Draft
12/24/03

Reliability Must-Run Analysis

2004–2013

January 31, 2004
APS Transmission Planning

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Appendices (Note: these are not included in the 12/24/03 draft)

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APS Reliability Must-Run Analysis 2004-2013

I. Executive Summary

This report documents the study methodology, results, and conclusions of Arizona Public Service Company's (APS) Reliability Must-Run (RMR) Analysis for the ten years from 2004 to 2013. This analysis was conducted in response to the Arizona Corporation Commission's (ACC) Second Biennial Transmission Assessment (Assessment) and Decision No. 65476 (December 19, 2002). The 2004 RMR Analysis covers a ten-year period and includes detailed analysis of the years 2005, 2008, and 2012.

If a city or load pocket must be served by local generating units at certain peak times, then those units are designated as "reliability must-run" or RMR units. In APS' service territory there are two major areas where load cannot be served totally by power imported over transmission lines – the Phoenix metropolitan area which is served by a combination of APS and SRP facilities, and the the APS service territory in the Yuma area.

While ninety-nine percent of the Phoenix area energy requirements can be met by remote generation, local generation is critically important for the reliability of the local power system. The November 2003 U.S.-Canada Power System Outage Task Force Interim Report: Causes of the August 14th Blackout in the United States and Canada pointed out the importance of the reactive capability of voltage support from local generation. Local generation can provide critical support for transmission contingencies and other power system disturbances and can prevent customer outages including blackout conditions such as those experienced in the Northeast on August 14, 2003.

Comments during the workshop for the 2003 RMR analysis held in February 2003 indicated that electric power system industry participants desired to have a more participative role in the 2004 RMR analysis. To facilitate this participation, APS and the other Arizona transmission providers utilized the Central Arizona Transmission Study forum to publicly determine the 2004 RMR study plan, have extensive discussion on study models and preliminary results, and ultimately conduct a workshop scheduled for January 15, 2004 to present the study results for comment. This process led to the decision to study the Phoenix area as a combined APS and SRP network, the determination of the specific years to study; 2005, 2008, and 2012, and the specific loads to include in the Phoenix area for the three study years.

The year 2005 was selected to provide a benchmark for the 2003 RMR study. The years 2008 and 2012 were selected as representative years during the ten-year window and because databases for these years were being used to perform studies in other study forums such as the Southwest Transmission Expansion Plan (STEP) planning group and the Seams Steering Group-Western Interconnection (SSG-WI).

This study found that the results for the 2005 study were similar to those from last years study for 2005. The results for 2008 indicate lower RMR requirements than for 2005. In 2012, the RMR requirements are similar to those for 2005. However in 2012 available Phoenix area generation reserves are presently projected to be less than the reserve requirements. To mitigate the 2012 deficiency in Phoenix area reserves APS and SRP are presently evaluating both transmission alternatives to increase import capability and alternatives to increase Phoenix area generation.

The cost of using must-run units can be measured by the difference between generation costs with the transmission limit and costs without the limit. This report looks at and compares the cost of serving these two areas with and without the existing transmission constraints.

This report concludes that for the Phoenix metropolitan area, the cost of RMR with the transmission limit is less than $100,000 annually and does not at present outweigh the cost of transmission improvements beyond those already included in the APS and SRP ten-year plans. Costs to relieve import limitations were documented in the 2003 RMR study to be in excess of $16 million. For Yuma, the report shows that the new North Gila 500/69-kV transformer and the new 230-kV line from Gila Bend-to-Yuma included in the present APS ten-year plan is sufficient to cost-effectively address RMR conditions. Environmental effects for both areas with and without transmission constraints are also documented in this report. Because there is such a small RMR requirement for both areas in all three years studied, the environmental effects are minimal.

A. Study Overview

The existence of transmission import limited areas is not uncommon in the United States, and particularly in the West where load centers are generally separated by long distances. APS has transmission import-limited areas in Phoenix and Yuma. An import area is transmission limited when all load cannot be served solely by importing resources over local transmission lines, thus requiring some use of local generating units to reliably meet peak load.

The two transmission import-limited areas in APS' system were studied to determine:

- The system simultaneous import limit (SIL), which is the maximum amount of capacity that can be reliably imported into an area with no local generation;
- The maximum load serving capability (MLSC), which is the total load that can be reliably served from imports and from local generation;
- Annual RMR conditions, including magnitude of load in excess of the SIL and number of hours the load exceeds the SIL; and
- Estimated economic and environmental impacts of the import limits.

The Phoenix area is a tight network of APS and Salt River Project (SRP) load, resources, and transmission facilities. Because the Phoenix system is highly integrated, the import limits must be determined for the combined area. This analysis was coordinated with SRP personnel, who had significant involvement in the study and were helpful in the overall analysis. The Western Area Power Administration (WAPA) coordinated with APS and SRP in the study because their transmission facilities interface with the Phoenix network.

After the combined import limit (SIL) for the Phoenix area was determined, RMR conditions were evaluated for the Phoenix area based on the Phoenix area import limits, the Phoenix area load, and Phoenix area local generation, which includes generation owned by APS, SRP and Pinnacle West Energy Corporation (PWEC).

