ORIGINAL

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July 15, 2013

Bob Stump, Chairman
Gary Pierce, Commissioner
Brenda Burns, Commissioner
Robert L. Burns, Commissioner
Susan Bitter Smith, Commissioner
Arizona Corporation Commission
1200 W. Washington
Phoenix, AZ 85007-2996

Re: In the Matter of the Commission's Inquiry into Retail Electric Competition; Docket No. E-00000W-13-0135

Dear Chairman and Commissioners:

Arizona Public Service Company ("APS" or "Company") has reviewed the questions raised in the Commission's Notice issued on May 23, 2013 and crafted a detailed response. That response, attached to this letter, provides both a general overview of the many critical issues that attend any electric market restructuring proposal, as well as specific answers to each of the 18 questions.

Whether or not to restructure Arizona's electric market is a question so significant that even entertaining a conversation about the possibility has unintended consequences. The decision you will make later this year in this docket will be among the most important you will make as public officials. I know from firsthand experience living and working in deregulated states how poorly residential customers fare and how very much communities lose when the traditional utility regulatory model is disrupted.

Electricity is fundamental to all advanced economies, but in Arizona – the hottest state in America – reliable electric service is literally a life or death necessity. APS has proudly accepted responsibility for reliably serving our customers and communities since before Arizona was a state. Our Company's mission, to safely and efficiently generate and deliver reliable electric power and related services to our customers, is one we embrace with gravity. We are proud to be stewards of Arizona's communities. It is no coincidence that APS is a national leader in every aspect of service reliability and customer service.

APS's accountability extends not just to our customers, but to this Commission. The Commission has long demonstrated a keen sense of duty to Arizona electric customers and consistently holds APS and Arizona's other regulated utilities firmly accountable for their actions and investments. I am convinced that companies located in other states – possibly even other countries – would lack that same sense of Arizona stewardship. And in a deregulated environment, this Commission would lack the authority to hold those companies accountable to our customers. The Federal Energy Regulatory Commission would, instead, largely take control of Arizona's energy future.

Traditional regulation has been effective in Arizona for over a century. It is a key part of the State's foundation, ingrained in our Constitution. And although no institution is perfect, any perceived deficiencies argue for reform, not a radical restructuring of an industry so vital to the health and welfare of our citizens.

As you review the wealth of material presented in this Response and others, consider:

- One of the benefits to Arizonans of our current regulatory system is that elected public representatives set electric rates balancing both customer and business interests. We should be cautious about pursuing a model that offers customers no such protection. Arizona's residential customer rates are below the national average, and lower than 13 of the 17 deregulated states across the nation. Conversely, rates in restructured states are generally well above the national average.

- Another key advantage of traditional regulation is that it ensures investment in Arizona's critical reliability needs. APS's reliability scores are in the top quartile of all utilities nationwide, as measured by both number and duration of electric outages. As evidenced in Texas and several eastern states, no deregulated market structure can guarantee that quality of service reliability.

- The current regulatory model protects Arizona customers' long-standing investment in critical coal assets, including APS's Four Corners Power Plant and Navajo Generating Station. Coal generation has provided needed jobs and other economic benefits to the poorest regions of our state. Investment in coal is unlikely in any environment that looks only at short-term profitability to the detriment of long-term planning. Deregulation represents just as much a "war on coal" as anything planned by the federal government.

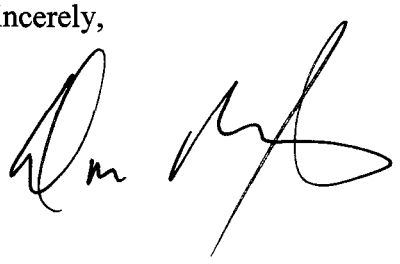
- APS offers multiple options today to help customers manage their energy bill. As a regulated utility, we work closely with the Commission to make sure that our programs are in the best interest of customers. In a deregulated market, customers must continually conduct appropriate due-diligence to make sure they are getting the electric service that best meets their needs.

I have touched on only a few of the risks of deregulation discussed in the APS Response, not the least of which are legal restrictions unique to Arizona. The case against deregulation is strong, and the case for it made only by the few who stand to financially gain to the detriment of the rest.

This is an issue that needs to be resolved quickly and permanently, and I respectfully ask that you continue to trust in the regulatory model that has kept the lights on in Arizona for more than a century. There is simply nothing fundamentally broken that needs to be fixed, let alone anything that warrants going down a path that has proven unpredictable at best and disastrous at worst.

Thank you for your consideration.

Sincerely,



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APS Initial Response to Commission Inquiry Regarding Electric Restructuring

Arizona Public Service Company
In the Matter of the Commission's Inquiry into Retail Electric Competition
Docket No. E-00000W-13-0135
Initial Comments

Arizona Public Service Company ("APS" or "Company") is providing these comments in response to the Arizona Corporation Commission's ("ACC" or "Commission") May 23, 2013, request for comments regarding retail electric restructuring. APS appreciates the Commission's interest in putting finality to the issue of retail electric restructuring in Arizona. These comments address the claimed benefits, costs, and risks to APS, its customers, and to the Arizona economy from restructuring of the electric industry.[1] Responses to the 18 questions posed by Commission Staff are attached to this response as Attachment A.

I. EXECUTIVE SUMMARY

The Commission rightfully abandoned retail restructuring in 2002. Thanks to that decision, Arizona was largely spared the chaos that engulfed much of the West and resulted in volatile power prices, market manipulation, and reliability concerns. Simply put, restructuring was not in the public interest then and not in the public interest now.

APS is a steward of safe and reliable electric service which is provided to Arizona customers at affordable rates. Arizona retail customers already enjoy rates below the national average. By contrast, as other jurisdictions experiences have shown, retail restructuring and associated actions will result in higher residential electricity prices, a transfer of jurisdiction from the Commission to the federal government, and reduced levels of reliability. Once Arizona goes down the path to restructuring, there is no turning back. Significant concerns about restructuring include:

a. Customers as a Whole do Not Benefit from Restructuring

The risks and costs associated with restructuring far outweigh any theorized benefits. Residential customers in restructured states pay higher rates and are subject to significantly more risk (e.g., threats to reliability and volatile prices) than customers in similarly situated regulated states. On average, residential customers in restructured states pay rates 26 percent higher than rates in regulated states.[2] The relatively small percentage of commercial and industrial ("C&I") customers who do benefit from retail restructuring do so at the expense of residential and small business customers because of cost shifting. Over the longer term, even those C&I customers will suffer from a higher degree of risk inevitable in a restructured market.

b. The Commission will Relinquish Jurisdiction to the Federal Energy Regulatory Commission ("FERC")

The Commission would give up its jurisdiction over the development and retirement of generation resources and how much customers pay for the capacity and energy that they provide. Customers will pay market prices rather than the cost-based prices that they pay today for the same resources that have already been financed and paid for. FERC oversees the nation's wholesale markets. If the ACC does not

[1] What APS is describing as electric industry restructuring is sometimes referred to as "deregulation." This characterization is controversial and some contend that there will be more regulation and litigation than before.
[2] Calculated from Energy Information Administration ("EIA") Table 5.6.A "Average Retail Price of Electricity to Ultimate Customers by End-Use Sector, by State", Form 826 April 2013 data.

like the results of a FERC decision, the Commission will be forced to plead its case just like every other party in a FERC proceeding.

c. Adequate Generation is Not Being Built, Jeopardizing Reliability

The wholesale capacity market "price signal" that was supposed to encourage the market to build the right type of new generation in the right location at the right time is not working. An insufficient amount of plants are being built, markets are vastly overpaying for demand response resources, fuel diversity is not valued, and reliability is being threatened. Texas is a prime example – in spite of a dramatic 66 percent increase in wholesale price caps, generation is not being built, and Texas now faces the potential of blackouts on the hottest summer days for the second year in a row.

d. Coal and Other Base Load Resources are Undervalued by Wholesale Markets

As a general rule, natural-gas fired units set energy market prices that all generators get paid in most hours of the year. While natural gas prices are low now, we can all painfully remember prices in the summer of 2008 that were two to three times higher than they are today. Relying more heavily on gas-fired generation, as happens in restructured markets, heightens the exposure of customers' bills to historically volatile natural gas prices. Further, over-dependence on short-term energy sales to generate revenues threatens the continued operation of existing coal and nuclear plants. The loss of coal generating facilities, such as the Four Corners and Navajo Generating Stations, would significantly hurt the very regions of the State that can least withstand such an economic loss. Tying Arizona's energy future to market based prices - predominantly on natural gas - is a significant and unnecessary risk.

e. Integrated Resource Planning is a Casualty of Restructuring

Integrated resource planning ("IRP") is critical to Arizona in ensuring an adequate supply of appropriate resources to satisfy the long term needs of its economy and citizens. Retail restructuring in other jurisdictions has resulted in a cavernous resource planning gap precisely at a time when the benefits of resource planning are greater than ever due to fuel price, technology, and environmental regulation uncertainties.

f. Competitive Wholesale Markets Falter in Other Jurisdictions

A functioning Regional Transmission Organization ("RTO") and competitive wholesale market are prerequisites for restructuring. Regional wholesale markets are incredibly complex, subject to unexplainable price volatility, and mired in endless litigation at the FERC and in the courts - jurisdictions where both state and customer interests are severely underrepresented. Market participants have a strong profit incentive to exert market power up to the edge set by rules and the law. Market manipulation still continues to be an issue. Since 2007, the FERC has levied hundreds of millions of dollars in fines and penalties for alleged market manipulation.

g. Arizona is Unique

Because Arizona utilities in general, and APS, in particular, operate their transmission systems in coordination with a large public power sector, the restructuring of the Arizona electricity market poses unique problems of jurisdiction and coordination compared to other parts of the country. Further, because most of Arizona's utilities operate in an extreme desert environment, reliable electric service is not simply a convenience for customers; in many cases they could be a matter of life and death.

h. Restructuring Produces Less Reliable Service at Higher Costs

Retail restructuring, including development of an RTO and regional wholesale market, is complicated and costly. Lengthy regulatory rulemakings and proceedings would be the first step. Years of litigation at the FERC (with the Commission as a party) should be expected, as would certain court challenges. The stranded costs alone identified the last time the Commission considered restructuring were up to $1 billion, excluding tens of millions of administrative, legal and consulting costs. Customers pay for all this before they have even a remote chance of benefiting from restructuring. And that is only the start. Restructuring is not a "one and done" activity. States that restructured 15 years ago are still fighting over the rules at FERC and in federal courts.

Although Texas is thought by many industry observers to be a successful example of electric restructuring, some chilling facts in Texas cannot be overlooked.

- For the ten years prior to restructuring, Texans paid average residential prices 6.4 percent **below** the national average. In ten years after restructuring, Texans paid prices 8.5 percent **above** the national average of regulated states.[3]
- Electric restructuring has cost Texas residential consumers more than $11 billion in higher rates. [4]
- Prior to the implementation of restructuring, electricity-related complaints to the Texas Public Utilities Commission averaged around 1,300 each year. After the implementation of restructuring, complaints rose to as much as 17,250 per year.[5]
- For the second year in a row, Texas faces the prospects of blackouts since adequate generation is no longer being built in spite of dramatically rising electricity prices.[6]

[3] *See "Deregulated Electricity in Texas,"* Texas Coalition for Affordable Power, December 2012 at 3.
[4] *See "Study tallies cost of deregulation: more than $11 billion in higher residential rates,"* Jack Z. Smith, Star-Telegram, February 15, 2011.
[5] *See "Deregulated Electricity in Texas, A History of Retail Competition – The First 10 Years, Appendix C: Electricity Complaints under Deregulation,"* Texas Coalition for Affordable Power, found at http://historyofderegulation.tcaptx.com/chapter/appendix-c-electricity-complaints-increase-under-deregulation/, accessed June 26, 2013.
[6] *See "Texas power retailers face tight supply, higher $5,000 price cap,"* Reuters. June 4, 2013.

I. INTRODUCTION

Restructuring the electric industry in other states has proven to be enormously complex, contentious, and risky. The promises of reduced prices for all have not materialized. Other "collateral" damage includes threats to reliability and price volatility. Like access to potable water, electricity is a "life line" service. There is minimal customer tolerance for either reliability problems or price shocks. In Arizona, there is absolutely no room for market driven service interruptions on a 110-degree day when air conditioning may be vital to health and safety. Electricity is also unique as a commodity: supply and demand must be balanced at the moment it is consumed to ensure reliability; there are no viable storage options; and electricity is a vital product to the smooth functioning of the state and national economies. A decision to pursue retail restructuring would begin a lengthy and costly transition process from which there is no return.

The frustration with restructuring in Texas and other states is captured by a newspaper article below telling the story of a small business owner in Illinois:

> This wasn't supposed to happen with deregulation. Electric bills were supposed to go down. Instead, Ellie Dorchincez can almost see the dollars evaporating every time she turns on the lights or opens the freezer at her small Farm Fresh grocery store. Her electric bill, which used to be about $800 a month, has jumped to $1,800. She's shut down a large freezer of frozen treats and now closes the store an hour early to cut costs but fears she still may have to raise prices and lay off some workers. "I'm just trying to figure any way that I can right now to keep my business afloat. My life is at stake here."[7]

It is easy to forget among all the talk of markets and economic efficiency, that customers like Ellie Dorchincez have an electricity bill to pay every month. At the end of the day, the Commission must be confident that electric restructuring will benefit all residential and business customers. State regulatory commissions are the last line of defense for these customers. The FERC, which focuses on wholesale markets, is at least a step or two removed from this everyday reality, focused primarily on policies relating to the wholesale market – not the retail market.

Retail electric restructuring will radically change Arizona's long-term energy future by introducing significant risk to the reliability and cost of electricity that fuels the state's economy. Even by simply announcing its intention to consider deregulation, the Commission has adversely impacted Arizona utilities' planning and financial outlook. Nothing evidences this better than APS's announcement to postpone its decision to move forward with the Four Corners transaction until this electric restructuring matter is resolved[8] and investment broker downgrades to UNS Energy Corporation.[9]

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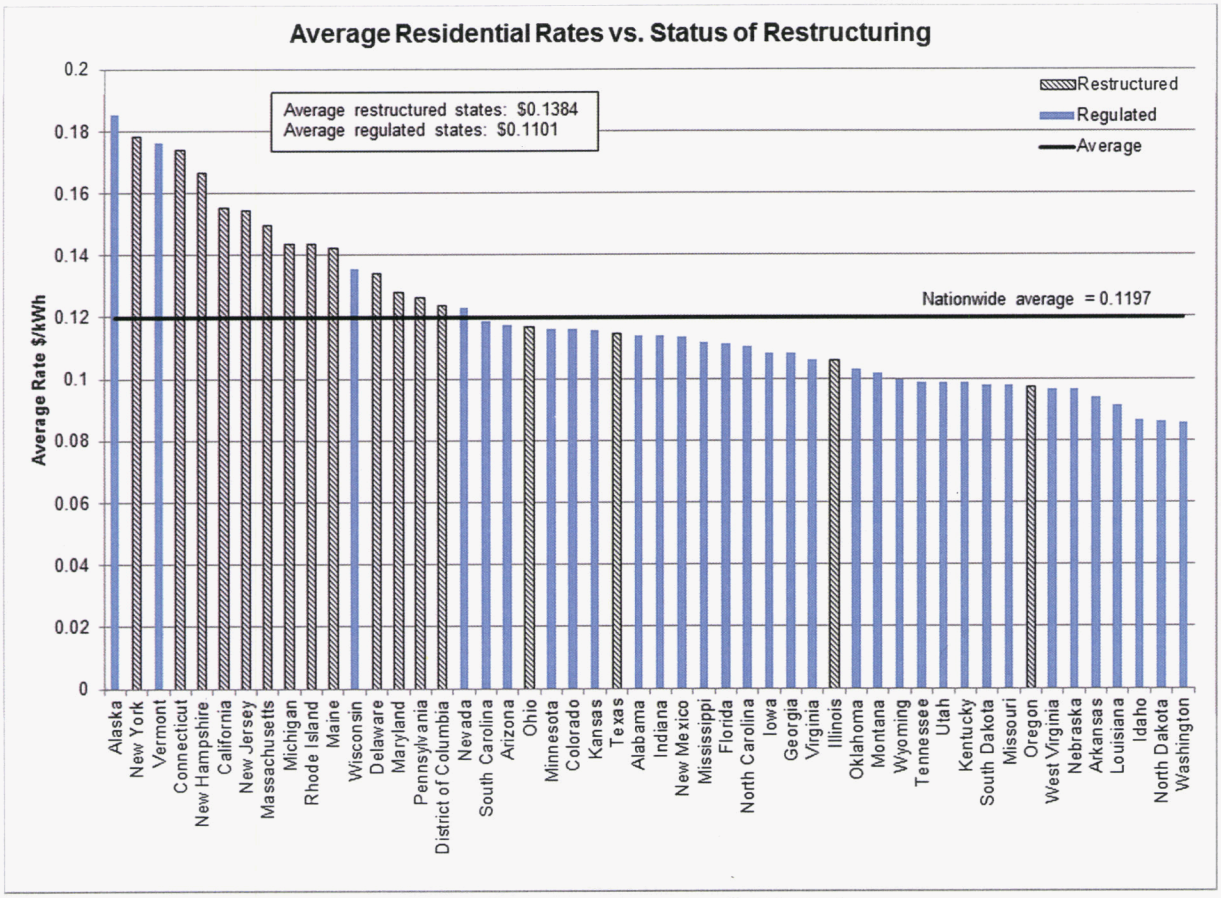
[7] *See "Electric Deregulation Fails to Live Up to Promises as Bills Soar,"* Ryan Keith, April 21, 2007.
[8] Pinnacle West Capital, SEC Form 8-K, June 17, 2013.
[9] *See "Calling Ariz. regulation 'clear as mud,' Jefferies downgrades UNS Energy",* SNL Financial, June 20, 2013.

