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BEFORE THE ARIZONA CORPORATION COMMISSION

WILLIAM A. MUNDELL
Chairman
JIM IRVIN
Commissioner
MARC SPITZER
Commissioner

Arizona Corporation Commission
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IN THE MATTER OF THE GENERIC PROCEEDINGS CONCERNING ELECTRIC RESTRUCTURING.	~~DOCKET NO. E-00000-02-0051~~
IN THE MATTER OF ARIZONA PUBLIC SERVICE COMPANY'S REQUEST FOR VARIANCE OF CERTAIN REQUIREMENTS OF A.A.C. R14-2-1606	DOCKET NO. E-01345-01-0822
IN THE MATTER OF THE GENERIC PROCEEDINGS CONCERNING THE ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR.	DOCKET NO. E-00000A-01-0630
IN THE MATTER OF TUCSON ELECTRIC POWER COMPANY'S APPLICATION FOR A VARIANCE OF CERTAIN ELECTRIC COMPETITION RULES COMPLIANCE DATES	DOCKET NO. E-01933A-02-0069
IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR APPROVAL OF ITS STRANDED COST RECOVERY	DOCKET NO. E-01933A-98-0471

NOTICE OF FILING OF REBUTTAL TESTIMONY OF

THOMAS BRODERICK

ON BEHALF OF HARQUAHALA GENERATING COMPANY, LLC

Harquahala Generating Company, LLC, by and through its attorneys, hereby files the Rebuttal Testimony of Thomas Broderick, Director, External Relations, West Region, PG&E National Energy Group, pertaining to the issues in "Track A" for the above-captioned proceeding.

RESPECTFULLY SUBMITTED this 11th day of June, 2002

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By Sarah Menne

BEFORE THE ARIZONA CORPORATION COMMISSION

WILLIAM A. MUNDELL
Chairman
JIM IRVIN
Commissioner
MARC SPITZER
Commissioner

IN THE MATTER OF THE GENERIC PROCEEDINGS CONCERNING ELECTRIC RESTRUCTURING.	DOCKET NO. E-00000-02-0051
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REBUTTAL TESTIMONY OF THOMAS BRODERICK ON BEHALF OF HARQUAHALA GENERATING COMPANY, LLC

June 11, 2002

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REBUTTAL TESTIMONY
OF
THOMAS BRODERICK
HARQUAHALA GENERATING COMPANY, LLC
June 11, 2001

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS AND OCCUPATION.

A. My name is Thomas M. Broderick. My business address is 1100 Louisiana, Suite 1650, Houston, Texas 77002. I am Director, External Relations, West Region, PG&E National Energy Group ("NEG"). NEG is the owner of Harquahala Generating Company, LLC ("HGC"), the owner of an approximately 1,040 Mw facility under construction.

Q. PLEASE DESCRIBE YOUR PROFESSIONAL QUALIFICATIONS AND EXPERIENCE.

A. A summary of my professional qualifications and experience is included in the Statement of Qualifications attached as Exhibit 1 to this testimony.

Q. HAVE YOU REVIEWED THE TESTIMONY FILED BY THE PARTIES ON THE "TRACK A" ISSUES?

A. I have. Track A concerns one component (asset transfer) of implementing the competitive market structure envisioned under Arizona's Electricity Rules and as embodied in the settlement agreements of Arizona Public Service (APS) and Tucson Electric Power (TEP). For example, under **R14-2-1606(B) of the Arizona Electricity Competition Rules:** "After January 1, 2001, power purchased by an investor owned Utility Distribution Company shall be acquired from the competitive market through prudent, arm's length transactions and with at least 50% through a competitive bid process." And, under the APS settlement, APS agreed that it "[S]hall procure generation for Standard Offer customers from the competitive market as provided for in the Electric Competition rules. An affiliated generation company formed pursuant to this Section 4.1 may competitively bid for APS' Standard Offer load, but enjoys no automatic privilege outside of the market bid on account of its affiliation with APS."