The Yuma area, which has a forecast 2005 summer peak demand of approximately 344 MW, is served by an internal APS 69-kV sub-transmission network containing all of the load in the import-limited area. There are external ties to WAPA and the Imperial Irrigation District (IID), as well as a bulk power interface with the Hassayampa-to-North Gila transmission system. This analysis was coordinated with the WAPA Phoenix office to ensure accurate modeling.

B. Summary of Results

Results of the analysis for the three years of the study, 2005, 2008, and 2012, assume that present plans for system improvements are completed on schedule.

The following table summarizes the estimated RMR conditions and costs for the Phoenix area.

Table ES1
Phoenix area RMR Conditions and Costs

Year	SIL[1] (MW)	Peak Demand (MW)	Max RMR[2] (MW)	RMR[3] Hours	RMR Energy[4] (GWH)	RMR Energy (% of total)	RMR Cost[5] ($M)
2005	8,617	11,141	2,524	678	550	1.2	0.0
2008	10,511	12,425	1,914	338	222	0.4	0.0
2012	11,103	14,406	3,303	758	805	1.3	0.1

Table Key:

[1]**SIL** – System Simultaneous Import Limit is the maximum amount of capacity that can be reliably imported into the area with no local generation operating.

[2]**Max RMR** – The amount of local generation required to meet the area peak demand (Peak Demand minus SIL).

[3]**RMR Hours** – The number of hours that the area's demand exceeds the SIL, thus requiring the use of local generation to meet load, even if otherwise economically dispatched.

[4]**RMR Energy** – The annual energy required to be met by local generation (in excess of the SIL).

[5]**RMR Cost** – The difference in annual generation cost with and without the transmission limitation.

The following table summarizes the estimated RMR conditions and costs for the Yuma area.

Table ES2
Yuma Area RMR Conditions and Costs

Year	SIL[1] (MW)	Peak Demand (MW)	Max RMR[2] (MW)	RMR[3] Hours	RMR Energy[4] (GWH)	RMR Energy (% of total)	RMR Cost[5] ($M)
2005	265	344	79	714	20	1.3	1.0
2008	292	380	88	676	21	1.2	0.0
2012	410	425	15	12	0	0.0	0.0

Table Key:

[1]**SIL** – System Simultaneous Import Limit is the maximum amount of capacity that can be reliably imported into the area with no local generation operating.

[2]**Max RMR** – The amount of local generation required to meet the area peak demand (Peak Demand minus SIL).

[3]**RMR Hours** – The number of hours that the area's demand exceeds the SIL, thus requiring the use of local generation to meet load, even if otherwise economically dispatched.

[4]**RMR Energy** – The annual energy required to be met by local generation (in excess of the SIL).

[5]**RMR Cost** – The difference in annual generation cost with and without the transmission limitation.

The following table shows the Phoenix area Maximum Load-Serving Capability (MLSC) for the three years studied and compares the MLSC to the forecasted peak demand. This includes the new generation of Santan 5 in the 2005 study and Santan 6 in the 2008 study. The MLSC is determined by adding the SIL and the local generation minus the local reserve requirement. APS determined the Phoenix area reserve requirements by performing a probabilistic analysis that considered the size and forced outage rates of the local generating units and resulted in 99 percent reliability of serving all load. This analysis resulted in reserve requirements of 809 MW, 865 MW, and 865 MW for the Phoenix area for the years 2005, 2008, and 2012 respectively.

Table ES3
Phoenix Area Maximum Load Serving Capability

Year	SIL	Local Generation	Required Reserves	MLSC (SIL+LG-RR)	Peak Demand (MW)	Projected Reserves
2005	8,617	3,374	809	11,182	11,141	850
2008	10,511	3,649	865	13,295	12,425	1735
2012	11,103	3,649	865	13,887	14,406	346

The following table summarizes the Yuma area MLSC. The reserve requirements for the Yuma area were determined to be 138 MW for all years studied.

Table ES4
Yuma Area Maximum Load Serving Capability

Year	SIL	Local Generation	Required Reserves	MLSC (SIL+LG-RR)	Peak Demand (MW)	Projected Reserves
2005	265	267	138	394	344	188
2008	292	267	138	421	380	179
2012	410	267	138	539	425	252

Local generating units are dispatched based on cost. Thus, most of the RMR hours shown above are "in the money" when dispatched. However, the presence of a transmission constraint may require local generation to be dispatched "out of the money." This report considered all Phoenix area and Yuma area transmission limitations and generation resources in determining the overall RMR situation. The economic impact of RMR can be seen from the following tables.

The following table summarizes the estimated total number of hours that local Phoenix generation must run out of economic dispatch, the amount of energy that is produced out of economic dispatch and the associated cost.

