest ISO as "in disarray," the commission chairman believes that if the governance of the transmission system is bifurcated, it would "likely lead to a dysfunctional system."[28] In December 2001, FERC approved MISO as the first official RTO in the country, rejected the Alliance RTO, and urged utilities to consolidate the two RTOs into one single Midwest RTO.[29]

The electricity market is reported to be transmission-constrained, and supplies are tight at certain times. However, a certain amount of plant construction activity is taking place, and there are plans to build more plants in the future. Recently, the chairman has taken an equivocal position on the adequacy of generation and transmission capacity in Illinois, perhaps because he is trying to contrast Illinois with California: "Most commentators agree that Illinois currently has adequate base load supply and peak load supply is likely to be adequate as well. However, there is concern about adequate supply in future years." [30]

Earlier, the commission had been more outspoken. In describing its investigation of wholesale market conditions in 2000, it said "there is every reason to believe that retail prices, passed through from the concentrated wholesale markets, will be higher than they would be with a market structure that is supporting actual wholesale competition. . . . Given the incentives in the present market structure of affiliates and holding companies, there is little evidence that this situation will change in the near future." (Assuming there are no changes), "the preliminary evidence indicates that there are reasons to believe that retail prices may increase dramatically by the time the general rate freeze expires in 2005." The commission's evidence for this dire assessment included the fact that "the overwhelming majority of power is still coming from incumbent utilities;" limited inroads of independent power producers; and "concern regarding the ability of the Illinois transmission system to support a competitive wholesale market between and within utility territories."[31]

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[28] Illinois Commerce Commission, Can a California Energy Debacle Occur in Illinois? An Outline of Some Differences and Similarities Between California and Illinois, February 2001, p.6.
[29] Illinois Commerce Commission, 2001 Annual Report on Electricity, Gas, Water and Sewer Utilities, January 2002, p. 63.
[30] Illinois Commerce Commission, Can a California Energy Debacle Occur in Illinois? An Outline of Some Differences and Similarities Between California and Illinois, February 2001, p. 5.
[31] Illinois Commerce Commission, Assessment of Retail and Wholesale Market Competition in the Illinois Electric Industry, April 2001, p.iii.

Restructuring and Market Activity to Date

Although not required to do so, most of the state's six major utilities have in fact transferred or divested generation assets. Meanwhile, with two exceptions, Illinois utilities have transferred their generation facilities to affiliated companies.[32] An important exception is ComEd, which sold its coal- and gas-fired plants to an unaffiliated company, which is an affiliate of Southern California Edison. ComEd has a purchased power agreement with the buyer that gives it the right to purchase substantial portions of the output of these facilities for a number of years.

The data on customer switching to competitive suppliers in Illinois is confusing for several reasons, including differences between one utility service area and the next, and the phase-in of eligibility. According to the commission's latest Annual Report, approximately 20,000 customers have switched to an alternative provider, or to a lower-cost generation service offered by their utilities -- this is the PPO described below. Of these, about 18,000 or about 90% are in the Commonwealth Edison service territory. In five utility service areas there has been no switching at all. At least 673,000 customers were eligible to choose other suppliers; only 3% have done so.

Even though the proportion of load that has switched is much higher, because larger customers are more likely to switch, this experience is disappointing, especially when one considers that much of the switching was merely to the utility PPO option or to a utility affiliate. PPO is a rather complex option available to large customers during the transition period. A purchase power option (PPO) allows them to switch out of bundled utility service, but still obtain power from the distribution utility at an *estimated* market price set for one year. The customer can assign this right to a power marketer, which will only make sense if the market price has fallen below the PPO price. Since market prices have tended to be higher than PPO estimated prices, the result has been that the utility effectively still remains the provider.

At the end of 2001, there were 14 alternative retail electric suppliers certified by the commission, of which five had been added during 2001. Some of the suppliers operate only in certain areas, however, and in many utility service areas there is limited availability of suppliers.[33]

In April of each year, the commission submits an annual report to the legislature and the governor, *An Assessment of Retail and Wholesale Market Competition in the Illinois Electric Industry*. The latest available report is, of course, somewhat dated because it is for 2000. However, it reveals the same picture as we have seen in 2001. By the end of 2000, 22% of eligible customers had switched in the ComEd service territory, approximately 10-15% in three other service territories, and few if any customers in the remaining five investor-owned utility service territories. "Most suppliers continue to concentrate their efforts in the ComEd service territory." Many of the customers who switched to delivery-only service still obtained supplies

[32] Illinois Commerce Commission, Can a California Energy Debacle Occur in Illinois? An Outline of Some Differences and Similarities Between California and Illinois, February 2001, pages 1-2.

[33] Information on switching and alternative providers is from Illinois Commerce Commission, 2001 Annual Report on Electricity, Gas, Water and Sewer Utilities, January 2002, p. 64.

under other arrangements with the utilities or their affiliates. The 2000 report concluded that "(d)elivery services' customers relatively high rate of use of utility-generated power may provide an indication that the wholesale market is not presently capable of producing a sufficient supply of low-cost power to support a retail market."

Why has customer switching been so uneven? Is there anything we can learn from the high level of switching in the ComEd service territory in Chicago? It is not due, apparently, to the transmission situation: Chicago is a load pocket, which implies that it could be difficult for competitive providers to bring in power from out-of-town. The likely factors could be ComEd's high regulated rates, ComEd's divestiture of generation to an unaffiliated company -- which took the utility out of the generation business -- and/or Chicago's high concentration of customers.

Maine

Summary

Maine embarked early and vigorously on its electricity restructuring project. It did this in step with the general move to restructuring in New England, with the objective of ending the high-price utility monopoly regime. New England was already a relatively high-cost region, because of its dependence on oil and its distance from sources of low-cost fuels such as natural gas and coal. The over-building of nuclear power plants in the 1970s and 1980s made the situation worse and provided much of the political momentum for restructuring.

New England states could depend on having the bulk power system coordinated by a tight power pool, NEPOOL, which provided the basis for an ISO in 1997. ISO New England administers the wholesale markets and controls the system for purposes of ensuring reliability. Maine's restructuring legislation states that in order for retail competition to function effectively, ISO governance must be "fully independent of influence by market participants." The Commission does not believe that independence has yet been satisfactorily achieved. (Annual Report, p. 20) And despite the modification of NEPOOL protocols, and the existence of several vigorous competitive generators, there have been continuing concerns over market power abuses. For example, although a number of independent power producers and merchant generators have succeeded in entering the New England market, they have complained that the interconnection rules are onerous and can result in significant project delays. In July 2001, FERC proposed that ISO-New England, together with New York and the PJM Interconnection, be part of a larger Northeastern RTO. It is not clear whether this combination will take place, or whether alternative means will be found to foster the interchange of power between these regions. In February 2002, ISO New England and the New York ISO announced plans to explore the benefits of merging the two power pools. They committed to completing their evaluation by the end of June 2002.

Certain features of Maine's restructuring effort are noteworthy. First, after the restructuring act was passed in 1997, the Maine Public Utilities Commission used rulemaking procedures and stakeholder groups to develop the rules and procedures during 1998 and 1999 that would govern distribution utilities and competitive electricity providers. The legislature decided that utility divestiture of generation assets was desirable, if a truly competitive power market was to be created. The Commission developed unbundled rates for distribution service and approved the sale of the utilities' generation assets. "Because of the comprehensive preparation, entities operating in Maine avoided some of the technical and procedural problems encountered in many other states."[34] The Commission also conducted a consumer education campaign.

A result of divestiture was that standard offer would have to be provided in some manner from the now-separated generation market. Maine decided that standard offer franchises should be broken up into manageable areas and put out to bid by suppliers for successive periods of two years. This procedure has not been without its difficulties: in some cases all bids had to be rejected because the prices seemed out of line. However, contracts were eventually entered into and the Maine PUC appears to be reasonably satisfied with them.

On the other hand, direct access has not yet taken hold in the residential and small commercial market. Less than one percent of these customers have switched to competitive suppliers in the two largest utility service territories. Rather than entering through the front door, competitive suppliers have entered through the side door by competing to provide standard offer service, which effectively covers the entire small customer market, and most medium-sized customers too.

Most large customers, however, have switched to competitive suppliers. A large customer is defined as one with a load of 400 or 500 kW, depending on the service area, and includes paper manufacturers (the largest users of electricity in the state) and also the largest colleges, hospitals and supermarkets.

After two years of restructuring, the Commission believes that Maine has accomplished "the most successful overall transition to competition in the nation." (Annual Report, p. 29)

<u>Restructuring Legislation and Regulation</u>

On May 29, 1997, L.D.1804, *An Act to Restructure the State's Electric Industry*, was signed into law by the Governor. It provided that all retail electric customers would be able to choose their electricity supplier beginning March 1, 2000. It directed the Maine Public Utilities Commission to conduct rulemaking procedures on several issues that would have to be resolved in opening up the retail market to competition.

The Act requires that utilities divest their generation assets (except for nuclear generation) and their purchased power agreements, and that the Commission conduct a rulemaking on the bidding procedures for these sales. Standard offer service would be available to all customers. Franchises to supply electricity for standard offer service must be put out to competitive bid, and at least three providers should, if possible, be chosen. A docket was opened to implement this process in terms of Chapter 301 of the Act, which contains the terms for standard offer service and the procedure for selecting bidders.

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[34] Maine Public Utilities Commission, Annual Report on Electric Restructuring, December 31, 2001. This report, which the commission is required to submit to the legislature at the end of each year, is a valuable source of information on restructuring developments in Maine. It is available on the Commission's website.

Other rulemakings covered such issues as licensing requirements -- including a showing of technical and financial capability and providing a surety bond or letter of credit -- and uniform information disclosure requirements for competitive electricity providers. Rules were promulgated to implement a resource portfolio standard contained in the Act, and to provide for net energy billing, load profiling procedures and metering, and protocols for transactions between utilities and providers. Utility stranded cost recovery is provided for.

The state now has significantly less involvement in utility plant siting and planning. Certificates of public convenience and necessity, with their traditional showing of need, are no longer required.

The Electricity Market in Maine and the Rest of New England

Maine, like the rest of New England, has long suffered from high electricity prices. Generation depended on oil, or on coal or gas, which were expensive when transportation costs were taken into account. Nuclear power was seen as the technology that would overcome the disadvantage of high fuel costs. The escalation of nuclear power costs, and the problem of excess capacity that resulted when demand growth slowed in the 1970s and remained relatively constant in the 1980s, resulted in high retail prices. These, together with controversy over nuclear power as a technology, led to a consumer backlash against the utilities and provided a backdrop to the movement to restructure the electricity industry.

Apart from the isolated northern part of the state, Maine is closely integrated into the New England electric grid, which was operated by NEPOOL, and since 1997, operated by ISO New England. ISO New England also administers the wholesale markets that were implemented in May 1999 under a contract with the NEPOOL Participants who continue to own the generation and transmission assets in New England. Even before the push towards ISOs and RTOs, NEPOOL was one of the country's few "tight" power pools. This meant that the New England power system was operated and planned on an integrated basis. The system was centrally dispatched, and the integration of new power plants and transmission facilities were coordinated by NEPOOL to ensure that loads and resources were matched.

The movement towards state restructuring in New England has depended on the development of NEPOOL from a tight power pool to an ISO. Current ISO New England market rules and tariffs contain provisions for tracking and accounting for supplies not only among utilities and between utilities and independent power producers, but also from IPPs to retail customers under direct access arrangements.

ISO-New England has experienced a fair number of market disruptions and price spikes, but has not suffered the extreme malfunctions such as those that afflicted California in 2000 and early 2001. However, the Maine PUC acknowledges in its Annual Report that, "The development of regional market rules has been fraught with discord, but there appears to be some progress toward an efficient market." There have been continuing complaints about the exercise of market power by suppliers in the New England market. First, independent power producers believed that the transmission interconnection arrangements discriminate against them and favor incumbent utilities.

Second, prices in the wholesale market appear to be higher than can be justified on the basis of power plant costs. There is the perception that the two or three large companies that between them account for the majority of generating capacity in the market are able to manipulate prices. In 1999, approximately 12% of the energy transactions were sold through the spot market, with most transactions still sold through bilateral contracts. In 2000, spot market energy transactions increased to about 20% of all sales. There is no way of knowing the extent to which bilateral contracts might, as a result of market power, be higher-priced than they would be under a more competitive market. An analysis of the New England market commissioned by ISO New England and the Massachusetts Attorney General after the price increases during 2000 found that the New England electricity market was at least as efficient as PJM's and more efficient than California's, with market-based prices 4-12% above costs. Continued monitoring of the market was necessary, however, the report concluded.

In the initial market design, ISO New England administered a spot market for Installed Capability (ICAP) as well as a spot energy market. The existence of an ICAP market can be justified as way to reward suppliers for keeping generating capacity available for purposes of system reliability. However, it was felt by many participants, including the Maine Commission, that prices in that market have been far too high at times. Recall that the spot energy market already clears at the highest bid accepted, which is higher than operating costs for all intra-marginal bidders, so there is the danger of duplicative rewards for capacity. After serious abuses occurred in the ICAP spot market in early 2000, the spot market was eliminated and replaced with a price-cap administered market that levies a deficiency charge, on a monthly basis, on any market participants who fail to secure sufficient ICAP resources in the bilateral markets. Additional changes are being considered; however, with the increased supply of new generation in 2001, there have been sharp reductions in ICAP prices.

Despite the problems encountered in the operation of the New England power market, a number of developers have entered the New England market. According to the Maine Office of Public Advocate, 1,500 MW of new capacity is currently being added in Maine alone. Almost all of the capacity being added in Maine and the rest of New England is natural gas-fired, which has been made possible because of the construction of new pipeline capacity o bring gas in from Canada to supplement U.S. sources of gas.

Corporate Restructuring Activities to Date

Utility generation asset sales were generally at prices much higher than book value, and were regarded as successful. The result was that electricity companies are primarily engaged in either the wires business or power supply, ending the era in which utility companies typically provided both types of service.

Customer bills were unbundled in January 1999. Customers receive one consolidated bill -- from the distribution utility, which calculates consumption and issues a bill for energy supplied as well as for distribution service.

Utility distribution companies may have marketing affiliates, which are subject to various restrictions. They cannot advertise jointly with the utility, and they must compensate the utility if they use the utility name and logo.

Municipal and cooperative utilities are restricted to selling electricity in their own service territories.

Standard Offer Service

The Commission is required under the Act to attempt to have at least three competitive providers of standard offer service in each utility service territory. Bidders may bid on all or part of the load of each designated group of customers. The first round of bidding took place in 1999, to provide service for the initial period commencing on March 1, 2000. Some winning bids were accepted by the Commission for service to residential and small commercial customers of the state's largest utility, Central Maine Power (CMP). But other winning bids were rejected and the bid process was terminated. The Commission found that some bids did not conform to the bidding procedures and others were simply too high-priced. The utilities were ordered to procure power for the groups of customers involved.

During 2000, the Commission conducted proceedings to amend the standard offer procedures to correct certain problems that had emerged during the first bid process and to resolve certain opt-out issues. At the end of 2000 a second round of bidding took place for providers who would begin service in March 2001. Again, some winning bids were accepted (to provide service for a three-year period) and others were rejected. There had been price spikes in the wholesale market and the bid prices were unacceptably high. The Commission, predicting (correctly) that prices would drop, arranged again for utility purchases on the wholesale market.

In planning for standard offer service for the period beginning March 1, 2002, the Commission hedged its bets by requesting bids, and, in parallel, directing the utilities to solicit bids for power on the wholesale market. In the end, the Commission awarded standard offer service for most residential and small business customers for a three-year period to a company which would acquire the utilities' purchased power entitlements, a creative solution. (Annual Report, p. 15)

Standard offer providers have to take on "load risk," namely the uncertainty about how many customers will take standard offer during the contract period, which all depends on the relative prices of standard offer (set at the beginning of the period) and market prices (which change during the period according to market conditions). This risk tends to result in bids that are somewhat above-market, which paradoxically causes more migration. The way in which standard offer tracks the market, but with a time-lag and a premium above market, may explain why there has been more migration to the competitive market in Maine and why it has been relatively steady compared with most or all other states. Simply put, standard offer is not a bargain for customers compared with prices they can get on the open market. Transaction costs for small customers, coupled with the fact the potential gains are small for those customers, probably explain why they have not migrated along with larger customers.

Marketing affiliates of distribution utilities may bid to provide standard offer service in the service territory of their affiliate utility, but they may provide no more than 20% of the affiliate utility's load, unless required to do so by the Commission.

The Commission says it has learned several lessons from its intensive experience with standard offer service bidding over the past two years (Annual Report, p. 14). Suppliers, the Commission has found, are *risk averse*. For example, they don't like to leave their bids open for long periods of time. Initially, bids were required to be open for two months, and even when the period was reduced to two weeks, market volatility made the bidders reluctant to keep bids open for longer than 24 hours. Second, suppliers can be creative, e.g., including contingencies or indexed or formula bids. In response, the Commission needs to be flexible in its requirements, even though it makes it more difficult to compare bids with each other.

A third lesson learned by the Commission is one that has heightened relevance in light of the collapse of Enron -- the need for contractual protections and financial security. In Maine, there was a contract dispute between a standard offer provider and its wholesale supplier. Because the standard offer price was below market, a switch back to the market at that point would expose customers to price increases totaling as much as $150 million. However, the provider's performance bond was for only $33 million. Fortunately, with Commission facilitation, the contract dispute was settled.

During 2004, the Commission will conduct an investigation into whether standard offer service should be continued after March 1, 2005. Meanwhile, the Commission is not planning any changes in the standard offer rules, but will continue to monitor the situation. The Commission accepts the fact that direct access is slow in coming for residential and small business customers, partly as a result of the success of standard offer service. It believes the market may grow gradually, as suppliers extend their reach from larger to medium and then smaller customers. (Annual Report, p. 16)

Direct Access

Customers can switch to a competitive provider at any time. They can also return to standard offer at any time, but there are certain penalties and restrictions in this case.

The attractiveness of direct access to retail customers in Maine -- and to competitive electricity providers has thus far been directly related to the size of the customer. While the state's three investor-owned utilities have somewhat different situations, the figures for CMP tell the story -- 88% of large customer load, 42% of medium-sized customer load, and less than 1% of residential and small commercial customer load was served by competitive providers, as of December 1, 2001. Statewide, 44% percent of load has migrated to the competitive market.

The percentages vary considerably by time period. Most of the growth in supplier switching took place after September 2000, notwithstanding the spikes in wholesale market prices. For medium-sized customers, migration accelerated during 2001. Standard offer service prices locked in some of the higher prices from late-2000, while wholesale market prices dropped during 2001, creating a favorable opportunity for competitive providers. Presumably, if wholesale prices drop further and stay down, switching will continue, but again, it will all depend on relative standard offer and market prices.

Changes in Prices

It is difficult to summarize the changes in prices paid by customers since March 2000, when direct access was introduced. The factors that have influenced prices have included some utility-specific factors, and the fluctuations in wholesale market and standard offer prices. Transmission and distribution rates (including stranded cost charges) dropped initially, and have remained roughly stable during the past two years.

For standard offer customers of Central Maine Power, the state's largest utility, all-in prices are still lower than they were in March 2000. For some other customers, prices rose in 2001 and are falling back to around March 2000 levels in March 2002. The Commission does not know the prices paid by large customers on the open market, but believes that customers "generally retained the benefits of lower prices." (Annual Report, p. 8)

The overall effect of having a reasonably stable regulatory environment in Maine -- the 1997 legislation has remained in place virtually unchanged -- may be to provide suppliers and customers with a good framework within which they can make consistent and complementary decisions.

Metering and Billing Competition

The Act provided that metering and billing services, like generation, would be open to competition. The deadline was set for March 1, 2003. However, the Act has been amended to remove the deadline and leave the matter within the discretion of the Commission.

Renewables Portfolio Standard

The legislation includes a requirement that suppliers provide 30% of their supply from renewable resources. "Eligible" resources include traditional renewables such as wood, biomass and hydro, as well as trash and efficient cogeneration using mostly fossil fuels, but in some cases new sources such as tires or sludge. According to the Commission (Annual Report, p. 10), in 2000 at least 38% of generation sold in Maine was generated by eligible fuels. Of that amount, about 60% was from traditional renewables (hydro and biomass). Municipal solid waste accounted for 23%.

"Green" products have not caught on in Maine. One provider offered a green product at a price premium of about one cent per kWh, but consumers showed little interest and the product was dropped. One aggregator received some interest from consumers but could not find supplies at a reasonable price. (Annual Report, p. 11)

Montana

The Electric Utility Industry Restructuring and Customer Choice Act of 1997 (SB 390) set a schedule for a transition to retail competition by July 2002. However, Montana shared the concerns of other western states over regional electricity price increases starting in 2000. In December 2000, finding that there would not be workable competition in the Montana wholesale electric market for the foreseeable future, the commission exercised the discretion given to it under SB 390 to extend the transition period by two years, to July 2004. And in 2001, the Montana legislature, in HB 474, extended the transition period even further, to July 2007.

There was a lot at stake. Under SB 390, the state's principal investor-owned electric utility, Montana Power Company (MPC), is required to offer default service -- which is the service available to residential and small business customers who do not choose an alternative provider or wish to return to utility service -- at cost during the transition period. A premature switch to market pricing at a time when the wholesale market was not yet workably competitive could have resulted in much higher prices.

Meanwhile, MPC had sold its generation assets to PPL Montana in December 1999. Further, MPC, which is focusing on the telecommunication business, is selling its transmission and distribution assets to NorthWestern Corporation, a company that operates electric utilities. For purposes of this description, we will refer to the transmission and distribution company as "MPC."

The thinness of the Montana electricity market made it obvious that MPC would continue to obtain the power it needed as default service provider from PPL Montana. At what price would MPC buy back the power? MPC narrowly escaped entering into a deal with PPL Montana in 2001 that would have fixed the price at 4 cents/kWh, a price that did not seem so unreasonable at the time but seemed too high to the commission and others. Hindsight has confirmed that the commission was quite right. Commissioner Bob Rowe said recently, "I commend the commission for taking many strong steps including...rejecting a $.04 supply price last spring that subsequent events demonstrated would have been substantially out of market."[35]

A threshold issue in MPC's generation asset sale was whether the state or the FERC would have jurisdiction over the purchased power agreement. Normally, one would assume that the buy-back agreement would now come under FERC jurisdiction. However, there were certain legal issues specific to Montana law that we will not explore. Suffice it to say that the determination was made by the state commission that under the particular provisions of Montana law, the generation assets could *not* be transferred out from under state jurisdiction. As the commission chairman is reported as saying, "Today the commission stepped up and took the leadership role in the electricity price crisis." And commissioner Bob Rowe said, "The commission cannot repeal energy supply competition, but we are attempting to soften the price shock on the road to competition." (Montana PSC press release, March 28, 2001)

[35] Montana Public Service Commission, Final Order in the Matter of the Application of Montana Power Company for Approval of...Transition Plan...(and) Sale to NorthWestern Corporation, Concurring opinion of Commissioner Rowe, January 31, 2002

The commission ruled that MPC had an ongoing obligation to provide default service at cost during the transition period, and it had sold the assets to PPL Montana subject to that obligation. The assets remained in MPC's regulated rate base, despite the transfer, the commission found. Accordingly, the PPA would be a full-requirements contract at a cost-based rate during the extended period to July 2007. Only after the commission had approved MPC's transition plan, would its jurisdiction end. At that point, the purchase would be in the wholesale market which is deregulated, or at least is not regulated by the Montana commission. Meanwhile, FERC too seems to have given precedence to PPL Montana's contractual obligation to supply power to MPC at cost.[36]

Nevada

Summary

In 1997, Nevada committed to restructuring its electric industry and allowing retail choice by January 1, 2000. However, in the ensuing years, Nevada initially postponed implementation and then repealed its restructuring laws in the spring of 2001. Issues internal to Nevada, including increasing rates and reliability concerns, as well as external issues, primarily the problems that California was experiencing with the implementation of its restructuring process, combined to persuade the legislature to abandon Nevada's restructuring plan before it was fully implemented.

Electric System

The Nevada system is comprised of two vertically integrated utilities -- Sierra Pacific Power in the north (peak load of 1563 MW) and Nevada Power in the south (peak load of 4412 MW). In 1999, Nevada Power was merged with Sierra Pacific Power and its parent company Sierra Resources. The two systems are physically separate, but both have interconnections with California and other states. Nevada also has a few municipal and rural cooperative utilities, as well as the Colorado River Authority Project.

Restructuring history

As with many states, Nevada has evaluated restructuring issues through a combination of legislation and utility commission proceedings. In 1997, the NV PUC (then known as the Public Service Commission of Nevada) issued a report entitled "The Structure of Nevada's Electric Industry" which discussed the many options available for restructuring the electric utility industry in Nevada. Also in 1997, the Nevada Legislature passed AB 366, which authorized retail competition for Nevada consumers starting on January 1, 2000, unless the Nevada PUC determines that a later date is necessary to "protect the public interest". That legislation also required the restructuring of the Public Service Commission into the Public Utilities Commission. This involved a reorganization of the agency to better prepare for retail electric competition, reduced the number of commissioners from five to three, and transferred

[36] The legal issues are described in a Montana PSC staff memorandum dated May 30, 2001, Montana Public Service Commission's Regulation of MPC's Electricity Supply Obligation Under SB 390 (1997) and after HB 474 (2001), May 30, 2001.

jurisdiction for some transportation related issues to a newly created Transportation Services Authority. AB 366 gave the NV PUC a wide-range of discretion to establish the services that can be supplied on a competitive basis, the regions in which those services can be provided, and the dates upon which service should commence.

In 1999, the Legislature made significant modifications to the timetable established under AB 366 by enacting SB 438. The rate caps set in 1997 were removed and new caps implemented that would continue until 3/1/03. Retail choice was delayed until March 1, 2000, unless the Governor, in consultation with the PUC, decided that further delay was necessary to "protect the public interest". Alternative providers, after 7/1/01, could offer competitive services if they agreed to cover at least 10 percent of the load of the existing provider, provided service to more than one class of customers, and provided at least a 5 percent discount in price. SB 438 also required that existing power contracts be honored and that the Nevada PUC provide each utility with an opportunity to recover the costs associated with those contracts.

Concurrent with the actions of the Nevada Legislature, the Nevada PUC was evaluating a proposed merger of Sierra Pacific and Nevada Power. In an Order issued in January 1999, the PUC approved the merger, with a requirement that the new merged company divest itself of its generation assets. Although the legislation permitted the sale of generation assets to an affiliate, such sales would have been subject to an administrative procedure to allow the recovery of stranded costs. In addition, the incumbent utilities would have been required to comply with operational restrictions designed to ensure functional separation of the affiliates. These restrictions, burdensome in the view of the incumbent utilities, would not be applicable to competitive providers who were only seeking to serve loads. Sierra Pacific and Nevada Power decided their best course was to auction off their generation assets to independent third parties. Since the Legislature had consistently required the incumbent utilities to be the default providers for any customers who did not select an alternate provider, the incumbent utilities faced the difficult task of having to sell off their generation assets and then enter into power contracts to secure adequate resources for an uncertain amount of load.

In July 2000, the NV PUC approved a Global Settlement that had been proposed by a diverse group of Nevada stakeholders, including the incumbent utilities, the Commission Staff, Bureau of Consumer Protection, the Nevada Resort Association and many individual large customers. The Settlement resolved a number of outstanding lawsuits related to when and how the incumbent utilities could recover deferred costs. SB 438 had eliminated deferred energy accounting, but allowed the utilities to file for "one more" deferred accounting order. The lawsuits were mostly about how to interpret SB 438. The Settlement ended collections from the deferred accounting orders, but allowed increases to the fuel and purchase power components of each utility's rates on a rolled in basis. The Settlement also provided for a revised timetable for retail open access. The utilities' largest customers would be eligible to select alternative providers starting on 11/1/00. Two other customer groups would be eligible for choice starting on 4/1/01 and 6/1/01 respectively, with all remaining customers eligible no later than 12/31/01.

However, before the Global Settlement could be fully implemented, the Legislature enacted AB 369 in April 2001. This measure repealed all previous restructuring legislation (including AB 366 and SB 438). In large part a response to the extreme distress experienced by

California in late 2000 and early 2001, AB 369 prohibited the sale of any generation assets by the incumbent utilities prior to July 1, 2003. After July 1, 2003, any proposed sales would have to be approved by the NV PUC with a specific finding that the sale was in the public interest. The NV PUC would be able to condition the sale upon such terms or modifications that it deemed appropriate. Any existing PUC Orders approving sales of generation assets prior to July 1, 2003 were vacated by the legislation. In addition, the legislation required incumbent utilities to utilize deferred energy accounting beginning 3/1/01 for fuel and purchased power. The deferred accounts would need to be cleared at the end of each twelve-month period through a proceeding of the NV PUC; that proceeding would include a specific prudence finding for the fuel and purchased power costs. Under Nevada law, the PUC has no discretion to allow even a partial recovery of any cost that is determined to have been imprudently incurred.

Also in 2001, AB 661 was enacted. One of the significant features of this legislation is that it allows commercial, industrial, or governmental customers with loads of 1 MW or greater to enter into agreements with alternative providers. There are several conditions to such arrangements. First, an exiting customer must provide 180 days notice and have its request approved by the NV PUC. If the customer is in a densely populated county, it must arrange to purchase 110 percent of its energy needs and make the extra ten percent available to the incumbent utility for its remaining customers. The NV PUC will determine if the ten percent extra energy is in the best interests of the remaining customers; if so, the incumbent utility must accept the energy and provide it to its remaining customers, with a preference for residential customers with small loads. The exiting customer may return to the incumbent utility with reasonable notice and a requirement that any incremental costs to serve the returning customer will be paid by that customer. Prior to July 1, 2003, the aggregate purchases of exiting customers cannot exceed one half of the incumbent utility's purchased power requirements.

AB 661 also restored the NV PUC to five members, after July 1, 2003. It created a Fund for Energy Assistance and Conservation that would be funded by a Universal Energy Charge of 3.30 mills for each therm of natural gas sold at retail and 0.39 mills for each kWh of electricity sold at retail (public utilities, rural cooperatives, and general improvement districts, as well as electrolytic manufacturing processes were exempt form the charges) and imposed a maximum quarterly cap of $25,000 for a single customer or customers under common ownership and control. Seventy-five percent of the money in the fund would be designated for low-income energy assistance through the Welfare Division and twenty-five percent of the money in the funds would go towards energy conservation, weatherization, and energy efficiency improvements through the Housing Division. Furthermore, a Trust Fund for Renewable Energy and Conservation was created, administered by a nine-member Task Force (six appointed by the Legislature, two by the Governor, and one by the Consumer advocate). Through separate legislation, Nevada utilities are required to obtain fifteen percent of their wholesale power form renewable resources by 2013. AB 661 also expanded net metering opportunities.

Special features

Under AB 366 (1997)

- Residential rates frozen at 7/1/97 levels, but PUC can raise them under certain circumstances.
- Vertically integrated utilities can provide competitive services only through an affiliate.
- PUC must monitor the market place and prevent activities inconsistent with the bill.
- Disco must provide all non-competitive services unless PUC designates another entity.
- Bill establishes mechanism to calculate and recover stranded costs of vertically integrated utilities
- PUC must implement regulations to prevent slamming, provide information disclosure, provide consumer education, and establish an increasing RPS
- PUC must develop forecasts of electricity usage, establish equitable obligations for customers and suppliers to ensure adequate capacity, and make quarterly reports to the Legislature on developments in the electric industry,
- A Bureau of Consumer Protection is created and the Nevada Public Services Commission is re-named and restructured into the Nevada PUC.

Under AB 369 and 661(2001)

- All prior restructuring legislation is repealed
- No generation assets can be sold prior to July 1, 2003 and must be approved by the NV PUC and the Consumer Advocate is a party.
- Deferred energy accenting is re-instated
- Rates frozen at April 1, 2001 levels until all deferred accounts are cleared and a general rate application, filed by October 1, 2001, is approved.
- Large customers (>1MW) may apply to exit the incumbent utility, subject to NV PUC approval and must purchase 110% of their annual energy consumption to assist remaining customers.
- Low income assistance and energy conservation fund established through a system benefits charge on gas and electric utilities
- Renewable portfolio requirement of 15% by 2013.

Current status

Nevada Power is just completing its application for clearing its deferred energy account, currently over $900 million. Sierra Pacific has filed its application for its deferred energy account in the amount of approximately $350 million. In January 2002, Barrick Goldstrike Mines became the first large customer to file for permission to leave Sierra Pacific Power. In March 2002, Rouse Fashion Show Management, Coast Hotels and Casinos, Station Casinos, and Gordon Gaming all filed for permission to leave Nevada Power.

New Mexico

The Electric Utility Industry Restructuring Act of 1999 set in motion the opening-up of the state's electric market to direct retail access beginning in 2001, and with all customers to have access by January 2002. As provided in the Act, the New Mexico Public Regulation Commission (PRC) has conducted various dockets to implement restructuring.