II. RESIDENTIAL CUSTOMERS HAVE BEEN HARMED BY RESTRUCTURING

Residential Rates Continue to Rise

Two of the principal motivations behind restructuring initiatives were to reduce rates and increase efficiency. The movement began largely in states with relatively high electricity prices that hoped to bring their prices in line with the rest of the country. However, with fifteen years of history to point to, efficiency benefits are being captured by the owners of generation rather than being passed on to customers. In some cases, these same owners work to prevent new supplies from entering the market thereby resulting in threats to system reliability. Residential rates in restructured states are 26 percent higher than those in regulated states. Thirteen of the seventeen states whose rates exceed the national average are restructured.[10]



Source: U.S. Energy Information Administration, April 2013 data

[10] Based on EIA Table 5.6.A "Average Retail Price of Electricity to Ultimate Customers by End-Use Sector, by State", Form 826, April 2013 data. Of note, Oregon's market currently allows customer choice for a limited number of large customers. Oregon's historical reliance on low-cost hydroelectric generation and cost-based rates for residential customers helps explain the comparatively low customer rates. Additional detail can be found in APS's response to Staff Question 1.

Residential Customers pay for Other Customers' Short Term Benefits

On the retail side, marketers have focused on the largest customers and on those customers that have load characteristics that are less expensive to serve than the rest of their rate class. This "cherry picking" of the most desirable customers leaves behind and increases the cost to serve all other customers, including residential and small commercial consumers.

In many states, smaller customers were guaranteed temporary price decreases imposed by regulatory bodies as part of restructuring, only to be exposed to dramatic price jumps when the guarantees expired. For instance, Maryland froze prices to customers who continued to rely on utility sales service at levels that were approximately 5 percent below existing levels, only to have them increase by over 70 percent as soon as the caps were removed.[11] The Public Service Commission became the target of much of the blame for this poorly conceived approach in many states.[12]

The promise of new pricing options and other services has not materialized for the vast majority of residential and small commercial customers. The substitution of cost-based utility generation, supported by resource planning, with market-based wholesale rates in markets that are not functioning well has added to the upward cost pressure for this large group of customers.

Provider of Last Resort ("POLR"): A Large Risk for All Customers

Utilities in restructured markets that have divested their generation often continue to have responsibility for acquiring supplies for a large portion of their total load, including virtually all of their residential customers and many smaller C&I customers that receive POLR service. If utilities are no longer allowed to own or build generation, or even to enter into long-term power purchase agreements, then they must depend on short-term purchases from the wholesale market. Utilities generally conduct auctions each year for a portion of their portfolio (*e.g.,* one-third) and then enter into power purchase agreements with the winning bidders. These POLR customers are completely exposed to the short-term wholesale market and cannot take advantage of longer-term generation or contractual hedges that are a fundamental element of any utility resource portfolio. Further, if the retail restructuring model allows customers to switch back and forth between a POLR service and an alternative provider, this creates reliability concerns and results in yet higher costs for all POLR customers.

Restructuring Costs Customers

Most significantly, while rates in all states have risen over time, rates in restructured states have risen faster. From 1990 to 2011, the average price in restructured states grew by approximately 60 percent, while prices in regulated states during the same time period

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[11] Maryland Office of People's Council, Regulatory Activities – Electricity: http://www.opc.state.md.us/RegulatoryActivities/Electricity.aspx

[12] The Maryland General Assembly attempted to fire the entire Maryland Public Service Commission in 2005 because of the large increases in retail electricity rates after the expiration of price caps. This attempt was eventually ruled unconstitutional. *See*, for example, http://www.thebaynet.com/News/index.cfm/fa/viewStory/story_ID/3415/comment_categoryID/3415-News/comment/Y

rose by 48 percent. Newspapers have published article after article criticizing the deregulation debacle, with headlines like:

- *"Electric Deregulation Fails to Live Up to Its Promises as Bills Soar"* (USA Today; April 21, 2007).
- *"Lights Go Dim For Electricity Deregulation: Lawmakers Across Nation are Contending Power Generators, Not Consumers, Benefitted"* (Chicago Tribune, April 2, 2006)
- *"The Jolt of Deregulation"* (Chicago Tribune, 2006).

The response as reported in the press has been predictable:

- *"Time for State to Consider Electricity Re-Regulation"* (Baltimore Sun; January 18, 2011)
- *"Energy Deregulation a Total Failure - Lawmakers Struggle to Deal with Consequences of 99 Vote"* (Baltimore Business Journal, May 24, 2008);
- *"Hype About Electric Deregulation Never Came True"* (Capital News Service; October 21, 2007)
- *"Fixing Maryland's Deregulation Will Be Harder Than Its Start"* (Baltimore Sun; May 27, 2007);
- *"Electricity Deregulation: High Cost, Unmet Promises"* (Washington Post; March 12, 2006)
- *"Deregulation of Electricity Called a Failure"* (Baltimore Sun; July 31, 2004)
- *"Time to Pull the Plug on Deregulation"* (Baltimore Sun; February 26, 2002)

III. RESTRUCTURING MEANS A SIGNIFICANT LOSS OF STATE JURISDICTION

Prior to restructuring, state regulatory commissions exercised considerable control over the resource portfolios of electric utilities, including oversight of integrated resource plans, contracting for supplies from third-parties, and the development or retirement of utility-owned generation. In restructured states, these functions are either not being performed at all, are organized by regional markets (e.g., auctions for new capacity), or are left to the whim of generation companies through unilateral development and retirement decisions. In many respects, jurisdiction in restructured states is shifted from state regulators to the FERC. The outcome, and impact on customers, is dependent on how well electricity markets function. This places state regulators in the unenviable position of approving customer bills that recover supply costs, which are dependent on rules established by the FERC and the response to those rules by generation owners.

The Commission currently has fairly comprehensive jurisdiction over and transparency into all elements of customers' electricity service. Similar to other regulated jurisdictions, the Commission reviews utility IRPs and retains oversight over the prudence of all new generation investments, all power purchase agreements, and the determination of supply cost allocations among and subsequently recovered from customers. By exercising these authorities, the Commission has oversight over every major supply-related decision and the resulting impacts on the cost, reliability, and environmental attributes associated with the resource portfolio on the Company's customers. If Arizona's retail market is restructured, the Commission will abdicate its jurisdiction over generation, a significant component of a customer's electricity bill.

The Commission's current role in energy policy would change dramatically with the restructuring of the Arizona market and potential adoption of divestiture of utility generation assets. In short, the Commission's role with respect to future supply would be restricted to the design and implementation of the POLR contracting process. The prices that will be paid by POLR customers will be determined by wholesale market operations, rules, and market conditions.

In a restructured market, the FERC is the jurisdictional "backstop" authority. As in regulated markets, the FERC has jurisdiction over the use of utility-owned transmission facilities in interstate commerce and the review of bilateral wholesale contracts that are entered into by utilities.

State commissions in restructured states have effectively been transformed from the decision-maker in state proceedings to one of several intervenors in FERC proceedings. State commissions have banded together and formed organizations that can participate as a block in certain Independent System Operator ("ISO") discussions and FERC litigation matters, but states do not always share the same interests. The FERC does not defer to the states in its decision-making. This presents an enormous resource challenge for states to keep up with issues before the FERC that have an impact on customers within their jurisdictions, particularly if those customer interests are not effectively represented by other parties, as is often the case. Of course, keeping up with issues is one challenge; participating as a litigant in FERC proceedings is another resource-intensive and expensive undertaking.

The experience of states like Maryland and New Jersey illustrates the frustration of Public Service Commissions in being reduced to the status of participant in FERC proceedings. The frustration is exacerbated by the fact that customers and elected officials may continue to hold the state commission responsible for all costs that are passed through the electric bills, when in fact a significant portion of the bill would fall outside of the Commission's authority.

In a 2011 order, the Maryland Public Service Commission effectively ordered Maryland consumers to help finance new generation that was not being developed despite high capacity and energy prices within Maryland:

> The Commission finds that Maryland continues to face the threat of insufficient new capacity, as PJM's capacity market construct, the Reliability Pricing Model ("RPM"), has been unsuccessful in attracting appreciable new generation to the State since its inception in 2007, despite the fact that RPM has imposed prices in the Southwest MAAC[13] zone that are approximately double that of the rest of the PJM region[14].

A subsequent request for proposals ("RFP") resulted in an award to a generator to construct a power plant in Maryland. This award has been challenged in federal district court by existing generators that are determined to restrict new entry based on their interpretation of FERC rules governing PJM's capacity auctions. Maryland is effectively being

[13] Mid-Atlantic Area Council.
[14] Order issued September 29, 2011 by the Maryland Public Service Commission in Case No. 9214, at 2-3.

blocked from making a resource decision that advances the objectives of its citizens as determined by their commission.

New Jersey reached a similar conclusion, and has taken action that is also being challenged in a different federal district court by existing generators. The frustration of New Jersey is demonstrated in the following excerpt from a 2011 commission staff report.

> New Jersey faces intractable obstacles in the development of adequate electric resources to meet the needs of its residents and businesses. . . . New Jersey's reliance on the Reliability Pricing Model ("RPM") capacity market, however, has been a disappointing experience which can impact the state's economic health and its prospects for recovery from a severe and lengthy recession. . . . Since its implementation in 2007, RPM's annual capacity auctions have brought to New Jersey consumers high capacity prices - reflecting local generation shortages - but have produced little new generation capacity in response to those high market price signals. Rather, RPM has largely served as a new and lucrative source of revenue for incumbent generators who, in Staff's opinion have deferred the retirements of old, inefficient generation plants, reactivated previously deactivated facilities, or made comparatively modest investments to upgrade the capacity ratings of existing generating stations.[15]

IV. GENERATION INVESTMENT IS NOT SUFFICIENT, JEAPORDIZING RELIABILITY

In many restructured markets, generation investment is insufficient to meet future needs, markets are overpaying for demand response resources, and fuel diversity is not valued, all of which threatens reliability. The wholesale capacity market "price signal" that was supposed to encourage the right type of new generation in the right location at the right time in restructured states is not working. It takes years and hundreds of millions of dollars to build generation, which must be matched with transmission investment. These long-term commitments rarely occur in restructured markets, where the price signals are short-term in nature. As one Texan points out, "deregulation as enacted in Texas has created a situation in which we must now choose between reliability and higher prices. The stakes are high."[16]

The capacity auction rules that generators use to value generating supply are the subject of extensive litigation at the FERC. Existing generators argue in support of rules that make it harder for new entry in an effort to bolster ever higher capacity and energy price levels, particularly within transmission-constrained areas. Markets appear designed to create scarcity wherever possible, a condition that favors existing generators and harms customers.

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[15] New Jersey Board of Public Utilities, Board Staff Report on New Jersey Capacity, Transmission Planning and Interconnection Issues, Docket Nos. EO11050309 and EO09110920, at 3.

[16] *See "Poll: electricity price cap hike generates consumer backlash"* Houston Chronicle. June 28, 2012. Found at: http://blog.chron.com/lorensteffy/2012/06/electricity-price-cap-hike-generates-consumer-backlash/

A recent study of deregulation in Texas found that prior to restructuring Texas had a healthy reserve margin, but now Texas has among the lowest reserve margins in the nation, threatening the state's reliability for customers. The study further stated:

> "Reliability challenges have begun to emerge under deregulation. There have been two statewide rolling blackouts in four years under the new system, and there were at least nine reliability emergencies during 2011 alone. By contrast, ERCOT ordered statewide rolling blackouts *only once* in 30-plus years before deregulation."[17]

In a Washington Times Article, Maryland Senator E. J. Pipkin commented on Maryland's effort to restructure and the lack of new generation:

> Mr. Pipkin said new plants are unlikely to be built unless the state regains authority to command their construction. "At the end of the day, serving the retail customer is better left to public utilities," he said.[18]

Maryland, unfortunately, cannot turn back the clock and must attempt to influence the wholesale markets without any real supervisory authority. This is not an isolated sentiment; many articles criticize restructuring and its impacts to system reliability:

- "*Report on Electric Grid Cites Concerns with Reserves*" (The Texas Tribune, June 1, 2012)
- "*New power plant to be built in Waldorf: First new plant since electric deregulation*" (Baltimore Sun, April 12, 2012)
- "*Texas Power Grid Falls Short*" (The Wall Street Journal, August 12, 2011)
- "*Power Failures Thrust Deregulation into Public Glare*" (The New York Times, February 19, 2011)
- "*Electricity Deregulation Intensifies Energy Crisis*" (Voices of Central Pennsylvania, December 2, 2007)

V. RESTRUCTURING UNDERMINES INTEGRATED RESOURCE PLANNING AT A TIME WHEN THE INDUSTRY NEEDS IT MOST

Long-Term Resource Planning is Critical

IRP has served a critical role over the past 25 years for utilities, regulators and other stakeholders. It is one of the most important functions of a state regulatory body. IRP is a rigorous, open analytical process, supported by sophisticated industry planning software, that helps utilities, regulators, and other stakeholders determine their energy future, weighing all the benefits, costs, risks and extraneous implications over time. The best resource decision at a particular point is not always the least cost option and may be preferred because it contributes to greater fuel diversity, helps satisfy an impending environmental obligation, or provides a hedge against a significant future uncertainty.

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[17] *See "Deregulated Electricity in Texas,"* Texas Coalition for Affordable Power, December 2012, at 2.
[18] *See "The Washington Times, State Legislature Say Utility Deregulation Has Failed in its Goals,"* Hill, David, *May, 4, 2011.*

In Arizona, as in most markets that have not restructured, the regulatory commission retains oversight over the entire resource acquisition process, including the analysis of potential resource options; planning, siting and development; placement in rate base for cost recovery purposes; and ongoing maintenance and operation activities.

As the Commission is aware, generation expansion, refurbishment, and retirement decisions have an enormous impact on the cost, reliability, fuel diversity and environmental and public policy attributes of the supply of electricity for twenty years or longer. Regulated utilities must make and have made these large capital decisions while considering future uncertainties regarding load growth, relative fuel prices, and changes in environmental and other regulations. Unregulated generation suppliers, in contrast, focus on their own near-term profitability.

In restructured markets, state commissions may retain authority over siting of new independent power plants. RTOs perform transmission planning, but they do not in any sense perform integrated resource planning. Regulated utilities that have divested their generation assets are no longer required to perform IRP. Because generation resources compete in wholesale markets based on economic and operational attributes, with less attention paid to other critically important portfolio objectives such as price stability, fuel diversity, technology diversity, and environmental attributes, there is no constructive way for states to directly influence the composition of generating portfolios. States are left hoping that new capacity will be built to address local and regional reliability concerns and that the objectives that have historically been the focus of resource planning such as cost, reliability and environmental quality will be produced by a market over which they have almost no control.