These provisions raise questions with regard to the timing of the implementation of the asset transfer from the incumbent utility to its affiliated competitive power supplier as well as to when in this process the bidding for standard offer service should occur. As contemplated, these two actions are linked, with some arguing that they should occur simultaneously. However, there is a question as to what that actually means. HGC's interpretation of these rules is that the competitive procurement of power is to occur prior to the transfer of assets. Further, meeting the competitive procurement requirement of the Rules requires that all or nearly 100% of Standard Offer ("SO") requirements have been successfully contracted for in a valid competitive procurement process; the mere issuance of an RFP or a plan to conduct a process is not satisfactory under the Arizona Rules to permit a transfer of generation assets to affiliates. It is likely that at least some of the existing APS assets will continue to supply native load after its transfer to Pinnacle West. Because this involves an affiliate transaction, it is in the best interest of all parties – and the responsibility of the ACC – to conduct the procurement before a transfer so there is no question that the process is transparent and does not advantage APS' affiliates.

Q. PLEASE ANALYZE FURTHER THE TESTIMONY AND PROVIDE THE REACTION OF HARQUAHALA GENERATING COMPANY TO IT.

A. Yes. The following are our responses to the significant issues raised by the testimony.

1. HGC feels strongly that existing network transmission service rights should **not** be part of the asset transfer from APS and TEP to their generation affiliates. If the generating affiliates received the transmission rights, they would be the only parties who could supply a delivered product in the utility auction. This would presuppose the winner of the competitive procurement for standard offer service, which is antithetical to the objective of the Electricity Competition Rules. In short, the generation affiliate would possess market power because, in the absence of a functioning RTO/ISO, they would be the only entity to have sufficient transmission to deliver their product. Instead, these rights should be designated for use by APS and TEP in securing power from the successful bidders for SO service for the duration of their contracts . As Mr. Kebler states in his testimony, if some of a UDC's generation assets that are transferred to affiliates are not successful in competition to provide SO service, that transmission should be available to others.

2. HGC agrees with the recommendation contained in the testimony of Craig R. Roach that to successfully implement Arizona's Rules, competitive procurement of nearly 100% of SO requirements must occur **prior** to any asset transfers. This recommendation is valid even if the selected procurement design results in several rounds of RFP's and/or auctions over a defined period to competitively procure nearly 100% of SO. Hence, divestiture can occur en masse following successful contracting with the winning bidders, which will, no doubt, include affiliates of APS and TEP. As a result, Arizona retail customers will benefit due to compliance with the Rules.

3. Alternatively, if the Commission waits until after the asset transfer to conduct competition procurement of generation, it will immediately face the need to approve or accept the

price, terms and conditions for the purchase of thousands of Mw from the UDCs' affiliates on an interim basis without knowing what the competitive market could achieve were it allowed to operate. It is HGC's opinion that this does not support the ultimate objectives of the Electricity Competition Rules and the utility settlements – that customers have access to the benefits that market competition can bring. This scenario is also akin to what APS proposed as part of its variance last October, and what the Commission stayed.

4. The role of must run generation in this process is discussed in detail in the testimony of Matt Rowell, Jerry Smith and Craig Roach. HGC is generally supportive of their testimony and believes the RFP-based competition process described by Craig Roach for must run generation should occur as early in the competitive procurement process as possible and the market power issues associated with must run generation need to be addressed. Furthermore, the contracted providers of must run generation should **not** be permitted to use these contracts to create an advantage when bids are submitted utilizing other resources they own or otherwise control. The must run generation is readily identifiable for APS and TEP – it is located inside metropolitan Phoenix, Tucson and Yuma.

5. Ideally, the must run RFP would be a component of a comprehensive RFP for all SO service. This will allow bids for generation inside load pockets to be compared to bids from outside the load pocket. The latter bids will, in many instances, include the allocated incremental cost of transmission to bring power into the inside load pockets. Under this approach, a system-wide, least cost criterion should be applied as the basis for bid selection

6. As a practical example of the workability of the procedure I have described, HGC's owner, National Energy Group ("NEG"), responded to a large RFP from Public Service