Beginning in August 2000, in response to the California electricity crisis, a number of stakeholders started pressing for a delay in implementing retail competition. They included the State Attorney General, who has the authority to participate in PRC proceedings on behalf of ratepayers, PRC staff, some large energy users, and electric cooperatives. These stakeholders expressed concerns about the inadequacy of generating capacity in the Southwest to ensure a smooth transition to competition, and an irrevocable loss of jurisdiction by the PRC over retail electric power supply. The PRC has this to say:

Similar to California's restructuring law, New Mexico's Restructuring Act requires utilities to sell or transfer all of their generation assets. Once this asset separation is completed, the state will lose jurisdiction over the generation assets. Utilities will no longer own generation. All power sold to consumers will be priced at market. Asset separation is the most significant act of restructuring and represents a point of no return for states moving towards deregulation. When generation assets are separated from the utility, neither the Commission nor the legislature can reverse this act. Prior asset separation, only the legislature can delay restructuring or modify the Restructuring Act, and the Commission's approval of utilities' requests to separate generation assets from the regulated utility would foreclose any such legislative opportunities.[37]

Under the Act, asset separation was scheduled to take place in August 2001, and the 2001 legislative session passed SB 266, signed into law by the governor on March 8, 2001, delaying the implementation of electric restructuring by five years to 2007. Under SB 266, utilities must sell or transfer their generation assets and file transition plans during 2005.

SB 266 also included incentives for the building of new generating capacity in the state, to avoid supply inadequacy. Provisions included permission for utilities to build or acquire generation assets for the wholesale market, provided their cost is not included in retail rates. However, the utility still has an obligation to serve during the delay period, and if a new, unregulated plant is used to serve retail customers, it will be priced at cost, not at market.

On January 8, 2002, the PRC adopted an interim energy policy for New Mexico, which would guide the energy sector during the period up until restructuring. The commission took a negative view of the benefits of restructuring, finding that, "Very little of those predicted benefits have materialized anywhere in the nation." Some of the points in the commission's 24-point policy statement are as follows:

[37] New Mexico Public Regulation Commission, 2001 Annual Report and Electric Restructuring Report, December 1, 2001, p. 8.

-- A thorough risk benefit analysis of competition, as well as a review of the lessons learned from other states, should be performed prior to opening up New Mexico markets.

-- New Mexico utilities should be required to support more diverse generation sources, including renewable energy, as a means to hedge against market and fuel price spikes.

-- Rules to promote reliability should be developed and adopted.

-- A thorough analysis of New Mexico's transmission system should be performed to determine under-capacity and constraints on a regional basis as well as within the state of New Mexico.

-- The (commission) should commence an investigation into areas and services in the electric industry which through opening to competition could provide greater benefit or savings to consumers.

-- Vigilant oversight of utilities' obligations to provide safe, adequate, and reliable service at just, reasonable, and non-discriminatory prices should be continued.[38]

Ohio

Summary

In Ohio's electric restructuring, all retail customers have been permitted to choose competitive providers since January 1, 2001. "Aggregation is the true success story," according to Public Utilities Commission of Ohio chairman Alan R. Schiber.[39] The state's restructuring act provides for governmental aggregation of either the opt-in or opt-out variety. Of the approximately 600,000 retail customers who have chosen direct access in Ohio in the first year, the vast majority have entered buying pools organized by their municipalities or other government entities.

In other respects, the restructured retail and wholesale markets bear many similarities to the situation in Illinois, another state that is in the process of becoming part of the Midwest ISO system. As in Illinois, direct access has been chosen by a large number of customers in only one part of the state -- the northern Ohio area served by FirstEnergy subsidiaries that have high electric utility prices -- and there are few competitive providers in most other parts of the state, where electric utility prices are low. There are mixed views about the adequacy of the transmission grid, and much will depend on the early successes (or failures) of the Midwest ISO.

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[38] New Mexico Public Regulation Commission, *In the Matter of the Development and Adoption of an Electric Energy Policy for New Mexico*, Utility Case No. 3668, Resolution dated January 8, 2002.
[39] Alan R. Schriber, Ohio Electric Choice: One Year and Counting, Public Utilities Commission of Ohio news release dated December 27, 2001.

What is curious to an outside observer is that in Ohio there is a greater sense of achievement and optimism about restructuring than there is in Illinois, despite the highly uneven record of direct access so far, and the uncertainties surrounding the adequacy and management of the transmission system. Perhaps the difference can be accounted for, at least in part, by the success and pride of ownership of the aggregation feature. Furthermore, the legislation contains provisions that provide incentives for each utility to reach a target of 20% of customers choosing direct access, and the sense seems to be that it is only a matter of time before the market opens up more evenly.

The Ohio Consumers' Counsel's assessment is: "While electric choice is off to a reasonably good start in Ohio, the results are far from conclusive. At the current time, most residential customers in Ohio are better off than they were before electric choice...But it will take time and effort for Ohio's competitive electric market to develop and mature. In the meantime...Ohio awaits the arrival of additional new electric suppliers for residential customers..."[40]

Legislation and Regulations

On July 6, 1999, SB 3 was signed into law. Under the Act, the commission is to supervise a transition to retail electric competition during a "market development period" that will end by no later than December 31, 2005 (earlier in the case of one utility).

Generation services were opened to competition on January 1, 2001, and the commission is required to initiate a proceeding by 2003 to determine whether customer services such as metering, billing and collection should also be made competitive.

Rates were reduced in 2001 and are frozen for a period of at least five years. The utility is required to continue to provide standard offer service at these rates. Shopping credits for customers who switch to competitive providers are to be set at levels that induce a target of at least 20% of customers to switch by December 21, 2003. Customers who switch may get one bill -- from the distribution utility -- or two, one from the utility and one from the competitive provider.

Stranded cost recovery is provided for. Utilities may offer both non-competitive and competitive services, provided there is structural separation. Functional separation is permitted only on an interim basis.

At the end of the market development period, utilities are required to engage in open, competitive bidding procedures to supply standard offer services.

Wholesale Market Profile

There are several major electric utilities in Ohio (although two holding companies -- FirstEnergy and American Electric Power -- dominate electricity supply in the state), and the electricity grid connects the state to neighboring states. Ohio's utilities are joining the Midwest

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[40] Ohio Consumers' Counsel, End-of Year Report: A Review of Ohio's Electric Market in 2001, January 9, 2002

ISO, which has a green light from FERC to create a regional RTO. There is a certain amount of generation construction underway or planned, but there are still concerns over the adequacy of the generation supply situation, and the effectiveness of control and planning of the transmission grid.

FirstEnergy, the parent company of Cleveland Electric Illuminating Company, Toledo Edison in northern Ohio, and Ohio Edison, has made a portion of its generation capacity available to competitive marketers. No other Ohio utility has taken a similar step. This may be part of the reason why retail competition has been successful only in northern Ohio, and to a lesser extent the Ohio Edison area, so far.

Interestingly, the wholesale power market in Ohio was subject to scrutiny by the PUCO after a period of disruption in June 1998. The commission found that an extremely constrained supply situation had developed. The regional reliability council had predicted that supplies would be tight, but a combination of factors coincided to create a worse situation than was expected. It was rather like the California experience in 2000, except that it was far from being as bad as California's "perfect storm." The factors included scheduled and unscheduled plant outages, hot weather, transmission system constraints, and non-performance by certain power marketers.

Although FERC staff studied the matter and concluded that a recurrence was unlikely, the Ohio commission was "somewhat less optimistic," in view of traditional problems like extreme weather and new problems like the reduced predictability of transmission system performance "in view of burgeoning wholesale power transactions and the prospect of retail wheeling."[41] The commission added that environmental restrictions on power plant operations could make the situation more precarious.

The commission also stated that, "The manner in which retail wheeling is implemented will also affect the extent to which the supply and demand of electricity is balanced. Without the implementation of public policy that encourages effective competitive entry in the generation market, assures coordinated operation of the transmission system, facilitates access to price information, and encourages utilization of financial hedging instruments, events may conspire again to disrupt electricity supplies and drive prices up. If competitively induced downward pressures on prices are not present, Ohio's major electric utilities will be in a position to exercise market power. (Report, pages ii-iii)

To ensure that "there is effective competition at the outset of any retail wheeling environment," the commission listed some public policy implications of the June 1998 events. These included actions to place regional transmission under the control of an RTO, to facilitate the development of power exchanges and risk management tools like forward markets, and to retain explicit Ohio jurisdiction to prevent abuse of market power. (Report, p. iii)

There will presumably be considerable attention directed at the issue of wholesale market adequacy to support direct access, and the potential for exercises of market power, during the

[41] Public Utilities Commission of Ohio, Ohio's Electric Market June 22-26, 1998: What Happened and Why, a report to the General Assembly (web version undated), p. ii.

remainder of the market development period which ends in 2005. PUCO chairman Schriber has noted that "federal issues regarding the interstate transmission of electricity have hindered the development of electric competition in Ohio. Working with the Federal Energy Regulatory Commission and other states to improve our regional transmission system is one of the PUCO's biggest priorities for next year...Competition and choice will continue to develop as a more efficient interstate transmission system falls into place and the wholesale electric market improves."[42]

Retail Market Situation

The development of direct access in the period of a little more than a year since it was initiated on January 1, 2001 has been highly uneven. In the northern Ohio service territories of FirstEnergy's subsidiaries, which have high utility rates, many customers have switched to competitive providers. This includes 54% of Cleveland Electric Illuminating Company's residential customers and 35% of Toledo Edison's residential customers. In the area of Ohio Edison, the third subsidiary of FirstEnergy, 17% of residential customers have switched. In the service areas of the other five major electric utilities, fewer than 1% of residential customers have switched, and there are few competitive providers.

What lies behind these figures? A major factor is, of course, the variation in utility rates across the state. Also, FirstEnergy's decision to make a portion of its generation capacity available to competitive marketers fuels the competitive market in northern Ohio. The other major factor is governmental aggregation. If high rates provide the motive for switching, aggregation -- as well as competitive supplies -- provides the means. The legislation provides for the formation of buying groups by municipalities and other governmental groups. Of the more than 600,000 residential electric customers who switched to new providers during 2001, the vast majority did so as members of buying groups. Mostly in northern Ohio, 158 communities have decided to aggregate so far.

The legislation allows municipalities and others to adopt either an opt-in or an opt-out model. In the opt-in case, customers must request membership. (This is the only model allowed in some states, such as New Jersey, that are concerned about "slamming." It can have the effect of being a barrier to aggregation.) In the opt-out case, a municipality signs up its residents as participants automatically, but it must allow them to opt-out (choose not to participate) if they wish.

It is an over-simplification to describe customer inclusion in Ohio's opt-out model as "automatic." The rules require municipalities to get public approval before they can bind their residents. First, a majority of voters in the municipal area have to vote for it, which means it has to be put on the ballot. Second, the municipality has to form a plan of operation and management, and must hold at least two public hearings where residents can air their concerns. And third, customers must be notified of the planned switch. Even if initially included, customers have the opportunity to opt-out every two years.[43]

[42] Alan R. Schriber, Ohio Electric Choice: One Year and Counting, Public Utilities Commission of Ohio news release dated December 27, 2001.
[43] PUCO, Energy Governmental Aggregation: The PUCO's Guide to Community Buying Groups.

Much of Ohio's switching has, in fact, resulted from one deal, described as the country's largest-ever aggregation contract. Northeast Ohio Public Energy Council, representing 100 Cleveland-area communities with 400,000 customers, selected Green Mountain Energy Company as its supplier for a period of six years starting in September 2001. The contract contains provisions for clean and renewable energy resources.[44]

The importance of aggregation in easing market entry is evidenced by the fact that Green Mountain had earlier decided *not* to enter the Ohio retail market, on the grounds that shopping incentives "make it difficult for Green Mountain to offer renewable energy to customers there at an attractive price, at least when we're competing for those customers one-by-one."[45]

In a "First-Year Report Card on Electric Choice," the Ohio Consumers' Counsel, Rob Tongren, concluded that customers were better off after the first year of direct access than they had been a year earlier -- customers had switched, rates were down -- but he also said that there was much room for improvement.

Among the issues that the Consumers' Counsel believes need to be addressed are the following. A state plan is needed to spur competition in areas of the state where there are currently no alternative suppliers. Rules need to be developed for the competitive bidding process that utilities are required to offer at the end of the market development period, including guidelines about participation by utility affiliates. Metering and billing services need to be reviewed; advanced metering needs to be developed. The Midwest RTO needs to be fully implemented. Market power needs to be monitored by the federal authorities. And a federal mechanism is needed to ensure the adequacy of power reserves in the wholesale market.[46]

Oregon

Oregon is an example of a state that has delayed introduction of direct retail access in light of the instability of the Western wholesale electric power market caused by the California electricity crisis, and the failure of competitive providers to enter the retail market in Oregon.

Oregon's Electric Industry Restructuring Law, SB 1149, which was passed in 1999, provided for direct retail access commencing on October 1, 2001. In the summer of 2001, HB 3633 delayed customer choice until March 1, 2002. After that date, business customers may choose to switch to competitive providers, but they will also have the choice of staying with regulated utility service at cost-based rates if they wish to do so. The Oregon PUC may waive this requirement for large business customers after July 1, 2003, if it makes certain findings about market development. These include findings that supplies are adequate and reliable, customers can obtain multiple offers from alternative providers, and prices are not unduly volatile.

[44] Akron Beacon Journal, February 16, 2001, reported in Restructuring Weekly.
[45] Green Mountain vice president Karen O'Neill, reported in The Electricity Daily, January 5, 2001.
[46] Ohio Consumers' Counsel, End-of Year Report: A Review of Ohio's Electric Market in 2001, January 9, 2002.

HB 3633 does not include direct access for residential customers, although small business customers may, if they wish, switch to competitive providers. Residential customers will now be offered a choice between several regulated options by their utilities. These options include a traditional basic rate, a time-of-day supply service, and certain green power alternatives.

The commission must report to the legislature by January 1, 2003 "on whether residential electricity consumers would benefit from direct access to electricity services. The report shall address, at a minimum, issues of market development for residential and small-farm consumers..."

The commission is directed to develop policies to eliminate barriers to the development of a competitive retail market. Three competitive providers have been certified by the commission, but they are complaining that they are being squeezed out of the market by the incumbent utilities. Among the barriers that they face is an exit fee attached to sales to direct access customers to recover the stranded costs of the incumbents.[47]

Pennsylvania

Summary

Pennsylvania is often regarded as the poster child of electric restructuring. The principal reason is that a number of customers have switched to competitive providers. The factors that account for switching include high utility rates and, more significantly, higher shopping credits than in most other states. The result has been that some customers have found it worthwhile to shop, and it has been profitable for some marketers to target small customers as well as large ones.

Closer scrutiny shows, however, that Pennsylvania's experience, like that of other states like Ohio and Illinois, has been highly uneven and has been influenced by utility-specific circumstances. Of the retail customers served by alternative suppliers as of January 1, 2002, 98% are in the Duquesne Light (Pittsburgh) and PECO Energy (Philadelphia) service territories, while in all other service territories less than one percent of customers have switched.[48] And Pennsylvania has not been immune to the "prodigal customer" problem that other states have experienced. Of the Pennsylvania customers who had migrated to the competitive market by April 2001, 30% have switched back to utility providers as of January 2002.

The other significant feature of the Pennsylvania experience is that the electric system had already for many years before restructuring been operated and planned as part of a tight pool by Pennsylvania-New Jersey-Maryland Interconnection (PJM). Under the aegis of FERC, PJM has now been transformed into an ISO. While PJM has its problems, it has clearly provided a stable wholesale market structure without which Pennsylvania's retail restructuring effort would have been much more problematic.

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[47] The Oregonian, February 3, 2002, reprinted in Restructuring Weekly.
[48] Pennsylvania Office of Consumer Advocate, Pennsylvania Electric Shopping Statistics, January 2002.

The Pennsylvania PUC chairman Glen R. Thomas believes that the example of Pennsylvania is a good one and that states should continue in the direction of restructuring. He argues that "the perception that competition is dead after California and Enron is wrong...Don't look at California or at Enron for the lessons of competition. Look at Pennsylvania. Following a year of bad news, Pennsylvania remains the national model for competition done right."[49]

Pennsylvania's Consumer Advocate sees the glass as half full rather than half empty. "I think our policy goal should be to stay the course and continue to provide protections for consumers while we see how competitive markets develop."[50] He recognizes that "it is impossible for a successful retail market to develop unless the wholesale bulk power markets are workably competitive," but he believes that the market failures of California will not occur in Pennsylvania. "The PJM markets are far from perfect but they are, in my opinion, far superior to virtually every other wholesale market region in America."[51]

In the retail markets, the Consumer Advocate notes that competitive suppliers are still supplying about 10% of customers. He acknowledges that many customers have returned to utility service, but he believes that "the way to increase retail competition in Pennsylvania is by fixing the remaining flaws in the wholesale market, not by increasing retail rates and violating the price caps that were supposed to protect consumers during this transition period."

Legislation and Regulations

The Electricity Generation Customer Choice and Competition Act of 1996 initiated retail competition with a pilot program in 1998. Two thirds of Pennsylvania's retail customers became eligible to choose alternative electricity suppliers by January 1999, and all the remaining retail customers became eligible by January 2000.

Competitive providers have to be licensed by the Pennsylvania Public Utility Commission and have to provide a performance bond or other surety. Generation services have been opened to competition, and in some service territories competitive providers may also offer customer services such as metering and billing.

Utilities must provide standard offer service to customers who do not choose competitive providers. Utilities are also required to be providers of last resort for those customers who choose to return to the utility or whose suppliers fail. The terms and conditions of provider of last resort service need not be the same as those for standard offer service -- e.g., a minimum period can be required.

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[49] Address to National Association of Regulatory Commissioners' Winter Meeting, reported in Pennsylvania Public Utility Commission press release dated February 12, 2002.

[50] The quotes in this paragraph and the next are from House Judiciary Committee Testimony of Sonny Popowsky, Consumer Advocate of Pennsylvania, November 27, 2001.

[51] In other testimony, before the Pennsylvania House Consumer Affairs Committee Regarding Electric Reliability, on March 7, 2001, the Consumer Advocate emphasized that it was essential to ensure that planned construction, and construction that was actually proceeding, would be enough to match demands, and would not be overly dependent on natural gas.

There has, of course, been a loss of state jurisdiction to federal authorities and regional entities. This affects the roles of state regulators and consumer advocates. As the Pennsylvania Office of Consumer Advocate reports, "Since much of the decision-making that affects Pennsylvania electric consumers now occurs at the federal and regional level, the OCA has greatly expanded its participation in key electric proceedings before (FERC) and in the committees of the PJM Interconnection."[52]

Restructuring Activities to Date

Functional separation of generation is required of utilities, rather than structural separation or divestiture. However, several of the state's utilities have voluntarily transferred generation assets to separate subsidiaries of their holding companies, and in some cases have divested generation assets. For example, Duquesne and the GPU subsidiaries Metropolitan Edison and Pennsylvania Electric Company have completed their divestiture of generation assets.

Wholesale Market Profile

Pennsylvania utilities are members of the PJM Interconnection that is now operating as an ISO and has responsibility for ensuring system reliability in the region, which in addition to Pennsylvania includes New Jersey, Maryland, Delaware, the District of Columbia and part of Virginia.

PJM rules include a mandatory generation reserve requirement for all companies who serve customers in the area. It also administers an installed capability (ICAP) market.

FERC is encouraging PJM to combine with other ISOs in the Mid-Atlantic and Northeast to create a large regional RTO. It is not certain that this combination will take place.[53] PJM has announced its intention to explore merging with the Midwest ISO.

PJM functions as an independent system operator and also runs the wholesale power markets in its area. As the Office of Consumer Advocate has noted, "PJM's rules for and operation of those markets is critical to ensuring that retail competition in Pennsylvania will work...(FERC) required that RTO and ISO filings reflect certain basic governance and pricing characteristics, including requirements for independent governance and elimination of rate pancaking...The OCA's main challenge in the federal electric arena is to ensure that the proper RTO structures and rules are in place to protect consumers from the potential for market power abuses and to support competition in both the wholesale and retail markets so that even small consumers can benefit from retail choice."[54]

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[52] Annual Report of the Pennsylvania Office of Consumer Advocate, Fiscal Year 2000-2001, November 2001.

[53] A recent report titled Economic Assessment of RTO Policy prepared for FERC (ICF Consulting, February 26, 2002) concluded that properly functioning RTOs, with consistent and effective market design throughout the country, would bring substantial economic benefits. However, the report found that the creation of larger as opposed to smaller RTOs would bring only minor additional benefits, unless larger RTOs resulted in more effective market design than smaller ones. This report may dampen FERC's enthusiasm for larger RTOs, unless of course FERC believes that larger RTOs would have better governance and market design.

[54] Annual Report of the Pennsylvania Office of Consumer Advocate, Fiscal Year 2000-2001, November 2001, p. 17.

In November 2001, the Pennsylvania Public Utility Commission opened an investigation into the operation of wholesale electricity markets. This followed on the publication of a PJM report that found that during the period January through March 2001 market power had been exercised to raise prices on the installed capability (ICAP) market. The PUC chairman has called for steps to "hasten the maturing of the wholesale power markets."

Retail Market Development

Closer scrutiny shows, however, that Pennsylvania's experience, like that of other states like Ohio and Illinois, has been highly uneven and has been influenced by utility-specific circumstances. Of the 551,106 retail customers served by alternative suppliers as of January 1, 2002, 98% are in the Duquesne Light (Pittsburgh) and PECO Energy (Philadelphia) service territories. In all other service territories apart from Duquesne's and PECO's, less than one percent of customers have switched.[55]

Aggregation of a kind is responsible for about 41% of the customers who have switched. PECO agreed in its restructuring plan to assign 20% of its residential customers, for whom it was provider of last resort, to a special Competitive Discount Service. A competitive supplier would be selected for these customers as a block. Three bids were obtained, and New Power Company was selected as supplier. Later, Green Mountain Power was selected to provide power to an additional group of PECO customers.

In addition to the uneven development of the direct access market, Pennsylvania has not been immune to the "prodigal customer" problem that other states have experienced. Between April 2001 and January 2002, 30% of the Pennsylvania customers who had migrated to the competitive market switched back to utility providers when wholesale market prices rose relative to standard offer rates.

A new kind of problem faced the Pennsylvania authorities when Utility.com, a competitive provider, went out of business in 2001. A number of retail customers were left without a provider, and since the Utility.com website went down, customers didn't know the status of their consumption or bills. As the OCA said in a December 13, 2001 bulletin, "The company has no employees, no address and no website. CM Business Credit Services, Inc., a California firm that helps insolvent businesses to close, is handling any remaining claims against the company." The OCA tried to provide customers with the information they would need to submit claims and switch back to utility provider of last resort service.

Texas

Summary

Texas had been intensively investigating and negotiating electric restructuring for some time before the California electric crisis occurred. There was considerable political commitment to restructuring, which was supported by then-governor George W. Bush and then-Public Utility Commission of Texas chairman Pat Wood III.

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[55] Pennsylvania Office of Consumer Advocate, Pennsylvania Electric Shopping Statistics, January 2002.

Factors that favored restructuring in Texas included the state's control through the Electric Reliability Council of Texas (ERCOT, now the ERCOT-ISO) of its own intra-state electricity grid, and compromise features of the legislation that gave it continued support. These features included limits on the sizes of incumbent utilities in the restructured wholesale market.

Convinced that its market design would not be vulnerable to a California-type failure, Texas decided to proceed with direct access for all customers on January 1, 2002, as scheduled, after a five-month period during which a pilot program was in place, designed to identify technical problems and give participants a chance to iron them out.[56]

As far as the Texas authorities are concerned, the market's first responses have been promising, despite some initial technical glitches, with competitive suppliers functioning in the market and a number of customers switching away from their incumbent utilities. The independent power industry already has a foothold in the generation business in Texas, and, as required under the restructuring law, utilities are reducing their control of generation. The law also allows for retail customer aggregation.

At this point, the Texas authorities are optimistic. There are some skeptical observers, such as the editor of Public Utilities Fortnightly, who sees in Texas one of the problems that bedeviled the California utilities -- vulnerability to high wholesale prices while their retail prices for standard offer service are frozen (after initial reductions) until 2007 -- although he also recognizes the Texas advantage of having "a state-regulated ISO, dedicated to state interests."[57] It is too soon to be able to dismiss this type of concern.

The continued success of Texas restructuring will depend, as it does in other states, on the twin pillars of a workably competitive wholesale market -- a regulatory and market framework within which independent power producers are encouraged to maintain adequate supplies of generation -- and an effective ISO or RTO that can monitor, identify, and correct market power and other market abuses. And in the retail market, the success of competition will depend, as it does in other states, on not only a competitive wholesale market, but also a level playing field that enables new entrants to acquire retail customers individually or through aggregation. As far as the Texas Public Utility Commission is concerned, these essential features are in place.

Legislation and Regulations

The Texas Electric Choice Act, SB 7, was signed on June 18, 1999. It provides for direct access for all retail customers beginning January 1, 2002, after a pilot program period, which was planned to start in June 2001 but was delayed for technical reasons to August 2001. Initially,

[56] Computer problems delayed the start of the pilot program by two months. Restructuring has been delayed in the non-ERCOT portion of southeast Texas served by Entergy, which is a member of the Southeastern Reliability Council (SERC). For the SERC area, FERC has not approved an RTO, which is a prerequisite for direct retail access under the Texas legislation. Xcel Energy regulated service is being retained in the El Paso and Texas Panhandle areas, which are not being opened up for competition for the next three and five years respectively, and deregulation is being delayed indefinitely in the Southwestern Electric Power Company (SWEPCO) area of northeast Texas.
[57] Public Utilities Fortnightly, February 1, 2001, pages 4-6.

generation and billing services are opened to competition, with metering to follow later. Standard offer service is available from the utility for residential and small commercial customers.

Structural (corporate) separation of generation by divestiture or transfer to an affiliate company is required. Utilities must also be separate from retail electricity companies (REPs), which are entities that may market electricity to customers. The distribution utility itself may not participate in the wholesale or retail market except to purchase electricity for its own requirements for standard offer service. An REP which is affiliated with a distribution utility cannot sell electricity in the utility's service territory, except as standard offer provider, for three years, or until at least 40% of residential and small commercial customers have switched to competitive providers, whichever comes first. This means that it cannot offer services at different prices until this 40% condition is met.

An REP serving an aggregate load of more than 300 MW must sell at least 5% of its energy for three years to residential customers. By this provision, and the restrictions on affiliated REPs, SB 7 is intended to pry open the small-customer market to competitive entry, notwithstanding the continued low-cost option of standard offer service.

Aggregation or pooling of customers is permitted, provided the aggregator registers with the Commission. Aggregators may include cities and towns, non-profit organizations, and businesses.

An important feature of the Act is its provisions intended to break up the potential market power of incumbent utilities and prevent new entities from establishing and exercising market power. Utilities and their affiliates must auction off 15% of their generation assets. This provision -- which may be achieved by leasing or some similar method, as opposed to outright sale -- is in place for five years, or until at least 40% of residential and small commercial customers in the area have switched to competitive providers, whichever comes first.

And, wholesale generators may not own more than 20% of the installed capacity located in, or capable of delivering power to, a power region. This requirement may be waived in the case of utilities in a power region that is not entirely within Texas. Generators who are found to violate this requirement must file a market power mitigation plan.

An ISO must be established in each area. ERCOT is under the primary jurisdiction of the state Commission, but FERC has jurisdiction over some areas of the state in which utilities are interconnected with neighboring states or have interstate holding companies.

The state Commission may delay competition -- as it has done in certain areas of the state -- if it determines that the power market in the area is not yet able to offer fair competition and reliable service to customers.

Wholesale Market Profile

Most parts of Texas are in the area covered by the Electric Reliability Council of Texas (ERCOT). Texas is in a unique situation in having its own state-regulated reliability council.

Listing its reasons for optimism about the prospects for success of retail competition in Texas, the state Commission has said that: "Unlike other areas of the United States, where Federal and state policies relating to the electric industry are sometimes inconsistent, regulatory authority with respect to ERCOT rests exclusively with the Texas PUC."[58] For other states, restructuring involves allowing utilities to shift their generation out from under state regulation, while in Texas there does not have to be any such loss of jurisdiction (at least, not in the ERCOT area). ERCOT has now evolved into the ERCOT-ISO. It controls the transmission system and is responsible for system reliability.

ERCOT does not operate a centralized wholesale power market. The intention is to allow market participants to develop markets, rather than preempt or channel their efforts as other states have tended to do.

The auctioning off of 15% of utility generation assets, and the cap of 20% on the market share of a single generator are aimed not only at opening up the market to competitive entry, but also to avoid a situation in which large generators are in a position to exercise market power. These provisions respond to market power concerns expressed by the Texas Office of Public Utility Counsel (OPUC) and others.

Dallas-based Texas Utilities (TU) and Houston Lighting and Power (HL&P), which had 40% and 28% respectively of the generation capacity in ERCOT, and between them more than 80% of the peaking capacity, were the main cause of concern. A consultant's study Commissioned by OPUC had reached the following conclusions.

(M)arket power will exist in ERCOT. Both TU and HL&P would have the ability to exert control over prices and increase profits by noncompetitive pricing or restricting supply. Further, the ability to control prices will exist in both the summer peak season as well as the off-peak months when plant maintenance occurs. One of the factors that compound the market power of TU and HL&P is the ability to 'leverage' the diversity of their supply mix. These large suppliers can increase profits on lower cost coal and nuclear baseload plants by restricting the supply (or increasing prices) of higher cost (gas fired) intermediate and peaking plants. Even though such strategies may reduce market share or even profits for gas fired generators, the increase in profits on baseload plants more than offsets possible decreases in profits on gas plants."[59]

The study recommended that, "Divestiture is the most effective means of dealing with market power." It noted that utilities in many other states had divested generation assets to reduce market power and quantify, and possibly mitigate, stranded costs. Divestiture of peaking capacity was the best course. No one generator in Texas should own more than 10,000 MW of gas-fired capacity.

Another study done for OPUC by a different consultant reached somewhat similar conclusions regarding the problem of horizontal market power, and recommended that "the best

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[58] Public Utility Commission of Texas, Scope of Competition in Electric Markets in Texas, Report to the 77th Texas Legislature, January 2001, p. 3.
[59] Office of Public Utility Counsel of Texas, Electric Power Restructuring Issues for ERCOT: Market Power and Divestiture, October 1998.

competitive policy would be to reduce the size of the largest ERCOT suppliers..."[60] This report also addressed vertical market power, and concluded: "The only way to completely address vertical market power problems is through the complete divestiture of all generating assets by integrated utilities."

The Commission is aware of the importance of these issues. "A vibrant wholesale market is important for a retail market to work," it said during 2001, but it believes that the favorable environment for merchant power plants in Texas, including standardized procedures for interconnection to the grid, will ensure that that the state does not run short of power the way California did.[61]

The Commission contrasts the power plant construction in Texas from that in California and some of the northeastern states.

In California and New York, it appears that the primary impediment is the state siting process. In New England and Pennsylvania, the construction of new generation appears to have been slowed by transmission interconnection rules that require the developers of new generation projects to pay for upgrading the transmission network so that the output from the generation plant can be moved to the market. In some of the Northeastern states, the natural gas pipeline infrastructure is not adequate to support significant levels of new gas-fired generation, which is the most economical technology in the market today...

Texas has adopted a different approach on many of these issues. Non-utility generation does not require a state license, other than environmental permits, and new generation facilities are not required to pay for transmission facilities to deliver their power to market. Texas also has a strong gas-delivery infrastructure...A better supply-demand situation is already evident in Texas.[62]

Retail Market Developments

After initial rate reductions, there is a rate freeze for standard offer service for a five-year period, or until 40% of eligible customers have chosen competitive suppliers, whichever comes first. The supplier is the distribution utility's affiliated REP. The standard offer rate is termed "the price to beat" in the service territory.

The Texas Office of Public Utility Counsel has expressed concern over the utility practice of offering special discounted rates to large industrial customers. Traditionally, the concern was that special rates could result in cost-shifting to other customer classes. On the eve of direct access, the additional concerns are that special rates and contracts may tie up customers before they have an opportunity to shop around in the competitive market, and may undermine

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[60] Report to the Office of Public Utility Counsel on the Criteria for the Sale of Generation Assets by ERCOT Generation-Owning Utilities, Criteria for Electric Generation Divestiture in ERCOT, October 1998.
[61] Public Utility Commission of Texas, Scope of Competition in Electric Markets in Texas, Report to the 77th Texas Legislature, January 2001, pages 3-6.
[62] Public Utility Commission of Texas, ibid., p. 37.

the equitable recovery of stranded costs. The Commission has taken steps to address these concerns.

It is too soon to know how many customers will switch to competitive providers in Texas. According to early reports, more than one half of the electricity purchased by large customers is now coming from competitive providers. The Houston Chronicle reported on February 14, 2002, that 3% of residential customers in the state had switched suppliers, which would be a significant achievement in a little over one month.

It is also too soon to know how quickly initial technical and other problems will be resolved. There have been some initial technical problems, and the rate of customer complaints is high. ERCOT is initially taking 30 days, or even 60 days, to switch customers. And there are allegations of slamming and deceptive marketing practices.

Governmental aggregation appears to have taken hold quickly in Texas. A recent list of aggregation programs includes one for 142 school districts, one for 46 local governments, one for 180 school districts and 11 other public entities, one for 71 cities and one for 40 cities. The annual savings for these programs are estimated at about $150 million.[63]

Another early development is that non-utility providers of last resort have been selected for a number of utility service territories.

Vermont

Summary

Although an early leader in New England and the nation in evaluating the benefits of retail choice and competition, Vermont was unable to agree on an implementation plan for restructuring its electric utility system. It came close in 1997 when the Vermont Senate passed a bill supported by the Governor, utility commission, many business groups, and the state's two large investor owned utilities. However, opposition by liberal Democrats in the Vermont House, as well as some consumer advocates and municipal utilities, was enough to prevent passage. Subsequent events in wholesale markets, including price increases and the California debacle, convinced most legislators and policy makers to adopt a "wait and see" approach.