Competitive Wholesale Electric Markets are not a Substitute for IRP

In theory, capacity markets operated by the RTOs should determine when new capacity should be built (or retired), where it should be developed, and what type of resource is needed. However, capacity auctions are based solely on price and do not take into account other important considerations such as fuel diversity, operating flexibility, or environmental attributes. In restructured markets, there is no one "minding the store" when it comes to these important resource planning considerations.

Natural gas is now at historically low prices. While natural gas prices are low today, these prices have been volatile over time. For instance, prices in the summer of 2008 were two to three times higher than today's prices. Relying more heavily on gas-fired generation, as happens in restructured markets, heightens the exposure of customers' bills to volatile natural gas prices. Further, with uncertain customer relationships, utilities' inability to safely invest much needed capital in coal plant emission control technology would threaten the viability of existing coal plants. The loss of coal generating facilities, such as the Four Corners and Navajo generating stations, would significantly harm the very regions of the state that can least withstand such an economic loss.

With the loss of coal generation in the state, Arizona would become a price-taker of natural gas. Meaning, regardless of the price, customers would have no choice but to bear the brunt of volatile natural gas prices as there would be little else in the way of energy resources to supply electricity. In addition, a significant increase in natural gas demand would necessitate significant new capital investment in pipeline infrastructure. It is difficult

to determine who would be willing to make the long-term commitments to support the much needed capital to invest in that infrastructure. Needless to say, tying Arizona's energy future to an electricity market based predominantly on natural gas pricing is a significant risk for consumers.

Further, new gas-fired generation may or may not be built depending on the developer's contractual and financial circumstances and their appetite for risk. The inability to reliably forecast capacity prices presents significant financing hurdles for utilities. It is questionable whether a large baseload plant could be financed at all under restructured market models.

Competitive wholesale markets are not a good substitute for a Commission-approved IRP process. The IRP process ensures that utilities are considering all relevant factors necessary to provide reliable, cost effective, and environmentally responsible service to customers. The IRP is the only process whereby generation, transmission and fuel supply infrastructure are brought together in one, comprehensive analysis, thus ensuring plans are in place to serve customer's energy needs now, and in the future.

VI. WHOLESALE MARKETS ARE NOT WORKING WELL IN OTHER REGIONS

A Well-Functioning Wholesale Market is a Prerequisite to Retail Restructuring

It is not possible to introduce retail restructuring on a broad scale without establishing a RTO. While this could theoretically be an Arizona-only RTO, it would likely be more cost effective to form a new RTO that comprises a broader region, or Arizona's utilities could join an existing RTO – the California ISO is an obvious choice. Under any option, the Commission would relinquish its regulatory jurisdiction over restructured generation to the FERC. Deciding which of these options appears to be the most promising would take a year or longer and be based on many shaky assumptions. Given the failures in other wholesale markets, it is unlikely that any market structure can be legitimately relied on to produce consistent net benefits at an acceptable risk level for Arizona customers.

While RTOs are voluntary organizations, the FERC has done everything within its power to encourage their formation. In restructured markets, in place of the traditional utility grid operating model, RTOs perform a function for electricity transmission that is akin to the role of air traffic controllers. They are generally responsible for: (1) operating the regional bulk electric power system; (2) developing, overseeing, and administering the wholesale electricity marketplace; and (3) managing the power system planning processes to address future transmission needs. RTOs provide retail marketers with the ability to acquire capacity, energy, and ancillary services to construct a supply portfolio that they need to serve their retail customers. A short-term market is particularly important as it is not possible to perfectly forecast capacity and energy requirements. Wholesale markets are not only designed to allow retail marketers to buy and sell energy products and services, they also contain financial tools that provide retail marketers with the ability to hedge against demand risk and price volatility.

Formation of an RTO is Complicated and Costly

Forming an Arizona RTO would require a lengthy (measured in years) and costly (hundreds of millions of dollars) development effort. There are numerous steps required to form an RTO, with many regulatory approvals along the way. This process is estimated to take between 3-4 years, but could take longer. Steps include:

- Negotiations among the various stakeholders on operating protocols and RTO structure;
- Filing and approval with the FERC;
- Additional FERC filings to transfer operational control of transmission assets;
- Modifications to existing transmission Open Access Transmission Tariffs;
- Additional approvals from other reliability governing bodies;
- Once approved, developing operating systems, policies and staffing; and
- Development of an internal market monitoring function and retention of a qualified independent market monitor to identify and report market violations, market design flaws and market power abuses.

Overall, the initial formation of an RTO and establishment of energy, ancillary and potentially capacity markets and related financial-hedging tools should be expected to take at least five years and an investment in the hundreds of millions of dollars, with the FERC making all key decisions. Considerable investments will be required to develop information systems to operate new markets and to form a new legal entity that will have hundreds of employees. All of these costs and complexities will need to be weighed against the perceived benefits of moving forward with an RTO, particularly if the sole purpose for such movement is to support a competitive retail market.

Wholesale Markets are a Work in Progress and Require Constant Adjustments by the FERC

Markets that have long since deregulated continue to struggle with updating existing rules and writing new rules as they learn from their experiences. Overall, customers are now paying higher market-based rates for electricity generated by many of the same plants that used to serve them based on the lower cost structure of actual fuel costs and depreciated net plant. Markets have proven adept at securing demand response resources, but it is not clear how reliable those resources will continue to be. It is clear, however, that the energy and capacity markets are not serving either the near-term or long-term needs of customers.

Mature RTOs such as PJM are facing serious challenges in successfully designing capacity markets that solve what is often referred to as the "missing money problem." This refers to the need for generators to derive sufficient revenues from short-term competitive wholesale markets to provide what they have determined is a reasonable return on invested capital in order to encourage sufficient new generation investments. The early RTO market designs were based on energy-only markets. However, there was little tolerance to allow energy prices to spike to reflect scarcity and expose retail customers to price volatility. Offer caps were put in place to dampen this volatility. Recognizing the need for these caps,

RTOs have been working for years to develop a capacity market approach that allows generators the opportunity to recover the fixed costs associated with their investment and encourage new investments. These efforts have resulted in non-stop litigation at the FERC and to date have been universally unsuccessful.

Market Manipulation is a Serious Concern

There are voluminous examples of market structure abuses and market manipulation accusations across the country where restructuring has occurred. Since 2007 the FERC has levied hundreds of millions of dollars in fines and penalties to various Companies.[19] In fact, at least some of the entities promoting restructuring in Arizona have been fined millions of dollars by FERC for market manipulation. As part of its oversight, FERC has taken repeated steps to enhance its enforcement capabilities — including reorganizing and staffing up its Office of Enforcement, requiring detailed market data reporting from organized market operators, and pursuing landmark penalties against energy traders in 2012 and 2013. The Commission's only ability to participate in any way in the review of market abuses and manipulations, regardless of their effect on Arizona customers, would be as one of many parties to FERC proceedings – a party with only a small fraction of the resources enjoyed by the merchant generators and power marketers.

VII. ARIZONA WILL FACE UNIQUE CHALLENGES IF IT TAKES A SECOND RUN AT RESTRUCTURING

Arizona has Tread this Legal Path Once Before

Arizona already has direct experience with the complicated and volatile nature of restructured electricity markets that has left many scars and exposed complicated constitutional and legal hurdles.

In 1998 the Arizona State Legislature codified the process of electricity market restructuring through the passage of The Electric Competition Act (HB 2663). That law envisioned a gradual approach to the introduction of retail restructuring into the electricity market in Arizona, with 20 percent of system-wide load opened to competitive providers by the end of 1998 and all of the market opened up by the end of 2000. Importantly, the law included the Salt River Project ("SRP") as a participant in the restructuring process since SRP is not under ACC jurisdiction. In tandem, the Commission implemented a series of rulemakings (the "Competition Rules") to implement the Act. As part of the restructuring, the investor-owned utilities in the state were required to either divest or transfer their rate based generation facilities to unregulated affiliates. The investor-owned utilities in Arizona identified stranded costs of close to $1 billion as of the end of 1998.[20] APS spent more than $47 million to prepare its systems for retail restructuring. In APS's service territory, few customers (slightly over 300 general service accounts) switched to an alternate generation supplier. However, residential and small business customers did not participate.

[19] http://www.ferc.gov/enforcement/civil-penalties/civil-penalty-action.asp. This site details FERC's civil action enforcements since 2007, the first year in which the Commission put the precepts of the October 2005 Policy Statement on Enforcement into practical effect.
[20] ACC Decision No. 61973 (October 6, 1999) and Decision No. 62103 (November 30, 1999).

Shortly after Arizona began down the path to divesting regulated generation assets and introducing retail electric restructuring, western wholesale electricity markets experienced the region-wide crisis, which began in California and eventually affected states across the western interconnect. As a result, it became physically impossible for Arizona market participants to meet the requirements established by the Commission's rules. In September 2002, the Commission rightfully determined that the restructuring of the electricity market was not feasible and abandoned the timeline and path to a restructured market. Fortunately, the state had not passed the point of no return with the divestiture of regulated generating assets and was able to unwind the restructuring that had occurred, although at significant cost to customers.

Restructuring is Not Legal in Arizona

Key elements of restructuring are not legal in Arizona. Shortly after they were implemented, the Commission's restructuring rules were challenged in court as unconstitutional or otherwise unlawful. The legal challenges to the initial and final Competition Rules were consolidated and resolved in *Phelps Dodge Corp. v. Arizona Electric Power Cooperative*, 207 Ariz. 95, 83 P.3d 573 (App. 2004). A variety of entities alleged, among other things, that the rule permitting market prices to determine utility customer rates was unconstitutional. The Court agreed. In 2004, in response to stakeholder challenges in the Court of Appeals, the *Phelps Dodge* Decision found that key provisions of the Competition Rules were either unconstitutional or invalid for administrative reasons and remanded back to the Commission. This determination recognized that there are inherent defects in the current Competition Rules. The critical provisions found to be unconstitutional included: 1) the requirement that utilities divest their generating assets, 2) a determination that rates set by the market for competitive services are just and reasonable and 3) the requirement that utilities create and join the Arizona Independent Scheduling Administrator (an interim organization that functions in some manner similar to a RTO.[21] Utility generation divestiture, market based pricing, and RTO membership, are key tenants of restructured markets. If pursued in Arizona, enabling these prerequisites would require both extensive rulemaking and a Constitutional amendment. Undoubtedly, amending the State Constitution to adopt key provisions of market restructuring would result in a contentious and time consuming political and legal process.

Prior to the *Phelps Dodge* decision, the Commission initiated the difficult process of reversing the steps that had been made toward a restructured market in Arizona. In 2005, as part of a settlement process ending a full seven years after the state legislature issued The Energy Competition Act, APS integrated the generating assets that had previously been held in its unregulated generation affiliate.

[21] Among other provisions invalidated for administrative reasons, the *Phelps Dodge* decision invalidated A.A.C. R14-2-1603 relating to the issuance of Certificates of Convenience and Necessity ("CC&N"), leaving a gap in the Competition Rules addressing the process for Electric Service Providers ("ESP") to file for Commission certification. The Court held that the following portions of the Rules were invalid because the ACC lacked constitutional and/or legislative authority to enact them: A.A.C. Rules R14-2-1609 (C-J) (rules regarding creation and operation of an Arizona ISO); R14-2-1611(A) (rule providing that market rates are deemed just and reasonable); R14-2-1615(A) and (C) (rules regarding forced divestiture of generation assets).

Since that time, the Company has operated as a fully integrated electric utility, delivering electricity produced by a regulated fleet of generating units to customers on its delivery system, in coordination with the other electricity providers in the state of Arizona.

Commission Rules and Policies Would Need to be Revisited

Since the adoption of the Competition Rules, the Commission has adopted a number of rules regarding resource planning,[22] energy efficiency,[23] renewable energy,[24] and net metering.[25] The Commission's own staff found that a review of the Commission's rules as a whole must be considered should the Commission proceed with restructuring. In a Staff report issued in August 2010, Staff found that:

> [A] better path forward would be to revisit the issue of electric competition as a whole, rather than revise the Retail Electric Competition Rules in a piecemeal fashion. This is especially so given the need to address any issues that arise from the interaction of retail competition and the renewable energy, energy efficiency standards and the resource planning rules.[26]

Further, at a May 9, 2013 open meeting on the issue of deregulation, the Director of the Utilities Division commented on the status of the rules:

> ..right now we have rules that are basically Swiss cheese. You have a piece of the rule that's good, a piece of the rule that's not good because it didn't go to the Attorney General, and the other piece is unconstitutional. So those rules are pretty much worthless...as far as Staff is concerned.[27]

All of these various rules would need to be revisited and potentially modified, if not abandoned, should the Commission pursue restructuring. Rulemakings and other lengthy regulatory processes would be required to review all relevant policies.

There is no Promising RTO Solution for Arizona

APS operates its transmission system as a stand-alone control area, processing interconnection requests and requests for transmission service on a stand-alone basis. However, the dispatch and day-to-day operations of the Company's transmission grid are closely coordinated with the operations of the Salt River Project's transmission system, because those two systems are so integrated. Restructuring of APS's control area would increase the problems of trying to coordinate between the two contiguous control areas to promote reliability.

Because Arizona utilities in general and APS in particular operate the transmission system on a stand-alone basis, integration of their systems into a region-wide RTO would

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[22] A.A.C. R14-2-701 et seq.
[23] A.A.C. R14-2-2401 et seq.
[24] A.A.C. R14-2-1801 et seq.
[25] A.A.C. R14-2-2301 et seq.
[26] Docket Nos. E-00000A-02-0051 and E-00000A-01-0630. Laura Furrey, August 12, 2010, *Staff Report for Generic Proceedings Concerning Electric Restructuring Issues*, at 13.
[27] Staff Meeting May 09, 2013 – Audio from Meeting (Quote at minute 48) - http://www.azcc.gov/Divisions/IT/streaming/events.asp

require significant re-engineering of systems and processes to support a restructured market. APS coordinates supply resources regionally on a limited basis for the purpose of reliability and bilateral electricity purchases, but the bulk power functions assumed by a system operator are handled on a stand-alone basis within APS's control area. There are several activities that APS undertakes as part of its standard business practice that encompass some of the functions of an operating RTO. Those activities include APS's participation in the Southwest Reserve Sharing Group ("SRSG") and the continued existence of the Arizona Independent Scheduling Administrator ("AZISA"). The SRSG is an organization that allows its members to share reserves across the southwestern United States through coordinated scheduling. Unlike in an RTO, however, the SRSG's member utilities supply their customers based on their own available generation and rely on the SRSG arrangement for assistance in responding to contingency events. The AZISA was meant to act as an interim organization that would begin to assume some of the functions of a RTO.[28] The State of Arizona would be essentially starting from the ground floor in the development of a RTO that would coordinate the restructured market's electricity flows.

Arizona-specific circumstances must be considered when establishing a RTO. First, apart from California, Arizona is surrounded by states with vertically-integrated public utilities. Scheduling reserve sharing through the SRSG is about as much coordination as APS expects to achieve under the current industry climate. Without the extension of a RTO outside of the borders of the state, the benefits of establishing such an organization are very limited.

Moreover, the costs of establishing and running a RTO are substantial. When spread over a larger system, those costs may reflect economies of scale. However, given the size of the native load of the State of Arizona, such scale would not be achievable. For example, the ERCOT system in Texas met a total load of approximately 319,000 thousand megawatt hours ("MWh") in 2010, whereas total retail sales in Arizona in that year were approximately 73,000 thousand MWh. Such a discrepancy in size, considering that all the functionality would need to be replicated, would point to a more costly implementation in Arizona than in Texas on a per MWh basis. A 2007 study of RTO operations found that the operations and administrative costs to run a full-fledged RTO varied between $0.393 and $0.912 per MWh annually.[29] Simply assuming the same costs, at an average expense of $0.526 per MWh, to operate and run a RTO in Arizona would approach $40 million per year in new costs.

The only other alternative is the integration of the Arizona transmission system into the nearest operational RTO, the California ISO. Assuming that it is even technically possible to integrate the Arizona and California transmission grids, the control and dispatch of the Arizona transmission grid could be run as part of the broader California ISO market

[28] As discussed in more detail in response to Staff Questions 10 and 13, the AZISA has established protocols for operational parameters, such as the allocation of retail network transmission service and must-run generation protocols. The AZISA is not a replacement for an RTO, and was always envisioned to be a temporary organization that would function as a bridge to an RTO. In part, the FERC declined to approve Phase II protocols of the AZISA since an RTO would supersede the functions of the AZISA. It is APS's opinion that to implement AZISA's Phase II protocols, Arizona customers would be required to pay an amount that is significant in contrast with the additional functionality gained, particularly when compared with the cost and functionality of a full RTO.