Table ES5

Phoenix area RMR Outside Economic Dispatch

Year	Hours outside economic dispatch	Energy outside economic dispatch (GWH)	RMR Cost ($M)
2005	18	6	0
2008	0	0	0
2012	14	1	0

The following table summarizes the estimated total number of hours that APS local Yuma generation must run out of economic dispatch, the amount of energy that is produced out of economic loading and the associated cost.

Table ES6
APS Yuma Area RMR Outside Economic Dispatch

Year	Hours outside economic dispatch	Energy outside economic dispatch (GWH)	RMR Cost ($M)
2005	336	8	1
2008	2	0	0
2012	0	0	0

C. Report Conclusions

Phoenix area Conclusions

1. All Phoenix area transmission and local generation are necessary to reliably serve Phoenix area peak load in 2005 with the local generation reserve margin just exceeding the required reserve margin. In 2008, the local generation reserve margin significantly exceeds the required reserve margin. However, in 2012 the reserve margin is 346 MW which is 519 MW less than the required reserve margin of 865 MW. To mitigate this deficiency APS and SRP are presently evaluating both transmission alternatives to increase import capability and alternatives to increase Phoenix area generation.

2. During the summer, Phoenix area load is expected to exceed the available transmission import capability for approximately 680 hours in 2005, 340 hours in 2008, and 760 hours in 2012. These hours represent only approximately one percent of the annual energy requirements for the Phoenix area.

3. From a total Phoenix load, transmission, and resources viewpoint, import limits are expected to cause a minimal amount of local generation to be dispatched out of economic dispatch order in 2005 and 2012, and no impact in 2008.

4. The estimated annual economic cost of Phoenix area RMR generation is negligible, therefore advancement of transmission projects to increase import capability are presently not cost justified.

5. Removing the transmission constraint could reduce total Phoenix area air emissions by the following annual amount for 2005. There is a minimal impact for years 2008 and 2012 due to the increased import capabilities and resources resulting in fewer hours of operating local generation.

Table ES7
Phoenix area Air Emissions Reduction

Pollutant	Reduction[1] (tons/year)	Reduction of Phoenix Area Emissions (% of total emissions from all sources)
VOC	0.0	0.000
NO_x	4.0	0.007
CO	1.0	0.000
PM_{10}	0.0	0.000

[1]2005 results, impact for 2008 and 2012 is negligible

6. Removing the import restriction into the Phoenix area has no impact on local generation capacity factor. The capacity factor ranges from approximately 11% in 2005 to 26% in 2012.

Yuma Area Conclusions

7. All existing Yuma area transmission and generation resources are necessary to reliably serve the Yuma area load.

8. The Yuma area load is expected to exceed the available transmission import capability for 714 hours in 2005, 676 hours in 2008 and 12 hours in 2012 although the amount of total load in the Yuma area is approximately 350-425 MW.

9. From a total Yuma load, transmission, and resources viewpoint, the import constraint could cause APS Yuma generation to be dispatched out of economic dispatch order for 336 hours in 2005, 2 hours in 2008, and 0 hours in 2012.

10. The estimated annual economic cost of Yuma area generation required to run out of economic dispatch order is relatively small, therefore advancement of transmission projects to increase import capability are presently not cost justified.

11. Removing the transmission constraint could reduce total Yuma area air emissions by the following annual amount for 2005. There is a minimal impact for years 2008 and 2012 due to the increased import capabilities resulting in fewer hours of operating local generation.

Table ES8
Yuma Area Air Emissions Reduction

Pollutant	Reduction[1] (tons/year)	Reduction of Yuma Area Emissions (% of total emissions from all sources)
VOC	1.0	Unavailable
NO_x	20	Unavailable
CO	5	Unavailable
PM_{10}	1.0	0.001

[1]2005 results, impact for 2008 and 2012 is negligible

12. Removing the import restriction into the Yuma area could reduce the APS Yuma generation capacity factor from 1.6 percent to 1.2 percent in 2005.

D. Report Organization

This report is organized in eight sections. Section I provides an executive summary of the report. Section II provides general background information of the study requirements, an overview of RMR, and describes the study methodology. Section III describes the Phoenix area, the nature of the import limit, the resulting import limits for 2005, 2008, and 2012, and the impact of various generators in and around the Phoenix area on the import limit. Section IV provides a similar discussion of the Yuma area. Section V describes the RMR conditions such as number of hours, maximum capacity, and annual energy for the Phoenix and Yuma areas. Section VI provides results of the economic analysis of the Phoenix and Yuma area RMR conditions performed utilizing a regional planning model (GE MAPS) and emissions impact. Finally, Section VII lists the conclusions of the analysis.

II. Introduction

A. Background of Study Requirement

Like all large electric utilities, Arizona utilities have historically relied on both transmission, to deliver remote generation into its load centers, as well as local generation to reliably serve its customers. Due in part to environmental, economic, and fuel availability considerations, large base-load thermal generators have typically been located away from the load centers while smaller but less efficient intermediate and peaking units — with lower capacity factors — were located within the load centers. Although this local generation is relied on for a relatively small amount of the local energy requirement, this local generation is critically important for the reliability of the local power system. The November 2003 U.S.-Canada Power System Outage Task Force Interim Report: Causes of the August 14th Blackout in the United States and Canada pointed out the importance of the reactive capability of voltage support from local generation. Local generation can provide critical support for transmission contingencies and other power system disturbances and can prevent customer outages including blackout conditions such as those experienced in the Northeast on August 14, 2003. Local generation also results in lower power system losses and lower capital expenses for transmission infrastructure.