Company of Colorado ("PSCO") in 1999 that sought generation bids from a variety of locations both in the Denver load pocket and from remote delivery locations. After literally hundreds, if not thousands, of computer-modeled scenarios (run overnight) of alternative generation portfolios, PSCO awarded 12 contracts. NEG was a successful bidder and our newly constructed 111 Mw Plains End peaking facility, which is located inside suburban Denver, achieved commercial operation last month (May 2002). This was only 28 months after the issuance of the RFP. I note that other PSCO contracts provide peaking, intermediate and base load power from various locations inside and outside the load pocket and, in some instances, required significant transmission infrastructure additions, which were and are still being undertaken by PSCO. In the case of Plains End, PSCO constructed the necessary transmission infrastructure on time and NEG is now delivering to PSCO's retail customers as a network designated resource as specified in PSCO's transmission tariff. In Colorado, PSCO is the control area operator for NEG's facility. This is a service that APS has refused to provide HGC in Arizona. In other words, through normal utility resource planning processes, PSCO was able to successfully weigh the advantages and disadvantages of a large proposed portfolio of potential new generation resources of many types and locations, both inside and outside load pockets. In some instances, some amount of existing transmission was available. In other cases, varying amounts of new transmission infrastructure were identified as cost effective and were or still are being constructed in a timely manner.

7. Mr. Kebler has proposed a thoughtful and creative means to enhance the market prior to the competitive solicitation process for SO. Unfortunately, the lack of a functioning RTO or ISO for APS and TEP leads HGC to conclude that Mr. Kebler's proposal may be premature

and the Arizona market structure needs to evolve further first. For similar reasons, the concept of procuring a "slice of system" product is also premature. HGC would enthusiastically support revisiting both of these concepts after an RTO or ISO in the area is functioning with features conductive to a slice of system auction. However, prior to an RTO/ISO, APS and TEP can use their proprietary knowledge of the transmission system and their market power over the provision of ancillary services to stifle slice of system competition. Only a very small subset of competitors has a generation portfolio adequate to offer a slice of system This would generally limit the pool of able bidders.

8. As an idea to evolve towards, Mr. Kebler's competitive auction proposal would significantly assist in the establishment of a competitive market structure and thereby improve market liquidity, reduce incumbent market power and provide the Commission with additional market benchmark information that would be helpful in evaluating the fairness of contracts between APS, TEP and their affiliates. NEG and many other generation providers successfully participated in the Texas capacity auction in 2001. The capacity NEG obtained from this auction plus the additional ancillary services available daily from the ERCOT ISO augments the single power plant NEG owns in Texas, thus allowing the company to meet long-term 100% full requirements of the City of Denton, Texas and other retail customers. In Texas, the services NEG obtains daily from the ERCOT ISO are critical to establishing a level playing field for the economics of transactions, especially the cost of energy imbalances. In the case of Arizona, Craig Roach and Curtis Kebler have recommended the establishment of a short-term energy market including a real time energy balancing market. This step would be helpful to both wholesale and retail competition.

9. Unfortunately, absent a fully-functioning RTO/ISO as is the case in Texas, we believe the market structure is insufficient to support a slice of system auction even with a capacity auction. While it is possible today for some merchants to provide a slice of service at a single or a few delivery points, absent an RTO/ISO, it is nearly impossible for a merchant to provide a true slice of system which covers all major delivery points for all hours of the year.

10. Therefore, HGC recommends APS and TEP utilize an RFP process for soliciting standard wholesale products – baseload, intermediate, peaking, and ancillary services at multiple delivery points such as Palo Verde, Mead, Four Corners and other locations where the utilities have transmission rights or physical utility owned capacity to accept power. It would likewise be helpful for APS and TEP to indicate preferred transmission locations. Such a process will be much less complicated, will draw the maximum number of bidders and will result in pricing that is transparent and easily verifiable. HGC is confident that both APS and TEP have the resource planning tools, quantitative models and skilled employees to successfully conduct an RFP process. If an RFP process seeking standard wholesale products is concluded prior to generation asset transfer as we have recommended, it is critical for the Commission to work closely with an independent evaluator to ensure that the RFP process is fairly conducted. Hence, this simpler approach for the time being will enable the retail customers of APS and TEP to reap the benefits of a "buyers" market in a time frame during which new generation assets are coming on line.

11. HGC disagrees with the statement of Mr. Jack Davis on page 14 of his testimony that "Divestiture is also the basis for the competitive bidding provision of Rule 1606, which makes absolutely no sense in its absence." While HGC does not oppose divestiture per se and understands that certain details of the competitive bidding process need to be altered in the

absence of divestiture, competitive bidding continues to make significant sense even without divestiture.