Electric System

Two large investor owned utilities, Central Vermont Public Service and Green Mountain Power, serve approximately 70 percent of the state's 1100 MW peak load. One additional IOU, Citizens Utilities serves about 60 MW of load. The state's largest city is served by a municipal utility, Burlington Electric, with about a 70 MW peak load. Two cooperatives, twelve small municipals, and one small IOU serve the remaining 200 MW of peak load. The entire state is dispatched as a single entity by ISO New England, the regional administrator of the New England bulk power system, through a cooperative arrangement among Vermont's utilities embodied in an entity called the Vermont Electric Power Company (VELCO). VELCO was

[63] Electric Utility Restructuring Legislative Oversight Committee, February 5, 2002. On PUC website.

created in the1970s to allow for the more efficient dispatch of power; in essence, VELCO is an early for-profit Transco. Although dominated by the two large IOUs, CVPS and GMP, the voting and management structures are designed to accommodate minority views.

Restructuring history

In 1996, Vermont was in the vanguard of states seeking to restructure the state's electric industry and provide retail choice to consumers. The VT Public Service Board, the state's utility commission, had conducted a series of workshops (The Vermont Roundtable on Restructuring) to establish basic principles and issued a report on the opportunities and necessary conditions for the provision of competitive electric services (Docket No. 5854, Order of 12/30/96).

A significant impetus for restructuring had to do with impending rate increases to cover the costs of expensive generation and purchased power contracts. Large customers were concerned that their competitive position within their industries would suffer if they were forced to absorb large rate increases over the coming years. Consequently, a great deal of the debate and tension over restructuring was directly related to the utilities insistence that they receive full recovery for their "stranded costs" and the reluctance of their customers to agree in advance to any such "guaranteed" recovery. Other stakeholders, including the Vermont Department of Public Service (the consumer advocate and state energy policy agency), had significant concerns about the "stranded benefits" that would occur as a result of restructuring.

In early 1997, Senate Bill 62 (S.62) was introduced as a comprehensive plan for restructuring Vermont's electric industry. After three months of debate in four Senate Committees, it was approved by the full Senate in early April and sent to the Vermont House for review. The House leadership focused almost solely on the stranded cost issue and took a very public stance that ratepayers should not pay anything for the utilities' expensive power contracts. S.62 proposed a fifty-fifty sharing between ratepayers and utility shareholders, after a Public Service Board proceeding to eliminate any imprudently incurred costs and mitigation of above-market prudently incurred costs. CVPS and GMP had already stated that S.62 would likely cause bankruptcy due to the impact of absorbing even fifty percent of the above-market costs. With neither side able or willing to negotiate, S.62 wallowed in perfunctory committee hearings over the next two years. Alternative and modified House and Senate proposals were unable to garner any significant support.

Meanwhile, CVPS and GMP both became entangled in rate case proceedings where the VT Department and other intervenors pressed their claims that significant portions of the utilities' above-market contracts were the result of imprudent utility actions and should be disallowed for rate recovery. The outcome of these cases would have a significant impact on any restructuring efforts in the state.

In July 1998, VT's Governor Dean issued an executive order establishing a Workgroup to evaluate the best course for Vermont to take in regard to electric restructuring. In a report issued in December 1998, the Workgroup concluded that with appropriate protections and safeguards for consumers and utilities, retail choice could be beneficial to Vermont's economy. No particular initiatives followed.

In late 1999, the VT Board opened an investigation, in response to petitions from CVPS and GMP, to determine if retail competition could be implemented without specific legislative authorization. That investigation, although still technically open, has been inactive for the last three years.

More recently, the escalating costs of wholesale power that began in the fall of 1999 and continued through the winter of 2000-2001 have made many of the Vermont utilities' purchased power contracts more attractive. Combined with the well-publicized problems in California's wholesale power markets and smaller, yet significant, problems in the Northeast ISO-administered wholesale markets, many of the large customers of Vermont's utilities are less enthusiastic above a rapid move to retail choice. With the benefit of hindsight, some of the more vocal proponents of retail choice, including Vermont's five-term Governor, are endorsing a thoughtful re-evaluation. Many of the vocal critics of restructuring are proclaiming the wisdom of their early opposition.

Special features of S.62

Consistent with the VT Board's Order in Docket 5854, Senate Bill 62 proposed a comprehensive approach to retail competition. Some of the key features included:

- Stranded costs: a fifty-fifty cost sharing between ratepayers and shareholders after Board proceedings to eliminate any imprudent costs and to determine mitigation strategies (including securitization) of prudently incurred above-market costs.
- A functional separation of utility generation resources with strict codes of conduct to ensure arms-length relationships. Although divestiture was mentioned as an option, it was not required.
- A comprehensive education program for consumers about retail choice options
- An auction for retail providers of "basic service" (standard offer service) subject to terms and conditions set by the VT Board. Incumbent utilities may be awarded basic service contracts only if no other acceptable bids are provided.
- A competitive transition charge established by the VT Board to provide recovery of adjudicated stranded costs
- A system benefits administrator who would collect and distribute wires charges for the following programs:
    - A low income affordability program
    - An information disclosure program for consumers
    - An energy efficiency utility to provide statewide programs
    - A renewable portfolio standard for all retail providers (approximately 15% existing renewables; and 1-4% new renewables over ten years)
    - An emissions portfolio standard for all retail providers
- A net-metering provision for residential and commercial customers who install small renewable generation less than 50 kV.

Current status

Despite the inability of the legislature to enact a comprehensive bill such as S.62, certain elements have been enacted through separate legislation and Board proceedings. In 1998, a net-metering provision similar to the one in S.62 was signed into law. In 1999, Vermont created the first statewide energy efficiency utility to oversee the implementation of comprehensive energy efficiency programs through a consortium of utility support.

As mentioned above, although there is technically an open proceeding before the VT Board on a utility request to allow retail choice, the docket has been inactive for the last three years. Based on discussions with VT Board staff, it is unlikely that any new restructuring proposals are imminent.

Virginia

We will address only one feature of the Virginia electric restructuring situation. The Virginia Electric Utility Restructuring Act requires each incumbent electric utility to submit a plan for the functional separation of the utility's generation, transmission and distribution assets and operations. The plan has to be filed with the State Corporation Commission for approval.

On January 3, 2001, American Electric Power Company-Virginia filed its proposed separation plan, which was not only a functional separation, but would transfer its generation assets and operations into a separate *corporation*, Genco. This new entity, which would be an affiliate of AEP-Virginia and a subsidiary of the AEP holding company, would be an Exempt Wholesale Generator and would no longer be under the jurisdiction of the Virginia commission.

During 2001, there were initiatives before the legislature that affected the AEP filing, and when these were resolved, the commission proceeded with the matter, requesting parties to attempt to enter into a stipulation on the issue.

In the resulting stipulation, the company agreed to continue with its current functional separation of its distribution, transmission and generation functions *by division*. During 2002, there will be a further inquiry into the terms and conditions for the proposed transfer of generation assets to an affiliate. "This inquiry will examine, among other things, conditions necessary for the maintenance of reliable electric service and the development of an effectively competitive market for generation services; and...AEP-VA will continue to use its best efforts to provide reliable service and to minimize generation costs to its retail customers."[64]

This matter, which is clearly not yet resolved in Virginia, underscores the concern of state commissions about loss of jurisdiction over generation assets, particularly when it is not clear that the FERC-regulated wholesale market is workably competitive. In the Virginia case, furthermore, there is concern that even if the wholesale market is highly competitive, prices may be higher than regulated rates, which are based on the relatively low embedded costs of service of the state's utilities.

[64] Virginia State Corporation Commission, Application of Appalachian Power Company D/B/A American Electric Power-Virginia for approval of functional separation plan, Case No. PUE010011, Order on Functional Separation, December 18, 2001.

Appendix Two: Staff's Summary of the Responses to the Commissioners' Questions

Commission Staff has summarized the responses to the Commissioners' questions. The following entities filed responses in whole or in part to the Commissioners' questions:

- Arizona Public Service Company (APS)
- Citizens Communications (Citizens)
- Tucson Electric Power Company (TEP)
- The Arizona Competitive Power Alliance (AzCPA)
- The Electric Power Supply Association (EPSA)
- Calpine (Calpine)
- Duke Energy North America (Duke)
- Panda Gila River (Panda)
- PG&E National Energy Group (PG&E)
- Reliant Resources (Reliant)
- Sempra Energy Resources (Sempra)
- AES New Energy (AES)
- APS Energy Services (APSES)
- Strategic Energy (Strategic Energy)
- Arizona Electric Power Cooperative, Southwest Transmission Cooperative, and Sierra Southwest Cooperative Services (AEPCO, Southwest and Sierra)
- Grand Canyon State Electric Cooperative Association (REDCs)
- Trico Electric Cooperative (Trico)
- Arizona Consumers Council (Arizona Consumers Council)
- Residential Utility Consumers Office (RUCO)
- Arizonans for Electric Choice and Competition (AECC)
- Land and Water Fund of the Rockies (LAW Fund)
- Southwest Energy Efficiency Project (SWEEP)
- Arizona Clean Energy Industries Alliance (ACEIA)
- Stirling Energy Systems (SES)
- The Center for Energy and Economic Development (CEED)
- Arizona Cogeneration Association (ACA)
- The Arizona Utility Investors Association (AUIA)

Chairman Mundell's Letter of January 14, 2002

I. Identification of Retail Electric Products and Services for Which Competition Could Bring Benefits

A. What are the possible goods and services traditionally provided by the electric utility for which retail competition is possible? You may address the following categories of goods and services:

1. generation, including baseload, intermediate and peaking power; green power; distributed generation; firm and nonfirm power; long- and short-term contracts; backup and coordination services.

Investor-Owned Utilities

APS states that competition is possible for all categories of generation, except for firm and non-firm power for small customers to a limited extent. Further, for baseload, intermediate, and peaking generation APS states that for small customers competition is possible collectively.

TEP states that competition is possible for baseload, intermediate, and peaking power generation; power transactions with varying levels of firmness and duration; and derivative instruments related to fuel, emissions, and forced outages.

Wholesale Power Producers

The AzCPA states that large consumers are best able to take advantage of many of the services that may be offered.

Panda states that competition is possible in generation. PG&E states that its Harquahala Generating project may operate as a baseload, intermediate, or peaking facility; will procure backup power and control area services from other providers; and participates in renewable energy projects in other areas and are willing to participate in Arizona renewable projects in the future. Reliant states that competition is possible in all the generation services listed.

Electric Service Providers

AES states that competition is possible for all the generation services listed.

Strategic Energy states that competition can reduce the need for regulatory oversight in certifying providers. Competition shifts risk from utility consumers to stockholders. Strategic Energy believes that aggregating smaller customers can result in significant savings for these customers. Aggregation also reduces risks for companies.

Electric Cooperatives

AEPCO, Southwest, and Sierra state that competition in power delivery is possible, but may not make sense for most customers. In rural areas the risks and costs outweigh the benefits. Distributed generation provides an alternative to customers.

The REDCs state that competition is power delivery is possible, but may not makes sense for most customers or the rural cooperatives.

Residential Consumers

The Arizona Consumers Council states that competition for generation services is possible if the market is robust and mature. There is a need for players to have adequate information available for making decisions.

RUCO states that the question remains whether small users can get services at a rate that is less than or equal to marginal cost and that this will depend on the viability of the western wholesale markets.

Industrial Consumers

AECC states that all the generation services listed, with the possible exception of coordination services, can be provided in a competitive environment.

Environmental and Energy Efficiency Advocates

The LAW Fund states that competition's ability to foster development of green power is marginal at best.

SWEEP states that current demand-side management (DSM) programs do not meet the needs of all customers and are under-funded. SWEEP also states that market barriers to energy efficiency exist. Publicly-funded energy efficiency programs could reduce market barriers, thereby increasing energy efficiency in the market. Funds could be obtained through system benefits charges or by other charges on ratepayers.

Utility Investors

AUIA states that all generation services, with the possible exception of must-run generation, are susceptible to competition.

> ***2. distribution services, including ownership, construction, maintenance and repair of the physical lines; metering ownership, installation, reading and data analysis; and the process of planning for and negotiating with distributed generators.***

Investor-Owned Utilities

APS states that competition is not possible for distribution lines and planning for and negotiating with distributed generators. Competition is possible but unlikely for metering.

TEP states that competition in distribution services is not in the public interest and that meter ownership, installation, and maintenance should be limited to UDCs and ESPs. Meter reading and data analysis should stay with the UDC, but under the right circumstances could be provided by ESPs. Planning for and negotiating with distributed generators shouldn't be a competitive service and UDCs shouldn't be required to buy surplus capacity or energy.

Wholesale Power Producers

AzCPA states that distribution service should remain with the incumbent utilities at this time, meter ownership should be open to other parties, information flow from the meter is important, and competitive metering should be part of a move to more competitive markets.

Reliant states that distribution services should remain a regulated service but that metering services can be competitive in a functional market.

Electric Service Providers

AES states that competition is possible for all of these services but that rules must allow parties to compete equally.

Electric Cooperatives

The REDCs state that all distribution services should not be subject to competition and should continue to be regulated.

Residential Consumers

The Arizona Consumers Council states that the maturity of the market will determine whether competition exists.

RUCO states that most of these services are not expected to be competitive, but that meter ownership could become competitive.

Industrial Consumers

AECC states that these services could be offered competitively, but that competition in distribution services is unlikely to benefit customers and could have negative impacts, creating unnecessarily complications.

Utility Investors

AUIA states that distribution services generally should not be competitive, but that metering could be competitive.

> *3. aggregation services, such as load profiling; load planning; customer services; data analysis; billing; generation planning; power supply acquisition; demand side management; energy efficiency and other services related to matching supply and demand.*

Investor-Owned Utilities

APS states that all these services can be offered competitively with the exceptions of load profiling, load planning, generation planning, and must-run generation.

TEP states that with the exceptions of demand side management and energy efficiency, aggregation services should be provided by the UDC, rather than being competitive. However, under the right circumstances some services, such as customer service, data analysis, billing, generation planning, power supply acquisition and other services related to supply and demand could be made competitive. Load profiling and load planning should be conducted by the provider of last resort.

Wholesale Power Producers

AzCPA states that mid sized customers are attractive to competitors and that the current rules are appropriate regarding these services. Further, energy efficiency services are already competitive.

Reliant states that all these services have at least to some degree been successfully offered competitively elsewhere in the country and that a well functioning wholesale market is necessary.

Electric Service Providers

AES states that competition is possible for all of these services but that rules must allow parties to compete equally.

Electric Cooperatives

AEPCO, Southwest, Sierra and The REDCs state that other than aggregation and power supply acquisition services, all these services have long been offered by competitive suppliers in the energy field and that they have never been considered to be functions offered only by public service corporations.

Residential Consumers

The Arizona Consumers Council states that the maturity of the market will determine whether competition exists.

RUCO refers to its response to Question 1.A.1.

Industrial Consumers

AECC states that load profiling does not led itself to competition and that planning for competitive services is competitive but that planning for noncompetitive services is not a competitive activity.

Environmental Advocates

The LAW Fund states that competition for demand side management has been offered competitively, but has only been marginally viable for smaller customers, absent a supporting utility program. The ability of competition to foster DSM and energy efficiency is marginal at best.

Utility Investors

AUIA states that all aggregation services form a package of competitive services.

B. For each good or service for which competition is possible, what are the possible benefits of competition for each good and service?

1. What are the potential price benefits?

Investor-Owned Utilities

APS states that the potential benefits vary by item and some items may incur negative price benefits. The potential benefits include lower prices, technology advancements, lower line losses, lower costs, better risk management, better reflection of cost of service, more rational pricing, economies of scale and scope, better information, and weeding out of inefficiencies.

TEP states that potential benefits include more efficiency, lower prices, better information dissemination, more options available to customers, and greater customer awareness of energy use.

Wholesale Power Producers

The AzCPA states that benefits include lower prices, efficiency increases, and risk shifting from consumers.

Panda states that benefits include safe, reliable, and competitively-priced electricity. PG&E states that benefits include the risk is shifted from ratepayers to shareholders, price competition among multiple plants, and pressure for competitors to become more efficient. Reliant states that benefits include lower prices, improved service, increased innovation, and more efficient use of resources.

Electric Service Providers

Strategic Energy states that it has a unique pricing program that mitigates consumer costs in times of high electric prices. Consumers can negotiate long term contracts which can result in cost savings and price certainty for customers.

Electric Cooperatives

AEPCO, Southwest, Sierra and the REDCs state that although competition theoretically should improve efficiency and lower cost, in the cooperative service territories it is questionable whether there will be benefits, while costs could be increased.

Residential Consumers

The Arizona Consumers Council states that benefits are lower prices and more services available. RUCO states that benefits are difficult to predict, some skepticism is in order, and long run market prices may be higher than Arizona's embedded costs.

Industrial Consumers

AECC states that price benefits will vary depending upon whether there is excess capacity or capacity scarcity at a given time and that much of the potential price benefit will be found in contract structures between providers and consumers.

Utility Investors

AUIA states that benefits will vary with market conditions and will become more accessible once stranded costs have been recovered. Further, there is a risk of losing fuel diversity by becoming too reliant on natural gas as a fuel source.

2. Do the price benefits differ in the short-term and long-term?

Investor-Owned Utilities

APS states that for generation in most cases benefits will grow in the long term. For metering and aggregation services benefits will also grow over time.

TEP states that benefits will generally increase over time as the market matures.

Wholesale Power Producers

The AzCPA states that the Alliance can sell long term power at prices less than those contained in the APS/PWCC proposal.

Panda states that the price benefits from competition will begin right away. PG&E states that there are price benefits in both the short term and long term, but will depend upon market conditions, technology advancements and the level of competition. Reliant states that price benefits are likely to be greater in the long term and that in the short term a well functioning wholesale market is needed.

Electric Cooperatives

AEPCO, Southwest, and Sierra and The REDCs state that for in cooperative service areas it is unlikely that price benefits will differ between the short term and long term for meter services, billing, and data analysis.

Residential Consumers

The Arizona Consumers Council states that price benefits tend to be long term unless mandated otherwise.

RUCO states that it depends upon what generators are in the current rate base and that long-term prices could be higher.

Industrial Consumers

AECC states that short term price benefits may occur as a result of an excess supply situation. Long-term benefits depend on whether competition leads to lower long-run costs of production.

3. What are the potential non-price benefits?

Investor-Owned Utilities

APS states that potential non-price benefits of competition include supplier diversity, higher customer satisfaction, increased supply security, increased power quality, greater efficiency in generation unit use, and elimination of possible customer cross-subsidization. Further potential non-price benefits include better matching of supply options and demand, new technologies, bundled product offerings, and possible peak use reductions and resultant savings.

TEP states that potential non-price benefits of competition are spurring of the creation of new products and services, more information and options available to customers, more efficient use of existing generation, and more efficient use of energy that would free up financial resources for other activities.

Wholesale Power Producers

The AzCPA states that potential non-price benefits of competition are customer convenience, matching of products and services with customer needs and desires, more efficient use of generation, and less environmental impact.

Panda states that potential non-price benefits of competition are new state-of- the-art generating facilities and improved reliability due to arms-length contractual arrangements between UDCs and unaffiliated generators. PG&E states that potential non-price benefits of competition are new generation projects that are designed with respect to environmental and community concerns.

Reliant states that potential non-price benefits of competition are increased product and services innovations, improved customer service, customer choice, and the option for a customer to negotiate a fixed price contract that would provide price stability.

Residential Consumers

The Arizona Consumers Council states that potential non-price benefits of competition are diversity of services and long term contracts providing stable prices, although the opposite could also happen. RUCO refers to its answer to Question Nos. 1.B.1 above.

Industrial Consumers

AECC states that potential non-price benefits of competition are customer service innovations, accelerated product development, better information for customers, better contract terms, increased risk management opportunities, and greater consumer input.

Renewable Energy Advocates

The ACEIA believes that competitive markets can encourage the use of green power and other renewables. Distributed generation and renewable energy provide public benefits to all citizens. The Environmental Portfolio Standard (EPS) should be changed so that the percentage increase extends beyond the year 2007. More effective and competitive green pricing programs should be encouraged by creating a structure for utilities to pursue these programs.

4. **Are there any other potential benefits (e.g., environmental, energy security, etc.)?**

Investor-Owned Utilities

APS states that other potential benefits include energy security from supplies that are diversified geographically and technologically, new products and technologies, and reduced air emissions, water consumption, and waste disposal issues. Further potential benefits are pressure to increase technological progress, opportunities to integrate energy management services and metering services, product bundling, and better DSM offerings.

TEP states that it has discussed other benefits in response to Questions I.A.2, I.A.3, and VI, and on response to Commissioner Spitzer's questions regarding generation products.

Wholesale Power Producers

The AzCPA states that other potential benefits include new efficient and environmentally friendly power plants and if demand for renewable resources increases, the price of those resources will be paid by consumers demanding those renewable resources.

Panda states that other potential benefits include enhanced economic development opportunities. PG&E states that other potential benefits include that the emissions of the Harquahala generating project are a fraction of existing gas, oil, and coal plants. Reliant states that other potential benefits include a more efficient use of resources and providing customers the opportunity to choose environmentally friendly generating resources.

Residential Consumers

The Arizona Consumers Council states that other potential benefits include benefits from alternative energy fuels and stable companies with long-term reserves could bring price stability.

RUCO states that other potential benefits include the spread of green power and distributed generation. However, competition isn't likely to impact environmental or security issues.

Industrial Consumers

AECC states that other potential benefits include a possible market niche for green power, more efficient plants will over time generally displace less efficient plants.

II. Determination of the Feasibility of Competition.

A. Are the product and geographic markets for the good or service conducive to effective competition or manipulation by a single entity? For example--

1. Are there economies of scale which make it most efficient for the service to be provided by a single company?

Investor-Owned Utilities

APS states that generation services as a whole are not likely to have significant economies of scale. In distribution services there are significant economies of scale, demonstrating natural monopoly features. For aggregation services, some show a constant rate of return, such as power supply acquisition and customer demand services. Other aggregation services, such as customer services, data analysis, and billing, show economies of scale.

TEP states that economies of scale may be achieved in the construction of generating plants, but depends upon the skill of each company. TEP refers to is answers to questions 1.A.2 and 1.A.3 in regard to issues of a single company providing related services.

Wholesale Power Producers

AzCPA states that transmission and distribution can achieve economies of scale over large areas. However, there are no economic reasons for power to be generated by a single entity.

Panda states that it believes competitive markets will exist in Arizona for wholesale generation and ancillary services. PG&E states that for generation services, economies of scale are not a factor. For distribution services there are cases where economies of scale exist. Reliant states that for generation and aggregation services, a competitive market with multiple suppliers is most efficient. For distribution services economies of scale make it conducive to being regulated.

Electric Service Providers

AES states that economies of scale are present in marketing, billing, and customer services but that larger customers are relatively immune to economies of scale.

Electric Cooperatives

AEPCO, Southwest, and Sierra state that a large body of economic thought support offering many utility services most efficiently by a single supplier. The REDCs state that there are economies of scale in the utility distribution system and as the customer base grows, the lower the per customer rates are.

Residential Consumers

The Arizona Consumers Council states that economies of scale exist only if the single utility has the most efficient system and utilizes the most advanced technology.

RUCO states that it cannot answer this question because it does not have sufficient information.

Industrial Consumers

AECC states that generally transmission and distribution services are most efficiently provided by a single company. Competitive retail services are not natural monopoly services, but have important economies of scale.

Utility Investors

AUIA states that generation pricing is plant specific but that some suppliers may have greater buying power and benefit from economies of scale. For billing and metering the UDCs operate the most efficient systems.

> 2. ***Are there economies of scope which make it most efficient for the service to be provided in a bundle with certain other services?***

Investor-Owned Utilities

APS states that it is likely that there will be economies of scope between generating services. Distribution services may have some economies of scope, such as between distribution lines and metering. Aggregation services may also have economies of scope, including billing, data analysis, and customer services. In general the economies of scope are unlikely to be significant enough to overcome the increased efficiency resulting from competition.

TEP states that there are not economies of scope and refers to its answers to questions I.A.2, I.A.3, and II.A.1.

Wholesale Power Producers

AzCPA states that on a retail level there may be some natural bundling of services and that as competition develops economies of scope will grow.

Panda states that that it believes competitive markets will exist in Arizona for wholesale generation and ancillary services. PG&E states that in the current retail price structure it is difficult for ESPs to compete and that Harquahala is looking at multiple options for selling its output. Reliant states that there may be economies of scope and a competitive market with customer choice is the best way of determining if there are.

Electric Cooperatives

AEPCO, Southwest, and Sierra state that many of the rationales for provision of bundled service by a single entity still remain. However, for large customers who have traditionally subsidized other customers, contracts could be negotiated which would be more reflective of the cost of service. The REDCs state that there are economies of scope involved with the utility distribution system.

Residential Consumers

The Arizona Consumers Council states that economies of scope are similar to economies of scale. RUCO states that it cannot answer this question because it does not have sufficient information.

Industrial Consumers

AECC states that there may be economies of scale between services, but that these must be distinguished from vertical market power. The benefits of economies of scope are outweighed by competitive benefits.

Utility Investors

AUIA states that most generation and aggregation services should be bundled in ESP offerings but that metering and billing should remain regulated distribution services.

B. Are or will there be a sufficient number of competitors in each potentially competitive market?

1. Is the product or service one which viable competitors will actually be interested in providing?

Investor-Owned Utilities

APS states that generation, distribution, and aggregation services have been competitively offered to varying extents in other states, resulting in a degree of competition for such services. A variety of factors will influence whether any individual retail supplier will enter a market.

TEP states that experience shows that a variety of entities will enter a newly competitive marketplace, but that companies that may appear to be viable may withdraw from the market. TEP also refers to its answers to questions I.A.2 and I.A.3.

Wholesale Power Producers

The AzCPA states that it is difficult to assess how many competitors are needed to constitute viable competition. Rate freezes and moratoriums have been a large market impediment and the desire to protect consumers has often worked against the desire to deregulate the electric industry.

Panda states that there are a sufficient number of competitors, as evidenced by the number of projects being developed. PG&E states that there is a construction boom in generating capacity in Arizona and that merchant generators also have plants in nearby states.

Reliant states that a well functioning market in combination with appropriate retail market rules will result in a sufficient number of competitors. With the current state of the Arizona market, competition is unlikely to develop for several years. Further, APS should be required to enter only short-term contracts with affiliates, later conducting bidding for longer term contracts.

Electric Service Providers

AES states that there are a viable number of competitors willing to provide service and cites 13 other states with significant amounts of competition.

Electric Cooperatives

AEPCO, Southwest, and Sierra state that there are not a viable number of competitors since electric service providers do not want to serve undesirable loads. The REDCs state that meter installation, meter reading, and data analysis are not viable competitive services and cites the experience of Navopache Electric Cooperative since June 2000.

Residential Consumers

The Arizona Consumers Council states that from recent history it does not appear that all possible suppliers are willing and able to serve all customers. RUCO states that it depends upon the profit margin and that as margins become larger competitors will be induced to enter the market.

Industrial Consumers

AECC states that viable competitors are willing to provide competitive services and cites a recent survey of ESPs in which several indicated they would be pursuing opportunities in Arizona as soon as in 2002. Several DSM service providers are actively providing services in Arizona.

Utility Investors

AUIA states that there are plenty of generators to provide electricity if they can get their product to market.

2. Is the cost of aggregating customers sufficiently small, relative to likely revenues, such that new suppliers will find it profitable to enter?

Investor-Owned Utilities

APS refers to its answer to question 2.2.B(1).

TEP states that the cost of aggregation for large customers is relatively small, but for it does not appear that aggregation of small commercial and residential customers is cost effective.

Wholesale Power Producers

PG&E states that the cost of aggregation can be significant, depending on the rules that are in place for aggregation. Aggregators need to have freedom and flexibility in the products and services they offer.

Reliant states that the cost of aggregating customers is sufficiently small for aggregation to be profitable.

Electric Service Providers

AES states that costs can be high when trying to aggregate residential and small commercial customers, but one possible remedy that has been successful elsewhere is community aggregation programs.

Electric Cooperatives

AEPCO, Southwest, and Sierra state that it is unlikely that aggregation of residential and some commercial customers can be profitable.

The REDCs state that a few large loads in cooperative territories might be targeted by aggregators, but new suppliers won't find it profitable to aggregate other customers. Cooperatives by their nature are aggregating entities.

Residential Consumers

The Arizona Consumers Council states that aggregation will only take place when it is profitable. RUCO states that costs are not likely to decrease unless a large number of residential customers can be aggregated.

Industrial Consumers

AECC states that all obtaining critical mass is a key issue for new ESPs and in that sense all ESPs are aggregators. Aggregation has been successfully undertaken in other states.

Utility Investors

AUIA states that for aggregation, large customers can be aggregated relatively easily, but aggregation of small customers is a significant barrier.

3. **Are there technical, legal, or other barriers to entry in the markets? For example:**

   a. ***Are there legal or technical barriers to the construction of the different types of generation plants by non-utilities?***

Investor-Owned Utilities

APS states that the electric competition rules prohibit incumbent utilities to construct new central station generation outside a non-utility affiliate but otherwise there are no significant legal or technical differences between different types of generating units. Further, it is possible that the need to receive approval for plants over 100 MW under the Siting Act could be considered a barrier.

TEP states that each type of generation has its own technical and regulatory issues and that it does not know of any differences in the standards that must be met by incumbent utilities and ESPs.

Wholesale Power Producers

The AzCPA states that non-utility generators face interconnection and control area barriers. Green power development is usually dependent on statute and methods for recovering costs.

Panda states that there does not appear to be any significant technical, legal, or other barriers to the construction of new generating facilities. PG&E states that the primary barrier for generation for non-utilities is the lack of opportunity to sell output, especially if incumbent utilities self-build facilities, rather than purchasing competitively. Reliant states that no technical barriers exist to the construction of generating units by non-utilities, but transmission and interconnection issues could impact some plants.

Sempra Energy Resources states that non-utility power producers face the same constraints in building generating units as regulated utilities and subsidiaries do and in some cases rules and regulations may encourage the construction and ownership of new generation by non-utilities.

Electric Cooperatives

AEPCO, Southwest, and Sierra state that the Certificate of Environmental Compatibility is a significant legal barrier.

Residential Consumers

The Arizona Consumers Council states that the competitive market has not developed. RUCO states that barriers appear to be transmission ownership and control, transmission availability issues, and lack of standards to manage pricing congestion.

Renewable Energy/Cogeneration Producers

The ACA encourages cogeneration, small power production, and renewables. Distributed generation should be one of the choices available to consumers in a competitive retail electric market. Uncertainty regarding deregulation and electric rates have led to low investment in distributed generation in Arizona. The Commission needs to establish standardized interconnection requirements as well as a more clearly defined application process for distributed generation. The ACA supports competitive bidding and the requirement that 50% of supply be acquired from competitive bidding.

Industrial Consumers

AECC states that there are significant hurdles to bringing a plant on-line, but such hurdles are not unique to non-utilities.

Utility Investors

AUIA states that as you move up the fuel chain it becomes increasingly difficult for new entrants to participate.

b. Is the cost of obtaining licenses, resources, knowledge and employees sufficiently small, relative to the expected revenues, such that new entrants will find the market attractive?

Investor-Owned Utilities

APS states that generally licensing, knowledge, and employee costs for new entrants are similar in Arizona to other parts of the country, although resource costs may be different.

TEP states that given the number of applications for new plants in Arizona, the market appears to be attractive, although it is not clear at this point how many new plants will actually be constructed.

Wholesale Power Producers

Panda states that there does not appear to be any significant technical, legal, or other barriers to the construction of new generating facilities. PG&E and Reliant state that generally these costs are sufficiently small to find the market attractive. Sempra Energy Resources states that before committing to construction in Arizona it determined that these costs were sufficiently small, assuming the competition rules would remain in place.

Electric Cooperatives

AEPCO, Southwest, and Sierra state that it is not certain whether such costs have risen to a point where they would deter market entrants, although there has recently been a sharp downturn in new power plant construction interest.

Residential Consumers

RUCO states that this is a minor issue in comparison to the huge market issues before state and federal regulators.

Industrial Consumers

AECC states that this question has already been answered affirmatively.

Utility Investors

AUIA states that as you move up the fuel chain it becomes increasingly difficult for new entrants to participate.

C. ***Is it necessary for the product or service to be provided by a single regulated company to assure reliability and safety, or can multiple companies provide the service subject to reliability and safety rules?***

Investor-Owned Utilities

APS states that generally the movement toward multiple companies offering products and services can impact safety and reliability. A significant weakness of the competition rules is that no party is responsible for supply reliability to retail customers. Control over reliability is more limited in a restructured competitive market than in a market where a vertically integrated utility coordinated the planning and operation of its system.

TEP states that it is not necessary for generation to be provided by a single regulated entity to ensure reliability and safety, since all market participants are required to meet reliability and safety criteria set out by a number of independent oversight entities.

Wholesale Power Producers

The AzCPA states that it is necessary for the load serving entity to provide reliable delivery of electricity over its wires. Reliability and safety can be offered by multiple companies. It is important to have clear rules where market participants know their responsibilities.

Panda states that it is not necessary for products and services to be offered by a single entity and such products and services are being offered today by multiple entities. It is critical for competing suppliers to accept and operate under a set of operating rules to ensure safety and reliability.

PG&E states that for distribution related functions a single entity is necessary, but that for competitive generation, experience has shown that multiple companies can provide service reliably and safely. Reliant states that multiple companies can provide generation and retail services reliably and safely. Sempra states that all suppliers, whether non-utility or utility, are subject to the same safety rules.