[29] See, "*Electric Market Reform Initiative (EMRI) Task 2 - Analysis of Operational and Administrative Cost of RTOs, Report for American Public Power Association (APPA),*" GDS Associates, Inc., Engineers and Consultants, February 5, 2007, at 5.

control area. That would make the Arizona transmission system subject to the policies and procedures of the California ISO, which are significantly influenced by California state politics. This prospect is one that the Commission should be very careful to pursue, because the overlay of California-specific carbon emissions or renewable energy requirements on Arizona's electrical system operations virtually guarantee that that electricity prices in Arizona will increase further.

VIII. RESTRUCTURING IS EXPENSIVE

Restructuring is a complicated, contentious and costly endeavor. Costs include: utility stranded investment, utility regulatory assets, grid management and market operations, utility administrative and operational costs, retail provider administrative and operational costs and retail provider marketing and sales costs. As a result of Arizona's experience with deregulation beginning in the late 1990s and early 2000s, APS customers alone would have paid over $350 million in utility stranded investment had deregulation succeeded. In 2010, customers finally paid off $47 million in utility administrative and operational costs (Competition Rule Compliance Charge) incurred by APS to transition to electric restructuring. Going forward, APS estimates that the costs to transition to restructuring (including RTO participation, utility stranded investment, and utility administrative and operational costs) is likely to exceed $1 billion depending on the type of market structure and the associated rules adopted by the Commission. The costs of moving to a deregulated market will be substantial and should not be ignored. Regardless of how these costs are assigned among participating stakeholders, retail customers will ultimately pay them.

IX. RESTRUCTURING HAS FAILED TO LIVE UP TO ITS PROMISES

Ironically, Restructuring was a Response to Rising Prices

The initial events leading up to electric industry restructuring grew out of frustration with upward pressure on electricity prices in the mid- to late-1970s and early 1980s due to a confluence of factors including the Arab oil embargo, rising natural gas prices, and wide-spread inflation. The first wave of Organization of Petroleum Exporting Countries (OPEC)-induced oil price increases in the mid-1970s sparked an "energy crisis" with oil prices spiking to $100/barrel and long lines at gasoline pumps. Congress began to focus on reducing our reliance on imported oil and encouraging more efficient use of energy. This led to the passage in 1978 of the Public Utility Regulatory Policy Act ("PURPA"), requiring electric utilities to purchase power from cogeneration facilities but leaving the contractual details up to the states to implement.

Prior to the passage of PURPA, development and ownership of non-federally owned power generation was the exclusive domain of state-regulated electric utilities serving exclusive franchise areas. These "vertically integrated" utilities were responsible for all aspects of electric service, from the production of the electricity (generation), to the transmission of electricity from one system to another (transmission), to the delivery to homes and businesses within the utility system (distribution), to retail billing and collection. Each of these segments is capital-intensive and utilities rely on capital markets to finance their capital expenditures. There was and remains a "regulatory compact" under which utilities finance and make investments on behalf of their customers and in exchange they are provided with the opportunity to recover their costs of providing service and to earn a return of and on their prudent investments.

IRP was Part of a Similar Effort

During the late 1980s and throughout the 1990s, many States imposed IRP requirements on electric utilities in order to improve the quality of decision-making with respect to new resources (which now includes energy efficiency and demand-side resources), and to introduce competitive elements into the generation segment. States wanted to ensure that demand-side resources were evaluated on equal footing with generation resources and that the planning process had sufficient rigor to assess many forecast uncertainties including demand growth and fuel prices.

The next step taken in the late 1980s by certain states was to require utilities to issue an RFP and allow third parties to compete against a utility-build option to serve increasing load. These RFPs became the subject of protracted litigation and by the early 1990s regulators from states with relatively high electricity prices started to question whether the generation function was a natural monopoly and whether it would be administratively more efficient to rely on market forces by requiring utilities to exit the generation function completely or compete in this business through an unregulated affiliate. The Energy Policy Act of 1992 further enhanced the role of independent power producers by permitting any entity, either utility or non-utility, to construct or acquire generation and compete in the wholesale market for electricity as long as it could prove an inability to exercise market power.

State Restructuring Laws were Short-Sighted

The extensive litigation of IRPs and subsequent RFP processes that effectively put regulators in the position of deciding generation development winners and losers contributed to the unproven notion that it would be easier to let the market decide which plants would be built. Legislation was required in the vast majority of states before utilities could divest their generation. In either circumstance, utilities sought recovery of stranded costs should generation sales produce revenues that were less than the remaining net book value - a request that was supported, in Arizona, by Constitutional legal analyses. Crafting legislation was a bewildering exercise that Enron was only too happy to help legislators with in order to ensure that electric restructuring was in the mix.

> "According to the National Institute of Money in State Politics, Enron's lobbying included more than $1.9 Million in campaign contributions to more than 700 candidates in 28 states. They met with utilities commissioners and worked in close tandem with other energy companies to make sure that electric power privatization passed in legislatures across the country. The massive political and lobbying power of these energy companies drowned out the voices of consumer groups and environmental groups who had serious questions and doubts about electric restructuring. These corporate victories set the stage for an "energy crisis" in California and other states."[30]

At that time, legislators and regulators strongly believed restructuring would benefit customers. The press releases that were issued to accompany restructuring legislation were

[30] *See "The Enron Debacle and Electric Power Deregulation",* Mike de Rosa, found at http://www.gp.org/articles/derosa_03_02_02.shtml.

remarkable in their own right. Consider these excerpts from Governor Wilson's press release issued when he signed California's restructuring legislation into law on September 23, 1996.

> "Every time a resident of this state flicks on the electric switch, they pay 40 percent more than residents across the United States," Wilson said. "The legislation I am signing today will end that by ushering in a new era of competition, making California the first state in the nation to dismantle its electric monopoly. This landmark legislation is a major step in our efforts to guarantee lower rates, provide consumer choice and offer reliable service, so no one literally is left in the dark." . . . During the transition, residential users and small commercial businesses are guaranteed a rate reduction of 10 percent starting January 1, 1998, followed by another 10 percent reduction by 2002, the end of the 5-year transition period. . . . . The legislation also establishes an Independent System Operator (ISO) to ensure there is a consistently reliable source of power for California consumers and to provide safeguards against the types of outages recently witnessed in large parts of the west.[31]

California's market restructuring, as we all know, achieved the opposite result, leading to skyrocketing prices, unprecedented volatility, and a series of rolling blackouts approximately two years after energy markets were established.

Restructuring Over-Promised and Under-Delivered

The restructuring legislative actions shared many common elements and promises. Many states encouraged the divestiture of utility-owned generation with any stranded costs to be recovered over a transition period through a non-bypassable delivery charge. They frequently included price caps and/or price reductions to "guarantee" that everyone would benefit from restructuring, including customers that elected not to choose a competitive supplier and were served by the utility under a regulated sales service. The utility had to rely on a new and untested regional wholesale market to obtain supplies to serve these customers and auction processes were established under the oversight of the utility commissions to acquire these supplies. Utility resource planning was suspended as this function would now, in theory, be served by the competitive market. The consensus thinking at this time was that the mass market would become competitive, served by large entities with millions of retail customers like Enron, and that the role served by the utility as a provider of last resort would quickly fade away.

X. CONCLUSION AND RECOMMENDATIONS

For the reasons identified in this introduction and others elaborated in the Company's responses to the Staff's 18 questions, APS respectfully requests that the Commission reject the wish of some interested parties to deregulate Arizona's electricity market. Arizona went down this path in the late 1990s and rightfully applied the brakes after the California Energy Crisis spilled over to several neighboring states, including Arizona. Arizona was joined by seven other states in repealing, postponing, or cancelling deregulation initiatives, thus

[31] *See "Wilson Signs Historic Legislation Restructuring Electric Industry"*, Monday, September 23, 1996, as filed in Edison International SEC Form 8-K, October 3, 1996.

minimizing the adverse impact on its citizens.[32] The known risks and potential costs associated with restructuring far outweigh the likely benefits. Among other things:

- Residential customers will not benefit from deregulation. In fact, many residential customers in restructured states are worse off than they were or would have been if restructuring had never occurred.
- To the extent that large C&I customers may benefit from deregulation, it is because they are no longer paying costs that the Commission determined should shift to them from residential and other classes for policy reasons. Any such benefit is not the result of a net efficiency gain when all customer costs and benefits are considered.
- Restructuring jeopardizes resource and fuel diversity, especially coal and nuclear generation. Four Corners Power Plant and Navajo Generating Station are at particular risk of closure if the Commission pursues electricity deregulation.
- Resource planning has a significant value to the State. Restructuring will decimate resource planning, risking the reliability of Arizona's electric system and generation supply as well as the pursuit of important public policy goals.
- A functioning wholesale market is a prerequisite to deregulation, and wholesale market flaws have caused a myriad of problems including market manipulation accusations and reliability concerns.
- Restructuring is not a "one and done" activity. States that restructured 15 years ago are still modifying rules and addressing issues.
- Restructuring costs may approach $1 billion or more.
- Any effort to restructure Arizona's electric industry will lead to a lengthy and litigious court challenge.

The reality of restructuring has been radically different from the promise. And once a state has taken the step to restructure its retail electric market, there really is no turning back. **APS thus recommends that the Commission should**: (1) find that deregulation is against the public interest; (2) retain its jurisdiction over the generation and resource actions of Arizona's regulated electric utilities; and (3) vote in Step One to close this Docket, and no longer devote its and other stakeholder resources to the consideration of electric deregulation.

[32] *See "Regulatory Research Associates Topical Special Report, Electric Industry Restructuring: Tier Redefinition and Update,"* SNL, August 1, 2012, at 1.

Exhibit A

APS Response to Staff Electric Restructuring Questions

Question 1. Will retail electric competition reduce rates for all classes of customers- residential, small business, large business and industrial classes?

No. Restructuring's hypothetical promise of lower retail electric rates for all has not materialized. There are definite "winners" and "losers" in any restructured market. From a rate perspective, in the short run, it is typically large commercial and industrial ("C&I") customers who "win" and residential and small business customers who "lose" when a state restructures. Large C&I customers generally have high energy demand on a relatively constant basis – or a "high load factor". On the other hand, residential customers and small businesses customers generally have lower energy demand on a less constant basis – or a "low load factor". For that reason, a customer base that is predominantly residential usually has relatively short bursts of high usage with the potential for supply resources to otherwise sit idle. This makes serving residential and small business customers more costly and less efficient than serving the more constant C&I load. The reason is because the utility must put in place the infrastructure to meet the low load factor customer's times of highest use, even if most of the time they use less energy. A close analogy is a city that must build a road wide enough to meet rush hour traffic, even if most of the time, few if any, cars use the road.

There are variations in load factors/costs to serve even within large C&I classes. **As a result, when a state restructures, the most attractive C&I customers – those with the most consistently high usage – are "cherry picked" by competitive suppliers, leaving the rest of the C&I customers in that class and most residential and smaller C&I customers to be served by the utility or provider of last resort ("POLR").** In addition to raising the costs to all of these remaining customers, this produces resource planning inefficiencies (for example please see APS's response to Staff Question 17), further increasing rates to all POLR customers.

It is telling to examine the participation rates of customers in restructured markets. In states that have retail access, residential participation rates are much lower than that of other customer classes: 5 percent v. 63 percent.[1] The extraordinarily low participation rates of residential customers is strong evidence that they simply cannot benefit from "choice" in generation providers.

Many states that restructured their electric markets imposed regulatory price caps on incumbent utilities' supply rates. This was done in attempt to protect customers from market prices during the transition to a restructured market. In some circumstances, these regulatory constraints helped create short-run benefits by establishing the "price to beat" for merchant power providers, who then "beat" those prices for a period of time as the market developed. However, as these artificial price caps began to expire, the average

[1] Based on KEMA Retail Energy Outlook, January 2012 and Energy Information Administration data, as reported at Table 1 of *Retail Electric Choice: Proven, Growing, Sustainable*, Philip R. O'Connor, Ph.D. April 3, 2012, at 21.

price of electricity increased.[2] For one Illinois utility (Central Illinois Public Service Company), **electric rates rose by as much as 92 percent the year the cap was lifted.**[3]

Even when large C&I customers have experienced rate reductions, however, the rate reductions have not been consistent or sustained. One study showed that the difference in **prices paid by industrial companies in restructured market states compared to regulated ones nearly tripled from 1999 to July 2007.**[4] The same study concluded that, in one year alone, **industrial customers paid $7.2 billion more for electricity in restructured states** than if they had paid the average electricity price of regulated states.[5] While this example is dated, it nonetheless relays the experience in markets shortly after they restructured.

There are a number of reasons why costs can go up in a restructured market to both customers that switch to a competitive supplier and to those that receive POLR service, including:

- strategic bidding by competitive power providers;
- market participants raising the price of electricity from cost-based average production costs to the higher cost it will incur to produce the *next* kilowatt;
- the market incentive for generators to increase prices wherever possible;
- the added costs that merchants incur to protect themselves against fluctuating sales to retail customers who may or may not remain loyal;
- the higher profit margin or cost of capital required by competitive market participants;
- "de-integration" costs incurred through the act of separating an incumbent utility's generation fleet from its delivery system; and
- High administration costs required to develop and sustain a Regional Transmission Organization ("RTO").[6]

By comparison, the traditional regulatory structure has cost advantages. One is that regulated utilities offer an "economies of scope" advantage. When a single entity owns and operates the various parts of the system needed to produce and distribute electricity, it can use the sum of its resources to supply those products at a lower price than could several separate entities buying and selling the same resources independently. Proponents of restructuring argue that retail electric market dynamics will lower prices sufficiently to more than offset the higher prices caused by the lack of these "economies of scope." Experience

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[2] *See "Electricity Restructuring: Deregulation or Reregulation?"* Severin Borenstein and James Bushnell, REGULATION, Volume 23 No. 2, at 46 (hereafter, "Borenstein and Bushnell"); *See also "Regulating Competition in Wholesale Electricity Supply,"* Frank A. Wolak, Stanford University, at 1

[3] Calculated from Energy Information Administration ("EIA") Form 826 data, 2006 and 2007.

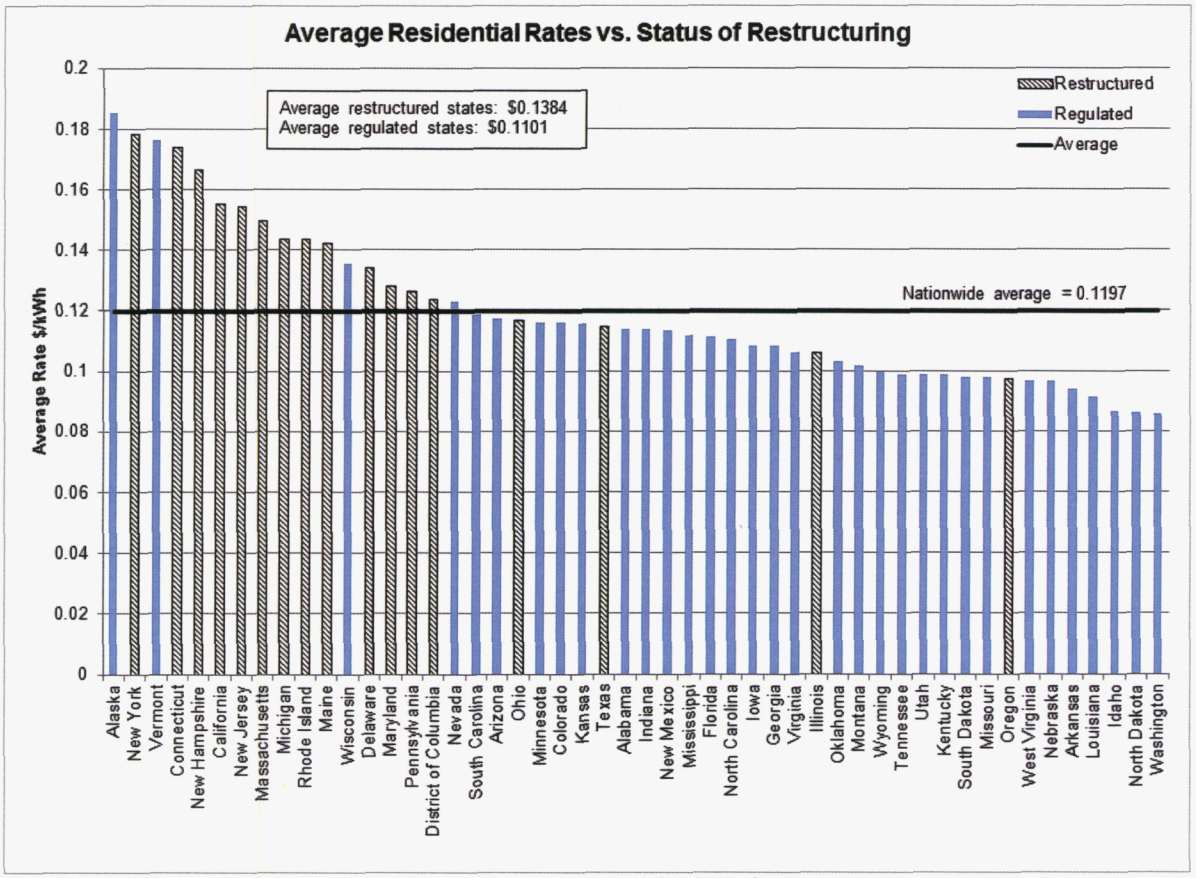
[4] *See "Competitively Priced Electricity Costs More, Studies Show,"* David Kay Johnston, New York Times (November 6, 2007).