12. Using APS as an example, the anticipated level of bidding without divestiture would be significant. Rather than contract with its affiliate, APS would need to bid out approximately 1,700 Mw before being allowed to contract with either Red Hawk or West Phoenix 5. This is approximately 28% of APS' current peak load. Additionally, APS would need to bid out load growth, load served under existing wholesale contracts upon their expiration, load served by generation that is soon to retire, and existing generation identified as having market power. Load growth alone would increase the total bid by approximately 3% per year. Hence, only 4 years into such a program at least 40% of APS' SO service would be subject to competitive procurement.

13. In fact, each of the categories listed above formed the basis for the Colorado competitive bidding program. Hence, the Colorado program is much more significant than simply covering incremental load growth as some have suggested. In Colorado, in more than 3 rounds of RFP bidding, approximately 42% of the SO load of PSCO was contracted with suppliers , the vast majority to suppliers other than PSCO or its affiliate. Furthermore, PSCO has not divested and Colorado is not open to retail competition.

14. Not only does bidding makes significant sense without divestiture, but the methods, practices and procedures developed in other states for bidding absent divestiture are informative and successful.

15. ACC Staff testimony recommends a price to beat be established for generation and, perhaps, for each generation asset, using existing tariffs. The apparent goal of this proposal

is to ensure that competitive bidding and the asset transfer do not increase tariffs, including the PPFAC component, over the next rate cycle. HGC notes that costs of specific generation facilities, whatever company owns them, will vary significantly around the system average. Baseload facilities such as the HGC plant are below the system average, whereas peaking facilities such as NEG's Plains End facility in Denver have costs above the system average. However, each of these facilities contribute to a least supply portfolio. Hence, an RFP that covers all or essentially all of APS' and TEP's SO load is the best way for the Commission to ensure that offers are evaluated on a system-wide and integrated portfolio basis. This approach also allows the Commission to obtain insights into the overall system revenue requirements for the preferred portfolio even in comparison to the existing portfolio. The system planning tools that utilities such as APS and TEP utilize will determine, in fact, the minimum revenue requirement and rate levels of integrated groups of standard wholesale products. Thus, the Commission can be confident that this modeling process will identify the least cost alternative without a separate cumbersome exercise to match and directly compare each selected asset with existing assets and their component of tariffs. Of course, at some more distant point in the future, tariffs may increase, but this approach provides the Commission with the comfort that no other portfolio will result in lower costs. At present, the wholesale market is highly favorable to buyers. For this reason, the near term price concerns are misplaced. A slice of system product, on the other hand, forces each bid to assemble all the components of service. In absence of an RTO/ISO, this would be a more costly scenario. Also note that an RFP solicitation will result in bids from both in-state and out-of-state generating companies.

16. It should also be noted that there is no reasonably current cost of service study by either APS or TEP, which reconciles the cost components for generation, transmission and distribution to existing retail tariff levels, let alone one specific to individual power plants. If the Commission intends to establish a price to beat either by total generation or by asset based on existing tariffs, we suggest that the Commission ask the utilities to begin preparing this study immediately. Given APS and TEP rate settlements which are both cost and incentive based, an attempt to match costs with tariffs is a quagmire best left for consideration until the next rate case.

17. Staff witness Barbara Keene has provided some excellent testimony on affiliate relationships. However, HGC wonders if one of Ms. Keene's suggestions might create a loophole that would allow Red Hawk to be transferred to APS without first obtaining Commission approval of a code of conduct or otherwise be subject to Commission scrutiny. Specifically, she recommends the code of conduct covers arms length transactions (page 8, line 7, Keene testimony) and includes as an arms length transaction, the sale or transfer of assets from an affiliate to the utility (page 8, line 18). Therefore, HGC's concern is that none of the four actions in Barbara Keene's testimony on page 7, lines 12 through 25, which trigger Commission approval of a new code of conduct, covers a situation in which APS purchases power from Red Hawk but only after Red Hawk has been transferred back to APS. Previously, APS/Pinnacle West has discussed the possibility of transferring Red Hawk to APS. To close the loophole, the Commission would need to add a fifth "trigger" action covering transfers from an affiliate back to a UDC.

18. HGC supports Erinn Andreasen's recommendation to form an Electric Competition Advisory Group and HGC would actively participate in such a group. HGC

recommends the Group's scope be expanded to support market/regulation/implementation monitoring.