Electric Cooperatives

AEPCO, Southwest, and Sierra state that integrating multiple suppliers significantly increases the level of complexity and regulation and ensuing costs. The REDCs state that the utility distribution system should be provided by a single regulated entity.

Residential Consumers

The Arizona Consumers Council states that it is theoretically possible for products and services to be offered by multiple companies, but to date it has not been proven. RUCO cites the Federal Energy Regulatory Commission's (FERC) belief that a competitive system must have an independent control operator.

Industrial Consumers

AECC states that reliability and safety is provided through control area operations for transmission and ancillary services and through the UDC at the distribution level, neither of which is competitive.

Utility Investors

AUIA states that distribution services must be provided by incumbent utilities to avoid compromising reliability and creating customer confusion. Generation and aggregation services can be provided by multiple companies of there are clear and enforceable rules and if aggregators are required to be certified by the Commission.

D. For customers, is the cost associated with learning how to shop and actually shopping sufficiently small, relative to the expected benefits, that customers would want to shop.

Investor-Owned Utilities

APS states that it largely depends upon the individual customer, although for large customers it is more likely that the costs of shopping are outweighed by the benefits. For small customers, because electricity bills have been declining in recent years, it is less likely that small customers will want to shop for electricity.

TEP states that it believes the cost of shopping for residential and small commercial customers has been an impediment to their participation in the competitive market. Large commercial and industrial customers have more resources to evaluate the benefits they would receive from participating in the competitive market.

Wholesale Power Producers

The AzCPA states that information is the key in educating customers and that customers have become much more skilled at buying a variety of products. Part of the product competitors must provide to customers is education about the products the competitor is selling.

Reliant states that the costs of education and shopping are low enough that it is worthwhile for customers to shop if there are appropriate market rules and a well functioning wholesale market.

Electric Cooperatives

AEPCO, Southwest, and Sierra and The REDCs state that the risks and costs of shopping are high enough to deter many residential and commercial loads from shopping.

Residential Consumers

The Arizona Consumers Council states that choice is not sufficient, but consumers must be assured of reasonably stable prices. So far in states with competition, the market is not robust and consumers refuse to switch or prices are low enough that they don't bother to switch.

RUCO states that it depends on available technology and to cost of consumers' time.

Industrial Consumers

AECC states that the cost of learning how to shop and shopping is sufficiently small and that generally more sophisticated customers will be the first to move to direct access.

Utility Investors

AUIA states that unless customers are upset and dissatisfied, few will shop for alternative providers. An AUIA survey found that no customers will switch for less than 10 percent savings and many would not switch for less than 20 percent savings.

III. Relationship of the Current Regulatory Regime to Competition

A. For each potentially competitive product or service, how does current state and federal regulation foster or inhibit (a) retail competition and (b) wholesale competition?

Investor-Owned Utilities

APS provides the following examples of federal legislation and regulatory actions that foster wholesale competition: the Energy Policy Act of 1992 (EPACT), FERC Order 592, FERC Order 888, FERC Order 889, FERC Order 2000, the EPA's market-driven air quality program, and Department of Justice and Federal Trade Commission guidelines for analyzing mergers. Examples of federal legislation and regulatory action that inhibit wholesale competition are the Public Utilities Holding Company Act of 1935 (PUHCA) and price cap regulation. APS states that Commission rules foster retail competition by providing for the licensing and regulation of ESPs, structural separation of generation from UDCs, open access at the retail level, and development of green power. State regulations or policies that deter retail competition are: not allowing load profiling for small commercial customers, long processing time for new ESP applications, no complaint resolution process before the Commission designed for competitive ESPs, and overly strict "need" analysis in siting power plants or transmission lines.

TEP believes that it is not possible to provide a meaningful description of the impact of federal and state regulation on retail and wholesale competition of generation products and related services because there is no discernible or uniform policy on electric competition.

Wholesale Power Producers

AzCPA states that the current Electric Competition rules will produce the intended result of reliable electric service for standard offer customers. Panda states that the rules are a crucial component in the transition to a competitive electric generation market and that 1606(B) is one of the most important sections of the rules. Removing the requirement would undermine the incentive for competitive wholesale generators to provide needed power. Panda further states that the current federal regime seeks to foster wholesale competition by ensuring that transmission providers treat non-utility suppliers comparably to how those transmission providers would treat themselves and their affiliates.

PG&E states that the Commission's requirement for competitive bidding encourages wholesale competition and can promote retail competition. Several merchant generation facilities have been or are being built in anticipation of selling power in a competitive market that, if sufficiently robust, can lead to a viable, competitive retail market.

Reliant states that current state regulations inhibit retail competition by creating market rules that favor the incumbent provider and provide inadequate incentives for entry by competitive service providers. Stated federal policy is to foster competitive wholesale markets, but recent FERC actions imposing price caps and other administrative controls are undermining the functioning of those markets. Implementation of the Arizona competition rules will foster competitive wholesale markets.

Sempra states that Commission rules and Federal regulation have been strongly encouraging wholesale competition. The Commission's requirement for competitive bidding has dramatically facilitated the entry of new wholesale power providers in Arizona. The Energy Policy Act of 1992 removed independent power producers from PUHCA's ownership restrictions and provided FERC with authority to order transmission access and wheeling. FERC's rule 888 addressed equal access to the transmission grid.

Electric Service Providers

AES states that the potential savings from competition have been limited for Arizona customers because of the requirement for customers to pay off the utilities' stranded costs from past investments in power plants through a competition transition charge (CTC). The primary reason for the failing retail market in Arizona is that administratively set shopping credits are not calibrated to the market price for electricity. But in TEP's area, it is difficult for customers to make a price comparison because of the way the shopping credit is recalculated quarterly.

Electric Cooperatives

AEPCO, Southwest, and Sierra state that the Commission's legal workgroup had authored a volume of work which in large part answers these questions. AEPCO, Southwest, and Sierra further state that the Commission cannot authorize market-based rates and individually negotiated outcomes without amendments to Article 15 of the Arizona Constitution.

Residential Consumer Advocates

Arizona Consumers Council states that the wholesale market is Federal responsibility. The retail market may work if wholesale market becomes truly competitive. With fewer producers and sellers, the market is ogopolistic. Transition from monopoly to competition has not worked.

RUCO states that retail and wholesale competition depend on FERC establishing a workably competitive wholesale market system for dispatching energy and ancillary services at marginal variable cost. The western states also need to have an installed capacity market, if generation is deregulated, including a required reserve margin. Federal and state regulations have also not yet created a system for price-responsive demand.

Industrial Consumers

AECC states that Federal regulation is generally neutral about retail competition for generation services, unless a state adopts retail access; then Federal regulation supports retail competition, with FERC requiring transmission access to be non discriminatory. Arizona state regulation has been highly favorable for retail competition. Federal policy is generally supportive of wholesale competition. The state role is extremely influential with respect to siting new generation.

Environmental/Energy Efficiency Advocates

The LAW Fund states that current Commission regulation promotes the development of renewable energy resources through the EPS. This policy is or should be independent of retail electric competition. Several aspects of the Commission's regulations do deter renewable energy, such as inappropriately low buy-back rates paid to qualifying facilities because buy-back rates are set on avoided conventional generation costs. Also, the Commission should ensure that the utilities have uniform net metering tariffs and implement them properly. To promote distributed generation, the Commission may need to start a rulemaking process on interconnection. The Commission currently does not emphasize demand-side management and energy efficiency (DSM/EE) programs. The Commission could promote cost-effective DSM/EE by requiring utilities to implement installation, rebate, and market transformation programs.

Utility Investors

AUIA states that FERC's open access orders enable wholesale competition. The Commission's rules enable retail competition in generation and aggregation, although the certification process discourages the entry of new ESPs, and there is too little incentive in the generation credit to promote competition.

B. How can the Commission protect Arizona customers from the risks of competition while promoting competition?

Investor-Owned Utilities

APS questions whether the Commission should protect customers from the risk of competition. However, the Commission should take the following steps: (1) adopt or clarify anti-slamming and anti-cramming rules, truth-in-advertising and disclosure rules, and credit-worthiness and bonding requirements; (2) continue consumer education; (3) allow development of competitive retail markets without "command and control" regulation; (4) protect financial health of utilities that have the obligation to serve; (5) promote construction of infrastructure; and (6) continue to provide standard offer default service.

TEP notes that the Electric Competition Rules and related Commission orders currently provide substantial protection for Arizona consumers. The Commission should continue to support workshops and working groups designed to effectively implement and foster consumer protection.

Wholesale Power Producers

AzCPA states that consumers benefit most from competition when a load-serving utility is compelled to bid for the lowest cost power from a liquid wholesale market and pass those prices through to the retail consumer. AzCPA further states that a merchant generator and its shareholders, not consumers, bear the risk of excess capacity. The Commission should encourage wholesale market development and competition to reduce the risks to consumers.

Panda states that the Commission's rules are designed to protect consumers while promoting competition in Arizona. The Commission should give the rules every opportunity to work as intended.

PG&E states that the Commission can minimize the risk of generation price volatility for standard offer by encouraging utilities to establish fixed price terms for contracts, including competitively bid contracts. The utility would contract for a portfolio of contracts (baseload, intermediate, peaking) with various duration (one month, one year, ten year, etc.). PG&E further states that market participants must be confident that once entities have competed in the bid process and a winning bidder (s) is selected, that the selection will stand.

Reliant states that the Commission can protect consumers with respect to generation by ensuring the existence of a well-functioning wholesale market and proceeding with implementation of the competitive resource procurement process. The Commission can protect consumers with respect to retail services by establishing effective retail competition rules including customer protection and ESP certification procedures.

Sempra states that the key risks are price level and price volatility. Competitive bidding will establish the proper price level. Price stability will be offered through long-term contracts. Prices offered by competitive wholesale power suppliers can be hedged with financial instruments. Sempra further states that the retail consumer would be insulated from power supply risks.

Electric Cooperatives

AEPCO, Southwest, and Sierra state that responds that the Commission cannot do both nor should it promote competition by attempting to structure a marketplace, disadvantage existing utilities, and advantage new market entrants. In addition, there are sufficient antitrust rules to deal with anti-competitive behavior, and FERC regulates transmission access and anti-competitive conduct.

Residential Consumer Advocates

Arizona Consumers Council states that regulation inhibits competition, but competition tends to sacrifice safety, reliability, and reserves. Rules must assure reliability, safety, and reserves, and each supplier must participate in this area.

RUCO states that risks of competition include dysfunctional wholesale markets, market power pricing, insolvent electricity providers, insufficient supplies, and inelasticity of demand to mitigate price spikes. In addition, system operators might become captive to independent generators and complacent about market abuse or reliability problems. The Commission might protect Arizona consumers through close collaboration with FERC, provided FERC has established a workably competitive, well-regulated wholesale market.

Industrial Consumers

AECC states that the current transition plan has achieved this objective so far by offering customers a choice of standard offer service at regulated prices or Direct Access service at market prices. APS' proposal of a long-term contract with an affiliate at cost-based rates would insulate standard offer customers from extraordinary price spikes, but those customers would not receive the benefit of lower generation prices when supply is plentiful. AECC believes that the amount of supply for standard offer service should be set at the maximum level that is in the public interest.

Utility Investors

AUIA states that the Commission's Competition Rules may expose the utility companies and their customers to unacceptable risks with regard to electric supplies and prices. It is possible for the Commission to bifurcate the market by load size or adopt a phased approach as proposed by the APS variance request.

C. ***How have the interim rate reductions for customers receiving standard service affected the ability or desire of generation suppliers to compete in Arizona retail markets?***

Investor-Owned Utilities

APS does not believe that the rate reductions have had any long-term impact on the competitive retail market for ESPs. APS further states that the rate reductions have not impacted the wholesale generation market because a wholesale supplier in an efficient market would be indifferent as to whether it sold to APS, an ESP, or another participant.

TEP believes that the interim rate reductions had a negligible effect on the entrance of new generation suppliers into Arizona because potential competitors react to market price signals not to the utility's cost-based rates.

Wholesale Power Producers

Panda states that it is not the standard offer rates that dictate whether wholesale competition is viable, although a competitive wholesale market will have a positive impact on retail rates. PG&E states that the rate reductions have not had any effect on its incentive and desire to supply the utilities affected by the rate reduction agreements. Reliant states that a competitive wholesale market can exist with or without a competitive retail market. Interim rate reductions make it more difficult for ESPs to compete against the incumbent.

Electric Service Providers

AES states that the interim rate reductions have negatively impacted the retail market because the rate reduction serves to further separate the shopping credit from the market price for electricity.

Electric Cooperatives

AEPCO, Southwest, and Sierra believe that interim rate reductions are not the cause for the failure of generation suppliers to compete in Arizona retail markets. Competitive generators could realize greater profits for far less effort by selling exclusively in the wholesale market. Many still refuse to provide any product but hour ahead and other short-term sales in the wholesale market. The REDCs state that Navopache is the only REDC which has a stranded cost settlement, and this settlement resulted in permanent rate reductions.

Residential Consumer Advocates

Arizona Consumers' Council states that it is unknown what market decisions any one company makes and why. Several have left the Arizona market. RUCO states that the rate reductions probably have had some effect. The difference between current cost-of-service rates and market rates under perfect competition is probably minimal. Few retail providers could compete for even the largest retail customers under such circumstances, where the retail margin might be only 1-2 mills per kWh.

Industrial Consumers

AECC supports the standard offer rate reductions in the Settlement Agreements and opposes keeping standard offer rates artificially high to induce competition. Given the high wholesale prices in 2000 and early 2001, the rate reductions had no material impact on whether a customer opted to remain on the standard offer.

Utility Investors

AUIA states that it is doubtful that the rate reductions have had a material effect on competitive retail offerings.

D. Do Commission policies or legal requirements ensuring that utilities recover investments from ratepayers affect the prospects for competition in any market for which competition otherwise would be possible?

Investor-Owned Utilities

APS states that the regulated utilities' opportunity to recover non-competitive investments would not affect the provision of competitive services by ESPs. The prospects for new entry into a competitive market are more affected by the rate-regulated utility being the lowest-cost supplier because of economies of scale or scope.

TEP responds "no" because stranded cost recovery is based on above-market generation costs.

Wholesale Power Producers

AzCPA states that it depends on the structure of the recovery of the investments. For example, if stranded costs recovery were charged to all customers as a flat fee, then there would be little impact on the market. Panda states that stranded cost recovery under the rules can become an impediment to a fully competitive market, to the extent such recovery reduces a party's incentive to seek competitive supply.

PG&E states that stranded cost recovery can impact the robustness of short-term retail competition. In the case of APS, both the accelerated amortization of regulatory assets and the low level of the generation credit are contributing factors to the inability of ESPs to offer significant savings to customers. This situation has contributed to several potential ESPs withdrawing from Arizona.

Reliant states that a policy that ensures recovery of past utility generation investments from ratepayers does not necessarily impact the prospects for wholesale competition. Depending on the design of the CTC mechanism, recovery of past utility generation investments can impede the functioning of the competitive retail market. Commission policies should be designed to foster reliance on competitive wholesale markets so that future investment risks are borne by shareholders and not ratepayers.

Electric Service Providers

AES responds "yes" but it is the manner in which the fee is structured that can be detrimental to the retail market.

Electric Cooperatives

AEPCO, Southwest, and Sierra state that stranded cost recovery can affect the market in the short run.

Residential Consumer Advocates

Arizona Consumers Council states that if consumers only see increased prices due to stranded cost recovery, they will be less likely to move as real benefits will not be perceived. RUCO responds "no" so long as stranded costs are set properly.

Industrial Consumers

AECC states that stranded cost charges create a barrier to direct access service, but considers this issue to have been resolved within the Settlement Agreements, which provide for payment and termination of stranded cost charges.

Utility Investors

AUIA states that stranded cost recovery may slow the rate of competition, but it is impossible to measure against the recent market volatility.

E. Does continuing utility control of depreciated generation assets affect the ability of competing suppliers to enter retail markets?

Investor-Owned Utilities

APS and TEP state that utility control of depreciated assets does not affect the ability of competing suppliers to enter retail markets. APS further states that the presence of those generating assets in the marketplace, regardless of ownership, will affect the decisions of potential competitors with respect to market entry.

Wholesale Power Producers

The AzCPA states that it does. Allowing utilities to recover investments from ratepayers through a ratebase mechanism will adversely skew the market in favor of the utility generation and will not result in the lowest costs to customers. Panda states that the problem would be mitigated if the assets are taken out of ratebase; the utility is required to procure all of its needs at arm's-length in the competitive market or through bilateral, negotiated agreements; and the transmission system is made available on an equal basis to the utility generators. PG&E responds that it may, depending on how that control is exercised. Reliant states that the ability of competing suppliers would be negatively impacted if generation assets remain in the regulated utility. The preferable market structure is where competitive aspects of electric service are separated from monopoly services.

Electric Service Providers

AES responds "yes" and believes that if utilities are allowed to retain their depreciated generating assets, they should only be used to serve core customers (residential, small commercial and industrial customers having less than 50 kW demand), because these small customers deserve a known, fixed default electricity price. AES further believes that larger customers should be required to procure their electricity supply from the open market, because those customers have the sophistication and resources to look after their own supply requirements.

Electric Cooperatives

AEPCO, Southwest, and Sierra respond "not necessarily" because any prudent competing retail supplier would purchase from both merchant plants and older generation plants as part of its resource portfolio.

Residential Consumer Advocates

Arizona Consumers Council states that if the depreciated asset can produce energy cheaper than new suppliers, then prices charged by the utility would be less expensive, and there would be no reason to switch. RUCO responds that it does but only if these assets give utilities market power to underbid a competitor due to excessive stranded cost recovery. But this is true whether the incumbent utility or another supplier controls supplies at the margin.

Industrial Consumers

AECC states that during periods of high market prices, control of depreciated generation assets may make it possible for a utility to sell below market prices without incurring losses. However, the concept of stranded cost presumes that utility assets would be unable to compete at low market prices.

Utility Investors

AUIA states that it would have a negative impact on potential competitors if the Commission's rules contemplated continuing utility control of major generation assets, but the rules require separation of generation from the UDC.

F. ***How does current Commission regulation promote or deter the ability of (1) renewables, (2) distributed generation, and (3) energy efficiency and demand side management to compete with traditional generation resources?***

Investor-Owned Utilities

APS and TEP state that the Environmental Portfolio Standard (EPS) promotes the ability of renewable energy resources to compete with traditional resources.

APS states that the Commission is working on interconnection standards and processes for distributed generation, which may aid the deployment of distributed generation resources. TEP states that current regulatory orders will not affect the decision of customers to select distributed generation options, but that appropriate tariffs for distributed generation are needed. APS also states that when the EPS was passed, the Commission elected to cease significant funding for DSM programs. TEP states that Commission mandates for DSM spending promote competition between DSM technologies and traditional generation resources, but that DSM has evolved into a competitive service provided by energy service companies.

Wholesale Power Producers

Reliant states that the Environmental Portfolio Standard promotes investment in renewables. Reliant is not aware of any action to implement the suggestions provided in the Final Report from the 1999 docket on distributed generation. The Commission should promote competitive wholesale and retail markets so that demand-side management can compete with traditional resources.

Electric Cooperatives

The REDCs state that the Environmental Portfolio Standard and corresponding surcharge promote the ability of renewable and distributed generation to compete with traditional generation resources. The REDCs believe in the value of allowing customers to choose these programs rather than mandating subsidies. The market place will determine which energy efficiency and DSM programs compete with traditional generation resources.

Residential Consumer Advocates

Arizona Consumers Council states that if the Commission does not encourage renewables, etc., those energy sources will not be able to compete with traditional sources that are already not paying their fair share. The Commission must work with these producers to insure that all new energy sources become part of the mix and pricing moves to cost.

Industrial Consumers

AECC states that with regard to distributed generation, the Commission should ensure that standby service rates and interconnection requirements are reasonable.

Environmental/Energy Efficiency Advocates

SWEEP states that current Commission regulation promotes renewables through the Environmental Portfolio Standard. The EPS should remain in place even if the Commission decides to suspend or abandon retail electric competition. In addition, the Commission should review buy-back rates and ensure consistent and effective net metering tariffs. The Commission should increase support for distributed generation with interconnection rules to ensure a reliable and safe grid without erecting undue barriers to distributed generation. The Commission should require a distributed resources plan as part of the Ten-Year Plans. Current Commission regulation provides little support for DSM and energy efficiency programs. Energy efficiency programs supported by ratepayer funding are needed for reduced societal costs for electric energy services, reduced electricity market prices, reduced customer bills, less environmental damage, and a more reliable electric system.

Utility Investors

AUIA states that widespread use of distributed generation would require rulemaking and tariff filings to clarify numerous issues like planning and notification, access to the grid, security, standby pricing, and potential stranded costs.

Renewable Energy/Cogeneration Providers

ACEIA states that the EPS balances the need for sound environmental policy with sensitivity to energy users' concerns, but that the rule should be applied to all Arizona utilities. The EPS should be retained regardless of actions on the overall issue of electricity restructuring. The Commission should proceed with distributed energy rulemaking, including rate reform that reflects time and day usage, interconnection, net metering, and reasonable transmission service fees. ACEIA believes that the Commission's lack of access to utility planning information under competition limits the Commission's ability to carry out a planning oversight function.

G. What are the risks of moving to a regime of retail competition for each product or service and what are the methods for managing those risks?

Investor-Owned Utilities

APS provides the risks and methods for managing risks for several products or services in tabular format. See Table 2.3G on pages 30-32 of APS' responses.

TEP believes that the risks of moving into a competitive generation market include counterparty payment and performance issues. A scenario where utilities are required to purchase most or all of their resources from other participants in the wholesale market exacerbates the risks.

Wholesale Power Producers

PG&E states that there is sufficient generation coming on-line to meet supply. This competition will encourage the competitive purchase of generation for which consumers will be the ultimate beneficiaries. Reliant states that the competition rules form a sound basis for the transition to fully competitive electric markets, and therefore the risks of a California-style meltdown have been effectively managed. The Commission should proceed with the competitive resource procurement process to ensure a well-functioning wholesale market. With respect to retail services, the Commission should ensure that the shopping credit is sufficient, require utilities to provide better information related to retail competition, and require utilities to unbundle their standard offer tariffs.

Electric Service Providers

AES states that Arizona should not force retail customers into the spot market. The risk of price volatility to retail customers can be reduced when utilities are allowed to contract for power in the forward markets for customers under 50 kW. Price volatility for larger customers is managed on a customer-by-customer basis.

Electric Cooperatives

AEPCO, Southwest, and Sierra and the REDCs state that rural areas are at particular risk because they are not desirable markets generally. The loss of certain desirable loads drives up costs for remaining customers. AEPCO, Southwest, and Sierra further state that managing those risks requires a recognition of these issues and special treatment concerning rural areas. The REDCs believe that retail electric competition will not benefit rural Arizona and will only bring rate instability to these areas. There is little that the Commission can do to minimize these risks without re-regulation.

Residential Consumer Advocates

Arizona Consumers Council states that risks are higher prices, less reliability, safety concerns, and dropping certain consumers from the market. Bankruptcy of certain companies will put the system and consumers at risk. Without a regulated back-up system, we could all be in trouble.

RUCO states that a power pool might be one way to manage risks, but the West is not ready for such a concept. Another method for managing the risks is to maintain a regulated price cap in the form of the standard offer, at least for small customers. A price cap should be re-done periodically on a cost-of-service basis.

Industrial Consumers

AECC refers to its response to Question No. III.B. for its answer to this question.

Utility Investors

AUIA states that the risk for generation services is that the utilities and their customers will be exposed to inadequate or unreliable electricity supplies, prices that are higher than their own generation costs, and higher costs than they can recover under current retail rates. The risks may be mitigated by bifurcating the market, adopting a new phase-in schedule, or by granting the variance requests.

H. ***If the current regime is not conducive to retail competition for a particular product or service, what actions should the Commission take to promote its success in the future? Specifically --***

1. ***Should the Commission require existing utilities to procure particular products or services from unaffiliated competitors?***

Investor-Owned Utilities

APS and TEP state that utilities should procure products and services from whoever offers the best total value.

Wholesale Power Producers

AzCPA states that the single most important first step to ensuring Arizona consumers benefit from competition is requiring incumbent utilities to procure power from lowest cost merchant generators, affiliated or unaffiliated. Panda states that the Commission should continue to require existing utilities to procure power and ancillary services from the competitive market. PG&E urges the Commission to fully implement the requirement that incumbent utilities procure at least 50 percent of their needs for standard offer from the competitive market. Reliant states that if an affiliate provider participates in the bidding process, an independent third party should evaluate the bids to determine the selected provider(s). Sempra responds that purchases need not be limited to non-affiliates as long as the Commission has affiliate rules in place that require the utilities not to favor their affiliates.

Electric Service Providers

AES states that large customers must be responsible for procuring their own supply needs. During a transition period, the threshold defining core and non-core can be set at a higher consumption level. AES further states that utilities' generation rates must include all of their retail costs.

Electric Cooperatives

AEPCO, Southwest, and Sierra and the REDCs respond "no" for both legal and practical reasons. Utility micro-management is neither permissible nor desirable.

Residential Consumer Advocates

Arizona Consumers Council states that the Commission must be an active participant if it wants a competitive market. It will require a number of steps and an ongoing monitoring system, to insure those products and services are purchased at the lowest possible price.

RUCO responds that it should not if the utilities have to donate ancillary services to keep the system going. As demand grows, a utility could supply standard offer service from the competitive IPP market on a least cost basis. Also, when wholesale market prices are too high, the utility might be required to build new resources under a regulated return.

Industrial Consumers

AECC states that the current regime is not an obstacle to retail competition for generation service; the obstacle has been high wholesale prices. AECC further states that the provider of standard offer services should not receive any preferential treatment in receiving transmission and distribution service compared to providers of generation service to Direct Access service.

Utility Investors

AUIA states that the question highlights the conundrum facing the Commission and its regulated utilities.

> *2. Are utilities taking steps that will make competition more difficult down the road (e.g., retail marketing, internal restructuring, entering into agreements to avoid customer self generation)? If so, identify those steps and how the Commission should proceed.*

Investor-Owned Utilities

APS and TEP do not believe that utilities are taking any steps that will make competition more difficult in the long run.

Wholesale Power Producers

AzCPA states that the APS variance request is an obvious attempt to make competition more difficult. All competitors should be on a level playing field. Panda stated that, specifically, APS and TEP have requested that they be freed of their obligation to competitively procure power to serve standard offer customers. Panda further states that the Commission should deny the requests. Reliant responds that the APS variance request would undermine both wholesale and retail competition. The Commission should deny the request and proceed with implementation of the current competition rules. Sempra states that the APS variance request appears to be trying to lock in some high prices before competition hits. The Commission should deny the request.

Electric Cooperatives

AEPCO, Southwest, and Sierra and the REDCs state that the cooperatives are not taking any such steps.

Residential Consumer Advocates

Arizona Consumers Council states that those answers are internal company decisions. The Commission must make that determination in its oversight of the company in question.

Industrial Consumers

AECC is not aware of any steps being taken by utilities that would make competition more difficult, except for occasionally adopting postures that undercut the AISA.

3. ***Are utilities entering into long-term contracts with existing customers? If so, how do they affect prospects for future retail competition? Should the Commission allow them?***

Investor-Owned Utilities

APS points out that R14-2-1604(C)(6) limits the ability of utilities to enter into long-term contracts with customers, but APS would support modifying the rule to allow for long-term contracts, subject to Commission approval. TEP states that it enters into contracts at the customer's request and with Commission approval.

Wholesale Power Producers

AzCPA states that it is concerned that other competitive retail suppliers of electricity do not have the same access to these consumers as does the utility. Reliant states that any attempts by utilities to enter into long-term contracts with existing customers will negatively impact the prospects for future retail competition. If such contracts are permitted, the Commission should ensure that remaining customers are not adversely impacted by any discounts provided to the customer receiving the long-term contract.

Electric Service Providers

AES assumes that the Commission has not allowed these types of contracts to be executed. Utilities should not be able to enter into bilateral agreements with customers.

Electric Cooperatives

AEPCO, Southwest, and Sierra state that long-term contracts are necessary in certain situations for a variety of reasons. They are often with larger, more sophisticated customers which have other options. The Commission should allow them. The REDCs state that they must be allowed to enter into long-term contracts in order to recover the cost of the distribution system that is dedicated to a contract customer. Otherwise, the remaining customers will pay for the dedicated facilities. In addition, those customers are sophisticated buyers and can balance benefits against risks.

Residential Consumer Advocates

Arizona Consumers Council states that the question revolves around the issue of the price paid under the long-term contracts and if those prices will rise or fall in the future.

Industrial Consumers

AECC is not aware of new long-term contracts between customers and utilities under the Commission's jurisdiction. SRP is offering 3 and 4-year contracts to larger customers. AECC supports the existing Competition Rules that allow long-term contracts under certain conditions.

4. Should the Commission consider instituting competition for billing and metering services even if retail generation competition is premature?

Investor-Owned Utilities

APS and TEP oppose competitive metering services without a UDC or ESP to control it. APS further states that mandatory outsourcing by the utility would likely result in higher costs due to the loss of scale economies.

Wholesale Power Producers

AzCPA states that the Commission should gather comments and information regarding competition in these areas. It may be appropriate to have competition in metering regardless of the state of competition in other facets of electricity service. Reliant states that billing and metering services can be competitive given fully functional wholesale and retail competitive markets. Rules encouraging competitive metering, including real-time meters, support the development of the market because it provides consumers with the ability to respond to price signals.

Electric Cooperatives

The REDCs believe that the Commission should not consider instituting competition for billing and metering services even if retail generation competition is premature.

Residential Consumer Advocates

Arizona Consumers Council replies only if consumers can be assured that such practices are beneficial to them. Choice is only one aspect of competition.

Industrial Consumers

It is AECC's understanding that billing and metering are already competitive in accordance with the Electric Competition Rules.

Utility Investors

AUIA does not understand what this would accomplish for the consumer.

IV. Retail Generation Competition

A. Regarding each identifiable generation product --

1. Identify with particularity any defects in the wholesale market structure affecting Arizona.

Investor-Owned Utilities

APS states that there is insufficient competing generation not already committed to other loads, there are load pockets where local generation must run, and there is not yet an RTO. TEP states that there are some transmission constraints that restrict some generation transfers.

Wholesale Power Producers

AzCPA and PG&E state that the primary problem facing the wholesale market today is the lack of a functioning RTO. Panda states that the wholesale market structure in Arizona would be competitive both in theory and in fact if allowed to develop in accordance with Commission and FERC rules. Reliant states that deficiencies exist in the wholesale market structure including the lack of an RTO, FERC price caps, no competitive market for ancillary services, and regulatory uncertainty. Sempra responds that the benefits available to consumers by obtaining power from alternative suppliers is dependent on sufficient transmission capacity. The Commission should continue to support transmission upgrades.

Industrial Consumers

AECC states that Arizona utilities have been buying and selling power in the western wholesale market for a considerable period of time, and the market has worked well, except for 2000-2001. FERC found that during 2000-2001 generators accrued considerable market power that was used to send wholesale prices sky-high. Wholesale prices have stabilized considerably as new generation has come on line, demand has softened, gas prices have come down, and purchasers have used forward markets to secure resources.

2. Are there an adequate number of competitors to sell in Arizona to make the product sufficiently competitive? How many sellers are there?

Investor-Owned Utilities

APS states that the large number of wholesale suppliers and traders in the Western wholesale market means that wholesale power is competitive in Arizona. APS lists 12 suppliers physically located in Arizona and at least 5 suppliers with plants under construction. In addition, there are dozens of traders and power marketers. None of the merchant generators are retail suppliers. TEP states that there is a limited number of retail competitors in Arizona, but that there are 200 WSPP members that are providers of wholesale generation.

Wholesale Power Producers

AzCPA responds "yes" because it is possible that resources outside of Arizona would bid. Although it is difficult to assess how many sellers will bid, similar solicitations in other states resulted in many offers. Panda states that there are over a dozen potential new entrants to Arizona's wholesale market at various stages of developing new supply. In addition, two of the most active trading hubs, Palo Verde and Mead, are directly linked to Arizona's market, and traders throughout the WSCC region actively buy and sell wholesale products in all time frames at these locations.

PG&E states that there are a sufficient number of market participants and that it is quite possible that generators from outside Arizona will bid. It is also likely that bids will be received from projects not yet under construction as was the case in Colorado for all of the more than 50 bids received in 1999 (12 were selected and are now in various stages of construction).

Reliant responds "yes" provided that the Commission proceeds with its rules requiring the utilities to competitively procure generation resources. Announced projects, if completed, will add more than 12,000 MW of new capacity to Arizona's wholesale market by 2006. This is more than double APS' current generating capacity.

Electric Cooperatives

AEPCO, Southwest, and Sierra and the REDCs state that there are a number of competitive plants being built or planned. Whether it is an adequate number depends on a variety of factors including demand, actual completion of plants, and sales and operational strategies.

Residential Consumer Advocates

RUCO responds "no."

Industrial Consumers

AECC states that a large number of players can reach the Arizona market because Palo Verde is the largest trading hub in the western United States. The prospects for competition improve further as new generation is added to the region by independent generators. AECC expects that ESP interest in Arizona will improve with a return to more attractive wholesale prices and with stranded cost charges disappearing from most of the state by the end of 2004.