In the past, vertically integrated utilities, such as APS, managed the siting and construction of both generation and transmission resources needed to serve their customers. Electric systems were designed based on a detailed integrated resource planning process used to evaluate the appropriate balance of generation, transmission, and demand-side resources. Interconnections with neighboring systems were primarily intended to improve system reliability and lower the costs of reserves, by allowing for sharing of capacity reserves by multiple systems. Each utility's system was primarily designed to accommodate that utility's resources and that utility's load.

The Commission's Second Biennial Transmission Assessment requires "any [Utility Distribution Company] that currently relies on local generation, or foresees a future time period when utilization of local generation may be required to assure reliable service for a local area, [to] perform and report the findings of an RMR study as a feature of their ten year plan filing with the Commission in January 2003 and 2004." The Assessment required that the RMR study filed in January 2003 evaluate RMR conditions through the 2005 summer peak. The January 2004 RMR study covers the 10-year period from 2004 to 2013.

B. Overview of RMR

Local "load pockets" are areas that do not have enough transmission import capability to serve all load in the area solely by importing remote generation over local transmission facilities. For these areas, during peak hours of the year, local generation is required to serve that portion of the load that cannot reliably be served by transmission imports. This local generation requirement is often referred to as Reliability Must-Run or RMR generation. In these areas, during peak conditions, load is served by a combination of importing remote generation over transmission lines and operating local generation.

The maximum load that can be served in a load pocket with no local generation operating — in other words, the maximum load that can be served solely by importing remote generation — is referred to as the system Simultaneous Import Limit (SIL). The SIL is established through technical studies by ensuring that:

- With the local load at the SIL and no local generation operating there are no transmission system normal operating limit violations of thermal loading or voltages (N-0), and
- Under all single contingency outage events there are no emergency operating limit violations of thermal loading or voltages, and no system instability (N-1).

C. Study Methodology

Import limit analysis was performed for the Phoenix and Yuma areas. See Appendix A for power flow results. The import limit area or load pocket is defined as that load which, when increased, would increase the severity of the limiting contingency. For example, load in Flagstaff has no impact on the severity of the limiting contingency for the Phoenix import limited area, and therefore Flagstaff is not included in the Phoenix load pocket. In contrast, downtown Phoenix load does impact the severity of the limiting contingency and therefore is included in the load pocket. All area contingencies known to result in system stress were evaluated to determine the critical contingency for the area. Import limits were determined by contingency conditions of thermal loading at the emergency rating of a facility, steady state voltages at the emergency voltage limit, and system instability including voltage instability.

Import limits were determined for the Phoenix and Yuma areas with no local generation operating, with maximum local generation operating, and sufficient points in between to determine curves which define import limits at all load levels. This methodology was applied to studies of the Phoenix area, which for 2005 and 2008 is constrained by both voltage instability and thermal loadings, depending on the local load level. In 2012 the Phoenix area is constrained solely by thermal loadings. For the Yuma studies, the limitations are primarily post-disturbance thermal constraints and voltage drop limits. Generator sensitivities were performed to determine the relative impact of various generators on the import limits for the Phoenix and Yuma areas.

From each year's forecasted peak load and historical daily load cycles, the annual RMR conditions were determined including magnitude of local load, both demand and energy, expected to exceed the SIL and the annual hours for which local load is expected to exceed the SIL.

An economic analysis was performed in each area for each year using the GE MAPS production-costing model to determine the cost of the import limits. GE MAPS is a regional generation and transmission simulation model and is discussed in more detail in Appendix B to this report.

Additional transmission alternatives to mitigate the import limits of the Phoenix and Yuma area were not studied due to the minimal amounts of RMR conditions that were identified in the study. The cost for any transmission alternative would significantly exceed the costs associated with any RMR conditions. This report concludes that for the Phoenix metropolitan area, the cost of RMR with the transmission limit is less than $100,000 annually and costs to relieve import limitations were documented in the 2003 RMR study to be in excess of $16 million.

D. Determination of SIL and RMR Conditions

In this analysis, assessments of the SIL and RMR conditions for the Phoenix area and the Yuma area were performed for the years 2005, 2008, and 2012. The year 2005 was selected to provide a benchmark for the 2003 RMR study. The years 2008 and 2012 were selected as representative years during the ten-year window and because databases for these years were being used to perform studies in other study forums such as the Southwest Transmission Expansion Plan (STEP) planning group and the Seams Steering Group-Western Interconnection (SSG-WI). Base case and contingency power flow, stability, and voltage stability analyses were performed to determine import limitations. The initial starting cases were based on WECC heavy summer full loop base cases in GE Power Flow format for the corresponding year. Those base cases model the entire Western Interconnection's transmission system and were reviewed and then updated to represent expected loads and system configuration for 2005, 2008 and 2012. All cases were coordinated between APS, SRP, Tucson Electric Power Company (TEP), Southwest Transmission Cooperative (SWTC), and WAPA to capture the most accurate expected operating conditions for the Arizona transmission system.