[5] *Id.* (referencing the year 2006).

[6] *See "Does Deregulation Raise Electric Rates? A Cross Sectional Analysis,"* William B. Marcus, Principal Economist, JBS Energy, Inc., December, 2011 at 1-2.

to-date suggests that has not happened.[7] And those costs are ultimately passed on to the retail customer.

While there are many legitimate reasons why rates differ state-to-state or utility-to-utility, a simple review of average rates shows that (1) residential rates in restructured states are 26 percent higher than those in regulated states, and (2) thirteen of the seventeen states whose rates exceed the national average are restructured.[8]



Source: U.S. Energy Information Administration, April 2013 data

Though all rates have risen over time, rates have risen more, and more quickly, in states with restructured markets. From 1990 to 2011, the average price in restructured

[7] *"Retail Electricity Markets: How Are They Performing So Far?"* Kenneth Rose, electricpolicy.com, at 7-8 (hereafter "Rose").

[8] Based on EIA Table 5.6.A "Average Retail Price of Electricity to Ultimate Customers by End-Use Sector, by State", Form 826, April 2013 data. Due to its geographic isolation and associated resource planning and ratemaking issues, Hawaii was excluded from this analysis.

states grew by approximately 60 percent, while prices in regulated states during the same time period rose by 48 percent.[9]

In Arizona, some proponents of restructuring have stated that residential rates were reduced by 16 percent during the last Arizona restructuring effort, implying that and this is somehow proof that such customers would benefit from restructuring today. Nothing could be further from the truth. First the 16 percent refers solely to APS's residential rates.[10] Residential rates did not decline during this period in any other Arizona electric utility's affected service area.[11] It is illogical to believe that restructuring could function and provide supposed benefits in the half of metro Phoenix served by APS but not in the half served by SRP, or that restructuring could reduce residential rates in Flagstaff but not in Tucson. Second, some 9.7 percent of these rate decreases were agreed to and implemented by APS before the Arizona Corporation Commission's ("ACC" or "Commission") Electric Competition Rules were finally approved in 1999 – and some of the decreases relating to periods as far back as 1994. Another 2.7 percent of decreases took place after the Commission effectively moved to reverse restructuring in 2003. Thus, barely 3 percent of this 16 percent allegedly related to deregulation actually took place during the brief period of time Arizona generation markets were open to competitors.

The only logical conclusion is that these residential rate decreases were made possible because of traditional cost of service regulation as practiced by this Commission and were the product of conditions unique to APS in the decade plus from 1992-2004. Because restructuring in the late 1990s and the first few years of the 21st century was not responsible for any residential rate decreases[12], there is no reason to believe restructuring would produce them today.

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[9] Source: EIA Full Service providers. For purposes of this analysis, restructured states include: CA, CT, DC, DE, IL, MA, MD, ME, MI, NH, NJ, NY, OH, OR, PA, RI, and TX. Oregon's market currently allows customer choice for a limited number of large customers. Oregon's historical reliance on low-cost hydroelectric generation and cost-based rates for residential customers helps explain the comparatively low customer rates.

[10] The 16 percent is actually 15.5 percent, which represented the cumulative reductions in APS residential rates between 1992 and 2004. The compounded percentage reduction, which is what customers actually pay, would be less.

[11] ACC Decision No. 62301 (November 30, 1999) did reference two small reductions in TEP's rates, but those were reductions agreed to by TEP in a prior rate decision and had nothing to do with restructuring. No additional rate reductions were ordered in Decision No. 62301, and none were forthcoming thereafter.

[12] Although resulting in not so much as a dime of rate reductions, did saddle APS customers with nearly $47 million in additional transition costs – a sum it took many years to finally pay off.

Question 2. In addition to the possibility of reduced rates, identify any and all specific benefits of retail electric competition for each customer class.

As noted in APS's response to Staff Question 1, retail rates are not lower in restructured states than they are in more traditionally regulated states. In fact, rates in restructured states are both higher, and increasing at a faster rate, than rates in traditionally regulated states.

Proponents of restructuring argue that there are other benefits of restructuring, including fostering creativity and technological advances. While this sounds promising, there is limited evidence to support this claim. Electricity is generated, transmitted, delivered and consumed in the same manner regardless of whether the electric market is restructured or regulated. The restructured market offers limited benefit or innovation over a regulated market with respect to the elements of service that are required to provide reliable and safe energy to customers. In fact, many competitive suppliers do not have any ownership in the very components that are essential to providing the commodity they sell. Consequently, retail energy brokers will only focus on innovations or benefits that allow them to realize a profit. The purported benefits or innovations to end use customers associated with restructuring have included bundling of services, pricing schemes, and billing preferences. APS recognizes that these customized offerings, which are mainly offered to large commercial or industrial customers, may be viewed as a benefit of restructuring. However, many of these options are already offered by APS or could be offered, with Commission approval, within the current regulated market structure.

The Commission should be aware of increased risks associated with restructuring. For example, in exchange for the purported benefits associated with restructuring, customers will be exposed to, or otherwise pay for, the risks faced by retail suppliers. In addition to the risks passed through from the wholesale electricity markets, retail energy providers face additional costs and risks, including the risk that the load they serve will change due to weather, the economy, customer migration, a regulatory or fuel price changes, or that the wholesale market price will increase beyond expectations.[13] Although regulated utilities face many of the same risks, others – including the customer migration risk – only apply in a restructured market.

In addition to price risk, restructuring exposes customers to a contractual risk. Unlike a utility's obligation to serve all customers within its service territory, retail marketers are bound only by their contracts with customers. The risk of contractual default or retail marketers going out of business is not insignificant, as evidenced by more than 30,000 Texas customers that were forced onto a POLR rate after three retail energy providers defaulted on payments to the operator of the State's power grid.[14]

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[13] *See* Rose at 7.

[14] Stories abound in restructured states of customers opportunistically dropped by their service providers. *See,* e.g., "*Thousands Of Texas Customers Dumped By Electricity Providers*," KWTX.com, June 5, 2008, at http://www.kwtx.com/news/headlines/19567159.html.

Question 3. How can the benefits of competition apply to all customer classes equally or equitably?

There is no workable way to ensure that any benefits, or costs, apply to all customer classes equitably in a restructured market. In fact, the whole point of deregulation is to ensure that they will not. Embracing retail restructuring means embracing the notion that the market will function efficiently, but seldom, if ever, function equitably. Market-based outcomes will be different from outcomes that result from a regulator's public policy considerations

As discussed in the responses to Staff Questions 1 and 2, the purported benefits of retail restructuring have not materialized as promised. Typically, it is the largest C&I customers who "win" (although not always over the long-term) and residential customers who "lose" when a state restructures its electric market. The potential "benefit" to some C&I customers creates real inefficiencies and costs, many of which are borne by all non-switching customers, including residential customers.

Regulated utilities set rates for customer classes or groups by balancing an array of public policy objectives including equity, fairness, and gradualism in rate design. Regulators determine as a matter of public policy how costs should be allocated and rates set. In many jurisdictions, including Arizona, C&I customers are allocated a disproportionate share of the costs to provide service in order to maintain lower residential rates. If all subsidies were eliminated from APS's residential rates, residential customers would experience an immediate rate increase of approximately 8 percent, before consideration of the significant incremental costs that would be incurred to restructure the market.

When retail markets are restructured, the ability of regulators to balance public policy objectives is severely curtailed as the regulator only regulates the distribution service charges. When a state restructures its retail market its Commission loses jurisdiction and the ability to set and approve rates for generation, which can be the single largest element of most customers' total bill for electric service. As noted in the response to Staff Question 1, high load factor customers may enjoy reduced rates at the expense of residential customers who are left bearing significantly more costs.

Question 4. Please identify the risks of retail electric competition to residential ratepayers and to the other customer classes. What entity, if any, would be the provider of last resort?

Please see the response to Staff Questions 1-3 for a discussion of the risks and benefits of retail electric restructuring. As discussed, retail restructuring exposes customers to a number of risks including price increases, price volatility, loss of reliability, loss of regulatory oversight and prices that no longer reflect many public policy goals. In addition, customers face the risk that no competitive supplier will serve them or that the supplier they choose may go out of business.

Typically, to ensure that all customers (whether they reside in metropolitan or rural areas) continue to receive supply service, including those that have not switched to a competitive supplier, restructuring regulations require one or more entities to act as the "default" provider or POLR. A POLR is a power supplier that is required to act as a back-stop for customers who make no supplier election or whose former provider either refused to renew their contract or went out of business. In most cases, the default provider is the incumbent utility, but this service could also be bid out to third-party providers or provided by a state entity.

A POLR is an important element of a restructured retail electric market. Access to "life line" services, like electricity, should not be left to the whims of a competitive market, which is why, in part, it has historically been regulated. For POLR service to function appropriately, certain rules must be established. It would be patently unfair to give customers the ability to leave the default provider, test out the market, and then return to default service without consequence if market prices are too high to bear. This would be expensive to the entire electric market but particularly to the remaining POLR customers. Absent a long-term commitment, one cannot realistically predict how many customers will leave or return to its service and thus cannot economically plan for them. Assuming a functioning wholesale market is in place, relatively short-term market purchases or contracts tend to be very influential in the "default" rate. These rates tend to be volatile, and since most residential customers remain on POLR service, they experience this price volatility. Further, and as discussed in more detail in the response to Staff Question 17, this short-term approach to meeting customers' needs has numerous negative implications for effective resource planning.

Question 5. How can the Commission guarantee that there would be no market structure abuses and/or market manipulation in the transition to and implementation of retail electric competition?

It cannot. The Commission simply cannot guarantee that no market structure abuses and market manipulation will occur in the transition to, and implementation, of retail electric restructuring. In fact, profit-motivated participants have an incentive to exert market power, often pushing the envelope up to (and in some cases beyond) the edge of what is legal. This fact is particularly true in a competitive wholesale marketplace, which is not under Commission jurisdiction. There are numerous examples of market abuse in states in which restructuring has taken place. In fact, since 2007, the Federal Energy Regulatory Commission ("FERC") has levied hundreds of millions of dollars in fines and penalties arising out of market abuse allegations.[15] Between 2001 and 2012, also issued numerous civil penalties specifically tied to the California Energy Crisis.

Once a state restructures, the Commission's only ability to participate in the review of market abuses and manipulations would be as one of many participants in a FERC proceeding. In that scenario, FERC will be the final arbiter of market manipulation issues and may decide issues in ways that are not in line with the Commission's point of view.

As discussed in the response to Staff Question 6, designing markets is certainly not a "one and done" activity, nor is it limited to statewide issues. In fact, deregulated states have continually shifted their policies with respect to retail access and retail rates in order to address obvious flaws in the initial market designs. Wholesale electric markets that have long been restructured are still struggling with updating existing rules and writing new rules as they learn from their experiences, especially in the area of providing sufficient incentives to encourage necessary investment in infrastructure.

The interplay between competitive wholesale electricity markets and state-level retail access has also caused conflict. As shown by the examples of Maryland and New Jersey, state regulatory bodies have recently found it necessary to actively participate in FERC-regulated wholesale markets by passing legislation that allows customers of investor-owned utilities to help finance new power plant construction in an effort to address serious reliability concerns that arouse after the market consistently failed to result in new projects within their higher-priced Pennsylvania, New Jersey, Maryland Interconnection ("PJM") zones. It is important to note that, perhaps as a result of that participation, those states have been accused by other market participants of market manipulation and are currently being sued in two federal district courts.[16]

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[15] http://www.ferc.gov/enforcement/civil-penalties/civil-penalty-action.asp. This site details FERC's civil action enforcements since 2007, the first year in which the Commission put the precepts of the October 2005 Policy Statement on Enforcement into practical effect.

[16] Those case references are: PPL EnergyPlus, LLC v. Hanna, No. 11-745 (D.N.J.); and PPL EnergyPlus, LLC v. Nazarian, No. 12-1286 (D. Md.).

Question 6. What, if any, features, entities or mechanisms must be in place in order for there to be an effective and efficient market structure for competition? How long would it take to implement these features, entities, or mechanisms?

A functioning RTO and wholesale market are prerequisites to full deregulation. As discussed throughout APS's Initial Comments and in responses to these Staff Questions, restructuring, at the wholesale or retail levels, is not a "one and done" event. Restructured markets throughout the U.S. continue to evolve, changing rules and structures to address obvious flaws, unanticipated consequences, and alleged market manipulations.

RTOs were formed to administer the transmission grid on a regional basis throughout North America (including Canada). RTOs are generally responsible for: (1) operating the regional bulk electric power system; (2) developing, overseeing, and administering the wholesale electricity marketplace; and (3) managing the power system planning processes to address future transmission needs. RTOs provide retail marketers with the ability to acquire capacity, energy, and ancillary services to construct a supply portfolio that they need to serve their retail customers. A short-term market is particularly important as it is not possible to perfectly forecast capacity and energy requirements.

The current feasibility of establishing a truly regional RTO, including Arizona, is highly doubtful. Aside from California, Arizona is surrounded by states with vertically-integrated public utilities. APS already engages with its neighboring control areas to the extent possible given the current industry landscape. Without the extension of a RTO outside of the borders of the state, the benefits of establishing such an organization are limited.

Even after the identification of a suitable regional footprint, there are numerous steps required to form an RTO, with many regulatory approvals along the way. This process is estimated to take a minimum of 3-4 years, and could easily take much longer. Steps include:

- Negotiations among the various stakeholders on operating protocols and RTO structure (estimated to take one year or longer);
- Filing and approval with the FERC (estimated to take six to eighteen months);
- Additional FERC filings to transfer operational control of transmission assets (estimated to take at least six months);
- Modifications to existing transmission Open Access Transmission Tariffs (estimated to take twelve months or longer);
- Additional approvals from other reliability governing bodies (estimated to take six months or longer);
- Once approved, developing operating systems, policies and staffing (estimated to take a year or longer); and
- Development of an internal market monitoring function and retention of a qualified independent market monitor to identify and report market violations, market design flaws and market power abuses.

In addition, all of the following must be addressed when designing the market and determining retail restructuring rules. This process also could take several years.

- Capacity markets: Rules and rates must be established to set up energy markets and trading policies.
- Provider of Last Resort: Rates and rules must be set for the POLR, the provider who must serve a customer when another provider defaults or drops a customer. This includes determining who the POLR would be.
- Stranded costs: A process must be put in place for existing utilities to recover investments made in power plants.
- Generation divestiture: Although currently unconstitutional, existing utilities may be required by regulators to sell or spin off their power generation business/assets.
- Systems and Processes: Computer information systems must be established and procedures for switching customers to and from generation suppliers must be revisited.[17]

Overall, the initial formation of an RTO and establishment of energy, ancillary and potentially capacity markets and related financial hedging tools should be expected to take at least four years and an investment in the hundreds of millions of dollars.[18] Further, the issues and effort associated with operating in the new environment, which will be regulated by FERC, must be considered. Considerable investments will be required to develop information systems to operate new markets and to form a new legal entity that will have hundreds of employees.