> *3.* ***How have mergers and consolidations in the industry affected the competitiveness of the product in the region at the wholesale and retail levels?***

Investor-Owned Utilities

APS states that it is unlikely that mergers will lead to noncompetitive wholesale market conditions in the foreseeable future. TEP is not aware of any mergers or consolidations that have had an effect on the competitiveness of wholesale generation in Arizona.

Wholesale Power Producers

Reliant states that mergers and consolidations are an inevitable part of the industry's transformation and have not had a negative impact on wholesale or retail competition.

Industrial Consumers

AECC states that the effect of utility mergers is that ownership of IOU power generation capacity is becoming more concentrated, but AECC observes that with the influx of independent generators, the number of players on the regional scene appears to be increasing.

> *4.* ***Are competitors building new generation able to price their generation at rates competitive with existing generation?***

Investor-Owned Utilities

APS states that the long-run marginal cost of new natural gas-fired merchant capacity is likely above the blend of the costs reflected in APS proposed purchased power agreement. TEP believes that ESPs should be able to price their generation competitively under current gas prices.

Wholesale Power Producers

AzCPA believes that new generation is able to compete with existing generation. APS needs to accept competitive bids and choose the package that is best for Arizona consumers. If the bids do not meet price or reliability needs, then the state can further pursue APS' proposal. Panda states that its generation facility will be able to offer competitive prices relative to existing generation resources, as long as there is an open, transparent marketplace.

PG&E responds "yes" but some of the older, less efficient plants are protected from having to compete with new generators during peak hours when the urban load pocket is in effect. Over time, transmission enhancements should remove this condition. Competitive bidding is the best way to determine whether or not new generation is able to compete.

Reliant states that the best way to determine whether rates are competitive is to conduct the RFP required by the competition rule. The Commission should require APS to accept competitive bids and to choose the lowest economic cost resources. Sempra responds that new generation under construction has a lower heat rate than older units, thus operating with less fuel per kWh produced. This enables new generation to compete with older generation on price and environmentally.

Electric Cooperatives

AEPCO, Southwest, and Sierra refer to their response to Question No. III.E. for their response to this question.

Industrial Consumers

AECC states that in a competitive market, competitors will have no choice but to sell at the market-clearing price.

> 5. ***How has the Independent System Administrator affected the success of (a) retail competition and (b) wholesale competition?***

Investor-Owned Utilities

APS states that the AISA has acted as a transitional organization to an RTO, has established Direct Access protocols, and has made adequate transmission capacity available to ESPs to serve retail loads. APS further states that an RTO will be necessary to further develop competitive wholesale and retail markets in Arizona.

TEP states that the AISA-established protocols that all Direct Access Scheduling Coordinators and utilities are to follow have provided a sufficient basis for competition to occur, but that the AISA has had no effect on wholesale competition.

Wholesale Power Producers

AzCPA states that it will be the state's regulatory policy such as the Electric Competition Rules that will have the most impact. AzCPA further states that retail access will not reach its full potential for benefits without nondiscriminatory open access to transmission and that access cannot exist without an independent agency. Panda states that the AISA has had no significant effect on competition in Arizona. Panda further states that the AISA Protocols provide an invaluable mechanism for addressing transmission access issues and resolving disputes between the parties. Reliant states that the ability to obtain transmission rights through an independent administrator is imperative to any future retail competition. The AISA was not intended to impact wholesale competition.

Electric Service Providers

AES states that the ISA protocols set forth a reasonable means for retail competitors to access transmission into the Arizona load centers, but the protocols need to be implemented for effective retail competition. AES further states that the utilities' FERC-approved tariffs should be sufficient to address wholesale competition.

Electric Cooperatives

AEPCO, Southwest, and Sierra and the REDCs state that the AISA does not initiate, create, or drive either retail or wholesale competition.

Industrial Consumers

AECC states that the AISA will be necessary to ensure the success of retail competition prior to the operation of an RTO. The AISA Protocols address special challenges of transmission access and provide a mechanism for resolving disputes. The AISA adopted an interim transmission allocation that assured access to important market hubs for certain threshold amounts of competitive retail service. The AISA has no role in wholesale markets.

B. Regarding the transmission and distribution infrastructure necessary to support competition for each identifiable generation product --

1. Are there transmission constraints inside or outside Arizona that currently impede the ability of competitors to reach Arizona customers during any seasons of the year or times of the day?

Investor-Owned Utilities

APS states that there are congested transmission paths in several locations in Arizona and the Western United States, but transmission congestion does not necessarily impact retail competition because transmission rights follow retail load.

TEP states that its service territory has a voltage constraint that requires local generation units to be on-line. TEP does not believe that its voltage constraint has impeded competition within its service territory.

Wholesale Power Producers

AzCPA states that every marketplace has constraints that are locational in nature. Price signals developed by an RTO will point towards the areas requiring improvement. AzCPA and PG&E state that transmission constraints exist in the Palo Verde hub area as well as within the Phoenix load pocket. PG&E states that it focused on these interfaces by interconnecting its Harquahala generating plant directly to the new Hassayampa switchyard.

Panda states that there are transmission constraints that affect the ability of any generation supplier to reach load, but the constraints do not uniquely impact competitors. To the extent that the utility is no longer supplying power to serve standard offer customers, the utility will no longer need the transmission previously used to serve the load, and the transmission capacity will be available to competitive suppliers supplying power for standard offer load. Reliant states that the Commission could alleviate issues caused by transmission constraints by designating appropriate units as RMR units.

Electric Cooperatives

AEPCO, Southwest, and Sierra and the REDCs state that transmission constraints exist inside and outside Arizona. Building more transmission facilities in accordance with FERC's requirements will relieve the physical constraints. The FERC's requirement of open access transmission coupled with the recognition by incumbent utilities in their OATT that the same transmission that served a monopoly customer will serve a competitive customer will solve the contractual constraints.

Residential Consumer Advocates

RUCO responds "yes."

Industrial Consumers

AECC is aware of transmission constraints into Phoenix for peak hours of the day in the summer, into Tucson for peak hours of the day for much of the year, into Yuma, and out of Four Corners into Arizona.

2. What plans are in place to relieve transmission constraints?

Investor-Owned Utilities

APS states that utilities, generators, and federal power marketing administrations have plans to construct additional transmission in Arizona. In the future, transmission system planning will be undertaken through WestConnect.

TEP states that it is in the process of adding a second transformer and 500 kV interconnection at its Tortolita substation. These additions will provide additional voltage support on its North side, thus increasing the level of import capacity into TEP's area.

Wholesale Power Producers

AzCPA and PG&E state that APS and SRP have announced plans to construct a transmission line from Palo Verde to Phoenix. The Central Arizona Transmission System (CATS) study is examining additional transmission lines. Panda states that any constraints should affect all generation suppliers equally as long as the transmission provider offers non-discriminatory, open access to the transmission system. PG&E states that the recently approved

Estrella line and its associated upgrades are essential to moving power from the Palo Verde hub when new generation construction will be complete. Reliant states that the Palo Verde-SE Valley project, associated with CATS would increase the transfer capability from Palo Verde into Phoenix.

Electric Cooperatives

AEPCO, Southwest, and Sierra and the REDCs state that the CATS study group has completed initial studies that address the physical limitations to deliver the future generation patterns to the anticipated load centers. Southwest plans to build a new 230 kV transmission line (Winchester Interconnect) which will eliminate the need for local generation to serve local area demand under a single contingency outage.

Industrial Consumers

AECC is aware that three additional 500 kV lines and one 345 kV line connecting several load centers, generation switchyards, and substations are being constructed. APS and SRP have received Commission approval of the Southwest Valley 500 kV line. Sometimes, it is more efficient to construct new generation on the congested side of the transmission interface.

3. How long will it take to relieve any existing transmission constraints and what factors are affecting and will affect prospects for relief?

Investor-Owned Utilities

APS states that planned transmission additions should relieve known transmission constraints, but that transmission constraints will ebb and flow with load growth, new line construction, and new generation siting.

TEP states that the second Tortolita Interconnection has an anticipated in-service date of April 2003. In addition, the Central Arizona Transmission Study is determining what transmission projects will be pursued in Arizona and the anticipated in-service dates.

Wholesale Power Producers

AzCPA and PG&E state that some level of constraint will always exist due to Arizona's growth. AzCPA states that location of generation near load centers is difficult and costly and suggests that the Commission needs to make sitings easier. Panda states that any constraints should affect all generation suppliers equally as long as the transmission provider offers non-discriminatory, open access to the transmission system. PG&E states that the Estrella 500 kV line and its associated upgrades, the recently announced SRP southeast line, and the just announced APS Table Mesa line will make a significant contribution to moving the power from plants now under construction at the Palo Verde hub. Reliant states that new transmission could be built within 2 to 4 years if the following issues were addressed: the siting of new transmission lines and who pays and the development of an RTO that would more economically and fairly allocate transmission rights.

Electric Cooperatives

AEPCO, Southwest, and Sierra and the REDCs state that relieving existing transmission constraints could take several years. For example, the Winchester Project will take three years to place into service if there are no unexpected hindrances.

Residential Consumer Advocates

RUCO believes that national, regional, state, and local political entities should determine the optimum configuration for a transmission system that will promote workable electricity markets. The public must be willing to accept the costs and benefits of that system. Constraints will always exist to some extent. The issue is to relieve the constraints on a cost-effective basis to ratepayers.

Industrial Consumers

AECC notes that factors affecting the prospects for relief include: site selection processes, the site approval process, and the efficacy of the planning process of an RTO.

4. Are the owners of constrained transmission facilities, or holders of transmission rights, able to use their control to affect market prices?

Investor-Owned Utilities

APS states that owners of constrained transmission facilities or holders of transmission rights are not able to use that control to affect market prices in the long term, and are limited in their ability to affect short-term prices. TEP responds "no" because current AISA protocols require the price for must-run generation to be cost-based.

Wholesale Power Producers

AzCPA states that this should not be a problem if AISA protocols are enforced. Panda states that opportunities to exercise market power should be minimized if Arizona's transmission owners comply with FERC's open access requirements and Code of Conduct. Market power will be further limited should Arizona's transmission owners transfer control of their transmission facilities to a FERC-approved RTO. Reliant states that any action or inaction that a transmission rights holder takes that results in an uneconomic allocation of transmission rights will affect market prices.

Electric Cooperatives

AEPCO, Southwest, and Sierra and the REDCs state that although economic theory says that limited transmission capacity will affect market prices, economic dispatch policies of most utilities often belie that economic theory. FERC has rules that govern the conduct of transmission owners, rights holders, and users.

Industrial Consumers

AECC responds "yes" but that the AISA protocols ensure fair treatment for ESPs.

> 5. ***Are these transmission owners currently doing things that will allow them to exert more or less control in the future? If so, please detail.***

Investor-Owned Utilities

APS states that transmission owners supporting WestConnect are creating mechanisms that will promote the elimination of transmission constraints and the beneficial use of existing transmission which will facilitate competitive markets. TEP states that all FERC-jurisdictional entities are participating in efforts to develop RTOs that are intended to decrease the ability of any market participant to exert control over market prices.

Wholesale Power Producers

Panda states that Arizona's competitive wholesale and retail markets are more threatened by attempts to promote self-serving, sweetheart, non-arm's-length negotiated transactions with affiliates that lock out competitive suppliers than by abuse by transmission providers. PG&E states that the Commission should take a more active role in this area. In the absence of an RTO, incumbent transmission owners enjoy significant control. PG&E provides an example where APS declined to offer control area services to PG&E even though APS plans to provide them to their Red Hawk facility. Reliant states that through the filing of the WestConnect proposal, transmission owners have sought to preserve preferential access to the transmission system, rather than creating a system that efficiently allocates transmission rights to valued uses.

Electric Cooperatives

AEPCO, Southwest, and Sierra and the REDCs state that transmission owners are continuously ceding more and more control of their facilities to others by following FERC open access regulations, originating the AISA, forming Desert Star and WestConnect, posting on the OASIS, and planning and constructing new facilities to accommodate new generation plants and wheeling for non-native loads.

Industrial Consumers

AECC states that transmission owners agreed to form the AISA. An operational RTO will perform congestion management, resulting in individual companies having less control over congestion management functions.

> 6. ***Will the transmission system be adequate prospectively (e.g., in the next 5, 10, 15, 20 years) to deliver power from new generation plants?***

Investor-Owned Utilities

APS states that this is difficult to forecast because it depends on which new generation plants are actually built, where and when they are built, their total capacity, and what loads are served. TEP states that while there are significant generation projects being proposed and constructed, there have been very few transmission projects announced.

Wholesale Power Producers

AzCPA states that the transmission infrastructure will be adequate if competitive market forces are allowed to work. Panda states that the future transmission planning process must be revised to meet the needs of a competitive market and that the best means of achieving the objective is to establish a transparent wholesale market and ensure non-discriminatory transmission access. Panda strongly believes that the transmission planning process must be carried out by an independent entity, such as an RTO. Reliant states that implementation of an RTO will help facilitate construction of new transmission.

Electric Cooperatives

AEPCO, Southwest, and Sierra and the REDCs state that the transmission system will continue to meet the needs of new plants as well as existing and future load as long as all entities follow FERC regulations, siting approval is prompt, and adequate rights of way are secured.

Residential Consumer Advocates

Arizona Consumers Council states that it will not be adequate unless a plan is put into place to build adequate new transmission facilities and/or develop and integrate new technologies on an ongoing basis.

7. ***Is the natural gas pipeline infrastructure adequate to support all proposed new gas-fired generation plants? How many plants can it support?***

Investor-Owned Utilities

APS and TEP do not believe that the current gas pipeline infrastructure is adequate to support all of the current and proposed gas-fired generation. APS cannot answer how many plants can be supported because it is a function of day-to-day conditions related to load demand and market price.

Wholesale Power Producers

AzCPA states that existing facilities cannot support all the proposed plants running at full load all the time. However, market forces will keep some plants out of the market, thus reducing gas demand. In addition, the increase in gas demand has prompted market response, including the Desert Crossing Pipeline which provides access to a new natural gas supply basin and provides storage. Panda states that nearly all major interstate gas pipelines in the WSCC have strategic long-term plans to increase deliverability to match expected increases in power and non-power sector gas sales. Reliant states that proposed pipeline additions, if all built, would add 1.5 Bcfd in capacity, and proposed storage projects are estimated to total 1.7 Bcfd in capacity. The proposed projects would support an additional 16, 500 MW power plants.

Electric Cooperatives

AEPCO, Southwest, and Sierra state that the reliability of gas supplies for the proposed new merchant plants is a significant risk in the short run. In the long run, the current capacity shortfall on El Paso will be addressed through system expansion and market adjustments.

Industrial Consumers

AECC states that the existing natural gas infrastructure would not adequately supply all the gas-fired generation plants proposed for Arizona, but transporters are responding to the demand for natural gas. Generation developers are unlikely to risk building gas-fired generating projects without long-term gas supplies.

8. Does the transmission and distribution system facilitate or deter --

a. the development of renewable energy technologies?

Investor-Owned Utilities

APS and TEP state that transmission and distribution facilities would not have any direct impact on the development of renewable energy technologies.

Wholesale Power Producers

Reliant states that the T&D systems are necessary for the development of this item. Processes through which these systems are planned and operated may deter development if not structured to support development.

Electric Cooperatives

AEPCO, Southwest, and Sierra and the REDCs state that the location and size of the renewable energy technology will dictate whether the transmission and distribution system facilitates or deters its use.

Residential Consumer Advocates

RUCO states that it could go both ways depending on the technology.

Industrial Consumers

AECC states that the transmission and distribution system neither facilitates nor deters the development of renewable energy technologies.

Environmental/Energy Efficiency Advocates

The Law Fund states that current transmission and distribution system conditions facilitate development of renewable energy technologies in the sense that congestion on transmission lines increase the value of generation located near load centers. Because of the environmental and other difficulties of siting new conventional power plants in metropolitan areas, distributed renewable energy resources can play an important role in serving metropolitan area consumers. The Commission's review of proposed transmission investments should include a comparison of the costs of such investments with the cost of renewable energy generation distributed within load centers. The Commission should ensure that distribution system planning seeks out cost-effective use of renewable energy as an alternative to system upgrades. Uncertain future transmission planning and pricing policies adversely affect generation from large scale renewable energy projects.

b. the development of distributed generation?

Investor-Owned Utilities

APS states that utility delivery systems have not been planned to interconnect with distributed generation (DG), thus requiring investments that should be recovered from those who impose the costs to deter unsound investments. TEP does not believe that the transmission and distribution system either facilities or deters the development of DG.

Wholesale Power Producers

Reliant states that the T&D systems are necessary for the development of this item. Processes through which these systems are planned and operated may deter development if not structured to support development. The Commission should provide for streamlined procedures for interconnection of distributed generation resources.

Electric Cooperatives

AEPCO, Southwest, and Sierra and the REDCs states that the transmission and distribution system can facilitate the development of distributed generation because distributed generation can be a cost-effective alternative to system additions or upgrades. Uniform standards for interconnected facilities should be established by FERC at the transmission level and by the Commission at the distribution level.

Residential Consumer Advocates

RUCO states that the system is a facilitator and a burden for distributed generation. Technical, business practice, and regulatory burdens must be worked out so that the consumer may choose distributed generation when it is economical.

Industrial Consumers

AECC states that the transmission and distribution system neither facilitates nor deters the development of distributed generation. The greatest institutional barrier to distributed generation is the structure and pricing of utility standby service tariffs and demand ratchets.

Environmental/Energy Efficiency Advocates

The LAW Fund states that current transmission and distribution system conditions facilitate development of distributed generation in the sense that congestion on transmission lines increase the value of generation located near load centers. SWEEP states that transmission and distribution system planning and operations do not adequately consider distributed resources as cost-effective alternatives to transmission or distribution investments.

c. the development of demand-side management and energy efficiency?

Investor-Owned Utilities

APS and TEP state that demand-side management and energy efficiency equipment are not affected by transmission or distribution systems.

Wholesale Power Producers

Reliant states that the T&D systems are necessary for the development of this item. Processes through which these systems are planned and operated may deter development if not structured to support development. The Commission should encourage installation of real-time meters.

Electric Cooperatives

AEPCO, Southwest, and Sierra and the REDCs state that demand-size management and energy efficiency programs may be a cost-effective means of deferring, and possibly eliminating, transmission and distribution facility additions.

Residential Consumer Advocates

RUCO states that the system is potentially an avoided cost of DSM and in that sense the system facilitates the economies of DSM.

Industrial Consumers

AECC states that the transmission and distribution system neither facilitates nor deters the development of DSM and energy efficiency.

Environmental/Energy Efficiency Advocates

The LAW Fund states that DSM/EE measures are more valuable if the cost of bringing power into metropolitan areas is high due to transmission line congestion. The Commission's review of proposed transmission investments should include a comparison of the costs of such investments with the cost of DSM/EE within load centers. The Commission should ensure that distribution system planning seeks out cost-effective use of DSM as an alternative to system upgrades.

SWEEP states that system planning should consider energy efficiency in local geographic areas to relieve constraints. Energy efficiency is easier to site than new transmission lines. System planning should consider RTO support for energy efficiency programs that provide documented value to the regional system.

C. Regarding competitive bidding --

1. Identify with particularity any adverse consequences that would result from Commission approval of a substantial variance to the electric competition rules that require competitive bidding for 50% of the electric supply for standard offer customers, starting in 2003. Specifically:

a. How would retail customers be affected?

Investor-Owned Utilities

APS states that there would be no adverse consequences to retail customers resulting from such a variance. TEP believes that there may be positive consequences if the Commission approved a substantial variance.

Wholesale Power Producers

AzCPA states that granting the variance would cut the heart out of electric competition. Nothing has changed to compel the Commission to relax the requirement on monopoly electricity distributors to bid for competitive power for a portion of the supply portfolio. AzCPA further states that retail customers would not experience the cost savings associated with the lowest bid if the variance were approved

Panda states that all markets and ratepayers in Arizona would be adversely affected if the Commission were to approve a substantial variance to the Rules. Retail competition depends on a robust wholesale market. Allowing incumbent utilities to bar competition for a significant portion of Arizona's standard offer retail load by exclusively dealing with affiliates will drive wholesale competitors from the market, limit future investment in generation, and thereby reduce electrical supply and increase prices.

PG&E states that retail prices would be expected to be higher than otherwise due to a lack of competition. There is significant new generation capacity proposed and under construction in Arizona.

Reliant states that if the variance were approved, retail customers and regulators would be forced into a cost-based system. Customers would continue to bear the risks of fuel price increases, stranded costs, and inefficient plant operations. Sempra responds that retail customers will likely pay more for electricity without competitive bidding than with competitive bidding.

Electric Cooperatives

The REDCs state that their customers have suffered no adverse consequences as a result of the REDCs' exemption from the rule.

Residential Consumer Advocates

Arizona Consumers Council states that if we have a truly robust market and new technology is available and in use, competition should keep prices down. A bottleneck transmission system and rising spot prices could lead to higher prices, less reliability, and less choice. If utilities purchase all or most of their energy from their affiliates, would they get the lowest price? RUCO states that retail customers probably would not be adversely affected by such a variance, provided that power remains available to customers on a cost basis.

Industrial Consumers

AECC states that the APS proposal for a variance to the competitive bidding requirement offers a trade-off for standard offer customers of long-term price stability or the opportunity for prices to go down when supply is plentiful. If the bidding requirement is too high, the market-clearing bid price would be set by the higher cost producers, and the volume of standard offer sales so priced by the higher cost producers would be higher than would occur with a lower bidding requirement. If the bidding requirement is too low, standard offer customers will be deprived the benefits of competitive supply, and generators will be denied an opportunity to participate in the Arizona wholesale market.

b. How would retail generation competition be affected?

Investor-Owned Utilities

APS states that there should be no net negative effect on retail generation competition. TEP states that retail generation and wholesale generations markets are the same and would not be affected by a variance to the bidding rule.

Wholesale Power Producers

AzCPA refers to its response to Question No. IV.C.1.a. for its response to this question. Panda states that all markets and ratepayers in Arizona would be adversely affected if the Commission were to approve a substantial variance to the Rules. Retail competition depends on a robust wholesale market. Allowing incumbent utilities to bar competition for a significant portion of Arizona's standard offer retail load by exclusively dealing with affiliates will drive wholesale competitors from the market, limit future investment in generation, and thereby reduce electrical supply and increase prices. PG&E states that standard offer customers would not receive the full benefits of a competitive wholesale market if the 50 percent bidding requirement were not fulfilled. Reliant refers to its response to Question No. IV.C.1.a. for its response to this question.

Electric Service Providers

AES states that a healthy competitive market requires many buyers and sellers. A utility proposal that forces large customers to remain with the utility or pay an exit fee to leave harms the retail market because it would eliminate the Commission's ability to establish a core/noncore market.

Electric Cooperatives

Arizona Consumers Council states that if there are fewer suppliers, then we are back to monopoly utilities charging monopoly rates with no regulation.

Industrial Consumers

AECC believes that Direct Access service is not directly affected by the APS proposal, so long as implementation of the proposal does not undermine customer benefits achieved in the Settlement Agreement. If competitive bidding does not proceed, generation resources that are not committed to provide service to APS would be available for ESPs.

c. How would wholesale generation competition be affected?

Investor-Owned Utilities

APS states that the proposed variance would not affect the supply and demand balance in Arizona or the southern WSCC.

Wholesale Power Producers

AzCPA refers to its response to Question No. IV.C.1.a for its response to this question. Panda states that all markets and ratepayers in Arizona would be adversely affected if the Commission were to approve a substantial variance to the Rules. Retail competition depends on a robust wholesale market. Allowing incumbent utilities to bar competition for a significant portion of Arizona's standard offer retail load by exclusively dealing with affiliates will drive wholesale competitors from the market, limit future investment in generation, and thereby reduce electrical supply and increase prices.

PG&E states that wholesale competition will thrive when there are multiple opportunities for generators to sell their output. Wholesale competition would be impaired if the amount of power to be procured via competitive bidding is scaled back.

Reliant states that eliminating the competitive bidding requirement will severely reduce wholesale competition. Competitive generation providers will unlikely invest in future projects and may not complete announced projects. Consumers will be forced to continue to subsidize generation resources that are older, less efficient, more expensive, consume more gas, and emit more pollution. Sempra responds that construction of additional generation may be deferred or canceled altogether, maybe leading to higher prices and market price volatility.

Residential Consumer Advocates

Arizona Consumers Council states that if there are fewer suppliers, then we are back to monopoly utilities charging monopoly rates with no regulation.

Industrial Consumers

AECC states that adoption of the APS variance proposal could result in less generation being built in Arizona if developers are relying on he bidding provision to economically justify continuing their investments or if a change in the rules is a negative signal about the state's (de)regulatory climate. AECC believes that developers will rely primarily on their projections of wholesale market prices and growth of aggregate regional demand, assessment of transmission availability, project siting approval, and ability to line up profitable long-term sales contracts.

2. Are sufficient competitors available for an effective bidding process for 50% of standard offer service? A higher or lower percentage?

Investor-Owned Utilities

APS states that current market conditions do not support competitively bidding 50 percent of standard offer load in 2003. APS believes that a significantly lower percentage of standard offer service could be effectively bid out, but the percentage would depend on the area in question and the projected date of such bidding.

TEP states that while there may be sufficient competitors who would be willing to bid on supplying standard offer service, there are only a few that have power to commit to a bid.

Wholesale Power Producers

AzCPA responds "yes" and that some of its members have operational projects or are constructing new projects in Arizona. Bidders from out of state would also participate in the process. Panda states that it is apparent that there are more than a sufficient number of competitors to meet the standard offer customers' load requirements going forward after January 1, 2003. There is more than an adequate amount of generation capacity to serve 100 percent of APS' standard offer requirements by the company contracting with non-affiliated, generating entities.

PG&E responds "yes" and states that merchant plant owners would respond to the January 1, 2003, delivery deadline for 50 percent of APS and TEP needs by using existing assets and supplemental power purchases from the wholesale market. A literal interpretation of the bidding requirements can be met, but if the utilities and Commission propose a more attenuated schedule, the schedule should be stated in a Plan of Administration that is the result of input from all interested parties. Reliant also states that there are enough competitors in the market. Sempra responds "yes" and states that a higher percentage could be justified as additional generation comes on line and competitive wholesale prices continue to fall.

Residential Consumer Advocates

Arizona Consumers Council states that what the future will bring is highly debatable.

> ***3. Can retail competition develop if current rules are modified to allow a utility to procure all of its generation for standard service from an affiliated company?***

Investor-Owned Utilities

APS states that if a modification of the rules results in a more attractive standard offer, retail competition may suffer in the short term, but customers will benefit from lower prices. TEP states that affiliate transactions should be allowed, with adequate regulatory safeguards to ensure that generation costs charged to standard offer customers are just and reasonable. TEP believes that market price signals sent to potential generators, not utility cost embedded in current rates, will determine whether alternative suppliers enter the market.

Wholesale Power Producers

AzCPA responds "no" to this question. Panda states that retail competition will not develop without robust wholesale competition. If the incumbent utilities are allowed to procure generation for standard offer service through self-dealing contracts with affiliates, some competitors will be driven out of the market. Retail competition will be impeded if retail providers have fewer opportunities for procuring competitively priced supplies. PG&E believes that the rules, as written, provide for the greatest opportunity for competitive suppliers of generation in Arizona, which in turn will provide for the greatest possibility that retail competition will take hold.

Reliant states that the settlement agreement has such a low shopping credit that retail customers are effectively precluded from seeking alternative suppliers. Generation costs in APS' bundled tariff are underweighted relative to the true cost of generation. If APS' generation is forced to stand on its own, there would be far more room for other generators to compete.

Electric Service Providers

AES responds "no" because retail competition will not flourish if large customers are captive to utility service under the proposed PPA structure. In addition, the utility's affiliate should not get preferential treatment in procurement activities.

Residential Consumer Advocates

Arizona Consumers Council states that if there are only captive customers, then no market will ever exist. RUCO states that retail competition could develop if non-affiliated companies can provide generation at a lower cost than the incumbent's affiliate.

Industrial Consumers

AECC responds "yes" because the Direct Access service is not dependent on competitive bidding rules for standard offer service. The success of Direct Access service is more directly related to the delivered price of wholesale power relative to standard offer service and the availability of non-discriminatory access to the transmission system.

4. ***How would retail competition be affected by other deviations to the competitive bid rules? Be specific about the changes in the rules and their consequences.***

Investor-Owned Utilities

APS states that it is not likely that any change to the competitive bid rules would adversely affect retail competition, and that retaining the existing bid requirement could hurt competition by making standard offer service an unattractive alternative.

TEP states that modifications to R14-2-1606 could improve electric competition. Those modifications are: extending the date until completion of the Commission review of electric competition, clarifying the terms under which a utility can enter into prudent arm's length transactions, and easing the requirement for energy to be purchased through competitive bidding.

Wholesale Power Producers

Panda states that the Commission should reject any proposal to modify the competitive bid rules that would allow utilities to procure generation for standard offer service outside the competitive wholesale market. PG&E states that Arizona's retail customers presently enjoy the right to choose and does not see any reason to take this choice away.

Residential Consumer Advocates

RUCO states that if customers receive cost-based rates, then competition will have to produce a price that is below marginal cost.

5. ***Instead of entertaining individual requests for substantial variances to the competitive bid requirements, should the Commission proceed on a generic basis to modify the rules for competitive bidding?***

Investor-Owned Utilities

APS states that each of the three companies that have asked for modification or postponement of Rule 1606(B) are uniquely situated and are making discrete proposals that do not lend themselves to generic treatment. TEP responds "yes" to this question.

Wholesale Power Producers

AzCPA states that the APS request should be denied. However, if the Commission were to pursue these issues further, a formalized proceeding is necessary to ensure the issues associated with any new alternative are adequately addressed. Panda responds "no" because allowing utilities to procure generation through sweetheart contracts with affiliates would reduce wholesale competition, increase prices, and prevent retail competition from properly developing.

PG&E recommends that the Commission implement existing rules and settlements. If a change is desired, the Commission should proceed on a basis that creates a consistent set of rules for competitive bidding applicable to jurisdictional utilities.

Reliant states that markets function best in an environment where the rules are clear. Substantially changing the rules hinders further development of the market because regulatory uncertainty is introduced.

Residential Consumer Advocates

Arizona Consumers Council states that competitive bidding does not seem to have worked in other markets, and residential customers have seen no benefits. RUCO responds "yes."

Industrial Consumers

AECC responds "no" because the burden with respect to seeking changes in this Rule should be on the party seeking the change. If the Commission were to initiate a modification of the rules for competitive bidding, it would risk upsetting the balance of interests achieved between customers and utilities in their respective settlement agreements.

6. ***If the Commission would change the 50% bidding requirement for standard offer service, are there other specific measures the Commission can take to promote retail competition?***

Investor-Owned Utilities

APS states that the Commission should streamline the certification process, waive regulatory requirements intended for monopoly services, submit the Electric Competition Rules to the Attorney General, support WestConnect, and preserve standard offer Service as an economic option for customers. TEP states that the Commission could streamline the permitting process for electric transmission lines and generating plants and could provide additional consumer education.

Wholesale Power Producers

AzCPA, Panda, and Reliant state that approving the variance would impact or eliminate both retail and wholesale competition. PG&E believes that, although inferior to a truly competitive market, the process of having each utility filing a Plan of Administration, with public review and Commission approval, could be an effective method for affording a range of program alternatives.

Industrial Consumers

AECC states that the Commission can reconfirm its support for the AISA, which, prior to the formation of an RTO, is necessary for ensuring transmission access.

D. Regarding the pricing of power supply contract rates --

1. ***Identify any advantages that would result if the Commission approved a long-term supply contract for standard offer customers that was based solely on cost-based rates. (Your answer should define "long term" as compared with "short term" contract.)***

Investor-Owned Utilities

APS states that the benefits associated with a long-term contract include price stability, fuel diversification, geographic and technological diversification, proven track record of plants, option for customers to leave standard offer service, and responsibility for reliable supply.

TEP defines a long-term power supply contract as an agreement in excess of one year that contains a defined term for price stability. TEP states that advantages of those contracts include reduced market risk for the utility, reduced market risk for the generating company, and more stable rates for retail customers.

Wholesale Power Producers

AzCPA states that the assumed advantage that results from a long-term, cost-based contract is price stability, but that cost-based contracts do not provide the price stability as one would think because the producer has little incentive to control costs. The competitive wholesale electricity market can provide consumers with true price stability using fixed-price, multi-year contracts.

Panda states that there are no advantages from approving cost-based rate contracts for standard offer service. Disadvantages are: denied benefits of competitively determined wholesale prices for customers, chilling effect on incentives for new entrants to supply power, little incentive for suppliers to minimize costs, no incentive for companies to offer innovative products and pricing, distorted market pricing signals, little incentive to develop demand-side response programs and renewable resources, increased stranded investments, and increased transaction costs from regulatory approval process.

PG&E states that it is important for standard offer service to properly incorporate the elements associated with providing that service, including the costs of risk management, since that is the benchmark by which ESPs compete. The elements should not be buried in the transmission or distribution rate. Otherwise, direct access customers would pay twice for these services. Reliant states that the pricing of power supply contract rates should be based on a competitive bidding process.

Electric Service Providers

AES states that price stability is one possible advantage of approving a long-term supply contract for standard offer customers, but this option should only be for customers under 50 kW. In addition, standard offer terms that exceed one year in duration serve as a disadvantage to competition as retailers would not have an opportunity to compete for these customers. The Commission could institute an annual open shopping season for small customers to give notice of their departure for the coming year.