III. PHOENIX LOAD POCKET

A. Description of Phoenix Area

During summer 2005, the Phoenix area — which consists of both APS' and SRP's integrated network — will be served from the following major Extra High Voltage (EHV) substations: Westwing, Pinnacle Peak, Kyrene, Rudd, Browning, and Silverking. These EHV stations form the "cornerstones" of an extensive internal network of 230-kV transmission lines that constitute the high voltage energy delivery system within the Phoenix load area. By summer 2008, two new EHV substations will be added to the existing major EHV substations serving the Phoenix area. They are the TS5 substation and the South East Valley (SEV) substation. And, in 2012 the Raceway substation is added.

Since the summer of 2002, APS has served some northwest Phoenix area load from the Raceway substation, which has been built as an interconnection to the WAPA Westwing-to-Waddell 230-kV line. Because this line has no interconnections with other Phoenix area 230-kV lines, this load does not significantly impact the contingency response of the Phoenix area and is therefore not included in the Phoenix area load determination, until the 2012 case when Raceway becomes interconnected to Pinnacle Peak and the new 500-kV substation.

Because the City of Mesa load is served by dedicated resources external to Phoenix, the economic RMR analysis is performed with this load excluded.

Energy flows into the EHV delivery points from the EHV transmission lines and then is stepped down to 230-kV and transmitted into the load center via the 230-kV transmission lines. These loads, with area losses, are measured by determining the flows from the EHV substations into the load area to include all of these load stations. The specific loads to be included in the Phoenix area load for each of the three years was determined by sensitivity analysis performed early in the study effort to determine the impact of various loads on the severity of the critical contingency. Table 1 shows the results of the sensitivity analysis which was performed on a preliminary 2008 case.

Table 1
Phoenix Area Load Sensitivity

	Palo Verde-Rudd Outage Westwing-Surprise 230kV line Overload	% INCREASE
Base Case	**100.0%**	**xxx**
Surprise	107.2%	7.2%
White Tanks	102.6%	2.6%
West Phoenix	102.1%	2.1%
Country Club	101.8%	1.8%
Ocotillo	101.4%	1.4%
TS3	101.3%	1.3%
Buckeye	101.0%	1.0%
Kyrene	101.0%	1.0%
Thunderstone	101.0%	1.0%
Santan	101.0%	1.0%
TS1	101.0%	1.0%
Mooshine (EMA)	101.0%	1.0%
Pinnacle Peak	100.9%	0.9%
Gavilan Peak	100.8%	0.8%
Browning	100.7%	0.7%
Jojoba	100.7%	0.7%
Moonshine	100.7%	0.7%
Case Grande	100.4%	0.4%
Gila Bend	100.4%	0.4%
Yavapai	100.1%	0.1%
Avery	99.8%	-0.2%
Raceway	99.6%	-0.4%

	Jojoba-Kyrene Outage Kyrene 230kV Voltage ΔV	% INCREASE
Base Case	**4.72**	**XXX**
Browning	5.83	1.11
Santan	5.43	0.71
Kyrene	5.35	0.63
Thunderstone	5.35	0.63
Ocotillo	5.20	0.5
Country Club	5.15	0.43
Pinnacle Peak	5.10	0.38
Moonshine (EMA)	5.08	0.36
Gavilan Peak	5.08	0.36
West Phoenix	5.04	0.32
White Tanks	4.99	0.27
Buckeye	4.93	0.21
Surprise	4.93	0.21
Raceway	4.90	0.18
Yavapai	4.82	0.1
Casa Grande	4.75	0.03

The sensitivity analysis confirmed that all of the Phoenix area load included in last years study was appropriate, but that load at Buckeye, Gila Bend, the Eastern Mining Area, and Gavilan Peak should also be included. Figure 1 shows all of these loads included for the 2005 study. Figure 2 shows, in 2008, the Phoenix area load is expanded to include loads supplied by the new bulk power substations TS5 and South East Valley (SEV). Figure 3 shows, in 2012, the Phoenix area load is expanded to include loads supplied from the bulk substation at Raceway.