19. The TEP proposal to close the retail market for customers under 3 Mw is entirely unnecessary given the current circumstances. Indeed, it is a solution in search of a problem. Moreover, HGC believes it would be difficult, time-consuming, costly, and repetitive to re-open the market for these customers at a future date.

Q. DOES THE COMMISSION HAVE A ROAD MAP FOR IMPLEMENTING YOUR NEAR-TERM COMPETITIVE SOLICITATION RECOMMENDATIONS?

A. Yes. It was filed on March 29, 2002 in the testimony of Mr. Alan Taylor sponsored by HGC.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

Exhibit 1

STATEMENT OF QUALIFICATIONS

2001	PG&E NATIONAL ENERGY GROUP, Houston, Texas
	Thomas Broderick is Director External Relations, West Region for PG&E National Energy Group. He is responsible for regulatory, legislative and community relations. His current efforts are concentrated in Arizona, Colorado, and Louisiana where the Company has power plant projects or competitive bidding is planned or underway.
1999 - 2000	U.S. STATE DEPARTMENT /USAID, Kiev, Ukraine and Washington, D.C. • Senior Energy Advisor
1997 - 1998	PG&E ENERGY SERVICES CORPORATION, Scottsdale, Arizona • Energy Consultant
1984 - 1996	ARIZONA PUBLIC SERVICE COMPANY • Planning Manager • Supervisor, Forecasts • Supervisor, Regulatory Affairs • Economist, Regulatory Affairs
1982 - 1984	MILLER BREWING COMPANY, Milwaukee • Analyst, Marketing Research
1981	ILLINOIS HEALTH FINANCE REGULATORY AUTHORITY, State of Illinois, Chicago • Regulatory Economist

5-14

BEFORE THE ARIZONA CORPORATION COMMISSION

WILLIAM A. MUNDELL
Chairman
JIM IRVIN
Commissioner
MARC SPITZER
Commissioner

IN THE MATTER OF THE GENERIC PROCEEDINGS CONCERNING ELECTRIC RESTRUCTURING ISSUES)	DOCKET NO. E-00000A-02-0051
IN THE MATTER OF ARIZONA PUBLIC SERVICE COMPANY'S REQUEST FOR A VARIANCE OF CERTAIN REQUIREMENTS OF A.A.C. R14-2-1606.)	DOCKET NO. E-013450A-01-0822
IN THE MATTER OF THE GENERIC PROCEEDINGS CONCERNING THE ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR.)	DOCKET NO. E-00000A-01-0630
IN THE MATTER OF TUCSON ELECTRIC POWER COMPANY"S APPLICATION FOR A VARRIANCE OF CERTAIN ELECTRIC COMPETITION RULES COMPLIANCE DATES.)	DOCKET NO. E-01933A-02-0069
IN THE MATTER OF THE APPLICATION OF TUCSON ELCTRIC POWER COMPANY FOR APPROVAL OF ITS STRANDED COST RECOVERY.)	DOCKET NO. E-01933A-98-0471

REBUTTAL

TESTIMONY

OF

JERRY D. SMITH

ELECTRIC UTILITIES ENGINEER

UTILITIES DIVISION

June 11, 2002

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INTRODUCTION

Q. Please state your name and business address.

A. Jerry D. Smith, 1200 West Washington, Phoenix, Arizona 85007.

Q. By whom are you employed and in what capacity?

A. I am employed by the Arizona Corporation Commission ("Commission") as an Electric Utilities Engineer for the Utilities Division.

Q. Have you previously submitted direct testimony in these proceedings?

A. Yes.

PURPOSE OF REBUTTAL TESTIMONY

Q. What is the purpose of your rebuttal testimony in these proceedings?

A. My rebuttal testimony will respond to specific segments of testimony provided by Mr. Michael J. DeConcini, Mr. William H. Hieronymus, Mr. Kevin C. Higgins, Dr. Craig R. Roach, and Mr. Curtis L. Kebler. My rebuttal testimony focuses on the following topics:

1. Relieving transmission constraints,
2. Market power tests regarding local transmission constraints,
3. AzISA and Westconnect mitigation of reliability must-run ("RMR") generation, and
4. Network Resources and associated transmission rights.