Residential Consumer Advocates

RUCO states that if the contract provides power at cost, then consumers would have an advantage because market prices are likely to be higher in the long run than cost-based prices. A long-term contract would better protect consumers from price volatility.

Industrial Consumers

AECC states that the primary benefit to standard offer customers from such a contract would be long-term price stability based on cost-of-service.

2. What if the contracts are based solely on market-based rates?

Investor-Owned Utilities

APS states that the sale of power at market rates causes price volatility for customers and a risk of bankruptcy for utilities when the market costs cannot be passed through to customers due to rate freezes.

TEP states that advantages of market-based rate contracts could include additional market opportunities for the generating company, no rule changes would be necessary, greater acceptability among generation-related parties, TEP's Market Generation Credit would still be applicable, and customers could change their consumption in response to market price changes.

Wholesale Power Producers

AzCPA states that market offers provided by third-party generators in a long-term contract RFP process will be based on a diversified portfolio approach and will provide reliable power at reasonable prices. Market-based contracts would also eliminate the need for Commission prudency reviews because any risk of excess capacity or cost overruns will be borne by shareholders.

Panda states that advantages of market-based rates are: competitive market prices, increase in the number of potential suppliers, strong incentives for suppliers to offer lower prices, valuable market price information for future investments and innovations, and strong incentives for demand resources to compete with supply resources. Panda further states that a prudent mix of generation agreement lengths is optimal for all stakeholders. Reliant states that contracts that result from a competitive bidding process will provide reliable supplies and stable prices for consumers.

Residential Consumer Advocates

RUCO states that the quality of the market will be crucial to consumer health, safety, and welfare.

Industrial Consumers

AECC states that basing a long-term contract with an affiliate generator on market-based rates would defeat the purpose of entering into such a contract.

3. ***Describe how FERC's new approach for analyzing the ability of sellers with market rate authority to exercise market power affects generation companies selling into Arizona.***

Investor-Owned Utilities

APS states that all of the generators selling into the Arizona market would pass the Supply Margin Assessment (SMA) test. TEP states that the new test will result in tightly regulated wholesale power prices and make the economics of building new competitive generation unattractive in areas where capacity margins are tight.

Wholesale Power Producers

Panda states that the impact of the SMA screen on generators selling into Arizona will likely be minimized because only new applicants for market-based rate authority and sellers subject to FERC's triennial market review will be subject to the SMA screen, and most generators capable of selling into Arizona in the foreseeable future already have market-based rate authority. In addition, most generators selling power in Arizona will satisfy the SMA screen. Sellers most at risk are those selling into a region where they serve native load and own large amounts of generation in a single market. Also, when a FERC-approved RTO is operational, generators selling into Arizona will no longer be subject to the SMA screen. Reliant states that because of significant concerns raised by participants from various market sectors, implementation of the SMA test will be delayed until a technical conference is held to explore and resolve concerns.

Electric Cooperatives

AEPCO, Southwest, and Sierra state that the new approach will likely limit power prices in the short term. Because the rules are proposed to apply nationally, Arizona is unlikely to be disproportionately affected. In the longer term, the new policies may culminate in price spikes because wholesale sellers would be prevented from recovering much more than their incremental production costs. It may be difficult to recover capital costs, and new entry will be discouraged. Merchant plants, peaking units, and Western utilities appear particularly vulnerable.

Residential Consumer Advocates

RUCO states that the new approach, if implemented, would severely limit the use of market-based rates in Arizona.

> *4. Does the Commission have the ability to assure that approval of a long-term contract would protect ratepayers receiving standard offer service as well as foster competition?*

Investor-Owned Utilities

APS states that it would as long as the contract does not also prohibit customers from returning to standard offer service and as long as fostering competition does not entail creating artificial subsidies to benefit competitors instead of competition. TEP states that the Commission would consider the rate implications of the contract to standard offer service customers and that approval of a long-term contract is unrelated to the fostering of competition.

Wholesale Power Producers

AzCPA states that the Commission could approve longer term, market-based supply contracts from non-affiliated suppliers and protect ratepayers who receive standard offer service. Panda states that the Commission has the ability to assure that its approval of a long-term contract would protect ratepayers receiving standard offer service while fostering competition. A utility would still be required to demonstrate that its power purchases are reasonable and prudent before recovering the cost in rates. PG&E states that the best assurance comes from a well-conceived and designed bidding program that is implemented without subsequent secondguessing. Reliant responds "yes" provided that the long-term contract results from a competitive bidding process.

Residential Consumer Advocates

RUCO states that the Commission can probably find a way to do both.

Industrial Consumers

AECC states that the interests of standard offer customers can be protected if the Commission ensures that the terms and conditions of any long-term contract are fair and reasonable.

V. Industry Events External to Arizona

A. Describe in detail developments you believe will occur in both the wholesale and retail competitive electric generation markets nationally and in Arizona over the next 12 months, 24 months, 36 months, 48 months, and 60 months.

Investor-Owned Utilities

APS states that regarding what will happen and when it will happen. Given that, APS expects WestConnect to be functional within 60 months, possible increased use of forward markets could reduce market volatility, federal energy legislation could be enacted in the next five years, and there could be renewed interest in direct access across the country.

TEP states that western competitive electric generation markets in the west should remain stable in the next 12-24 months but longer term it is difficult to predict.

Wholesale Power Producers

PG&E states that it anticipates that current merchant power plants under construct will be completed and will provide significant potential for competition in Arizona.

Reliant provides a table in its comments that lists a variety of developments in Arizona and the United States over the next five years.

Electric Service Providers

AES, in its comments, provides a sequence of a number of events it sees taking place in Arizona in the next four years.

Residential Consumers

The Arizona Consumers Council states that predictions would have no meaning and would be guesses without foundation in the current environment.

RUCO states that it believes the west will continue to resist creating an RTO and federal jurisdiction over wholesale market my actually undermine competition.

Industrial Consumers

AECC states that in the next year the FERC will continue to push for RTO formation and interest in direct access in Arizona will decrease. In two years there will be a greater number of ESPs bidding to do business in Arizona and in three years an RTO will be operational in Arizona.

B. Is there anything the Commission should do to continue to avoid California's retail electric competition experience? Please be specific.

Investor-Owned Utilities

APS cites a list of factors that contributed to the California experience and states that the most significant structural factor was a poorly designed wholesale market. APS then lists policy objectives for generation, long-term procurement, siting and infrastructure development, customers, divestiture, and financial health.

TEP states that the Commission should encourage diversification of supplies for standard offer energy and that California was overly reliant on spot market energy purchases. TEP believes that prior to competitive bidding, the Commission should meet with parties to discuss resource portfolio diversification issues.

Wholesale Power Producers

The AzCPA states that load serving entities should be allowed to bid to serve standard offer customers and a solid margin of generating capacity should be required.

The EPSA recommends that the Commission: encourage new generation, expand transmission, improve interconnection, increase natural gas pipeline capacity, avoid price controls, develop demand-response programs, allow more customer choices, and provide credit assurances.

Panda states that the California experience was caused by a combination of factors, but the most important factors were the failure to site a substantial new power plant for ten years and the required divestiture of generation with no transition and no ability to enter into long-term contracts.

Reliant states that the California experience was related to supply/demand imbalance and poor market design. Reliant's comments list a number of actions and policies it believes the Commission should pursue.

Sempra Energy Resources states that the Commission has adopted the proper market structure.

Electric Service Providers

AES states that an effective retail market alleviates pressures on consumers and helps mitigate price fluctuations in the wholesale market. This is because effective retail competition increases the number of buyers in the market, retail competition offers customers more hedging opportunities, retailers don't have to worry about reasonableness reviews of their hedging decisions, and retailers have greater reason to be demand responsive.

Strategic Energy has several recommendations for the Commission in order to avoid California's negative electric competition experience: encourage new generation, expand transmission, improve interconnection, increase natural gas pipeline capacity, avoid price controls, develop demand-response programs, allow more customer choices, and provide credit assurances.

Electric Cooperatives

AEPCO, Southwest, and Sierra state that the safest course of action is to wait until there's a fully developed wholesale market and even then there would be concerns.

Residential Consumers

The Arizona Consumers Council states that absent regulation, which may not be possible, it does not think that there is anything for the Commission to do to avoid the California experience.

RUCO states that this question assumes that Arizona has avoided the California experience. One possible safeguard is to not force utilities to buy only from the unregulated market.

Industrial Consumers

AECC states that retail competition was a casualty of the California experience, not the cause. AECC recommends focusing on bottom line standard offer results, not requiring resource procurement in the spot market, encouraging utilities with standard offer customers to hedge costs, continue direct access, and avoid unnecessary regulatory obstacles to infrastructure development.

Utility Investors

AUIA's comments include a list of things it recommends the Commission do or not do in regard to competition.

C. Does the Enron bankruptcy have any lesson for retail electric competition in Arizona?

Investor-Owned Utilities

APS states that Enron's collapse has had little impact on the availability or price of electricity and that the most likely impact is on accounting standards. This situation also emphasizes the importance of standard offer service.

TEP states that the Enron failure highlights the importance of carefully designing the competitive market and also the importance of ESP credit quality.

Wholesale Power Producers

AzCPA states that the Enron situation provides little or no lesson regarding competition in Arizona or elsewhere. The EPSA believes that Enron's collapse was the result of financial and accounting practices, and does not indicate a problem with electric restructuring.

Reliant states that the minimal impact of Enron's bankruptcy shows that markets work. Sempra Energy Resources states that there are no lessons for competition because Enron's bankruptcy was due to accounting/off-balance-sheet issues. Further, Enron was the messenger, not the message.

Electric Service Providers

AES states that Enron's bankruptcy has no lessons for retail electric competition because the bankruptcy has nothing to do with competition.

Strategic Energy believes that Enron's collapse was the result of financial and accounting practices, and does not indicate a problem with electric restructuring.

Electric Cooperatives

AEPCO, Southwest, and Sierra and The REDCs list a number of lessons that can be learned from Enron's bankruptcy including that competition doesn't necessarily benefit consumers and that hard assets have value.

Residential Consumers

The Arizona Consumers Council states that while Enron's bankruptcy has not immediately impacted customers, Pacific Gas and Electric's situation has had a huge impact.

RUCO states that it is not clear at this time what lessons there are from the Enron bankruptcy.

Industrial Consumers

AECC states that lessons from the Enron bankruptcy include showing the value of a diverse supply portfolio and the importance of customer protection through regulation and contract.

D. How will FERC's RTO initiative affect the realization of effective retail generation competition in Arizona?

Investor-Owned Utilities

APS states that an RTO should help realize competition because it should help consumers access more generating resources, FERC requires the RTO to be provider of last resort for ancillary services, and it provides a market monitoring function.

TEP states that an RTO may provide some benefit to the wholesale market and may therefore also benefit the retail market, but the substantial cost of an RTO will be borne by wholesale and retail customers.

Wholesale Power Producers

AzCPA states that the goals of FERC in wholesale markets are consistent with the Commission's goals in Arizona.

Panda states that to the extent RTOs remove barriers to transmission, generators will be enabled to effectively compete in the wholesale and retail markets.

Reliant states that formation of an effective RTO will enhance competition, lower costs, improve reliability, provide economic allocation of transmission rights, and provide an easier interconnection process for new generators. The WestConnect RTO proposal is not properly constituted.

Electric Cooperatives

AEPCO, Southwest, and Sierra and The REDCs state that the effect of an RTO is unclear at this time. At this time no market power or failure of open access in Arizona has taken place to require an RTO to implement retail or wholesale competition.

Residential Consumers

The Arizona Consumers Council states that the affect of FERC's RTO initiative is unknown.

RUCO states that FERC's RTO initiative will not affect retail generation competition in Arizona for a long time.

Industrial Consumers

AECC states that FERC's RTO initiative will be helpful in realizing effective retail competition in Arizona because it will eliminate pancaked tariffs, ensure functional separation of transmission, and possibly provide congestion management benefits.

E. Do you anticipate changes in federal utility statutes to affect the jurisdiction of the Commission and its ability to foster retail competition in Arizona? Please detail.

Investor-Owned Utilities

APS states that it is impossible to predict what electricity related bills Congress may pass, but that there are at least two bills currently before Congress that could impact competition in Arizona. These are S.1766, "The Bingaman Bill" and H.R. 3406, "The Barton Bill". APS' comments contain a list of issues that are being addressed in these bills.

TEP states that recently introduced legislation would increase federal control over the interstate transmission system and could pre-empt the authority of the Arizona Power Plant and Transmission Line Siting Committee and the Commission to review and site transmission lines. If interstate transmission of electricity across Arizona is increased, there may be less transmission capability for in-state transmission, a key component of a robust retail market.

Wholesale Power Producers

Reliant states that it does not anticipate changes because FERC policy clearly recognizes that states have jurisdiction over retail competition issues.

Electric Cooperatives

AEPCO, Southwest, and Sierra states that such changes are unlikely at this time. Although there are numerous bills pending before Congress, most of them preserve states' ability to regulate retail competition.

Residential Consumers

The Arizona Consumers Council states that it is unknown whether there may be changes to federal statutes that might affect the Commission's jurisdiction regarding retail competition.

RUCO states that it does not anticipate any such changes.

Industrial Consumers

AECC states that AECC is not aware of any such changes.

Environmental and Energy Efficiency Advocates

ACEIA discusses two Congressional acts. The Securing America's Future Energy Act H.R. 4 impacts Arizona's treatment of renewables and distributed generation by encouraging these methods. The Renewable Energy and Energy Efficiency Act of 2001 (S. 1333) focuses on a nationwide renewable portfolio standard.

VI. System Security

A. Are there compelling reasons to be concerned about security for electric generation facilities since the Sept. 11, 2001 tragedy? Please include discussion of interconnection at a central location such as Palo Verde/ Hassayampa.

Investor-Owned Utilities

APS states that concern about security has increased since the tragedy but that the industry is making substantial strides in protecting critical infrastructure. APS further states that the risk is probably no greater for concentrated generation areas such as the Palo Verde/Hassayampa switchyards because of the increased overall security.

TEP believes that generating units have a high degree of plant security. TEP further states that anytime there is a concentration of required services at one location, the risk from a catastrophic event at that location increases and that the larger a generation or interconnection facility becomes, the greater the impact of the loss of that facility.

Wholesale Power Producers

AzCPA responds "no" and that the owners of generation facilities are compelled to protect their assets and revenue stream. AzCPA further states that the concern raised by some about the number of generators interconnecting to Palo Verde/Hassayampa is generally misunderstood. The fact is that two distinct hubs are forming that are connected but are separated physically and electrically. Electrical security is further enhanced by terminating new lines at Hassayampa versus Palo Verde. Reliant states that there is already Federal oversight of security at both nuclear facilities and power facilities and gas transportation facilities. The NRC, the DOE, the FBI, and the National Guard with the independent oversight of the facility owners already provide security oversight.

Residential Consumer Advocates

Arizona Consumers Council states that any vulnerability to any part of the generating and/or transmission system can be a problem whether it is from persons deliberately disrupting the system, accidents, or lack of maintenance. Any large facility, which goes out of service, places a burden on the entire system. These facilities need to be secured as much as possible, but the problems will always exist. RUCO states that the grid will continue to be vulnerable to acts of war.

B. Does transferring ownership of generation facilities out from traditional Commission jurisdiction have any potential negative security consequences?

Investor-Owned Utilities

APS states that transferring ownership would not likely have negative security consequences. TEP states that transferring ownership would only have negative security consequences to the extent that Commission security requirements are stricter than those imposed by the NRC, NERC and WSCC.

Wholesale Power Producers

AzCPA responds "no" because reliability and security issues will still be overseen by FERC and other organizations such as NERC. Security of the facilities is as or more important to the facility owners as it is to the Commission. Reliant states that security does not change simply because the generation facilities are removed from Commission ratemaking jurisdiction.

Residential Consumer Advocates

Arizona Consumers Council states that we will lose oversight and regulation. Companies may feel that the cost of security may not have a positive cost/benefit.

C. What if ownership after transfer results in a foreign corporation eventually controlling Arizona's generation?

Investor-Owned Utilities

APS does not believe it is likely that a single foreign corporation could ever control a majority of Arizona's generation. If it did occur, the entity would not have market-based rate authority and would have to offer generation at cost-based rates. TEP states that its response to this question is in its response to Question VI.B.

Wholesale Power Producers

AzCPA states that any corporation must follow the same rules and regulations as an Arizona-based company. Reliant states that there is nothing inherent in foreign ownership that would suggest security concerns.

Residential Consumer Advocates

Arizona Consumers Council states that it depends on the law that allows foreign corporations to control such assets.

D. Does such a transfer to a non-Arizona entity potentially impact security issues for Arizona?

Investor-Owned Utilities

APS states that its response to this question is in the responses to Questions VI.C. and VI.D. TEP states that its response to this question is in its response to Question VI.B.

Wholesale Power Producers

AzCPA responds "no" because FERC and NERC as well as statutes mandate the necessary security of generation facilities. Reliant states that there is nothing inherent to ownership by a non-Arizona entity that would give rise to security concerns.

Residential Consumer Advocates

Arizona Consumers Council states that it depends upon oversight and regulation.

E. Are there any positive security aspects to transferring electric generation out from Commission traditional regulation to a foreign corporation?

Investor-Owned Utilities

APS states that there are no specific security benefits to transferring generation to a foreign corporation, but that there are benefits to utility customers from transferring generation from traditional regulation, including reduced customer and utility exposure from the increasingly risk-laden generation business. TEP is not aware of any positive security aspects from transferring the generation.

Wholesale Power Producers

Reliant states that security issues and oversight does not change. Continued compliance remains a requirement.

Residential Consumer Advocates

Arizona Consumers Council responds "no."

F. Provide specific examples to support your answers.

Investor-Owned Utilities

APS lists 11 examples of foreign companies that already own or control generation in Arizona.

VII. Vision

Investor-Owned Utilities

APS states that the Arizona wholesale market is reasonably competitive. In the near term, improvement in supply and demand balances will continue to take pressure off of prices and supply adequacy. Arizona transmission owners and users will be part of WestConnect. In the near term, there will be excess generation supply. Competitive wholesale prices in Arizona will continue to be driven by prices in California. Mass-market retail access may not take root if customers can remain on standard offer service at prices at or below market.

TEP believes that unless factors that are beyond the control of regulators, utilities, ESPs and customers are properly accounted for or controlled, the Arizona competitive retail market will develop slowly. TEP further states that one of the most critical of those factors is generation price volatility in the wholesale market. The art of balancing regional supply and demand without a regulatory mandate and delivery infrastructure issues must be addressed before a robust competitive retail market can exist in Arizona. TEP suggests that Arizona should encourage the development of additional generating resources and/or load management and encourage the development of additional transmission, new gas pipeline, or railroad infrastructure. TEP also states that price volatility must be balanced between shareholders and customers.

Wholesale Power Producers

Panda states that the Commission's Rules and the 1999 Settlement Agreements offer a well-constructed framework for wholesale and retail competition. There is no reason for the Commission to backtrack in any way from the Rules. Competitive generators stand ready to bid for the right to serve standard offer customers or to negotiate bilateral contracts with Arizona utilities to supply reliable power at competitive rates. If the Commission bows to pressure and removes the significant capacity represented by standard offer service from the competitive market, the competitive wholesale market will be irreparably damaged, driving some participants from the market and driving up future prices by reducing supply. There is little hope for effective retail competition without a competitive wholesale market.

PG&E supports competitive bidding of standard offer retail service as the cornerstone of retail electric competition in Arizona. The Commission can measure the program's success by the MW and MWh competitively procured annually and the price(s) associated with them. The Commission has an important market-monitoring role and should respond negatively to APS' request to allow Pinnacle West to become its full requirements provider. PG&E hopes that the Commission will allow Arizona's retail customers to remain eligible for direct access service. The possibility that retail customers in large numbers might one day choose alternative providers is a powerful incentive for both incumbent utilities and competitive suppliers to moderate prices.

Reliant states that it supports the vision statement contained in FERC staff's recent concept paper and believes that Arizona's electricity markets are likely to develop in a manner consistent with that vision. The FERC staff vision statement states that by 2006-2011, electricity will be purchased and sold in both wholesale and eligible retail markets by any willing creditworthy participant. Wholesale markets will have the following characteristics: energy-related products will be fully unbundled, there will be few barriers to entry and exit, market participants will not be able to exercise market power, market institutions will exist that maintain market transparency and keep transaction costs low, good market-driven price signals will exist to support generation and transmission investment, buyers will receive accurate and timely price signals, non-investor-owned entities will be allowed to join regional organizations, there will be wholesale competition in states that do not have retail choice, and the wholesale market structure in states with retail choice will not prevent anyone from purchasing the products and services necessary to buy or sell delivered electricity.

Electric Service Providers

APSES gives a description of its vision for a competitive retail electric market. A competitive, liquid, and transparent wholesale market is needed for meaningful direct access by retail customers. The AZISA or an alternative independent RTO must assure meaningful delivery. The Commission should not regulate non-core customers' direct access contracts. Business rules that facilitate retail competition include: real-time pricing with flexible installation of meters, expedited complaint rules for tariff interpretation, regulatory certainty needed for investment in competitive business, no utility long-term contracts that foreclose competitive contracts, Code of Conduct applies to only commodity services, and competitive billing and metering can be offered by a utility or an ESP.

Electric Cooperatives

AEPCO, Southwest, and Sierra and the REDCs state that they have grave doubts as to whether retail competition will develop and benefit rural Arizona. Experience in the airline, banking, and telecommunications fields demonstrates that such initiatives usually leave rural areas unserved or underserved. Wholesale competition may offer new opportunities to acquire, through various means, least cost resources throughout the state. The REDCs believe that the focus of competition should be on the service areas of APS, SRP, and TEP where conditions are more favorable to competition. The REDCs should be exempted from the Retail Electric Competition rules at least in the near term.

Residential Consumer Advocates

Arizona Consumers Council states that there have been no discernable benefits for residential and small business customers. These consumers have had higher prices and/or lower reliability. There is now really no competitive market in the residential and small business area. There have been no widespread consumer benefits in other states that have restructured. Even in Pennsylvania, the market that did exist has essentially dried up, and the Commission is looking into irregularities. In Arizona, there has been no movement to service residential and small business consumers, and given what has happened over the nation, there will be no movement in the foreseeable future.

Industrial Consumers

AECC believes that wholesale competition will improve as RTO development proceeds. AECC believes that retail competition will become more viable as forward wholesale prices become more competitive with standard offer and stranded cost charges terminate. The standard offer option should be retained for any customer who elects not to shop in the competitive market, while the option to shop in the competitive market should be retained for all customers. With new generation coming on line, Arizona is well positioned to enjoy rate stability in the future.

Environmental/Energy Efficiency Advocates

The LAW Fund believes that wholesale competition is viable in Arizona as numerous independent power plants currently and will in the future sell electricity to retail utilities. Retail competition is not very viable. The LAW Fund believes that society would be better off wit greater deployment of renewable energy, distributed generation, and demand-side management. Benefits include lower long-run costs of meeting the demand for electric energy services and improved environmental quality. The Commission should continue to pursue policies in these areas regardless of whether the market is open to competition.

SWEEP states that markets should have both a supply side and a demand side, markets should provide options for all customers, markets should be diverse and resilient, markets should value geographic-specific and time-specific nature of energy use, markets should consider options, there should be protections against market power. Energy efficiency and other demand-side and distributed resources can help meet the needs of Arizona customers in a cost-effective, reliable, and clean manner.

Utility Investors

AUIA states that the wholesale market is already viable, although it is volatile. Operation of the wholesale market could improve when RTOs are brought on line and when a few transmission bottlenecks are cured. These developments could be achieved in three to five years but will probably take longer. AUIA sees no reason for dismantling the Competition Rules at this time. With the exception of the bidding provision, the rules could stay in place until the settlement agreements run their course.

Renewable Energy/Cogeneration Producers

ACEIA states that by furthering the EPS and implementing new rules for distributed generation, utilities will have to modify their long term planning. ACEIA envisions an expansion in renewables and distributed generation in Arizona.

Commissioner Spitzer's Letter of January 22, 2002

1. In a vertically integrated utility model, what incentives (regulatory, financial, and ratemaking) exist for the expanded use of renewable energies?

Investor-Owned Utilities

APS states that explicit regulatory support includes mandatory programs directly funded through rates, and implicit regulatory support occurs when voluntary utility programs, such as green pricing, receive full recovery during general rate proceedings. Government contributions include tax credits, direct grants, and tradable emissions credits programs. Private contributions come from foundations, public interest groups, or individual ratepayers.

TEP states that the primary incentive has been the Environmental Portfolio Standard which includes the certainty of cost recovery through a surcharge. Other incentives include production tax credits, reduced property tax rates, hardware buy-down payments, income tax credits, and other governmental subsidies.

Wholesale Power Producers

Reliant states that regulatory incentives exist if a renewable portfolio standard is in place with enforceable penalties. Financial incentives take the form of a renewable energy fund. Ratemaking incentives are limited to green pricing programs that rely on voluntary demand. Standardization of distributed generation interconnects and net metering are also incentives for renewables.

Electric Cooperatives

AEPCO, Southwest, and Sierra and the REDCs state that in a regulated model, the regulator may assure a revenue stream to support renewable applications regardless of whether they are a least cost solution.

Residential Consumer Advocates

Arizona Consumers Council states that the Commission has broad powers to give all kinds of incentives for renewable energies. Today, we have built-in incentives to use other than renewable. We can do the same for renewable energy. RUCO states that in the vertically integrated utility regime might support renewable resources by setting a voluntary standard offer rate for green power or establishing a state resource portfolio standard that includes renewable resources.

Industrial Consumers

AECC states that the first incentive is economic. If not, the regulated utility will seek to ensure that any renewable energy expenditures in support of regulatory directives are recoverable in rates.

Environmental/Energy Efficiency Advocates

The LAW Fund stated that the incentives for expanding the use of renewable energy in a vertically integrated utility model are: renewable portfolio standards, reasonable assurances of cost recovery, requirements for utilities to purchase energy from qualifying facilities at the utility's avoided cost, tax incentives, financial incentives, consumer demand for green energy, and public relations benefits.

Utility Investors

AUIA states that the Commission can authorize funding and/or a pass-through mechanism to encourage the use of renewables either on the utility's system or for the end user.

Renewable Energy/Cogeneration Producers

ACEIA states that the key incentive is that there is reasonable assurance of cost recovery of investments in renewable energy. Other incentives include system benefit charges, voluntary green pricing programs, federal and state tax incentive programs, and Federal cost-shared research and development.

2. ***In a competitive electric market model, what incentives exist for the expanded use of renewable energies?***

Investor-Owned Utilities

APS and TEP state that profitability is the primary incentive in a competitive energy model. APS adds that in states where the free market has been considered inadequate, regulators have developed programs to encourage green power. TEP adds that financial incentives, such as federal production tax credits and renewable portfolio requirements, have driven the development of renewable generation resources in the competitive marketplace.

Wholesale Power Producers

Panda states that a competitive electric market model may promote the use of renewable energies more than a vertically integrated utility model. Electric providers have the opportunity to differentiate a commodity product by marketing green energy. In states with retail electric competition, consumers have been willing to pay a premium for green power. In Arizona, studies have shown that a significant number of customers are willing to pay a premium for renewable energy resources.

PG&E states that mechanisms to encourage the use of renewable energy include: a renewable portfolio standard, a system benefits charge to collect money for grants, and incentives such as low-interest loans and tax credits. It is important to have a balance between encouraging the development of new sources and taking advantage of renewable resources that currently exist. In the long term, a highly competitive market will encourage the development of renewable resources.

Reliant states that in competitive markets, green tariffs have been replaced with specialized customer product offerings that often contain premiums for the portion of energy use derived from renewable sources. Competition motivates retailers to offer a diverse portfolio of renewable products and related marketing to attract consumers.

Electric Cooperatives

AEPCO, Southwest, and Sierra and the REDCs state that there generally are no incentives, but competitors may seek out niche markets for renewable applications.

Residential Consumer Advocates

Arizona Consumers Council states that there are incentives only to the degree that renewable sources can compete monetarily with what is in place today. Incumbent utilities have a guaranteed rate of return on investment, and renewable energy cannot compete with it. Renewable energy technology has not yet reduced its cost sufficiently to compete without incentives.

Industrial Consumers

AECC states that the first incentive power producers will look for is economic. The surcharge/subsidy approach may also be used in a competitive model.

Environmental/Energy Efficiency Advocates

The LAW Fund stated that the same incentives are applicable in a competitive electric market model, assuming that electricity derived from renewable energy costs more than conventionally generated electricity.

Utility Investors

AUIA states that the situation remains the same for the UDC. Retail competition in some jurisdictions has indicated that there may be a market among residential customers for green power.

Renewable Energy/Cogeneration Producers

ACEIA states that minimizing costs drives decisions in a competitive model

3. ***In a vertically integrated utility model, what disincentives (regulatory, financial, and ratemaking) exist for the expanded use of renewable energies?***

Investor-Owned Utilities

APS states that regulatory disincentives include requiring least cost resources and disallowing the higher cost of renewable energy resources in rates. TEP states that the high costs of developing renewable energy technologies and reliability questions are the primary constraints to renewable generation. Investment risk is better managed under a vertically integrated utility model.

Wholesale Power Producers

PG&E and Sempra state that the incentives or disincentives a vertically integrated utility has to provide renewable power are dependent on the regulatory parameters in which the utility operates. Some of the same mechanisms are available under both models. PG&E further states that it is unlikely that a significant supply of renewable power will develop under a vertically integrated utility model until the state decides that it is in the public interest for ratepayers to have access to renewable power. A competitive retail market is the best means to encourage consumers to purchase renewable power.

Reliant states that green tariffs provide minimal incentive compared to that of the competitive model. Unless instructed to do so, vertically integrated utilities do not have the incentive to execute long-term power purchase agreements required to stimulate investment in renewables.

Electric Cooperatives

AEPCO, Southwest, and Sierra and the REDCs state that renewables often cannot meet the regulatory goal to deliver power to the consumer at least cost. A regulator may mandate renewable requirements but not provide a revenue stream sufficient to support them.

Residential Consumer Advocates

Arizona Consumers Council states that the only disincentives are those which regulatory commissions place if requests are made to use higher than average costs. On-site renewable energy does not bring income to the utility, so they are reluctant to use it.

Industrial Consumers

AECC states that the primary disincentive is economic. For some technologies, there is a disincentive with respect to unit availability. Another disincentive is concern that investments made on the basis of a subsidy will lead to additional stranded cost in the future if the subsidy is removed.

Environmental/Energy Efficiency Advocates

The LAW Fund states that disincentives are: the high cost of renewable energy, lack of information about cost-effective applications, failure to consider the value of stable prices, and utility perceptions that renewable energy technologies should not be used because they are not dispatchable.

Utility Investors

AUIA states that cost is the major disincentive, although the Commission has greater ability to provide subsidies under the integrated model.

Renewable Energy/Cogeneration Producers

ACEIA states that disincentives are the higher capital cost and the higher risk of renewable energy technologies. Another disincentive is a utility bias for business as usual.

*4. **In a competitive electric market model, what disincentives exist for the expanded use of renewable energies?***

Investor-Owned Utilities

APS states that most competitive firms have higher required rates of return than do regulated utilities, thus discouraging even projects with positive long-term economics. TEP states that its answer to this question can be found in its answer to Question No. 3.

Wholesale Power Producers

Panda states that no inherent disincentives exist in a competitive electric market model for the expanded use of renewable energies. Product differentiation is a cornerstone of effective product marketing, and product choice will expand in competitive market places.

PG&E states that disincentives are often the lack of a market for the output of renewable generation and the lack of recognition of the benefits of renewable energy. Some transmission-related issues at the wholesale level must be addressed for intermittent generation sources. State air quality programs are a way to communicate and reward the contribution of renewable energy. Reliant states that in competitive markets, protocols on scheduling and settlement can create a disincentive for intermittent renewable energy such as wind power.

Electric Cooperatives

AEPCO, Southwest, and Sierra and the REDCs state that renewable energies are normally more expensive.

Residential Consumer Advocates

Arizona Consumers Council responds that a disincentive is the cost of producing renewable energy versus the existing cost of energy. New technologies must be able to produce energy cheaper to be useful in such a market.

Industrial Consumers

AECC refers to its response to the previous question for its response to this question.

Environmental/Energy Efficiency Advocates

The LAW Fund states that disincentives are: the high cost of renewable energy, lack of information about cost-effective applications, failure to consider the value of stable prices, risk that the utility will not recover costs, and utility perceptions that renewable energy technologies should not be used because they are not dispatchable.

Utility Investors

AUIA states that cost is a disincentive. Except for niche marketing, generators have no incentive to use renewables.

Renewable Energy/Cogeneration Producers

ACA states that very few distributed generation plants have been constructed in Arizona in the last five years because of well established barriers to grid interconnection and the uncertainty regarding deregulation and electric rates. The Commission needs to adopt standard interconnection requirements and an application process, and put in place DG tariffs, including partial requirements and standby rates.

ACEIA states that utilities meeting the EPS requirements by purchasing power from an independent power producer are unwilling to make the contractual time period long enough to reduce the cost. The lack of information in competitive markets is onerous.

5. ***During Arizona's period of reliance on the vertically integrated utility model, what renewable energy programs were enacted in Arizona?***

Investor-Owned Utilities

APS states that it helped to establish the first solar energy group in the 1950s, built the largest photovoltaic system up to that time in the 1970s, developed the APS Solar Test and Research (STAR) Center, began providing off-grid solar electric systems as an alternative to line extensions in 1994, launched a green power program in 1996, and tested other renewable technologies.