Figure 1

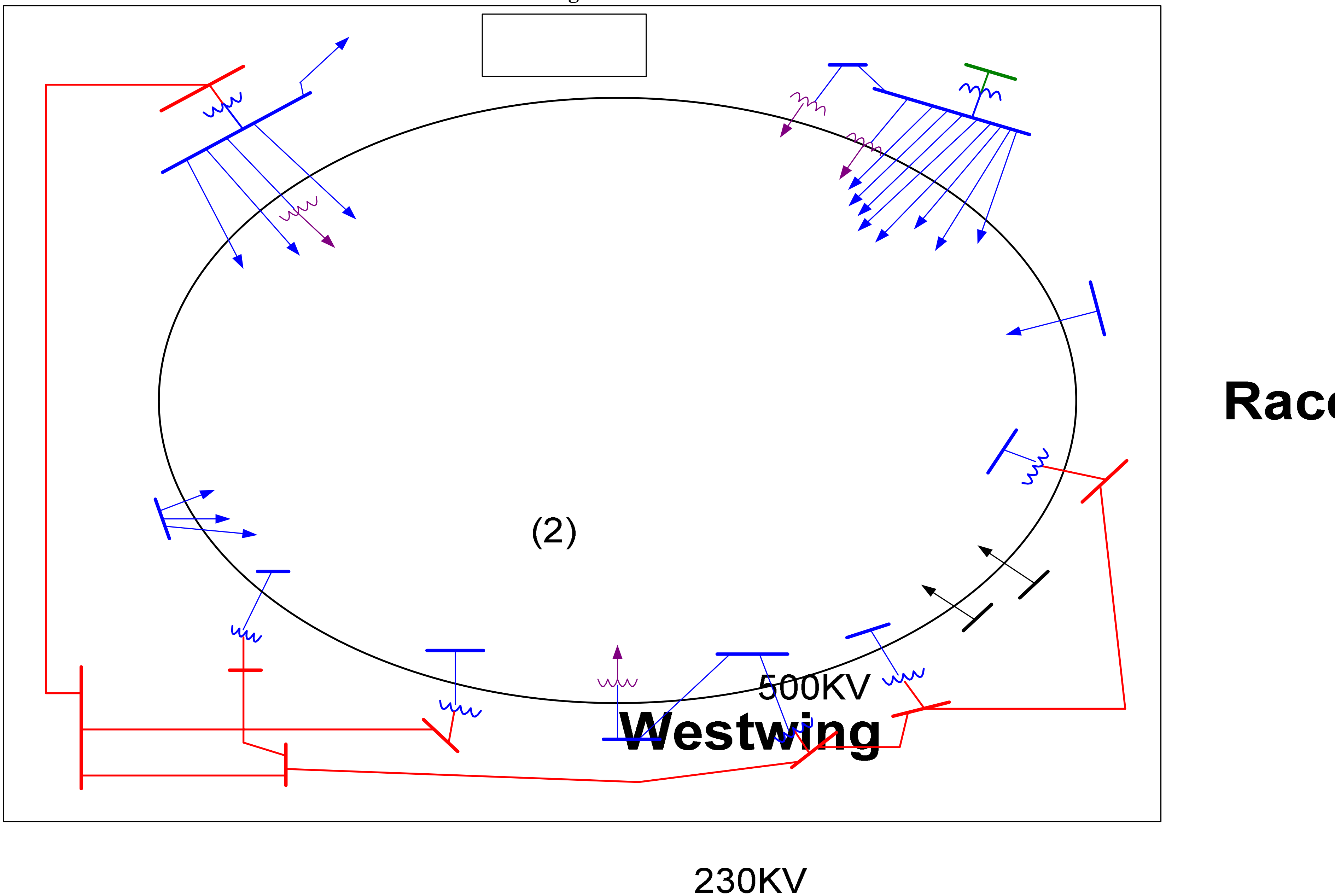


Figure 2