RELIEVING TRANSMISSION CONSTRAINTS

Q. Do others provide testimony supporting Staff's proposition that local transmission constraints need to be resolved to ensure reliable service to Arizona's consumers at just and reasonable rates via a competitive wholesale market?

A. Yes. Mr. DeConcini indicates that he broadly agrees with my testimony in the APS variance request proceedings (Docket No. E-01345A-01-0822) regarding transmission access and relieving constraints.[1] He further states that relieving transmission constraints is one of four key steps that needs to be taken in order to provide the opportunity for significant retail competition.[2] However, Mr. DeConcini does not believe that all transmission constraints must be eliminated for effective competition to exist. This statement seems to align well with Staff's position that there may be occasions when generation is justified as a solution to a transmission constraint.[3]

Mr. Hieronymus states that vertical market power has far greater potential to destroy competitive electricity markets than horizontal market power.[4] He further describes a transmission system owner's use of its monopoly over an "essential facility" to exclude or disadvantage competitors in related activities as generation or serving retail customers as a relevant example of vertical market power.[5] Furthermore, Mr. Hieronymus acknowledges that in earlier testimony he conceded that some APS generating units are RMR and could exercise market power.[6]

Mr. Hieronymus' testimony corroborates Mr. David A. Schlissel's testimony for Staff regarding how APS' and TEP transmission constraints create such vertical market power.[7] These facts lead to the conclusion that mitigation of market power caused by transmission constraints is necessary for a competitive wholesale market to emerge in Arizona. This need for mitigating vertical market power complements and supports my testimony that expedient resolution of transmission constraints are paramount to ensuring reliable service to consumers at just and reasonable rates.

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[1] Direct Testimony, Michael J. DeConcini, May 29, 2002, Docket No. E-00000A-02-0051, et. al, page 9.
[2] Ibid., at page 8.
[3] Direct Testimony, Jerry D. Smith, May 29, 2002, Docket E-00000A-0051, et. al, at page 21-22.
[4] Direct Testimony, William H. Hieronymus, May 29, 2002, Docket No. E-00000A-02-0051, et. al, at page 26.
[5] Ibid., at line 13-15, page 26.
[6] Ibid., at page 28.
[7] Direct Testimony, David A. Schlissel, May 29, 2002, Docket E-00000A-02-0051, et. al, pages 7-8, and 13.

MARKET POWER TEST REGARDING TRANSMISSION CONSTRAINTS

Q. Is there testimony supporting use of particular market power tests to address transmission constraints?

A. Several parties to this case cite tests used to address horizontal market power for supply. However, these market power test models seem ill suited to addressing local transmission constraints and load pockets within a utility's transmission network.

For example, several parties acknowledge that the Herfindahl-Hirshman Index ("HHI") or "hub and spoke" test addresses market concentration but ignores transmission constraints.[8] The supply margin assessment ("SMA") or "pivotal test" adopted by FERC as an interim test does consider transmission import limitations to the market under consideration but fails to consider reserves and transmission constraints or load pockets within the market area.

Panda[9] and Staff[10] have applied the SMA test to the utility's control area sub-market (i.e. the transmission import constrained Phoenix and Tucson load zones). However, Dr. Roach[11] and Mr. Higgins[12] contend the SMA has shortcomings. Dr. Roach contends that generation that cannot compete within the market should be excluded from the SMA test. If transmission constraints are the reason for generation not competing then I would agree with such exclusion from the SMA test. On the other hand, Mr. Higgins recommends that California ISO ("CAISO") Residual Supply Index ("RSI") is a more accurate model for determining market power on an hourly basis. The RSI purports to resolve the reserve modeling deficiency of the SMA model. However, it still lacks the ability to adequately consider transmission constraints.

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8 Ibid., William H. Hieronymus, at page 31.
9 Direct Testimony, Craig R. Roach, Ph.D., May 29, 2002, Docket No. E-00000A-02-0051, et. al, at page 26.
10 Ibid., David A. Schlissel, at pages 4-6.
11 Ibid., Craig R. Roach, Ph.D., at page 10.
12 Direct Testimony, Kevin C. Higgins, May 29, 2002, Docket No. E-00000A-02-0051, et. al, at pages 12-14.