TEP states that it implemented a 5 MW landfill gas energy generation system in response to the 1993 Integrated Resource Plan's goal that 5 MW of renewable generation be in place by the end of year 2000. In addition, TEP developed 35 kW of solar electric generation systems and started a wind survey program.

Wholesale Power Producers

Reliant lists the following programs: SRP's Solar Choice/Earthwise Energy (10/98), TEP's Greenwatts (1/00), and APS' Solar Partners (1997).

Electric Cooperatives

AEPCO, Southwest, and Sierra state that renewable energy matters were dealt with as part of the IRP process. It is the understanding of the REDCs that the larger investor-owned utilities such as APS and TEP may have implemented renewable energy programs focused mainly on research and development.

Residential Consumer Advocates

Arizona Consumers Council states that APS recently put forth a solar renewable source at a higher cost to consumers. Some who could afford it did purchase it.

Environmental/Energy Efficiency Advocates

The LAW Fund states that the integrated resource planning process encouraged utilities to start implementing renewable energy projects, and utility-sponsored projects accounted for about 170 kW of photovoltaics applications.

Utility Investors

AUIA states that during the 1970s and 1980s, in response to national energy policies, a system of grants and tax incentives was enacted to encourage use of solar energy.

Renewable Energy/Cogeneration Producers

ACEIA estimates that APS and TEP installed about 7 MW of renewable energy power.

6. ***Since Arizona's adoption of a competitive electric market model, what renewable energy programs have been enacted in Arizona?***

Investor-Owned Utilities

APS states that it continued to expand the STAR Center, provide off-grid solar systems, revised its green power program, and began meeting the Environmental Portfolio Standard. TEP states that it has implemented a number of renewable energy projects but that the projects were not developed in response to the competitive marketplace. TEP's more recent programs include green pricing and net metering.

Wholesale Power Producers

Panda and Reliant state that the Commission adopted the Environmental Portfolio Standard. Panda further states that although the EPS is not dependent on retail competition, the development of renewable energy sources is part of the competitive wholesale market. A renewable energy market did not develop under the prior vertically integrated utility paradigm.

Electric Cooperatives

AEPCO, Southwest, and Sierra state list the EPS rule. The REDCs state that most of the Affected Utilities are implementing renewable energy programs under the EPS. Navopache Electric Cooperative is implementing a very robust renewable energy program. The other REDCs have entered into agreements with AEPCO concerning the EPS requirements.

Residential Consumer Advocates

Arizona Consumers Council states that the rules call for a percentage of energy used by the utilities to come from renewable sources.

Industrial Consumers

AECC is aware of the Commission's adoption of the EPS to support renewable technologies.

Environmental/Energy Efficiency Advocates

The LAW Fund states that there are over 13 MW of renewable energy projects of 10 kW or larger capacity installed in Arizona. Motivations behind these projects include the EPS and utility management initiatives.

Utility Investors

AUIA states that it is doubtful that the structure of the industry has had much to do with utility renewable energy programs.

7. ***Under the vertically integrated utility model, what incentives exist to build newer plants that are less damaging to the environment to replace older, dirtier plants?***

Investor-Owned Utilities

APS states that over time a utility will build new capacity to meet growing demand, and newer plants generally operate cleaner than older plants. Incentives are economic and regulatory. TEP states that new generating plants are traditionally built only when there is a need and owners believe that they will be able to earn a reasonable rate of return. Existing plants are removed from service when they no longer operate efficiently or are no longer needed.

Wholesale Power Producers

PG&E states that it is not aware of any past, present, or future plans by incumbent Arizona utilities to replace older, dirtier plants. Since most of the capital costs of these plants have already been recouped, the plant owners have every incentive to keep them on-line. Reliant states that there are none, unless mandated to do so by the Commission.

Electric Cooperatives

AEPCO, Southwest, and Sierra and the REDCs state that an incentive may exist to remain with installed, depreciated resources under either regulation or competition. On the other hand, newer more efficient plants may be constructed if they are economically beneficial.

Residential Consumer Advocates

Arizona Consumers Council states that the Commission has authority, under the Constitution and Commission rules, to insist on compliance with environmental programs and to start shifting use to plants which are cleaner and comply with environmental orders. RUCO states that the competitive electric market and the vertically integrated utility models do not necessarily cause utilities to replace older, more polluting plants with cleaner plants. In either environment, the older coal-fired plants will have lower variable costs and lower fixed costs due to substantial depreciation.

Industrial Consumers

AECC states that there is not a lot of incentive to do this unless the new plant can be put into rate base.

Environmental/Energy Efficiency Advocates

The LAW Fund states that there are no incentives under either model for generator owners to replace older, dirtier plants. Under the regulated model, SRP and the co-owners of the Navajo generating plants agreed to retrofit the plants to reduce sulfur dioxide emissions. It is uncertain whether they would be as willing to do so in a competitive market since their costs would increase. Recovery of the capital costs of traditional baseload plants (coal-fired or nuclear) has been sufficient to keep regulated utilities in business.

Utility Investors

AUIA states that if any plant is in compliance with environmental standards, there is no incentive to replace it unless it has reached the end of its useful life or major efficiency improvements can be achieved.

8. Under the competitive electric market model, what incentives exist to build newer plants that are less damaging to the environment to replace older, dirtier plants?

Investor-Owned Utilities

APS states that the incentives are the same as under the vertically integrated model. Stricter environmental regulation raises the costs of older units and reduces the costs of newer units. TEP states that the primary incentive to build a new plant in the competitive marketplace would be that it has an economic advantage over competing plants.

Wholesale Power Producers

Panda and Reliant state that new cleaner plants will replace older dirtier plants under the competitive electric market model because the older plants are more costly to operate. Without competitive pricing of generation, there is little incentive to build new plants to replace older, dirtier, less efficient, more expensive plants.

PG&E states that the siting process under the competitive model results in proposed plants conforming to today's environmental requirements as compared to the existing vintage plants that have not been required to meet current environmental requirements.

Electric Cooperatives

AEPCO, Southwest, and Sierra and the REDCs state that an incentive may exist to remain with installed, depreciated resources under either regulation or competition. On the other hand, newer more efficient plants may be constructed if they are economically beneficial.

Residential Consumer Advocates

Arizona Consumers Council states that if newer plants can be built that are less damaging to the environment and produce energy for less than existing plants, they will sell energy as long as competition is on a level playing field.

Industrial Consumers

AECC states that competitive generators would not build new plants for the express purpose of replacing older, dirtier plants. However, as generation supply increases, inefficient plants are likely to be "out of the money" on an increasingly frequent basis, except in must-run conditions.

Environmental/Energy Efficiency Advocates

The LAW Fund states that in a competitive market, investment decisions are motivated by expected financial returns.

Utility Investors

AUIA states that the economics of the plant is the key to its viability in the competitive environment. Any plant must achieve competitive short-run marginal costs or it will not be dispatched.

9. ***Under the vertically integrated utility model, what disincentives (regulatory, financial, and ratemaking) exist to build newer plants that are less damaging to the environment to replace older, dirtier plants?***

Investor-Owned Utilities

APS states that there are the same economic and siting disincentives under both regimes. However, additional disincentives under regulation are that traditional ratemaking considers the recovery of sunk costs in evaluating the economics of new resource additions and that utilities are generally unable to raise prices during facility construction. TEP states that a major disincentive is uncertainty, including the outcomes of hearings on siting, ratemaking, and prudency, and approvals or permits involved with air, water, and land.

Wholesale Power Producers

Reliant states that in the vertically integrated utility model, new generation was added only after a regulatory-based need was determined, resulting in longer lead times. Older, dirtier plants were kept on the system if they were considered used and useful from an operating perspective rather than an economic perspective.

Electric Cooperatives

AEPCO, Southwest, and Sierra and the REDCs state that an incentive may exist to remain with installed, depreciated resources under either regulation or competition. On the other hand, newer more efficient plants may be constructed if they are economically beneficial.

Residential Consumer Advocates

Arizona Consumers Council states that one disincentive is the ability to have ratepayers pay for such plants under rate of return regulation.

Industrial Consumers

AECC states that older plants have the advantage of being heavily depreciated and therefore cost little in rate base. In addition, their typically higher operating costs are fully recovered as an operating expense in rates. An older plant may have a locational advantage where it provides voltage support and/or relief from load pocket congestion.

Utility Investors

AUIA states that if the older plants are in compliance, the ratemaking regime does not contemplate removing plants from service that are used and useful and adding new facilities that are not needed to rate base. It could be dangerous to sacrifice fuel diversity for a marginal environmental gain.

10. Under the competitive electric market model, what disincentives exist to build newer plants that are less damaging to the environment to replace older, dirtier plants?

Investor-Owned Utilities

APS states that a competitive market is driven by profitability. APS adds that increased public and regulatory opposition during the site selection process may discourage companies from building new facilities. TEP states that a merchant generator in the competitive marketplace faces the same disincentives as a regulated public service corporation, except that the merchant generator does not face an after-the-fact prudency review, but it must present a new plant to the financial market for approval in order to obtain financing.

Wholesale Power Producers

Panda states that the variances requested by APS and TEP have cast significant uncertainty over the current Rules. The uncertainty could delay or result in the cancellation of new electric generation facilities planned for Arizona, thus exposing consumers to increased rates and power shortages due to insufficient reserve margins and fluctuations caused by demand outweighing supply.

PG&E states that competitive generation suppliers will only build new, more efficient power plants in those areas where a competitive wholesale market exists and where there is opportunity to sell the power to either load-serving entities or alternative energy suppliers. Reliant states that the lack of economic viability of the new plant would be the only impediment in a well functioning competitive electric market model.

Electric Cooperatives

AEPCO, Southwest, and Sierra and the REDCs state that an incentive may exist to remain with installed, depreciated resources under either regulation or competition. On the other hand, newer more efficient plants may be constructed if they are economically beneficial.

Residential Consumer Advocates

Arizona Consumers Council states that a disincentive is the ability of suppliers to sell such energy to the utilities and the public. If new plants cannot produce energy at a lower cost, they could not sell it.

Industrial Consumers

AECC is not aware of any disincentives.

Utility Investors

AUIA states that newer plants should be more efficient, but market conditions may permit older plants to survive the cut on marginal cost.

11. During Arizona's period of reliance on the vertically integrated utility model, what emphasis did the Commission place on pollution control measures in Certificates of Environmental Compatibility?

Investor-Owned Utilities

APS states that the Commission has required compliance with all applicable environmental laws and requirements. TEP states that in the past few years, the Commission has place additional conditions regarding pollution control measures on CECs, but that it is a result of the Commissioners balancing the need for generating plants with the desire to protect the environment, not because of a competitive marketplace.

Wholesale Power Producers

PG&E states that the Commission's filing system for the first 15 years of CEC issuance makes obtaining such information virtually impossible. In addition, CECs are typically obtained prior to issuance of permits and licenses required by environmental laws. Thus, pollution control measures in a CEC may turn out to be more or less stringent than the measures subsequently required to comply with. PG&E further states that it is possible that CECs issued prior to adoption of the competitive market model contained less stringent requirements on average, were much less specific, more related to aesthetic rather than specific environmental impacts, and much more narrowly drawn.

Electric Cooperatives

AEPCO, Southwest, and Sierra state that very few power plants were certificated in this time period.

Residential Consumer Advocates

Arizona Consumers Council does not think any measures were taken outside possible compliance with federal laws.

Utility Investors

AUIA states that the Commission largely ceded the application of pollution control measures to EPA or local agencies assigned to carry out EPA directives.

a. What is the most stringent pollution control measure placed on a CEC during Arizona's reliance on the vertically integrated utility model?

Investor-Owned Utilities

APS states that the Commission required APS to actively monitor visibility impacts of new additions to the Cholla Generating Station both during and after completion of the plants. Other conditions addressed the applicant operating particulate and sulfur dioxide removal equipment as close to design efficiency as possible, and the location and treatment of the plant's ash disposal area. In 1976, the Commission added water management conditions.

12. Since Arizona's adoption of a competitive electric market model, what emphasis did the Commission place on pollution control measures in Certificates of Environmental Compatibility?

Investor-Owned Utilities

APS states that specific measures included in a certificate of environmental compatibility do not appear to be affected by whether the market is vertically integrated or competitive.

Wholesale Power Producers

Panda states that since the adoption of a competitive electric model, the Commission has used the CEC process to impose pollution control measure requirements on its approvals of new electric generation plants. PG&E states that CECs issued after adoption of the competitive electric market model differed from earlier CECs in the following areas: greater specificity of environmental impact mitigation measures, more stringent control technology requirements, restrictions on water usage and sources, compensatory environmental mitigation, and socio-economic mitigation. These additional, more stringent, and more extensive conditions in CECs are directly traceable to the advent of a competitive market and the need of merchant plant companies to build power plants to compete in that market.

Reliant states that the Commission has been quoted on several occasions to the effect that each CEC application is reviewed on a case-by-case basis and as time goes on the bar is raised with subsequent requests.

Utility Investors

AUIA does not think that the difference in regulation is attributable to the differing market models. It is a function of he personalities and priorities of the Commissioners.

a. ***What is the most stringent pollution control measure placed on a CEC since Arizona's adoption of a de-regulated utility model?***

Investor-Owned Utilities

APS believes that the most stringent CEC issued for a generating plant today is likely the Santan CEC issued to SRP.

Wholesale Power Producers

Panda states that the CEC for the Duke Energy Arlington Valley plant may impose the most stringent pollution control measures on any electric generation facility proposed since the onset of competition. Reliant mentions that the CEC was conditioned on the requirement that it install LAER control equipment. The Santan CEC has a five-year rolling evaluation as LAER technology advances.

Electric Cooperatives

AEPCO, Southwest, and Sierra state that it would probably be the LAER condition imposed in the Duke II rehearing.

Utility Investors

AUIA states that the most stringent application of pollution control measures to date was in the Santan CEC, but it had nothing to do with the competitive model.

b. ***What is the likelihood that the measure would have been placed on a similar CEC in a vertically integrated utility model?***

Investor-Owned Utilities

APS states that the conditions imposed in the Santan CEC are related to the urban location of the plant and not to whether the applicant is vertically integrated or a merchant generator. TEP states that the Commission would have placed the same conditions on CECs whether or not the Electric Competition rules were in place.

Wholesale Power Producers

Panda states that the stringent environmental controls placed on the Duke facility as well as the recent denial of CECs to other applicants due to environmental concerns would have been unlikely under the old vertically integrated utility model. Reliant states that the Commission bases its decisions on the impact new power plants have on all of Arizona's natural resources under either paradigm. If economics allow, merchants have raised the bar voluntarily.

Electric Cooperatives

AEPCO, Southwest, and Sierra states that the Commission's view of its jurisdiction under the siting statutes has changed radically in the past two years. The Commission might be less inclined to impose costly conditions on regulated plants because it would then have to approve higher rates to support them.

13. During Arizona's period of reliance on the vertically integrated utility model, what amount of excess generating capacity existed in Arizona?

Investor-Owned Utilities

APS is not aware of any installed capacity built or acquired by Arizona utilities that was not used to serve Arizona consumers, and APS is not aware of any generic Commission finding of excess capacity. TEP states that excess generating capacity has been the subject of debate over the years. TEP further states that the WSCC 1997 Loads & Resource Summary reported a 6.2 percent margin of resources over firm load, and the WSCC 2000 Loads & Resource Summary reported an 8.0 percent margin.

Electric Cooperatives

AEPCO, Southwest, and Sierra state that this figure has varied widely as new plants have come on line creating excess capacity at that time and then, over time, demand approached supply and new facilities were constructed.

Residential Consumer Advocates

Arizona Consumers Council thinks that excess capacity was generally within existing rules. RUCO states that excess capacity appears to be prevalent in both regimes, except for recent tightening of reserve margin. Less reserve capacity would be needed to preserve reliability under the vertically integrated utility model.

Industrial Consumers

AECC states that Arizona's vertically integrated utilities, like most western utilities, experienced considerable excess generating capacity for many years. In recent years, the capacity bubble contracted substantially with demand growth.

Environmental/Energy Efficiency Advocates

The LAW Fund stated that excess generating capacity existed in Arizona for several years during the late 1980s and early 1990s. That excess capacity included APS' share of Palo Verde Unit 3 and portions of TEP's Springerville Units 1 and 2. SRP suspended plans to add to the Coronado generating station in the late 1980s to avoid excess capacity.

Utility Investors

AUIA states that excess capacity depends on the kind of generation, when the excess happens, and a host of market factors.

14. Since Arizona's adoption of a competitive electric market model, what amount of excess generating capacity existed in Arizona?

Investor-Owned Utilities

APS states that the lack of centralized planning in a competitive generation market and the inability to tie specific resources to specific markets may make competitive markets more susceptible to "boom and bust" cycles with price volatility. TEP states that the volatile gas and wholesale market in 2000 made generating plant investments very attractive. TEP further states that the 2002 WSCC Loads & Resource Summary forecasts an 11 percent projected margin of resources over firm load for the 2002 summer peak.

Wholesale Power Producers

Panda does not believe there is currently any excess capacity in Arizona during peak periods. During certain times of the year, more costly electric power is being imported into the state. Reliant states that currently there is no excess capacity in Arizona. The amount of excess capacity in the future will depend on the purchasing practices and the reserve margin obligations established for load-serving entities in the state.

Electric Cooperatives

AEPCO, Southwest, and Sierra state that excess capacity existed a few years ago. That constricted in 2000-2001.

Residential Consumer Advocates

Arizona Consumers Council states that Arizona utilities are still under mandate to have excess peak power capability.

Industrial Consumers

AECC responds "little or none."

Environmental/Energy Efficiency Advocates

The LAW Fund states that the southwest appears to be entering a period of excess generating capacity. Western Systems Coordinating Council projections of reserve margins suggest excess capacity from 2003 through 2008 or later.

Utility Investors

AUIA states that the concept of excess capacity is largely irrelevant in a competitive market, since the risk falls entirely on the producer.

Chairman Mundell's Letter of January 30, 2002

I. Corporate Structure and Affiliate Relations

1. If the U.S. Congress repeals the Public Utility Holding Company Act of 1935 ("PUHCA" or "Act") PUHCA –

a. **what regulatory protections would be lost for Arizona consumers?**

Investor-Owned Utilities

APS states that a straight repeal of PUHCA would not affect the regulatory protections available to Arizona consumers for the simple reason that most Arizona electric utilities do not use the holding company structure. Those that do, such as APS, are currently exempt from all provisions of PUHCA except section 9(a)(2). That section addresses the acquisition be APS' parent, PWCC, of additional public utilities.

TEP does not believe that the repeal of PUHCA would result in the loss of regulatory protections for Arizona consumers. PUHCA was enacted to regulate transactions between a utility and its affiliates. TEP notes that the Commission has enacted affiliated interest rules to review such transactions and require the reporting or records relating to those transactions.

Wholesale Power Producers

Panda states that a repeal of PUHCA is highly unlikely given recent events such as the Enron bankruptcy. In addition, Panda comments that a repeal of PUHCA would not leave Arizona consumers unprotected because FERC and the Commission will have the authority to prevent cross-subsidies between a utility and its affiliates and authority to approve mergers and acquisitions.

Residential Consumer Advocates

RUCO discusses purposes of PUHCA as referred to in the National Association of State Utility Consumer Advocates resolution 1996-04. Some of the purposes discussed include market power mitigation and the prevention of preferential affiliate transactions.

b. what would be the risks for Arizona consumers?

Investor-Owned Utilities

APS and TEP do not believes hat there would be little or no risk to Arizona consumers.

Residential Consumer Advocates

The Arizona Consumers Council comment that if the Commission could not regulate those issues under the Act, Arizona consumers would be at the mercy of the market.

c. ***for any identifiable risks, are the risks reduced or increased under competitive retail regime?***

Investor-Owned Utilities

APS comments that the only identifiable "risks" are the expansion of existing Arizona holding companies into other areas and the expansion of out-of-state holding companies into Arizona, both which can be addressed by the Commission in the absence of PUHCA.

TEP refers to its response in Question Nos. 1.a. and 1.b.

Residential Consumer Advocates

The Arizona Consumers Council comments that risks in a competitive market increase if there is little or no oversight.

RUCO states that a competitive retail regime would not reduce the risks alluded to in the National Association of State Utility Consumer Advocates resolution 1996-04.

2. ***What is the extent of the Commission's authority to protect retail consumers from any potential adverse consequences resulting from multistate companies operating in either wholesale or retail markets in the state?***

Investor-Owned Utilities

APS comments that the Commission can take actions at FERC against entities that exclusively participate in the wholesale market. APS further comments that to the extent that the Commission belives that transactions between jurisdictional Arizona electric utilities and such "multi-state companies" may be imprudent, it can investigate such transactions. APS mentions that if such companies participate in the retail market, they subject themselves and their affiliates to Commission regulation, either directly as public service corporations or as affiliates under A.A.C. R14-2-801 to 806. The Commission also has limited constitutional authority over non-public service corporations pursuant to Article 15 section 4 and 5 of the Arizona Constitution.

TEP does not believe that there are adverse consequences from multi-state companies operating in the state. Please see responses to question Nos. 1 and 15.

Wholesale Power Producers

Panda states that if the competitive market is not functioning effectively, consumers can remain as standard offer customers with the full protection of Commission regulated rates. In addition, Panda notes that there are a variety of state and federal laws regulating various business practices. Reliant does not believe that there is an impact on the Commission's authority to protect retail customers whether or not retail customers are served by an in-state or multi-state provider.

Electric Cooperatives

Trico describes the Commission's authority as it is prescribed in Article XV, section 2, 3, and 14 of the Arizona Constitution. Trico comments that the Commission is mandated to regulate the rates of out-of-state companies providing retail electricity and has the duty to review all purchases of electricity by wholesale providers who sell to retail providers.

Residential Consumer Advocates

The Arizona Consumers Council comments that the Commission's powers are broad and sweeping but the courts would have to determine the extent of protection in both markets.

RUCO comments that the Commission might protect ratepayers through its power to set local retail rates for public service companies and requiring those companies, if necessary, to build facilities to meet their obligations to serve the public. In addition, RTO policy should be watched for conflicts with the Commission's jurisdiction under Arizona law.

3. ***How would the existence of effective retail competition in Arizona affect your responses to Questions 1 and 2 above?***

Investor-Owned Utilities

APS comments that the existence of competition reduces both the opportunity for consumer abuse and the need for active regulatory intervention. However, it would not reduce the Commission's legal authority to take actions to protect that market from abuses such as misleading advertising, and deceptive marketing practices.

TEP believes that the responses to questions 1 and 2 would be the same in a competitive market place.

Electric Cooperatives

Trico comments that retail competition that complies with the Constitution and laws of Arizona will provide retail consumers protection.

Residential Consumer Advocates

The Arizona Consumers Council comments that it would depend on the meaning of the term effective, if you have many buyers and sellers operating in an open dynamic market, regulation will not be necessary.

RUCO states that the Commission's coercive powers probably become more of a "backstop" for disciplining market participants and coercing appropriate behavior by public service companies.

4. What is the extent of any impact of effective federal or state regulation to protect Arizona wholesale and retail consumers, if a holding company is (a) registered or (b) "exempt" under PUHCA?

Investor-Owned Utilities

APS states that if any Arizona electric utility is part of a registered holding company the Commission would find some of its authority preempted by the SEC under PUHCA, as would FERC. APS comments that exempt holding companies and their retail affiliates in Arizona are subject to Commission and FERC authority.
Wholesale Power Producers

TEP does not believe PUHCA has significant impact on effective federal or state regulation to protect Arizona wholesale and retail consumers whether the holding company is registered or exempt. The protections afforded under PUHCA are largely duplicative of those provided by state Commissions such as the ACC.

Wholesale Power Producers

Panda states that there is no impact.

Residential Consumer Advocates

RUCO states that the state's regulatory structure is not materially affected. RUCO further states that the state might have slightly broader authority over the exempt entities' affiliate transactions in the sense that federal oversight would not exist to preclude exercise of the state's regulatory powers.

II. Questions Specifically for Retail Suppliers as Defined Above

5. Explain the retail supplier's corporate structure.

Investor-Owned Utilities

APS states that it is a Subchapter C corporation with all of its outstanding common stock owned by PWCC. APS has publicly-held debt, both secured and unsecured, but no preferred stock.

TEP refers to its answer provided in Question No. 12.

<u>Electric Cooperatives</u>

Sierra comments that it is a Commission certificated ESP that is a non-profit member owned cooperative with three classes of members. Class A members include six Arizona and California distribution cooperatives, Class B members are AEPCO and SW Transmission, and Class C members are others that receive services from Sierra. The REDCs provide a description of the coops, where they purchase their power from and the relationships between the REDCs.

6. ***Identify all subsidiary companies and the businesses in which they are engaged.***

Investor-Owned Utilities

APS states that Axiom Power Solutions (inactive), Bixco, Inc. (inactive), APS foundation, Inc. (charitable non-profit), PWENEWCO Inc. (non-operating corporation formed to effectuate the transfer of generation assets to PWEC) are subsidiaries of APS.

TEP refers to the subsidiary companies set forth in its answer provided in Question No. 12.

7. ***Identify all affiliate companies and the businesses in which they are engaged.***

Investor-Owned Utilities

APS states that in addition to PWCC, APSES (competitive ESP), El Dorado Investment Company (venture capital), PWEC (generation) and SunCor Development Company (real estate) are direct affiliates of APS. APSES has three subsidiaries involved in district cooling projects which include Tucson District LLC, Northwind Phoenix LLC, and Northwind Arizona Development LLC. PWEC created a subsidiary, Gen West LLC to own its proposed generating facility in Nevada. PWEC and SunCor also jointly own APACS Holdings LLC, which is a member of Copper Eagle Gas Storage, LLC, which is developing a gas storage site near Luke Air Force Base in conjunction with an affiliate El Paso Natural Gas Co.

TEP refers to the affiliate companies set forth in its answer provided in Question No. 12.

Utility Investors

8. ***Identify each entity that owns or has control of 5% or more of an affiliate of the retail supplier, and describe the businesses in which that entity is engaged.***

Investor-Owned Utilities

APS states that PWCC is a 100% owner of its four first tier subsidiaries. APSES is the sole owner of its three affiliates and APS is a sole owner of its subsidiaries. PWEC is the 100%

owner of Gen West LLC. SunCor and El Dorado have numerous investors in their various project-specific affiliates some of whom have interests greater that five percent.

TEP provides detailed in-depth information regarding it affiliates their relationships and ownership.

> *9. **Describe the financial relationships among the various affiliates and subsidiaries such as pledges of assets and encumbrances and contracts for services and goods.***

Investor-Owned Utilities

APS provides detailed in-depth information regarding the financial relationships between itself, its subsidiaries and its affiliates.

TEP indicates that a description of the relationships between the various affiliates and subsidiaries is described in the response to Question No.12. TEP comments that any time spent by TEP employees on corporate and administrative services for subsidiaries and affiliates is charged t the appropriate entity. TEP lists several loans to affiliates.

> *10. **Explain whether the retail supplier, or any affiliate or subsidiary of the retail supplier, is regulated by the Securities and Exchange Commission (SEC) as either an "exempt" or "registered" public utility holding.***

Investor-Owned Utilities

APS comments that PWCC is exempt from all of the provisions of PUHCA, except Section 9(a)(2). Neither APS or APSES, are a holding company and therefore are not regulated by the SEC under PUHCA.

TEP notes that Unisource and TEP are exempt public utility holding companies under Section 3(a)(2) of PUHCA.

> *11. **Identify any waivers or "no-action" letters the retail supplier, its affiliates, its subsidiaries, or other associated companies has received in the last 15 years from the SEC under PUHCA or the Investment Act of 1940 or from FERC under the Federal Power Act.***

Investor-Owned Utilities

APS provides several examples of waivers and no-action letters under PUHCA, the Investment Act of 1940, and the Federal Power Act.

TEP provides several examples of waivers and no-action letters under PUHCA, the Investment Act of 1940, and the Federal Power Act.

Electric Cooperatives

AEPCO states that in conjunction with its RUS approval of its restructuring, AEPCO, SW Transmission, and Sierra obtained a PUHCA "no action" letter.

12. Provide copies of filings to the SEC and FERC made by the retail supplier and any affiliates or subsidiaries in the last five years pursuant to the agency's administration of PUHCA.

Investor-Owned Utilities

APS has provided Form U-3A-2 filed February 28, 2001, February 29, 2000, March 1, 1999, February 27, 1998, and February 28, 1997. APS has indicated that it has also filed on September 12, 2000, an application (File No. 70-9745) with the SEC pursuant to Section 9(a)(2) of PUHCA requesting permission to establish a new public-utility company subsidiary in connection with the proposed corporate reorganization involving the relocation of certain generation assets from APS to PWEC.

TEP references "UniSource Energy Corporation and Tucson Electric Power Company staement of Holding Company Claiming Exemption Under Rule U-3A-2 from the provisions of the Public Utility Holding Company Act of 1935" for the years ending December 31, 1997, 1998, 1999, 2000.

13. If the retail supplier is a subsidiary of a registered holding company, identify any SEC-approved contracts with affiliates or subsidiaries in the last 5 years.

Investor-Owned Utilities

APS and TEP comments that this does not apply.

III. Divestiture or Corporate Separation

14. How would the divestiture or transfer of assets of vertically integrated utilities now serving Arizona affect the Commission's regulatory authority over the divested entities? What controls or limitations might the Commission place on divestiture or transfer of assets to limit any loss of authority over the divested assets?

Investor-Owned Utilities

APS comments that the electric competition rules currently in effect permit divestiture of generation to an affiliate and that affiliate is subject to A.A.C. R14-2-801, et seq. If the affiliate were also selling power to the investing utility, the Commission could review such power acquisitions. APS further comments that the use of long-term buy-back power agreements, such as the proposed purchase power agreement is a traditional means used by regulators to maintain control and provides the means by which the divesting entity can transition to a fully competitive market while managing risk.

TEP states that subsequent to the divestiture of generation assets the Commission would no longer retain jurisdiction over the newly formed generation subsidiary to the extent the subsidiary provided wholesale energy offerings.

Wholesale Power Producers

Panda comments that the provision of retail services by a UDC will be subject to Commission jurisdiction while the entity to which the generating assets are transferred to will be subject to the jurisdiction of FERC. Panda further comments that the Commission governs transactions between utilities and their affiliates and has the authority to review contracts of UDCs with unaffiliated or affiliated entities for reasonableness and prudency.

Reliant states that the Commission would continue to have control over the rules governing retail transactions and authority over divested assets to the extent permitted under state law.

Electric Cooperatives

AEPCO, Southwest, and Sierra comment that generally divestiture or transfer of assets to wholesale entities will remove them from Commission jurisdiction.

Trico comments that AEPCO, Duncan, Grahm, Sulphur and Trico have taken a legal position in the pending deregulation case before the Court of Appeals that involuntary divestiture is unconstitutional. Trico further comments that the Commission's regulatory authority of regulated utilities who do not voluntarily divest is unimpaired.

Residential Consumer Advocates

RUCO comments that some argue that when a regulated entity transfers to a wholesale power entity assets dedicated to local public service FERC becomes the sole and exclusive authority to determine whether rates are just and reasonable. RUCO suggests that a solution might be to require a conditional conveyance with a reversionary feature that immediately transfers title back to the regulated entity in the event the Commission loses or is about to lose jurisdiction.

Utility Investors

AUIA comments that currently the Commission does not have authority over generation because it has been declared a competitive service not subject to Commission jurisdiction. The Commission will continue to lack jurisdiction when the generation assets are spun off to an affiliated entity. AUIA further comments that the Commission's control over generating assets is through ratemaking, where the prudence of the UDC's power acquisition costs are open to scrutiny.

15. How would the divestiture or transfer of assets of vertically integrated utilities now serving Arizona affect federal jurisdiction under the FERC and the SEC over the divested entities?

Investor-Owned Utilities

APS comments that the divestiture or transfer of assets would have no effect on FERC or SEC jurisdiction over either the divesting entity or the entity to which such assets were divested.

TEP comments that the transfer of generation assets would not affect FERC jurisdiction. However, FERC has recognized that wholesale ratemaking does not, as a general matter, determine whether a purchaser has prudently chosen from available supply options. FERC has reserved that determination for the state Commission in some cases. TEP further comments that in the case of the transfer of transmission assets, FERC would exercise jurisdiction over the rates, terms, and conditions of any unbundled retail transmission service. In regards to the SEC TEP comments that a definitive assessment of the impact of the transfer of assets of the vertically integrated utilities under PUCHA can only be undertaken based on the facts of a specifically proposed transaction.

Wholesale Power Producers

Panda states that neither the divestiture nor transfer of generation assets would substantially change FERC or SEC regulation of utility owned generation assets. Reliant comments that wholesale sales are subject to FERC authority and the divested entity would be subject to various market power reviews required by FERC.

Residential Consumer Advocates

RUCO refers to its answer provided in Question No. 14 of this set of questions.

16. How would the potential effects of divestiture or transfer of assets on Commission authority differ under a competitive retail regime than under a monopoly regime?

Investor-Owned Utilities

APS states that the effect of the Commissions authority is unchanged as between a competitive retail regime and a monopoly regime. TEP comments that generation divestiture under either a competitive regime or monopoly regime would result in the Commission relinquishing jurisdiction over the assets engaged in providing wholesale power to FERC.

Wholesale Power Producers

Panda states that the Commission would retain jurisdiction over retail rates and FERC would retain jurisdiction over wholesale rates regardless of whether such a separation occurs under a competitive or monopoly framework. Reliant refers to its response in Question No. 15.