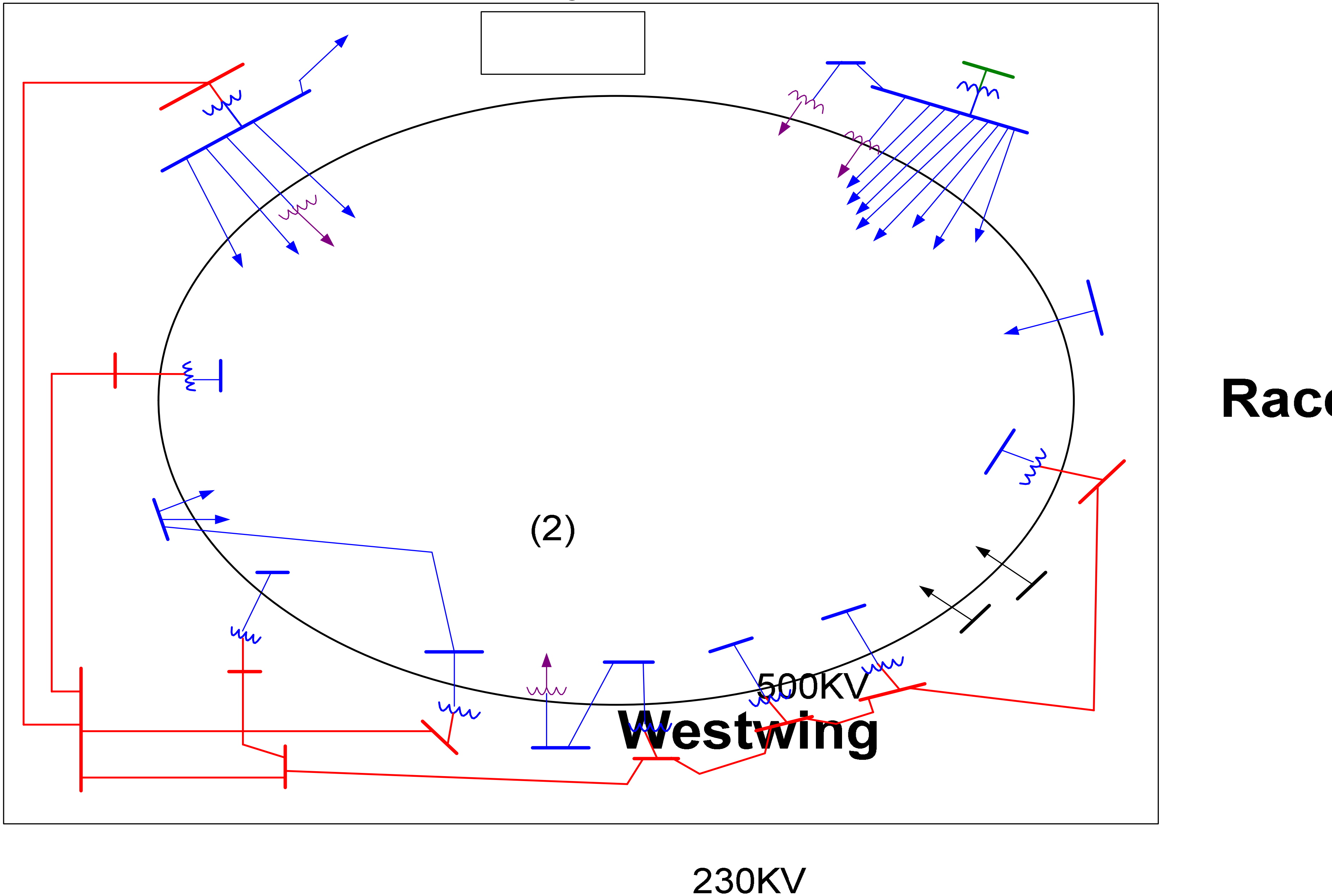
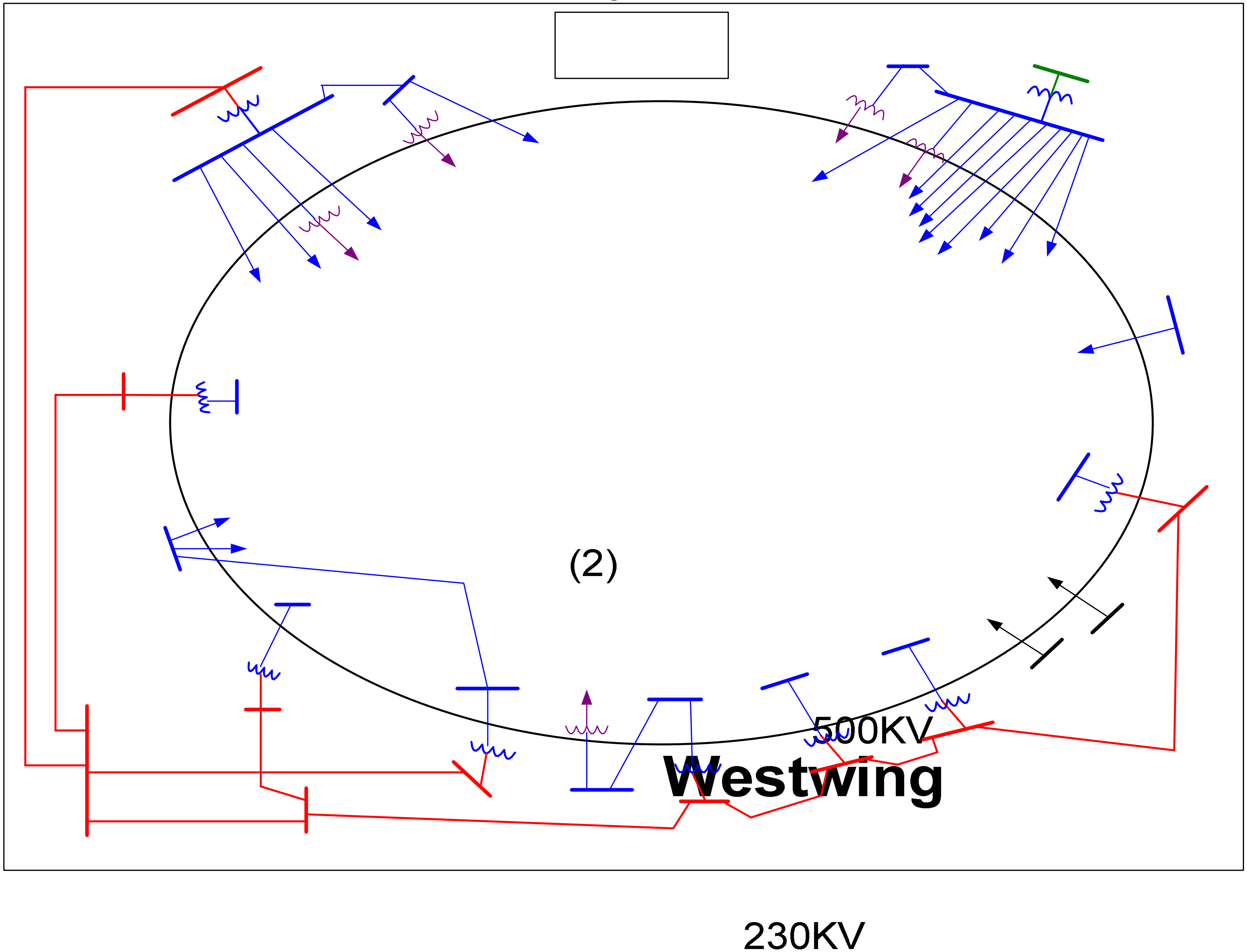