Parties claim that vertical market power is being adequately addressed by FERC. Numerous parties cite the formation of RTOs and establishing SMD and interconnection standards via pending NOPRs as FERC's solution for transmission market power. However, even with the future development of an RTO, the bulk transmission system will be the focus of transactions rather than local transmission constraints. As evidence of this claim, one need look no further that the numerous transmission constraints internal to the CAISO that have yet to be resolved and are impacting market behavior in California.

Staff contends that compliance with the two reliability principles contained in my direct testimony offers the best test for local transmission constraints.[13] Parties are not likely to find these tests appealing because they will require construction of new transmission lines. However, once these tests are passed, applying the SMA or RSI at the local market level seems to be a reasonable means of determining market power for supply.

AISA AND WESTCONNECT MITIGATION OF RMR GENERATION

Q. How do parties to this case suggest market power within load pockets be mitigated?

A. According to Mr. Hieronymus, the potential market power inherent in must-run units will be mitigated by APS' Open Access Transmission Tariff ("OATT") provisions and by a future RTO's market power mitigation measures.[14] He is indirectly referring to the AISA and Westconnect RMR protocols. These protocols apply to all transmission entities that are members of the two respective transmission organizations and parties that take transmission service over such transmission owners' system. Both APS and TEP are founding members of the two transmission organizations. Mr. Higgins offers an effective description of the two must-run protocols in his testimony.[15]

Q. Are you familiar with the AISA and Westconnect RMR protocols?

[13] Ibid., Jerry D. Smith, at lines 7-16, page 25.
[14] Ibid., William H. Hieronymus, at line 11, page 40.
[15] Ibid., Kevin C. Higgins, at pages 8-9.

A. Yes. I was one of two Staff members that participated in and monitored the AISA Operating Committee's development of the AISA protocols. I also served as an Ex-Officio Board member during DesertSTAR's development of its protocols that have since been adopted by Westconnect in its RTO filing at FERC.

Q. Does Staff believe the AISA and Westconnect protocols effectively mitigate RMR generation requirements?

A. Staff does not believe the two protocols necessarily serve as effective RMR mitigation measures. However, Staff does believe the two RMR protocols provide an effective non-discriminatory operational framework for managing RMR generation requirements. While the protocols are based upon sound market practices Staff disagrees with Mr. Higgins assertion that the two protocols mitigate load pocket market power and are in the public's best interest.[16]

Staff acknowledges that both RMR protocols are attempting to level the playing field for all parties trying to schedule energy into the constrained load pocket. The two RMR protocols in large part are non-discriminatory relative to pricing of RMR generation and in providing non-discriminatory transmission access. However, the protocols do not address the fundamental issue of vertical market power that exists when the transmission provider or its affiliates own the local must-run or must-offer generation.

Fundamental to this vertical market power argument is the fact that the transmission provider has elected to rely on RMR generation rather than build additional transmission import capacity to the load pocket.[17] This assures that local generation has access to the local market irrespective of price. Such action also precludes the opportunity to purchase power for the load pocket from power plants external to the constraint for the duration of

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[16] Ibid., Kevin C. Higgins, page 9.

[17] Rebuttal Testimony, Cary Deise, APS Request for Variance to Certain Requirements of A.A.C. R14-2-1606, April 22, 2002, pages 7-10.

the transmission constraint. Restricting access to the larger wholesale market may not be in Arizona consumer's best interest.

Q. **How do the AISA and Westconnect protocols differ regarding pricing of RMR generation requirements and is such pricing in Arizona consumers' best interest?**

The AISA protocol requires generation owners internal to the constraint to offer to sell to scheduling coordinators, on a cost-of-service basis, sufficient generation to serve load within the load pocket that exceeds the areas' transmission import capability. The Westconnect protocol allows the generation owner to sell at market based prices prevailing external to the load pocket. Neither of these protocols approaches pricing from the context of the UDC's obligation to provide reliable service to its customers at just and reasonable rates. For that reason, the pricing provisions of the two RMR protocols may not always be in Arizona consumers' best interest.