Electric Cooperatives

Trico comments that since a competition retail regime and a monopoly regime are subject to the same constitutional and statutory provisions, there should be no difference in effect.

Residential Consumer Advocates

RUCO refers to its answer provided in Question No. 14 of this set of questions.

17. How would a requirement that company services, such as generation services, be offered only through a separate corporate affiliate affect the Commission's regulatory authority and any risks identified in response to the questions above?

Investor-Owned Utilities

APS comments that that the Commission already has such a provision and it is embodied in the electric competition rules as well as APS' Code of Conduct. APS also comments that these provisions were designed to protect consumers from the risk of not divesting assets rather than the risk seemingly supposed by the question. APS also notes that the receiving entity will itself engage in retail competition, it would become directly regulated by the Commission in the same manner of other public service corporations.

TEP states that the transfer of generation assets to an affiliate would result in the Commission losing authority to regulate the newly formed generation entity.

Wholesale Power Producers

Reliant comments that if full divestiture is not required, complete functional separation with a strong code of conduct should be required. Reliant further comments that the Commission's authority would be the described in its response to Question No. 14.

Electric Cooperatives

AEPCO, Southwest, and Sierra do not believe that there should be any such requirement because jurisdictionally the Commission lacks authority under the Constitution or statutes and it denies economies of scope and scale.

Trico comments that nonprofit member owned cooperatives cannot have corporate affiliates as the term is defined in A.A.C. R14-2-801, *et seq*.

Residential Consumer Advocates

RUCO refers to its answer provided in Question No. 14 of this set of questions.

18. For any risks resulting from a divestiture requirement or a requirement that competitive services be offered through a separate affiliate, how might those risks be eliminated or reduced? Specifically –

a. What actions might the Arizona Commission take?

Investor-Owned Utilities

APS comments that if the separate affiliate will be providing retail electric services, as the regulatory agency the Commission can take lawful action to protect consumers. APS further comments that if the generation is being divested to an affiliate willing to enter into a cost-based buy back agreement, the customer is insulated from any potential risks.

TEP comments that the Commission ensures that the risks associated with divestiture are minimized through the Commission's review and approval of the utilities divestiture plan, settlement agreement, codes of conduct, and policies and procedures

Wholesale Power Producers

Panda suggests that the Commission could continue to uphold the affiliated interest rules, support the AISA protocols, and require the UDCs to develop codes of conduct.

Reliant comments that a code of conduct should ensure that the competitive affiliate is not receiving preferential treatment. In addition, Reliant suggests that a capacity auction process can reduce market concentration.

Electric Cooperatives

Trico comments that by exercising its mandatory duties pursuant to the Constitution and A.R.S. § 40-285, the Commission should be able to eliminate such risks

<u>Residential Consumer Advocates</u>

The Arizona Consumers Council comments that without oversight and regulation, the Arizona distribution companies would be at the mercy of generators, especially if the number of generators is limited or any single generation company gains a significant share of the market. RUCO states that these questions are ultimate policy questions for the Commission to decide and that the answers are fraught with legal uncertainty at the state and federal level.

b. Are there actions that the Commission might encourage the FERC or the SEC to take to maintain adequate oversight for the protection of ratepayers?

Investor-Owned Utilities

APS states that the Commission should encourage FERC actions that promote open competitive wholesale markets that will benefit Arizona consumers regardless of the development of retail electric competition. APS further states that the Commission should support the SEC in encouraging utilities under its jurisdiction to follow appropriate accounting practices that accurately reflect the firm's current value and profitability.

TEP comments that FERC has taken steps to ensure adequate oversight for the protection of ratepayers in that FERC has mandated market monitoring framework and code of conduct restrictions on RTO's. In addition, TEP notes that FERC has strongly enforced policies and requirements designed to ensure that there is no potential for harm to ratepayers due to transactions between a vertically integrated utility and an affiliate. FERC requirements address non-power goods and services, as well as power supply arrangements.

<u>Wholesale Power Producers</u>

Reliant comments that FERC and the SEC have sufficient authority adequate oversight related to any divestiture of generation assets.

Commissioner Irvin's Letter of February 7, 2002

I. *Arizona Independent Scheduling Administrator*

Please address whether Arizona's Constitution prohibits the Commission from giving up any authority with respect to the pricing of services by public service corporations which occur solely within the state.

Investor-Owned Utilities

APS states that the Arizona Constitution does not prohibit the Commission from giving up authority to federal agencies including FERC. APS further comments that when the Commission's pricing and ratemaking authority is preempted by federal law the Commission must defer to FERC under the "supremacy clause" of the U.S. Constitution.

TEP states that the question of what the Commission may delegate to the competitive marketplace has been in debated and litigated throughout the development and implementation of the electric competition rules.

Wholesale Power Producers

Panda states that the issue is before the Arizona Court of Appeals. Panda further comments that the Commission may not relinquish all of its rate setting authority with respect to public service corporations.

Electric Cooperatives

AEPCO, Southwest and Sierra state that the Federal Power Act grants FERC jurisdiction over wholesale power sales and transmission by public utilities and jurisdiction over retail sales and distribution is left to the states. They further comment that this issue surrounding the transmission component of retail end-use is pending before the Supreme Court.

The REDCs state that they are UDCs under the electric competition rules and are not subject to FERC jurisdiction. Trico states that the Constitution prohibits the Commission from giving up this authority.

Should Arizona be willing to let the federal government take over pricing jurisdiction (market-based rates) for all retail transactions which occur in the state, or is this an inevitable (and proper) result of opening retail markets to competition?

Investor-Owned Utilities

APS states that the implementation of electric competition will not result in the federal government taking over all aspects of ratemaking and pricing in the state. APS further comments that FERC has asserted exclusive jurisdiction over transmission service pricing. APS further states that the Commission will retain jurisdiction over retail sales, distribution services, metering, and billing.

TEP refers to its response to question number 15 of Chairman Mundell's supplemental questions dated January 30, 2002.

Wholesale Power Producers

Panda comments that retail rates are not and should not be FERC jurisdictional. Panda further comments that adopting market based rates for retail sales will not lead to federal jurisdiction over retail pricing. Reliant comments that FERC has sufficient authority over market based pricing to ensure that market power does not exist.

The Cooperatives

Trico states that if the federal government enacts legislation that preempts the provisions of the Constitution and State Statutes regarding retail pricing and transaction under the Supremacy Clause the State Constitution and statutes would be ineffective. However, Trico suggests that the Arizona Supreme Court held that the 1996 Federal communications Act did not preempt the applicable provisions of the Constitution and Arizona statutes.

Industrial Consumer Advocates

AECC comments that the pricing jurisdiction for retail generation service transactions would fall under the purview of the ACC. AECC further comments that a market-purchase requirement for the provision of standard offer would increase the amount of retail service in Arizona that originated from wholesale market purchases which are subject to FERC jurisdiction.

Can Arizona's UDCs modify their tariffs with the FERC to conform with AISA protocols so that retail transactions can still take place without the AISA? How may times has the AISA been used to resolve disputes over transmission issues to date?

Investor-Owned Utilities

APS and TEP comment that the UDCs can modify their tariffs to conform with the AISA protocols so that retail transactions can take place in the absence of the AISA. TEP states that the Commission could adopt the AISA protocols as part of revised electric competition rules. APS and TEP comment that the AISA has never resolved disputes over transmission issues.

Wholesale Power Producers

Panda states that it should be possible for the UDCs to incorporate AISA protocols into their transmission tariffs but an easier solution would be to incorporate the AISA protocols into a FERC approved RTO which includes Arizona. Panda comments that it is not aware if the AISA has been used to settle transmission disputes.

Reliant states that the UDCs should modify their FERC tariffs to incorporate AISA protocols if the AISA is no longer in place.

Electric Cooperatives

The Cooperatives state that the utilities could modify their transmission tariffs to conform with the AISA protocols so that retail transactions can occur with out the AISA itself. The Cooperatives comment that they are unaware of any dispute that the AISA has resolved.

Industrial Consumer Advocates

AECC comments that in the past FERC has been unwilling to accept modifications to their tariffs unless the change has been part of the AISA. AECC further comments that even if the modifications were approved by FERC, such an arrangement would lack the forum provided by the AISA, for making protocol modifications to address changed conditions and would result in different protocols being employed in different utility territories. AECC states that it is not aware of any transmission dispute provided by the AISA.

II. Retail Electric Competition Rules ("Rules"); Markets

If the majority of market participants intend to market electricity only to industrial, large commercial and load-serving ESP entities, should retail markets be limited by load size to allow those entities with true bargaining power to negotiate Direct Access?

Investor-Owned Utilities

APS states that limiting the ability of any Arizona consumer to select Direct Access when an ESP is available to serve, would be viewed as discriminatory. TEP states that all market participants regardless of size and bargaining power should be allowed to negotiate for Direct Access service.

Wholesale Power Producers

PG&E states that the lack development of retail access is due to lack of significant savings from exercising choice however, experience in other deregulated markets demonstrates that the price direction is downward. PG&E further comments that retail market participation is limited in early years because cost savings are frequently marginal and cost communication to customers is flawed. PG&E also comments that as wholesale competition becomes more vigorous price signals are better communicated and the retail market will become increasingly more robust.

Reliant comments that there is no reason to limit the benefits of competition to certain classes of customers and if desired incentives could be provided to retail providers to serve certain classes of customers.

Electric Cooperatives

AEPCO, Southwest and Sierra and REDC comment that certain loads by their nature will not provide a potential to realize profit. They further comment that residential, small commercial, and small industrial service are undesirable loads because they are costly to maintain.

Trico comments that the cooperatives dispute the constitutionality of electric deregulation. Trico further comments that retail markets limited by load would be appropriate if the Commission undertakes a revision of the rules that is constitutional or deregulation is constitutional.

Residential Consumer Advocates

The Arizona Consumers Council states that if the competitive market would be open only to large users of electricity, the residential and small business customers would bare the brunt of paying stranded costs through higher prices.

Industrial Consumer Advocates

AECC comments that all Arizona customers should retain the right to shop.

Utility Investors

The AUIA states that it does not believe a robust competitive market can be based only on large customers, but at this stage of market development, our answer would be yes. The AUIA further comments that virtually no large users are utilizing direct access and if the market is too unstable for large users, it is unstable for residential and small commercial users.

What will be a UDCs primary functions in a competitive market?

Investor-Owned Utilities

APS states that a UDC provides non-competitive electric services such as distribution service and bundled standard offer service. APS further comments that the UDC would seek reliable and reasonably priced sources of power for standard offer customers. TEP comments that UDCs should be responsible for the safe transmission and distribution of electricity as well as providing generation service to standard offer customers on a pass through basis.

Wholesale Power Producers

Sempra comments that the UDCs function is to transport electricity from the transmission system to the customer.

Electric Cooperatives

The REDCs believe that all distribution services such as metering, meter reading, and distribution should remain regulated and not subject to competition because competitive distribution would be an unnecessary duplication of facilities.

Residential Consumer Advocates

Arizona's Consumer's Council comments that the UDC would distribute electricity and maintain and expand the system to small customers.

Industrial Consumer Advocates

AECC comments that the UDC would provide distribution service, default revenue cycle services, and standard offer services

Utility Investors

The AUIA states that the UDC will be responsible for infrastructure, security, and reliability. The AUIA further states that it would include transmission service, except that we can't predict the fate of regional RTOs. The AUIA notes that it would expect the UDC to handle metering and billing for most of their customers because they are efficient providers of those services based on economies of scale.

Is it important to first establish functional wholesale markets before creating robust retail markets in electric generation? If so, why? If not, why?

Investor-Owned Utilities

APS states that the market in the West is functional but very volatile and unpredictable. APS further states that in a non-functioning market with insufficient resources, participants, liquidity, and transparency, it would be unlikely that an ESP could acquire sufficient quantities of reasonably priced power. APS also comments that without a sufficient number of ESPs, retail competition can never be robust.

TEP states that wholesale market must be both competitive and functional in order to support retail markets. TEP further states that in order for retail customers to benefit from competition, the retail energy provider must be able to supply the power at costs lower than the current regulated utility rates. TEP also states that the wholesale market must have a level playing field that neither favors or hampers any participant and provides protection to retail customers.

Wholesale Power Producers

Panda comments that a robust wholesale market is essential for a competitive retail market because a dysfunctional wholesale market will not provide incentives to retailers to participate in the market thereby ensuring that a retailer will buy all of its supply from an incumbent utility or its affiliates. Panda further states that the Commission has previously recognized that a robust wholesale market is essential for a competitive retail market and that requiring incumbent utilities to purchase power needed to serve standard offer customers on the open market was in the public interest. Panda also states that the Commissions vision for a competitive wholesale and retail market is only possible if the framework established in the competition rules and the settlement agreements is maintained.

PG&E and Sempra Energy Resources comments that a functional wholesale market is critical to retail competition. Reliant suggests that one approach to retail competition would be to first provide wholesale competition for some period of time before implementing retail competition. PG&E and Sempra Energy Resources further comments that establishment of a functional wholesale market is well underway with significant supply under construction to support wholesale competition and West Connect under development. PG&E suggests that retail markets should not be closed because it would take a significant effort to re-open those markets.

Electric Cooperatives

The AEPCO, Southwest, Sierra and REDC state that it is easier to establish wholesale markets before retail markets. They further state that once a supply of competitively priced wholesale generation is available and suppliers see the potential for profit from efforts needed to make retail sales, retail competition can begin.

Residential Consumer Advocates

Arizona Consumers Council comments that a whether a functional wholesale market will translate into a robust retail market is open for debate. Arizona Consumers Council further comments that demand must be created if suppliers will want to sell to residential customers.

Industrial Consumer Advocates

AECC comments that even if some believe that the wholesale market is imperfect, customers should be able to retain the right to take direct access service and decide themselves whether they believe the wholesale market is sufficiently functional to warrant taking direct access service.

Utility Investors

The AUIA states that one of its published positions regarding competition was that Arizona should not embark on retail competition until the wholesale market had matured under open access. The AUIA further states that it is not clear that a seamless and transparent wholesale market is possible today, given the electric rubble created in California and the continuing crisis in the Pacific Northwest.

When price caps are lifted for the majority of Arizona consumers, what assurances do we have that volatility in the market (for both natural gas and electricity) will not result in unstable or inflated rates? Will the generation price of electricity fluctuate with the price of natural gas?

Investor-Owned Utilities

APS states that the best assurance for standard offer customers would be the ability to lock in cost based prices for a fuel diverse portfolio of generating assets. APS suggests that the Commission should support jurisdictional utilities that take prudent advantage of financial and other commodity price hedging strategies to reduce price volatility of natural gas and purchase power. APS further suggests that the Commission should treat financial and commodity hedges as a fuel or purchased power cost and that they be recoverable through rates.

TEP states that upon expiration of the current rate freezes, the impact of short-term commodity price spikes to consumers will be proportional to the degree to which a provider utilizes spot and short-term purchases in its resource portfolio. TEP further states that a balance of short and long term, and fixed and variable components in a resource mix will mitigate the impact of brief price spikes. TEP also comments that during non-peak times, the price relationship between gas and electric diverges, as gas generators are taken off line or reduced to minimum operating levels. TEP further comments that during periods of low demand, the spot price of electricity is closely related to the marginal cost of the next type of generation in the dispatch queue.

Wholesale Power Producers

Panda states that the price of electricity in Arizona is dependent upon the marginal fuel resources going forward. Panda comments that if APS and TEP continue to run their less efficient units, then those units would represent the marginal resources in the Arizona market. Panda further states that there is some linkage between electric and gas prices but that the price of electricity is also affected by hydroelectric and other resources throughout the WSCC as prices are defined at the Palo Verde and Meade trading hubs.

Reliant comments that the assumption that customers should never be born by consumers is a recipe for disaster and that efficient market will allow customers to receive appropriate price signals. Sempra Energy Resources comments that Arizona utilities can mitigate price volatility for natural gas and electricity through competitively bid long-term contracts.

Electric Cooperatives

AEPCO, Southwest and Sierra state that the solution to price volatility is a commitment of the electric service provider to 5-year minimum least cost resources through construction of plants or through purchase power agreements. The Cooperatives comment that there is a high degree of interdependence between demands for natural gas and for electricity and gas fired generation should remain profitable over the long term.

The REDCs and Trico comment that the generation price of electricity will fluctuate with the price of natural gas. The REDCs further state that it is almost a certainty that at some point in the future, demand will exceed supply and rates will become unstable and inflated.

Residential Consumer Advocates

Arizona Consumers Council comments that there are no assurances that volatility will not result in inflated rates. Arizona Consumers Council further comments that as long as the production of electricity is dependent on natural gas, the price of electricity will increase with the price of natural gas.

Industrial Consumer Advocates

AECC comments that natural gas will play an important role in influencing electricity prices in the West. AECC further comments that the best assurance for reasonable price levels is to encourage generation supply from a variety of producers, and promote needed transmission construction and RTO development, as well as pipeline capacity additions.

Utility Investors

The AUIA states that in a competitive market the price of electricity will fluctuate with the price of natural gas. The AUIA further suggests that dedication to supply and portfolio diversity (coal, gas, and nuclear) will limit the state's exposure to market volatility.

Should there be a provision added to R14-2-1606(B) which would allow/limit a UDC to contract for wholesale power in three or five year intervals?

Investor-Owned Utilities

APS states that there is no purpose served in limiting the UDC's procurement options. APS further comments that the proper length for such contracts is whatever length is consistent with a prudent and conservative procurement strategy. APS suggests that the following factors should be considered: reliability of supply, diversity of supply, creditworthiness of counter-party, overall attractiveness of price, price level, stability, predictability and the availability of existing transmission infrastructure.

TEP states that a UDC should have a balanced, diversified portfolio of energy contracts of varying terms, including 3-5 year, 5-10 year and longer terms. TEP suggests that the contracts be approved by the Commission to ensure that they are in the customers' best interest and that the UDC will be provided recovery of the associated costs.

Wholesale Power Producers

Panda states that a diversified mix of spot market purchases, bilateral agreements of less that 1 year, agreements of 1 to 3 years and agreements of 5 or more years represents a conservative but optimal diversification strategy for standard offer customers and the stockholders of the states utilities.

PG&E states that the duration of wholesale contracts should not be prescribed in Commission rule. PG&E further comments that the UDC should have the flexibility to establish a well-balanced portfolio of contract lengths.

Electric Cooperatives

AEPCO, Southwest and Sierra state that they urge the Commission to take no action which would imperil all requirements or partial requirements contracts among AEPCO and its member distribution cooperatives.

The REDC state that there should be no provision added to the rule which would allow a UDC to contract for wholesale power in three to five year periods. The REDC further state that with the exception of Navopache the REDCs have signed full or partial requirements contracts with AEPCO whose term expires December 31, 2002. The REDC comment that Navopache takes its power from Public Service of New Mexico under a ten-year power sales agreement.

Residential Consumer Advocates

Arizona Consumers Council comments that it is difficult to predict what the market price will be in the future and therefore, it is difficult to know if a long-term or short-term contract will be at the high end or low end of the price in the future.

Industrial Consumer Advocates

AECC comments that standard offer providers should seek to hold a portfolio of contracts of differing lengths. AECC further suggests that the Commission should not legislate the contract length.

Utility Investors

The AUIA states that there is a lesson to be learned from the California experience in that a UDC must have flexibility to contract for power on a most favorable basis, whether it is long term or short term. The AUIA further suggests that the ACC should not specify contract limits in its rules.

What are the real benefits to residential consumers and small businesses in retail competition, other than consumer choice? Will IPPs market their power directly to retail customers, or are their efforts mainly focused on selling power to wholesale customers?

Investor-Owned Utilities

APS states that choice is a considerable benefit in the minds of many consumers and the existence of choice places competitive pressure on incumbent suppliers of standard offer service to be more cost-efficient and consumer-oriented. APS further states that it doubts that merchant generators will directly market generation to retail customers because they would be subject to the Commission's jurisdiction and would not be considered exempt wholesale generators.

TEP states that ESPs have limited their marketing efforts to larger energy consumers. TEP also states that with the onset of deregulation in Arizona electric rates have decreased for all consumer classes. TEP also comments that residential and small commercial customers have been exposed to various ancillary service offerings such as meter reading, energy audits and billing services. TEP further comments that IPPs will continue to focus on wholesale customer such as ESPs and UDCs and that it is not likely that IPPs will serve retail customers directly, but could create an affiliate ESP to serve large industrial consumers.

Wholesale Power Producers

PG&E states that it prefers to sell directly to UDCs on an arms-length or competitive bidding basis. Reliant states that all customers will benefit from the efficient use of resources brought about by a competitive market. Reliant also comments that IPPs may not market directly to retail customers but other retail energy providers including Reliant resources and others are marketing power to retail customers in other states.

Electric Cooperatives

The REDCs state that there are no real benefits to residential and small business customers other than consumer choice. Trico comments that some IPPs will market directly with retail customers while others will focus on wholesale customers.

Residential Consumer Advocates

Arizona Consumers Council comments that there have been no benefits to residential and small business customers in the states that have implemented electric deregulation.

Industrial Consumer Advocates

AECC discusses the benefits of competition through consumer choice, lower long run cost of generation production, the shifting of capital costs to investors, and the encouragement of construction of newer energy efficient facilities. AECC further comments that under current regulation, IPPs will sell to customers in the wholesale market not retail market.

Utility Investors

The AUIA states that in theory, the benefits to residential and small business customers are lower costs for energy. However, the evidence to date is less than convincing that small customers have much to gain from electric competition. The AUIA further states that the IPPs that are exempt wholesale generators cannot sell to retail customers.

Currently, is residential choice a real option? If not now, when?

Investor-Owned Utilities

APS and TEP comment that residential retail choice is not currently an option. APS states that the wholesale market must become less volatile or ESPs must garner enough non-residential business to allow them to hedge a volatile wholesale market to the point where they can offer residential customers price stability and predictability.

Wholesale Power Producers

Reliant comments that given the current state of the Arizona market, a competitive retail market is unlikely to develop for several years.

Electric Cooperatives

The REDCs comments that residential choice is not currently an option and a prediction of when it would be a viable market is to far into the future. The REDCs states that Navopache's service area is the only service area of the REDC that has been open to competition since June of 2000. REDC also states that since the territory has been open to competition there has never been any interest expressed by an ESP to provide competitive electric services and none of Navopache's customers has expressed interest in receiving competitive electric service.

Residential Consumer Advocates

Arizona Consumers Council comments that residential choice will not be an option for many years, if ever.

Industrial Consumer Advocates

AECC comments that residential retail choice does not appear to be an economic option in Arizona but it may become more viable once stranded charges are paid off.

Utility Investors

The AUIA states that there is no retail choice today, but no one is buying or selling. The AUIA comments that we don't know when retail choice will make sense but, continue to doubt that retailers will overcome the transaction costs involved in residential service particularly as long as the gap between wholesale and retail prices continues to shrink.

> ***What provisions, if any, are necessary to effectuate a gradual replacement of those existing plants in Arizona which are older, more polluting and less efficient than the newer combined cycle plants currently being built?***

Investor-Owned Utilities

APS suggest that the Commission should pursue an energy policy that recognizes the value of the older coal-burning plants instead of prematurely decommissioning and replacing them. APS further comments that a policy that allows continued operation of the older plants avoids the need to reimburse APS and other utilities for sunk costs and investments in new plants. APS further states that retaining the existing plants and ensuring that they run efficiently and cleanly makes sense because retaining coal burning and nuclear units will provide diverse fuel sources. APS' states that its coal burning units employ clean and efficient technologies, the location of these plants are in remote locations with a low population density, and replacement of these units would cause an economic disruption to the Navajo and Hopi reservations in northeastern Arizona.

TEP states that new plants will be built if the owners believe that new generation plants will be built if the owners believe that they will earn an acceptable rate of return on their investment. TEP also states that owners of existing facilities will remove existing facilities from service if they do not believe that additional expenditures for capital costs and operating costs will earn an acceptable rate of return. TEP comments that regulators provide the incentives to the regulated entity through the recovery of cost for the new asset and stranded cost of the old asset. TEP also comments that if newer more efficient generating units can generate electricity at a lower incremental cost than older units they will be dispatched before the older unit, thereby decreasing the output of the older unit.

Wholesale Power Producers

Panda states that the most effective way to determine which plants should be retired is by establishing a level playing field through applying regulatory policy such as environmental policies to all market participants. Panda further states that the older plants should be responsible for the additional cost associated with meeting environmental restrictions as would any merchant generating facility. Panda comments that the older dirtier plants will continue to be cross-subsidized by ratepayers and their owners will have no incentive to remove them from service.

PG&E and Sempra Energy Resources comments that incentives to decrease transmission constraints and increase the import capability into the Phoenix metro area will accelerate the retirement of these older, less efficient polluting units. PG&E also states that a functioning RTO would facilitate the process.

Electric Cooperatives

AEPCO, Southwest, Sierra and the REDCs state that no regulatory provisions are necessary to replace older plants with newer ones because it will happen on its own over the next few years as the plants will require major replacements to remain useful.

Residential Consumer Advocates

Arizona Consumers Council comments that the older plants will stay in service as long as they are profitable and meet minimum pollution standards. Arizona Consumer Council suggests that the Commission should provide incentives for generators to increase technology and utilize assets that are low polluting.
Industrial Consumer Advocates

AECC comments that inefficient plants are generally more costly to operate than modern, energy efficient plants and as generation supply increases due to competition, inefficient plants are likely to be "out of the money".

Utility Investors

The AUIA states that fuel diversity is essential to price stability and reliability. The AUIA comments that coal burning units are only less efficient than combined cycle plants when the price of gas is low and when they are located outside the load centers, they may have no negative effect on the environment.

What are the long-term effects of divestiture for APS? How does the Commission guard against a PG&E situation, where the distribution company declares bankruptcy after profits have flowed to its parent holding company?

Investor-Owned Utilities

APS comments that divesting generation will permit APS to focus on providing non-competitive electric service and remove the financial risk inherent in building new generation. APS further comments that divestiture will allow competitive suppliers to compete free of the perceived threat posed by incumbent owned generation. APS also comments that divesting generation reduces the ability of the UDC to hedge against market price volatility unless an agreement exists to provide the same hedge without the disadvantages associated with continued UDC generation ownership. APS states that the PG&E bankruptcy was caused by the utility being placed in a "price squeeze" between fixed retail rates and high wholesale costs. APS further comments that no one has accused PG&E of manipulating the wholesale market and there is nothing unusual about a company paying reasonable dividends to a company's shareholders. APS suggest that the Commission can avoid such a situation by promoting a predictable regulatory environment, encouraging UDC to lock in stable wholesale prices, and allowing recovery in retail rates of these legitimate purchases.

TEP refers to its response to Chairman Mundell's Question No. IV.C. TEP also suggests that the Commission can guard against the bankruptcy of a UDC by allowing a UDC to earn a fair rate of return and for the full recovery of prudent costs incurred in providing distribution and standard offer services.

Wholesale Power Producers

Panda states that the PG&E situation was a product of the dysfunctional California market. By avoiding the design faults built into the market Arizona can avoid the PG&E situation. Panda further comments that divestiture will not cause the impact seen in California as long as the divesting utility can enter into a prudent mix of differently lengthed agreements with competitive generators. Panda also comments that allowing APS to divest its generation to an affiliate and enter into exclusive deals with that affiliate will be detrimental to the wholesale market and harm standard offer ratepayers.

PG&E comments that that it would be difficult to speculate on the long-term effects of divestiture on APS. PG&E further comments that the PG&E situation resulted from a regulatory failure that prevented the utility from passing on high procurement costs and being forced to sell to retail customers at a loss.

Sempra Energy Resources comments that the PG&E bankruptcy was caused by retail price caps that did not allow the utility to flow through increasing wholesale spot market purchased power costs to consumers.

Electric Cooperatives

Trico comments that the ACC has power under R14-2-801, et seq., to preclude imprudent transactions between APS and its affiliates as both are public service corporations.

Residential Consumer Advocates

Arizona Consumers Council suggests that the Commission set up regulations that keep profits from flowing to a parent until such a time that there are reserves, which would handle similar situation.

Industrial Consumer Advocates

AECC comments that the long-term effect will differ depending on the outcome of the upcoming proceeding regarding APS and its affiliate. If a straight spin off proceeds as planned, the issue of whether Pinnacle West has too much market power will surface. AECC further comments that it is encouraged by the new generation that is under construction, which will mitigate a market power problem.

Utility Investors

The AUIA states that the most obvious effect is that the APS and Pinnacle West generating units will no longer be under Commission regulation and they will be free to compete in the open market. The AUIA comments that as long as APS is under Commission jurisdiction as the provider of last resort, Pinnacle West will be motivated to balance the disposition of its resources between prudent marketing initiatives and the needs of its standard offer customers. The AUIA states that the PG&E bankruptcy was caused by the requirement that the utility could not negotiate long term contracts and could not recover its high power costs from its retail customers.

Summary of General Responses to ACC Questions

The following companies provided general responses to the questions posed by the Commissioners.

I. APS Energy Services

APSES provided general responses to the some of the questions posed by the Commissioners. APSES states that the Arizona Administrative Code adequately covers concerns regarding affiliate transactions. However, in the realm of energy efficiency, an ESP affiliate should be allowed to do this work with the UDC. APSES supports subsidies for renewables to increase their use. Transmission access pursuant to AZISA protocols is very important for ESPs. Allocated Retail Network Transmission (ARNT) methods are not practical. An independent RTO is key to obtaining access to transmission and neutral administration of the OATT. AZISA is needed until an RTO is created. Billing requirements on ESPs in the Arizona Administrative Code constrain ESPs. Tariff disputes should be handled through an expedited process. The PSWG has been beneficial and should continue its work.

II. Calpine

Calpine provided general responses to the questions posed by the Commissioners. Calpine supports the current competitive bid process. Calpine is in favor of policies that encourage the development of renewable energy.

III. The Center for Energy and Economic Development

The CEED provided general responses to the questions posed by the Commissioners. Multiple generation methods should be encouraged in a restructured electric market. Maintaining low electric rates should continue to be the emphasis of the Commission. Environmental concerns should not be the primary focus of a move to restructure the retail electric market. National and state laws will ensure continued improvements in Arizona's environment regardless of whether Arizona restructures its electric market. CEED states that history has shown that low electric rates have reduced emissions.

IV. Citizens Communications

Citizens provided general responses to the questions posed by the Commissioners. Citizens states that the Commission should fully inform consumers of the potential benefits and risks of electric competition. A level playing field for all market participants should be encouraged. Providers of last resort should not be discriminated against in favor of competitive providers. No changes should be made in the Commission's regulations regarding holding companies and affiliated interest rules.

Citizens does not oppose distributed generation, but does believe that uniform equipment specifications are necessary. Citizens also proposes the termination of the AISA due to the fact that no competitive sellers exist that would require the services of the AISA.

V. *Duke Energy North America*

Duke provided general responses to the questions posed by the Commissioners. Duke states that a competitive wholesale market is necessary in order to have a competitive retail electric market. A vibrant wholesale market is developing in Arizona. A regional RTO is also important in creating a framework in which a wholesale market can thrive. Reliable electric transmission and gas transportation capacity is necessary. The ACC is reviewing and seeking to improve Arizona's transmission system.

Duke is in favor of electric competition in Arizona. Duke agrees with the ACC rules on electric competition that require procurement of 50% of generation from the wholesale market. A competitive bid process is key to reducing consumer prices. Duke states that the recent APS/TEP Variance docket will hinder wholesale competition.

VI. *The Electric Power Supply Association*

The EPSA provided general responses to the questions posed by the Commissioners. EPSA believes that competition will increase reliability, efficiency, and provide more choices to consumers. Service unbundling, guaranteed recovery of stranded costs, open access to transmission and distribution, and establishment of an RTO are keys to correctly implementing retail electric competition.

EPSA has additional recommendations for the Commission. All transmission services should be provided under one tariff. The market mechanisms of supply and demand are effective substitutes for regulatory certification processes. Power marketers play a role in obtaining lower cost energy. Fair and consistent interconnection rules are important. EPSA supports competitive bidding and aggregation of customers. Electric competition can decrease consumer prices. Price controls hurt the ability of consumers to make demand-side responses to rising electricity prices. Customer switching rules should not contain high exit fees or lengthy notice periods. Uniform switching rules are necessary.

EPSA supports divestiture of generation. EPSA also supports transferring assets to unregulated affiliates as long as there is full functional separation of competitive and non-competitive services. Merchant power plants should be encouraged. Merchant power plants are also beneficial to the environment.

VII. *Stirling Energy Systems*

SES provided general responses to the questions posed by the Commissioners. The current Environmental Portfolio Standard (EPS) should be more aggressive in encouraging solar power. More incentives to developing large-scale solar power are needed. Investments in renewables are not being made in Arizona to the degree that they are being made in neighboring states. The Commission should separate pursuit of deregulation from pursuit of increased use of renewable energy. In this way, renewables won't be lost in the myriad issues involved in deregulation.

VIII. ***Strategic Energy***

Strategic Energy provided general responses to the questions posed by the Commissioners. Strategic Energy states that competition can enhance reliability and increase the services offered to consumers. Price caps prevent supply and demand from responding appropriately and discourage competition. Uniform business rules for customer switching are necessary. Switching fees, lengthy notice periods, and burdensome authorization requirements are disincentives to retail competition. Competitive bidding can encourage the development of competition. The number of customers who do not choose direct access should be minimized.

Strategic Energy states that the ICAP charge (installed capacity charge) instituted in the Northeast is a hindrance to competition. This anti-competitive charge allows monopoly providers to extract fees from consumers in a competitive market.