Markets that have long been restructured are still struggling with updating existing rules and writing new rules as they learn from their experiences. Fifteen years after the initial market transition, restructured markets are still developing. If the Commission pursues retail restructuring, it should expect to spend years participating in FERC proceedings developing the market model and rules, and many more years participating in FERC proceedings as the model evolves.

[17] The Commission approved Direct Access Statewide Operating Standards and processes established by the Process Standardization Working Group must be reevaluated.
[18] For example, the PJM RTO opened a new control room in 2011, which – by itself – took five years to construct and cost the RTO members approximately $215 million to place into service. See, "*PJM prepares to open 2nd control center*," SNL Financial, October 24, 2011.

Question 7. Will retail electric competition require the divestiture of generation assets by regulated electric utilities? How would FERC regulation of these facilities be affected?

In Arizona, it would not. Divestiture was recommended largely to avoid the potential for market power or market abuses by incumbent utilities. While the proponents of restructuring in the late 1990s argued that divestiture was essential for retail restructuring to be effective, not all states that restructured required their regulated utilities to divest their generation. And, as noted in response to Staff Question 9, some states are actively considering building generation to fill the gap left by the competitive market.

But importantly for Arizona, and as expanded upon in the response to Staff Question 13, the *Phelps Dodge* decision found that mandatory generation divestiture violates the Arizona Constitution. Thus, any divestiture of generation would need to be voluntary on the part of incumbent utilities or would require a Constitutional amendment.

If generation is not divested, there would be no change to FERC regulation of generation. Wholesale transactions would continue to be regulated by FERC and retail transactions would continue to be regulated by the ACC. However, in a restructured marketplace, all owners of generation would seek to maximize the value of those assets. Faced with the market incentives described in response to these questions, it is altogether possible that incumbent utilities would find more value in choosing to divest key generating assets that currently serve the Arizona retail market. If generation is divested or operational control of generation assets vested in an RTO, then essentially all aspects of generation other than local siting would be "federalized" at FERC.

Question 8. What are the costs of the transition to retail electric competition, how should those costs be quantified, and who should bear them?

Based on Arizona's experience and the experience of other states, the costs of transitioning to a restructured market will be substantial. The transition costs will also be highly dependent on the particular market structures enacted and ultimately paid by retail customers.

There are numerous categories of costs that would need to be incurred in moving from the current regulated system to a market based on a deregulated electric market. The costs involved in restructuring the electricity industry will be substantial - in the billions of dollars range. However, the quantification of the costs will depend on the specific functions and responsibilities defined in the market structure. It is important to acknowledge at the outset that the rates paid by customers will need to reflect these real costs. The only way any particular subset of customers would experience a lessening of these costs would be through shifting their portion of costs to a different customer class.

The types of costs that would be incurred in restructuring the electric market fall into the following general categories:

1. Utility stranded investment: this type of cost relates to costs and commitments made by a utility under a regulatory model that included an obligation for the utility to serve all customers, but which will not be recovered when compensation is determined by short-term wholesale power markets.
2. Utility regulatory assets: this type of cost reflects costs incurred by a utility in the normal course of business that will be recovered from customers in the future under a regulatory "promise to pay."
3. Grid management and market operations: with the addition of many more market participants transacting in the wholesale market and scheduling and delivering power to retail customers through utility transmission and distribution networks, a robust system must be developed and expanded to maintain grid reliability and provide the appropriate "rules of the road" for all market participants to be treated equitably and fairly. These costs are significant and involve both complex information systems and people to use them to manage the grid and operate markets.
4. Utility administrative and operational costs: costs will be incurred to establish and maintain systems which allow each utility to keep track of which generation providers are serving which customers so that scheduling and billing information can be appropriately managed.
5. Retail provider administrative and operational costs: companies providing generation service to retail customers will incur costs similar to the costs incurred by utilities to manage the contracting, scheduling, billing and collections related to the customers for whom they are the provider. These costs include both supply procurement and sales to end-use customers.
6. Retail provider marketing and sales costs: companies providing generation service to retail customers will incur costs to advertise and market their products.

The costs of grid management in a restructured environment would likely be met with the establishment of an RTO. The experience of other states reveals that the costs of building and managing these organizations and their related systems have run into the

hundreds of millions of dollars, and there is little reason to think that Arizona would not face the same level of cost.

Utility stranded investment can be related to a variety of generation assets and any legacy systems that would not be used and useful under a deregulated model. These include both conventional and renewable generation assets, as well as both utility-owned assets and supplies procured under long-term purchased power agreements. These assets become stranded because the price for power on the wholesale market has fallen from the level it was at the time the initial investment decision was made. Although falling market prices have the potential to reduce retail customers' electric bills, any such reduction will be offset (and perhaps even exceeded) by new charges needed to address stranded costs. The last time Arizona embarked on a path to a restructured market, APS identified hundreds of million in stranded costs. Given that power prices are currently expected to remain low, under the current long-term outlook for wholesale power prices, the extent of APS's stranded costs could be significantly higher than that historical amount.

Regulatory assets are another version of stranded investment in that they were created as a result of a specific regulatory model. For APS, the bulk of its regulatory assets are pension and other postretirement benefit liabilities. The Company has incurred the obligation to pay these benefits in the future, and the regulatory model has validated in the past that these are legitimate and prudent costs of doing business. These expenses are gradually recovered through retail rates over time, but in a restructured market may require current balances to be written off, affecting utility company financial integrity. Regulatory assets currently being recovered through generation rates for APS are approximately $500 million.

In 2010 (eight years after the unwinding of retail access), APS customers finally paid off the roughly $47 million in expenses APS had incurred for the administrative costs of moving towards restructuring recovered through the Competition Rules Compliance Charge. Included in that sum was the cost to establish capabilities in the following areas: (1) identifying which customers have requested to be switched to a new provider; (2) identifying when the billing cycle would facilitate customer switching; (3) capturing billing information to be forwarded to new providers; (4) working with providers to schedule power deliveries for their customers; (5) doing after-the-fact accounting to reconcile actual deliveries from providers with actual load consumed by customers; (6) handling an expanding number of customer calls to deal with increased billing confusion, among other potential issues. Such costs can be expected to run into the tens of millions of dollars for each utility, and are costs that are not incurred under the current regulatory system. Ultimately, these costs will be recovered from retail customers. The precise level of such costs will depend on the market design adopted by the Commission.

Retail providers will face the same types of costs as utilities in managing the procurement and delivery of power for their customers and the corresponding billing and settlements processes. While these costs may be small for any individual provider (if they have relatively few customers), in aggregate, they could approach the magnitude of those incurred by the utilities in the state. These costs are not incurred today, will be at least partially duplicative of utility costs, and ultimately will be passed on to retail customers.

Finally, retail providers will incur costs to market their companies' products in order to attract business. Historical experience in other states shows that these costs have not been inconsequential. Ultimately, retail providers will need to recoup these costs from retail customers.

Question 9. Will retail electric competition impact reliability? Why or why not?

Electric market restructuring has the very real potential to harm reliability. There are numerous interrelated issues that threaten reliability. The substitution of FERC-regulated RTOs and regional wholesale markets for Commission-regulated utility Integrated Resource Planning and the oversight of all resource portfolio additions and retirements present a troublesome reliability risk. The importance of resource planning and the consequences of replacing the Integrated Resource Plan ("IRP") process with a market approach are addressed in APS's Initial Comments and in the response to Staff Question 17.

FERC's vision for wholesale markets has generally been that a relatively short-term capacity price signal will incent the development of new generation when and where it is needed. There is a fundamental disconnect between the FERC model and the requirements of financial markets that need greater confidence in projections of revenues that will be available to cover debt payments and provide a compensatory return to shareholders. The wildly fluctuating market-based capacity prices from year to year are not contributing the degree of confidence that investors should have in wholesale capacity markets, particularly when it is difficult to explain these prices as being the result of changes in demand and supply conditions. They appear to result from a relatively inelastic and administratively determined demand curve with a more elastic supply stack. Power plants are expensive and take a long time to build, and market participants have little incentive to make an investment for the future without a guarantee that prices will remain high long enough to justify the high capital spend. Moreover, independent power providers often lack the credit security of a regulated utility, and often have difficulty even financing a project without an executed long-term contract.[19]

A second issue with reliability is represented by the New Jersey and Maryland circumstances. In both cases, high capacity prices within constrained zones in successive annual auctions did not yield sufficient development of new generation capacity within those zones, despite analyses from the RTO itself that there might be potential reliability concerns within a reasonable time horizon. Ultimately, they were spared reliability issues by a recession and extraordinary offers from demand response. Texas has not been so fortunate either. The system operator has raised its price cap by 66 percent, and still faces the prospects of service interruptions this summer. This is not a position that a state government or public service commission wants to be in.

A third issue with wholesale markets is that retirement decisions are made by unregulated entities based on closely held and undisclosed financial analyses. Through the utility IRP, the utility identifies potential retirements and discusses the financial analyses of portfolio alternatives on a regular basis. In wholesale markets, a generation owner can issue a press release announcing an imminent shutdown of a large plant or even a fleet of

[19] *See "Incenting the Old, Preventing the New: Flaws in Capacity Market Design and Recommendations for Improvement,"* Synapse Energy Economics, June 14, 2011, hereafter ("Synapse").

plants.[20] The RTO can make a request that a plant keep operating for reliability purposes and be compensated for doing so, but, except for certain "Reliability Must Run" units, compliance with such a request is purely voluntary. The entire retirement economic equation has been changed by the transition to wholesale capacity markets. There are also strong incentives to shutter even a marginally profitable plant, if the owner owns other plants within the same pricing zone.

A flip side of the retirement issue, and a fourth concern, is that existing generation owners must consider the potential impact on capacity prices before proposing to develop new generation within the same RTO. This acts as a deterrent to the development of new generation, helps to maintain higher capacity and energy prices across the RTO, and contributes to reliability concerns in constrained regions within the RTO.

A fifth reliability concern with wholesale markets is that the markets appear to be structured to err on the side of maintaining scarcity conditions that come as close as possible to meeting North American Electricity Reliability Corporation ("NERC") requirements. While the amount of capacity secured in annual capacity auctions reflect a planning reserve margin, these margins can be considerably lower than exist in IRPs.[21] Even with these lower RTO reserve margins, in restructured markets, existing generators are incentivized to seek scarcity pricing for the electricity they produce. For that reason, they advocate for rules that make it harder for new entry, including the Minimum Offer Price Rule that has been the subject of extensive litigation at FERC. The states of Maryland and New Jersey argued that plants that are needed to meet a state policy objective (e.g., in-state reliability) should be exempt from this rule, but were denied. The preference for maintaining scarcity as an incentive to build new generation helps bolster energy and capacity prices that benefit existing generation owners. In the IRP world, a state commission can approve new capacity through a utility-owned plant or power purchase contract in advance of a need, creating a temporal surplus relative to margin targets because the plant provides reliability, energy savings, and environmental benefits. This strategic option, which provides real benefits to customers and the state economy, is not part of the wholesale market capacity model.

In summary, the concept of capturing the long-term reliability needs in current prices is absent in restructured markets. In theory, the market forces of supply and demand will cause new generation to be built when the price rises to a point where suppliers are incented to build. The "reserve margin" is hoped to occur organically as a result of market forces; no entity remains obligated to build adequate supply to ensure long-term reliability for customers. Existing power producers focus on short-term financial gains, not the long-term needs of the region being served.

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[20] On January 26, 2012 FirstEnergy announced that it was retiring five coal plants located in Ohio, Pennsylvania and Maryland, thus removing in a single action approximately 2,689 MW of capacity from PJM. *See, "FirstEnergy, Citing Impact of Environmental Regulations, Will Retire Six Coal-Fired Power Plants,"* FirstEnergy Press Release, January 26, 2012.

[21] For example, APS' 2012 IRP reflected a 15 percent planning reserve margin. The planned reserve margin for the ISO New England is 10.5 percent.

Left to its own devices, the market offers little guarantee that power producers will maintain enough capacity in reserve to meet demand spikes significantly beyond what is required for normal system operations. Generator owners earn no revenues on plants that do not operate, but they do earn windfall profits from the price impact of shortages. "In a market with instantaneous supply and demand balancing and high costs of entry, this is a recipe for massive market failure."[22]

There is not yet an effective means of incenting the market to address this issue and keep additional resources available in the market to ensure power reliability; it is one with which restructured markets continuously struggle.[23] For instance, Texas's "energy-only" market approach is contributing to a generation supply shortage. A national energy consulting firm estimates that by 2014, Texas's reserve margins will fall to 9.8 percent, well below their target of 13.75 percent -- one of the lowest reserve margins in the country.[24] Absent changes in regulation and market behavior, that reserve margin will likely fall further after 2014. The result has been devastating for Texas residents, who are at high risk of rolling blackouts during times of high energy use.[25]

Just last year, frigid temperatures in Texas caused dozens of the state's power plants to fail, causing the worst electricity outages in years. While several causes of the blackout have been identified, Texas's restructured market is under particular scrutiny as a contributing factor, reviving questions about the efficacy of a market system to meet the State's long-term needs.[26] In an effort to address the issue, Texas regulators have considered increasing the price that power providers can charge when supply is tight. At present, power generators can charge $5,000 per megawatt hour for energy supply. Maintaining the cap at that level would lower the State's reserve margin to *half* of what experts believe is needed for reliability purposes.[27] The Texas Utility Commission plans to raise that cap to a striking $9,000 per megawatt hour by 2015 – but even in that case, the resulting investment in power plants "would still fall short of what is needed to keep the lights on," causing a supply shortage that would translate into roughly one rolling blackout per year.[28] Even if a regulatory solution were found to incentivize new build, new power plants could not be built in time to forestall the rolling outages expected in 2014.[29]

To make matters worse, Texas power providers may be exploiting the supply scarcity to their financial advantage. As the Wall Street Journal recently reported,

> Energy Future Holdings Company is urging Texas officials to let power-plant owners reap greater profits if they can furnish electricity when the state needs it most. The market revision – billed as a way to help Texas address a looming energy shortage – could help fatten revenue for Energy Future

[22] *See* Synapse at 3.
[23] *Id.* at 16.
[24] *See* Brattle Group report on ERCOT Investment Incentives and Resource Adequacy, 2012.
[25] *See id, at 9.*
[26] *See "Power Failures Thrust Deregulation into Public Glare,"* The New York Times, Kate Galbraith, February 19, 2011.
[27] *See "Report on Electric Grid Cites Concerns with Reserves,"* Kate Galbraith, June 1, 2012.
[28] *Id.*
[29] *Id.*

> Holdings, the state's largest power plant owner, by $300 million per year, according to an estimate by UBS AG. The Company, suffering financially from investments that were uneconomic in hindsight, "is eyeing regulatory changes to the Texas power market as a way to lift its returns.[30]

This type of behavior, which would not be tolerated in a regulated utility model, is a rational response in a restructured market context.

All restructured markets share Texas's supply shortage concerns and have proffered a variety of potential regulatory fixes aimed at incentivizing the market to build new generation and prevent long-term reliability challenges. Proposals include eliminating price caps in wholesale markets, mandating future capacity requirements, developing forward capacity markets, and other complicated regulatory devices designed to encourage future build.[31] These measures, a complicated blend of regulated and market principles, are fraught with problems and unproven over the long-term. Potential fixes to market-driven capacity issues also add extraordinary complexity and cost to the system.

Lacking confidence in the market's ability to build for the future, some restructured states have taken it upon themselves to ensure that their customers have sufficient resources available to have continually reliable service. New Jersey, for example, recently passed legislation that provides financial support to new generation that is either located in or deliverable to a point in the State where capacity is needed; Maryland similarly issued a request for proposal for a similar purpose.[32] These state level initiatives are consistent with a more traditional regulatory model, as evidenced by the outcry from power providers who argue that these moves are "in essence an anti-competitive state subsidy that will, in turn, artificially depress capacity prices."[33] Such an argument serves only the interests of power providers that benefit from continued high supply prices, and contrasts sharply with the facts New Jersey and Maryland face: that the restructured "markets have failed to incentivize generation where it is needed most, despite high prices in these regions."[34] In spite of these state efforts to administratively address supply adequacy, no proposed market solution has yet proven successful in actually causing new generation to be built.