Q. **How do Staff's recommended RMR generation mitigation measures differ?**

A. Staff's recommendations for mitigating RMR generation requirements are based on the premise that the UDC has an obligation to reliably serve its customers at just and reasonable rates. Staff has recommended three actions to mitigation RMR generation. Staff recommends that RMR units not be transferred until the Commission has considered their must-run status and determined that they no longer have the potential to exercise market power.[18] Such a determination would emerge from the market power studies and mitigation plans that Staff recommends be filed prior to transfer of any generation asset.[19] Staff also recommends that jurisdictional utilities proceed to resolve any transmission import constraint by constructing needed transmission facilities as soon as practical if the Commission finds their RMR generation strategy to not be in consumers' best interest.[20] Staff supports use of the AISA and Westconnect RMR

[18] Direct Testimony, Matthew Rowell, at pages12-13.
[19] Ibid., Matthew Rowell, at pages 10-12.
[20] Ibid., Jerry D. Smith, at page 26.

protocols to operationally manage RMR generation requirements when such system conditions exist.

NETWORK RESOURCES AND ASSOCIATED TRANSMISSION RIGHTS

Q. What is network transmission service and Network Resources?

A. Network Integrated Transmission Service ("NITS") and Retail Network Integrated Transmission Service ("RNITS") provisions are defined by the respective utility's OATT filed and approved by FERC. Network Resources are generating units interconnected within the transmission network designated by the Network Customer for service to their Network Load via a network transmission service agreement. Network transmission service, as currently defined, is intended to be used by Network Customers for the purpose of delivering energy from designated Network Resources and other non-designated generating resources to their Network Load.

Q. Does Staff agree with the position taken by Panda and Reliant regarding designation of power plants as Network Resources and associated disposition of network transmission service rights?

A. The arguments offered by Panda and Reliant regarding designation of plants as Network Resource and use of network transmission service do have merit but are also very self-serving. Staff agrees with Mr. Kebler[21] that network transmission service rights are not assigned to generation assets. The Network Customer that has Network Load is the party that seeks and retains network transmission service rights. Therefore, generating assets owned by APS, TEP and their affiliates' that are not selected via the competitive procurement process must obtain transmission service as necessary for power delivery to other than standard offer customers.

Reliant's claim that APS must designate Network Resources on behalf of its native load customers in the same manner as any other customers taking network transmission

[21] Ibid., Curtis L. Kebler, at line 18, page11.

service under their tariff is accurate. But Reliant's argument is somewhat flawed in its application.[22] Reliant presumes that winners of the competitive procurement will necessarily be interconnected to the utility's transmission network and thus must be designated as Network Resources. Staff disagrees. For example, designation of a plant in Nevada as a Network Resource for APS seems inappropriate to Staff since such plant is not located within the APS transmission network.

The Network Resource designation is not applicable for sales to third parties or for service to other than Network Load. Therefore, Staff also disagrees with Panda's supposition that APS should be required to designate as Network Resource all generation with an interconnection agreement or for whom interconnection studies have been completed.[23] Such a requirement would only be practical if the full output of each plant were dedicated to standard offer service to UDC. Staff agrees that a power plant can be designated as a Network Resource if it has a Network Load and network transmission service has been established. Such a designation may even be desirable. For example, PWEC's Redhawk units 1 and 2 have been designated as Network Resource for APS.

Dr. Roach also espouses the merits of the two types of interconnection services contained in FERC's pending Interconnection NOPR.[24] The generation industry has done an excellent job of lobbying FERC for such interconnection services. However, neither the Energy Resource Interconnection Service nor the Network Resource Interconnection Service referenced by Dr. Roach considers the reliability impacts of such interconnections. These two types of interconnection services as currently defined are simply a means of generators avoiding any obligations for transmission improvements.[25] While such interconnections may be in the best interest of the market or generators they may not be in the best interest of Arizona's consumers. Staff has consistently taken

[22] Ibid., Curtis L. Kebler, at page 11.
[23] Ibid., Craig R. Roach, Ph.D., at line 8, page 18.
[24] Ibid., at line 16, page 18.
[25] Ibid., at lines 1-3, page 19.

exception to such interconnections throughout numerous power plant siting cases over the last two years. In fact, Staff has taken a position in this generic electric restructuring case that both Transmission Providers and Plant Owners have an obligation to resolve transmission delivery problems.[26] Adherence to such proposed reliability principles is the foundation for recommendations contained in my direct testimony.

Q. Does that conclude your testimony?

A. Yes.

[26] Ibid., Jerry D. Smith, at page 25.