There are also potential reliability concerns associated with transmission planning performed by the RTO/ISO. In theory, one would expect to see an improvement in reliability from coordinated transmission planning across a wide region. Of course, the downside to coordinated planning that involves stakeholders with competing economic interests is that the process is cumbersome and slow. The siting of every new transmission line will favor certain infrastructure owners and harm others by influencing capacity and energy prices across the region. A new transmission line that delivers power from a low cost area to a capacity constrained higher cost area is likely to reduce these price differentials, increasing market-clearing prices for the lower cost region. Individual state interests with

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[30] *See "Big Texas Power Provider Seeks New Rules"*, Rebecca Smith, Wall Street Journal, March 9-10, 2013.
[31] *See "PJM State of the Market, 2012,"* Monitoring Analytics LLC, March 14, 2013.
[32] *See* Synapse at 3.
[33] *See id.*
[34] *See id.*

respect to new infrastructure development can easily be in conflict with each other, a potential problem because states continue to exercise authority over siting. This is not a new issue, but it is exacerbated by the creation of wholesale markets.

Question 10. What are the issues relating to balancing area authorities, transmission planning, and control areas which must be addressed as part of a transition to retail electric competition?

As noted in APS's response to Staff Question 6, the establishment of an RTO is a prerequisite to the introduction of full retail electric restructuring in Arizona. It is the RTO and the rules established under the operational structure of the RTO that would handle the functions and responsibilities for balancing area management, transmission planning and control area coordination.

APS operates its transmission system as a stand-alone control area, processing interconnection requests and requests for transmission service on an independent basis. However, the dispatch and day-to-day operations of the Company's transmission grid are closely coordinated with the operations of the Salt River Project's transmission system, because those two systems are integrally situated. As such, the restructuring of APS's control area would increase the problems of trying to coordinate between the two contiguous control areas to promote reliability.

Because Arizona utilities, in general, and APS, in particular, operate the transmission system on a stand-alone basis, integration of their systems into a region-wide RTO would require significant re-engineering of systems and processes to support a restructured market. There are several activities that APS undertakes as part of its standard business practice, which encompass a small subset of the functions of an operating RTO. Those activities include APS's participation in the Southwest Reserve Sharing Group ("SRSG") and the continued existence of the Arizona Independent Scheduling Administrator ("AZISA"). The SRSG is an organization that allows its members to share reserves across the southwestern United States. Unlike in an RTO, however, the SRSG's member utilities supply their customers based on their own available generation and rely on the SRSG arrangement for assistance in responding to contingency events. The AZISA was meant to act as an interim organization that would begin to assume some of the functions of an RTO, but not all. The State of Arizona would be essentially starting from the ground floor to develop an RTO that would coordinate the restructured market's electricity flows.

In addition to the challenges introduced in establishing the costly and time-consuming RTO rules discussed earlier, Arizona-specific circumstances must also be considered. First, apart from California, Arizona is surrounded by states with vertically-integrated public utilities. Scheduling reserve sharing through the SRSG is about as much coordination as APS expects to achieve under the current industry climate. Without the extension of an RTO outside of the borders of the state, the benefits of establishing such an organization are limited.

The other alternative is the integration of the Arizona transmission system into the nearest operational RTO, the California ISO. Assuming that it is technically possible to integrate the Arizona and California transmission grids, the control and dispatch of the Arizona transmission grid would then be run as part of the broader California ISO market control area. That would make the Arizona transmission system subject to the policies and procedures of the California ISO, which are significantly influenced by California state politics. In such a case, the overlay of California-specific carbon emissions or renewable

energy requirements on Arizona's electrical system operations would virtually guarantee that that electricity prices in Arizona will increase.

Question 11. Among the states that have transitioned to retail electric competition, which model best promotes the public interest for Arizonans? Which model should be avoided?

There is no existing retail model that can be used to adequately address the unique characteristics of the electric industry in Arizona and promote the public interest of Arizonans. Because Arizona utilities in general, and APS, in particular, operate their transmission systems in coordination with a large public power sector, the restructuring of the Arizona electricity market poses unique problems of jurisdiction and coordination compared to other parts of the country. Please also see APS's response to Staff Question 6 and 18.

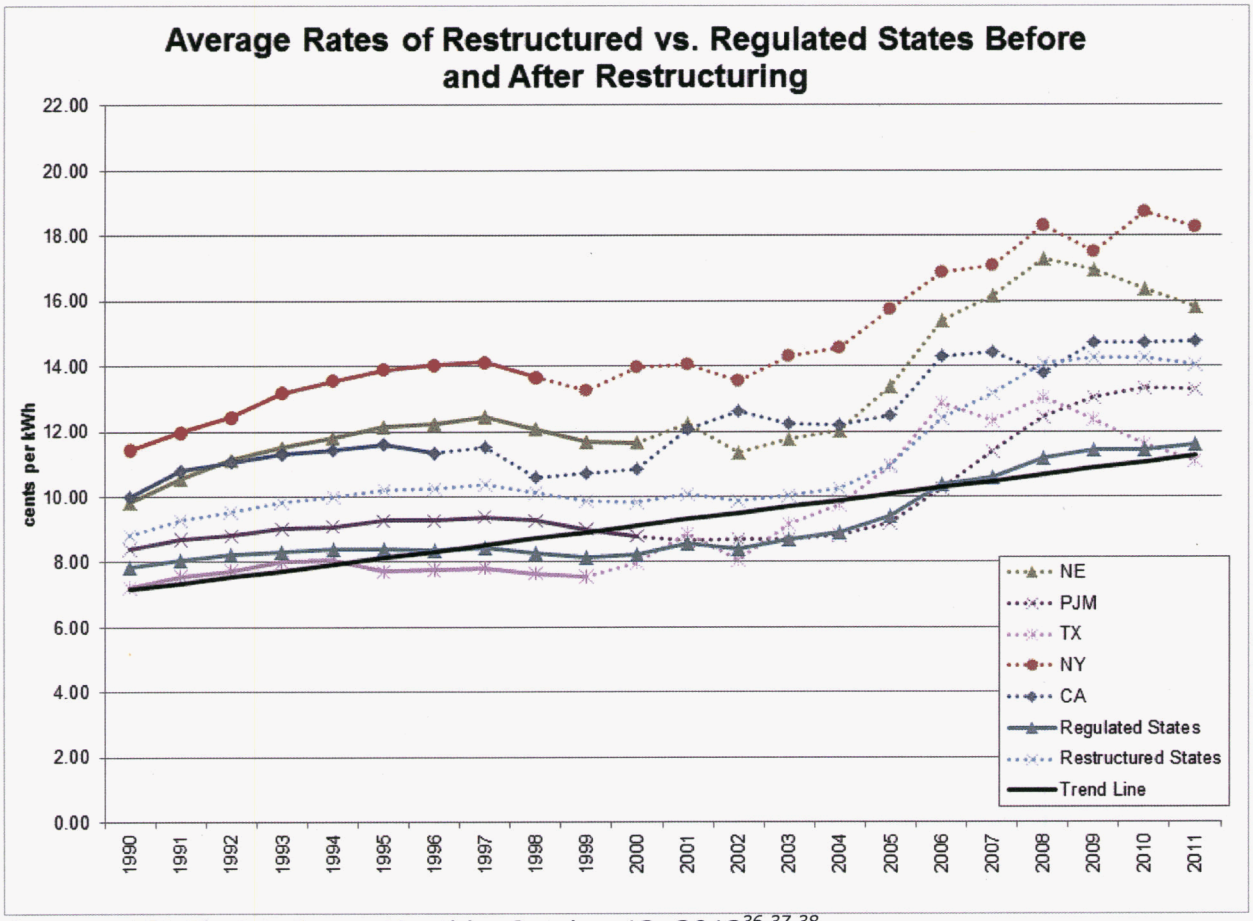
The unusual configuration of the separate but adjoining service territories of APS and the Salt River Project ("SRP") within the Phoenix metropolitan area – one of which is regulated by the Commission and one that is not – is just one of the unique concerns that must be weighed when considering a move to retail restructuring in Arizona. Unless SRP agrees to voluntarily participate in retail restructuring at the same level mandated for jurisdictional utilities, inequities of choice and cost will be created for residents and businesses alike. As discussed in response to Staff Question 13, even if SRP agrees to participate, the legal issues surrounding modifications to the 1955 Territorial Agreement must also be resolved before retail restructuring could proceed.

Although Texas is thought by many industry observers to be the state in which retail restructuring has had the most success, the Company believes the energy-only wholesale market employed by the Public Utility Commission of Texas ("PUCT") and the Electric Reliability Council of Texas ("ERCOT") will be unable to sustain long-term viability and should be avoided. In an energy-only market, where no direct value is placed on capacity and investment in new generation is largely determined by energy prices, reliability may suffer and resource adequacy and reserve margins may be at risk. In fact, the Texas energy-only model has recently come into question by NERC, the entity charged with ensuring the reliability of the bulk transmission system in the contiguous United States and Canada. Texas utility parent company Energy Futures Holding Company has asked regulators to establish a capacity market in attempt to remedy the State's capacity shortage. And as discussed throughout APS's Initial Comments and responses to questions, Texas is facing dramatically increasing prices, customer complaints, and a capacity crisis.[35]

[35] In early 2013, NERC requested ERCOT to formulate a plan to address the ERCOT declining reserve margin and projected capacity shortfall and file that plan with NERC, including a discussion of the risks to reliability if new resources were not constructed or acquired. ERCOT replied with a list of actions that have been taken and those actions in the planning stages, including additional demand response and the creation of an operating reserve demand curve. At this time, ERCOT has no plans to create a capacity market. Please see the Company's response to Staff Question 9 for additional information and recent complications associated with ERCOT's energy-only market.

Question 12. How have retail rates been affected in states that have implemented retail electric competition?

Please also see APS's response to Staff Question 1. A principle motivation behind restructuring initiatives has been that states with high electricity prices relative to other states hoped to bring their prices in line with the rest of the industry. That has not happened. Rates in restructured markets are still higher - 26 percent higher - than rates in regulated markets. And, while rates in all states, regulated and restructured, have risen over time, rates have risen higher and more quickly, in states with restructured markets. Over the 22 years from 1990 – 2011, the average price in restructured market states grew by approximately 60 percent, while prices in regulated states during the same time period rose by about 48 percent.

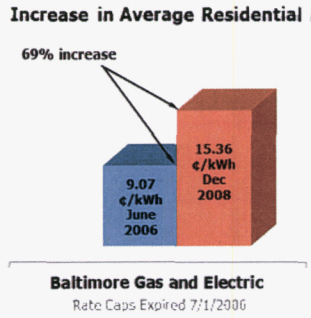


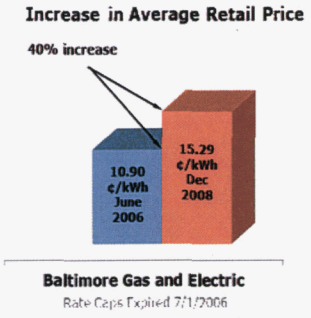
Source: EIA Electric Power Monthly, October 12, 2012[36,37,38]

[36] Rate calculations do not include fuel costs.
[37] Dotted line indicates implementation of state electric restructuring, and the creation of RTOs following 1996 FERC legislation.
[38] For purposes of this analysis, rrestructured states include: CA, CT, DC, DE, IL, MA, MD, ME, MI, NH, NJ, NY, OH, OR, PA, RI, and TX.

Further, utility customers have experienced extreme price increases when artificial retail price caps were lifted for utilities in competitive states, with residential customers bearing the largest of those increases.

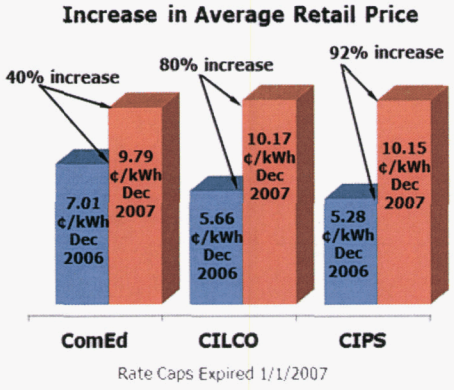
For example, customers of Baltimore Gas and Electric Company ("BGE") were expected to experience overall retail price increases of as much as 72 percent after wholesale power auctions were held in 2005 for standard offer service once price caps expired.





As can be seen in the above graphics, although the Maryland Public Service Commission ordered BGE to offer a rate stabilization plan to residential customers, average residential prices still increased by 69 percent, almost 30 percentage points above the average increase experienced by the overall customer base.

In another example, at the expiration of price caps in Illinois, standard offer rates were expected to climb as much as 75 percent. Although several bills were proposed in the Illinois legislature intended to mitigate this increase or freeze rates at 2006 levels, Illinois average utility customer prices increased by as much as 92 percent after caps were lifted.[39]



These examples reveal the significant risk of retail price increases and in particular, residential price increases due to the implementation of retail restructuring. They also demonstrate that a decision to rely on markets to set prices cannot be somehow bounded by "controls" designed to artificially shield customers from those same market prices. In

[39] Calculated from EIA Form 826 2006 data, 2006 and 2007.

other words, it is impossible to have both market and regulation setting the prices at the same time. Making a decision to rely on market prices means abandoning any safety net and results in a significant loss of control for the Commission.

Question 13. Is retail electric competition viable in Arizona in light of the Court of Appeals' decision in *Phelps Dodge Corp. v. Ariz. Elec. Power Coop.*, 207 Ariz. 95, 83 P.3d 573 (App. 2004)? Are there other legal impediments to the transition to and/or implementation of retail electric competition?

The *Phelps Dodge* decision invalidated many of the Electric Competition Rules required under A.R.S. Section 40-207. Without such rules, there can be no "Certificates" issued and thus no lawful competition. *Id.* Therefore, the first order of business, should the ACC determine that restructuring is in the public interest, would be to enact a new set of regulations under Section 40-207 that complies with the limitations established in *Phelps Dodge*.

The Court invalidated portions of the Electric Competition Rules for two different reasons – one procedural and the other substantive. The procedural flaw was failure to obtain Arizona Attorney General ("AG") certification as required under the Arizona Administrative Procedure Act ("APA"). The substantive objection to certain of the Electric Competition Rules was that they violated the Arizona Constitution.

As to the procedural flaws, until AG certification is forthcoming, the following rules are invalid:

- AAC R14-2-1603 – Issuance of CC&Ns
- AAC R14-1605 – Requirement for CC&Ns for competitive services
- AAC R14-2-1609 (A) and (B) – Transmission and distribution access; obligation of Utility Distribution Company ("UDC") to assure adequate transmission import capability;
- AAC R14-2-1612 – Service quality, consumer protection, safety and billing requirements
- AAC R14-2—1614 – Administrative Requirements
- AAC R14-2-1615(B) – Prohibition for Affected Utility or UDC to provide competitive services
- AAC R-14-2-1617 – Disclosure of Information to Consumers

Some of these rules have become moot or at least dated by the passage of so much time. And although the APA does not specify any particular time between when an agency enacts a regulation and when it is submitted for certification, the APA certainly never contemplated that that gap would encompass some 15 years stretching over two different centuries. The Economic, Small Business and Consumer Impact Statements that accompanied the original Electric Competition Rules, and which are required by the APA, are likewise stale. Bottom line, the rules for any contemplated deregulation are effectively non-existent, and need to be formulated, debated, and, if passed, submitted to the AG in accordance with the law.

As to the Electric Competition Rules that violate the Arizona Constitution, they include three elements vital to any restructured market throughout the country. These are: (1) the ability to charge market prices; (2) divestiture of generating assets; and (3) potential RTO formation.

As discussed throughout APS's Initial Comments and the responses to these Questions, a common element in all restructured electricity markets is the existence of wholesale markets to set the price of energy, capacity and ancillary products without significant government restrictions. *Phelps Dodge* specifically struck down the Electric Competition Rule allowing such pricing flexibility. While some of the Court's *dicta* in the decision discusses of a theoretical range of "just and reasonable" prices being conceptually permissible, nothing in the opinion indicates that even such a hypothetical range of prices would be exempt from the fair value requirements of the Arizona Constitution. Thus, the ACC would need to find that any price within the range posited by a market participant produced a reasonable return on the fair value of such market participant's assets used to provide service in Arizona. How wide a range of prices could satisfy this requirement is unknown, and is likely so narrow as to fully undermine the pricing flexibility needed in a market economy.

Why did these fair value issues not arise in the restructuring of other previously regulated industries in Arizona? In some instances (railroads, telegraph, most wireless communications services, etc.), deregulation came through federal pre-emption. In the case of motor carriers, the voters amended the Arizona Constitution. And even in the matter of communications services not subject to federal pre-emption, the ACC's actions were simply never legally challenged. That was not to be the case with the ACC's first attempted restructuring of the electric industry, and it is doubtful that any second restructuring effort would go unchallenged.

In addition, compulsory divestiture similar to that required under the electric Competition Rules violates the Arizona Constitution. Whether utilities would voluntarily divest their generation assets is a matter of speculation.

Finally, the Court held that the ACC had no Constitutional authority to order utilities to create or join the AZISA. Ironically, the AZISA, having been unlawfully created in the first instance, can now only be terminated by an order from FERC. If the ACC is not authorized to require formation of and participation in the AZISA, it would seem very unlikely that the ACC could require formation of and participation in an RTO. No state has restructured without an operational RTO in place. As in the case of divestiture, the question of whether a sufficient number of utilities would voluntarily join an RTO is presently unknown.

Beyond *Phelps Dodge*

Even if all the problems of *Phelps Dodge* are somehow resolved, other significant legal issues remain that were unaddressed by that opinion. The most obvious is that of rate and service discrimination. Both A.R.S. Section 40-374 and Section 12 of Article 15 of the Arizona Constitution prohibit discrimination in pricing or services. Thus, even if a range of "just and reasonable" prices could be formulated that also satisfied the fair value requirement, it is at best unclear whether Customer A could be charged one price within the range and Customer B another. Yet the ability to segment markets and tailor prices to individual customer demands is part and parcel of a restructured market.

Another issue closely related to that of potential discrimination is price transparency. A.R.S. Section 40-367 requires that all prices for services be both on file with the ACC and

open for public inspection. This provision serves both a notice to the public purpose and allows customers an opportunity to know whether they are being overcharged or otherwise discriminated against. Competitive electric service providers are notoriously secretive about their individual pricing schemes and other terms affecting their service offerings. As reasonable as this secrecy may seem in a deregulated world, it is inconsistent with the law.

Although the impact of any proposed deregulation on non-jurisdictional entities such as SRP is discussed elsewhere in the Company's response, a separate legal issue arises concerning the status of the Territorial Agreement between APS and SRP. Twice approved by the ACC, the Territorial Agreement ended literally a half-century of unproductive disputes between APS and SRP over customers, territory, facilities, etc., and has subsequently fostered the cooperation between the two entities that has help fuel the spectacular growth of the metro-Phoenix area[40]. If APS is deregulated and SRP is not, that could mean APS customers would be allowed to be solicited by SRP while APS would remain forbidden from soliciting SRP customers. If both APS and SRP are restructured, such a move could effectively vitiate the Territorial Agreement or at the very least, effectively require an amendment to accommodate the deregulated environment.

[40] The relationship between the Salt River Project and APS is memorialized in a 1955 "Territorial Agreement", which delineated the exclusive service territories served by the two parties, respectively. As in the previous restructuring, any future contemplation of electricity market design changes would need to incorporate the necessary negotiations and contractual amendments to the Territorial Agreement that would allow for a restructured electricity marketplace. Moreover, it is likely that other parties would intervene in such negotiations, adding significant uncertainty to the eventual outcome of any such negotiation and therefore, the restructuring process itself.

Question 14. Is retail electric competition compatible with the Commission's Renewable Energy Standard that requires Arizona's utilities serve at least 15% of their retail loads with renewable energy by 2025? (See AAC. R14-2-1801 et seq.)

Please see the response to Question 15.

Question 15. Is retail electric competition compatible with the Commission's Energy Efficiency Standard that requires Arizona's electric utilities to achieve a 22% reduction in retail energy sales by consumption by 2020? (See AAC. R14-2-2401 et seq.)

The following response addresses both Staff Questions 14 and 15. Assessing whether the Commission's Renewable Energy Standard ("RES") and Energy Efficiency Standard ("EES") are "compatible" with a restructured market requires that two questions be answered:

(1) Can RES and EES be "enforced" in restructured environment? As discussed below, yes, they can, but at a cost.

(2) Will RES and EES provide customers with the same benefits at similar costs as they provide when retail service is regulated? As discussed below, no. Retail deregulation creates an environment in which resources must compete based on short-term market signals that do not provide long-term benefits.

With respect to the RES (15 percent from renewable sources by 2025), it is possible, as other restructured states have done, to require all load serving entities (i.e., both the utility in supplying its POLR service and all retail suppliers) to meet the same standard by either including renewable energy in their supply portfolios or by acquiring Renewable Energy Credits, a tradable right to the environmental attributes associated with the production of renewable energy.

With respect to the EES (a mandatory 22 percent reduction in retail energy sales by 2020), in order to a retain level playing field between a competitive supply option and POLR, it is necessary to recover the costs of utility-sponsored energy efficiency programs through a non-bypassable distribution service surcharge for all customers. Such a charge would apply to POLR customers and competitive supplier customers equally.

At first glance, these two policy programs appear to be possible. From a practical standpoint, however, these investments in renewable energy and energy efficiency cannot be optimized in a restructured environment. Implementation of RES and EES require that the full breadth of benefits and costs of resources over the long-term be considered. The elimination of state regulation of generation supply service and IRP (see also the response to Staff Question 17) ensures that RES and EES decisions will be made on the basis of short-term market prices. The POLR (see also the response to Staff Question 4) should not be required to make long-term commitments on behalf of an uncertain customer base. The experience of some restructured states shows that flaws in wholesale markets lead to suboptimal investment in energy efficiency (e.g., higher market prices cause more energy efficiency to be considered "economic") and renewable resources (e.g., when local reliability

is threatened, states consider every resource option that is within their control) at the expense of ratepayers and state economies.

- Market prices in some restructured states (Massachusetts, Rhode Island, Delaware, and Maryland) have become so expensive that the states are seriously considering offshore wind at prices that are multiples of the cost of on-shore wind at more than 20 cents/kWh and escalating each year.
- The failure of PJM's capacity markets have caused local reliability concerns, driving Maryland to aggressively pursue expensive energy efficiency and demand response initiatives.
- New Jersey is now expressing reservations about how much it is costing to continue their commitment to solar energy.

Energy efficiency and renewable resources play an important part in a utility's balanced resource portfolio and, in that context, provide benefits to customers. Overinvesting in these resources in response to short-term price signals, however, simply increases costs.

Question 16. How should the Commission address net metering rates in a competitive market?

Restructuring the electric industry certainly complicates matters related to distributed generation. Fundamentally, the issue of net metering is an electricity generation issue. Therefore, one potential approach is for the retail supplier to provide a credit to the net metering customer based on the supply cost that they would have otherwise paid the retail supplier during those hours. There is some logic to this approach because it reflects the supply costs that the retail marketer would have incurred to serve the customer had power been flowing in the other direction and assumes that the net generation is credited to the retail suppliers account. All of this would need to be spelled out in the contract with the retail supplier.

As currently defined and implemented in Arizona, net metering could introduce additional complications in a restructured market. Net metering is a policy that allows a customer that has on-site generation (e.g., a solar photovoltaic facility) to deliver electricity to the grid that is surplus to their level of on-site demand and receive a credit for such production. The amount of the credit will depend on the value of electricity during each period of surplus production. This credit is effectively banked and then reduced during periods in which the on-site generation facility is producing less than the customer's level of demand, again valued at the prevailing value of electricity during each period that the customer is buying power from the grid. In many respects, net metering operates like an inventory account.

Net metering calculations are not particularly complex but do require the ability to determine the amount of surplus or shortfall production during every period (e.g., hourly) over the billing cycle, and then a methodology for determining the value of surplus or shortfall production in each period. This same fundamental concept applies whether the customer purchases their electricity from the utility or from a competitive retail supplier. However, the customer's contract with a competitive supplier would have to accommodate a net metering arrangement, just as a utility customer would take service under a net metering tariff.

The primary source of controversy with respect to net metering is the rate at which customers will be compensated when they offset their energy usage with their own production. Many net metering policies compensate customers at the retail price of electricity, a price that includes not only supply costs, but distribution costs that compensate utilities for the infrastructure that must be there to transmit power in either direction and be sized to meet the demands of all customers. Under this compensation methodology, customers without distributed generation are subsidizing those that have installed the systems.

If the Commission pursues deregulation further, it would need to revisit its net metering policies. In fact, should net metering become a significant portion of electric utility load, it would be appropriate for the Commission to reevaluate its policies in advance of a deregulated market in order to gather evidence on the significance of cross-subsidies and cost-shifting under the current net metering tariff.

Question 17. What impact will retail electric competition have on resource planning?

Competitive wholesale markets are not a good substitute for the Commission approved IRP process. The IRP process ensures that utilities are considering all relevant factors necessary to provide reliable, cost effective, and environmentally responsible service to customers. The IRP is the only process whereby generation, transmission and fuel supply infrastructure are brought together in one, comprehensive analysis, thus ensuring plans are in place to serve customer's energy needs now and in the future.

The introduction of full-scale deregulation, and in particular, the reliance on wholesale capacity markets to drive major capacity decisions that are now made by regulated entities (both new development and retirements), effectively eliminates resource planning and all of the benefits that it provides. This is also discussed in APS's Initial Comments and the responses to Staff Questions 4, 9, 14 and 15.

Utilities that divest their generation are no longer required to perform integrated resource planning, despite the fact that they typically retain the obligation to serve as the POLR to a significant portion of their distribution load. In order to serve these customers, utilities have been required by state commissions to go to the market for resources and are forced to rely on relatively short-term (three-years or less) contracts that do not provide any longer-term hedge against uncertainties (e.g., fuel prices and environmental regulations).

This large group of residential and small commercial customers are thus exposed to short-term wholesale market conditions and price volatility. This is a radically different outcome from the current circumstance in which the utility, guided by IRP, develops and maintains a portfolio that represents a mix of different generation types and is designed to produce a lowest reasonable cost mix of utility-owned generation, power purchase contracts, and demand-side options with customers paying rates that reflect the actual costs of the portfolio. These plans are designed to provide a reliable supply portfolio by explicitly analyzing varying risks across a broad spectrum associated with varying resource portfolios.

There are numerous flaws with current wholesale capacity and energy markets (see APS's Initial Comments and the response to Staff Question 9). They function in a way that gives preference to the objectives of existing owners of generation by maintaining scarcity of supply.

Resource planning has been replaced by a combination of these flawed capacity markets that rely on a relatively short-term pricing signal, state actions to promote renewables, on-site generation, and demand-side options, and transmission planning performed by the RTOs. IRP was explicitly designed to support long-term infrastructure decisions and to do so on an "integrated" basis to meet reliability, economic, and environmental objectives. Under the restructured model, there is no single party responsible for analyzing these diverse resource options in a coherent and integrated manner.

Only by chance will the mix of supply-side and demand-side resources optimally meet the reliability, economic and environmental goals of a state or region. In fact, it is more likely that large base load resources will not be developed or maintained in the wholesale market model and that fuel diversity will tilt increasingly toward natural gas-fired technologies. New England's regulators are currently studying this issue as the increased reliance on natural gas as a fuel for electric generation is creating reliability and cost concerns for both electricity and natural gas end-use customers. Recognizing the obvious resource planning vacuum created by restructuring, a few states have decided to prepare state energy plans but even these fall far short of the type of strategic analyses that are provided in IRPs. At the end of the day, they remain dependent on a wholesale capacity market that does not achieve its purported benefits. Not surprisingly, the states that have produced energy plans are those that have faced reliability issues after IRP requirements were eliminated: Maryland, New Jersey and Connecticut among them. Illinois has also formed the Illinois Power Agency that is authorized to perform energy planning, acquire power supplies through competitive bidding and develop new generation and cogeneration facilities that use indigenous coal and renewable resources.

One of the biggest problems with reliance on wholesale markets to incent new capacity is that it is not clear whether the relatively short-term (one to three-year) price signal is adequate to obtain the long-term financing to support construction of new long-lived generation assets. There is anecdotal evidence that a few combined-cycle plants have been able to finance projects but as unregulated entities, they are not required to disclose the contracts that they are relying on. It is much less clear whether any base load plant larger than a gas-fired combined cycle plant could be financed by current capacity market models. This will affect the development of new generation and the fuel diversity of the overall portfolio serving a state or region.

In the traditional vertically integrated utility framework, utilities rely on regulatory decisions to provide power plant developers with a foundation for making long-term investments. With stable, long term, customer relationships, utilities are able to provide developers with long-term contracts for power supplies. These long-term contracts are essential for developers to secure necessary financing for what are very capital-intensive projects.

Relying primarily on natural gas, and its associated price volatility, to fuel generation will mean increased price risk born directly by customers. Rather than the ACC having oversight of customer rates, customer bills will be directly subject to the type of natural gas price volatility that has been experienced in the past being driven by financial markets and weather phenomena.

In addition to infrastructure investment being at risk, there is also the strong likelihood that the current constructive and open dialogue regarding Arizona's energy future, facilitated by the Commission's IRP rules, would no longer continue. In a competitive environment, merchant generators and energy service providers will not share their plans for the future with other competitors. Likewise, APS would not want to share its plans for the future with competitors. Nor would this function be performed by the POLR provider. As discussed, planning for a reliable system is nearly impossible without a stable customer base. Simply because one market participant has been designated the POLR does not alleviate the reliability risk to customers. As such, dialogue on future energy policy would cease to exist

and be left to competitive market participants, each having their own set of plans with the sole purpose of profit maximization rather than ensuring a reliable, diverse set of resources, as the IRP process currently provides

Question 18. How will retail electric competition affect public power utilities, cooperatives and federal controlled transmission systems?

Public power utilities and federally controlled transmission systems are generally not subject to regulatory oversight at either the State or Federal level. Therefore, absent Constitutional and/or legislative changes, such entities cannot be required by the ACC to participate in a restructured electric market. Instead, public power utilities and federally controlled transmission systems will have to decide whether or not to participate in the competitive market on a voluntary basis. If such entities choose not to participate in the competitive market, there will likely be little change to either their customer/load profile or their current non-jurisdictional status. However, because oversight of markets and RTOs or ISOs fall under Federal control and oversight, if public power utilities and federally controlled transmission systems choose to voluntarily participate in a restructured market, such entities would be subject to FERC jurisdiction.

The impact of deregulation on cooperatives, which unlike public power utilities and federal controlled transmission systems, are currently subject to State and Federal regulatory oversight, will depend in large part on whether or not the ACC requires cooperatives to participate in the competitive market. If the ACC requires such entities to participate in the restructured market (as it did previously), the impacts of deregulation on such entities will be similar in scope to those faced by the investor-owned utilities. However, the impact of deregulation on cooperatives will likely be of a much larger magnitude and severity. This is because cooperatives are typically much smaller than investor-owned utilities and much more likely to depend on a small number of industrial or commercial customers to generate a large percentage of their revenues. In addition, cooperatives typically serve more rural and less densely populated geographic areas. As a result, the loss of even a very small number of customers can have a devastating effect on a cooperative's revenues and the cooperative may find it extremely difficult to offset the loss with the addition of new customers.

Regardless of whether or not public power utilities, cooperatives and/or federally controlled transmission systems participate in a restructured market, deregulation will still have a significant impact on at least two aspects of their operations: (1) their ability to engage in IRP activities with entities required to participate in the competitive market and (2) the reliability of their systems. As discussed in more detail in response to prior questions, deregulation greatly inhibits long-term planning and can threaten reliability. In fact, because prices in a restructured electricity market are directly tied to supply, participants in a deregulated market are actually incented to refrain from engaging in meaningful long-term planning and/or investing in infrastructure that will support reliability by providing a capacity reserve margin. Because public power utilities, cooperatives and federally-controlled transmission systems are connected to (and in some instances, integrally operated with) the transmission systems owned and operated by investor-owned utilities, public power utilities, cooperatives and federally controlled transmission systems are likely to face significant reliability and system planning concerns if the Commission chooses to deregulate and wholesale electricity markets change accordingly.