Figure 3



In performing the Phoenix area studies several planned projects were added to reflect transmission system upgrades for the next ten years. They are listed below under one of the three study years they will first appear:

Projects in service by 2005

- Gavilan Peak substation connected to Pinnacle Peak-Prescott 230-kV line
- Reach 2nd 230/69-kV transformer addition
- Browning 230/69-kV, 280 MVA transformer addition
- Cactus 3rd 230/69-kV transformer addition
- North Gila 2nd 500/69-kV transformer addition
- Surprise 2nd 230/69-kV transformer addition
- West Phoenix 3rd 230/69-kV transformer addition
- Thunderstone 2 new 230/69-kV, 280 MVA transformer additions
- Alexander 69-kV 46mvar capacitors addition
- Santan CC5 550 MW generation addition

Projects in service by 2008

- Silver King substation connected to Cholla-Saguaro 500-kV line
- South East Valley project
- A new Avery 230/69-kV substation with a 230/69-kV transformer and a 230-kV line from Raceway substation
- A new TS5 500/230-kV substation with two 500/230-kV transformers, a 500-kV line to Palo Verde area
- A new TS1 230/69-kV substation with a 230/69-kV transformer, a 230-kV line to TS5 substation
- A new TS3 230/69-kV substation with a 230/69-kV transformer, a 230-kV line to TS1 substation, and connected to Rudd-TS4 230-kV line
- Lincoln Street 2nd 230/69-kV transformer addition
- Rudd 4th 500/230-kV transformer addition
- A new Jojoba 230/69-kV substation with a 230/69-kV transformer and connected to Gila River-Liberty 230-kV line
- Santan CC6 275 MW generation addition

Projects in service by 2012

- A new Raceway 500-kV substation connected to Navajo-Westwing 500-kV line and a 500-kV line to TS5 substation
- A new TS2 230-kV substation with a 230/69-kV transformer and connected to TS1-TS3 230-kV line
- A new TS6 230/69-kV substation with a 230/69-kV transformer and connected to a new Avery-Pinnacle Peak 230-kV line
- Meadowbrook 2nd 230/69-kV transformer addition
- Alexander 2nd 230/69-kV transformer addition

B. Phoenix Area Critical Outages

1. 2005

The analysis determined that the critical single contingency for the Phoenix load area with less than 1400 MW of local Phoenix area generation is the loss of the Jojoba-to-Kyrene 500-kV transmission line. The loss of this major 500-kV line to the Phoenix area results in significantly higher flows on the remaining transmission lines and causes a large increase in reactive power (Var) losses in the transmission network. The increase in Var consumption results in insufficient Vars for voltage support in the load area. Consequently, this condition creates low voltages in the system and makes the area deficient in reactive power. The system is constrained by voltage instability, with local Phoenix area generation below 1400 MW. With local Phoenix area generation above 1400 MW, the critical single contingency for the Phoenix load area is also the loss of the Jojoba-to-Kyrene 500-kV transmission line. But, with at least 1400 MW of local generation on-line, the loss of the line results in a thermal overload of the Rudd-to-Orme 230-kV transmission line. Thus, the system is constrained by this thermal overload when local Phoenix area generation is above 1400 MW.

2. 2008

The analysis determined that the critical single contingency for the Phoenix load area with less than 1600 MW of local Phoenix area generation is the loss of the Jojoba-to-Kyrene 500-kV transmission line. The loss of this major 500-kV line to the Phoenix area results in significantly higher flows on the remaining transmission lines and causes a large increase in reactive power (Var) losses in the transmission network. The increase in Var consumption results in insufficient Vars for voltage support in the load area. Consequently, this condition creates low voltages in the system and makes the area deficient in reactive power. The system is constrained by voltage instability, with local Phoenix area generation below 1600 MW. With local Phoenix area generation above 1600 MW, the critical single contingency for the Phoenix load area is the loss of the Agua Fria-to-Glendale 230-kV transmission line. With at least 1600 MW of local generation on-line, the loss of the Agua Fria-to-Glendale 230-kV transmission line results in a thermal overload of the West Phoenix-to-Lincoln Street 230-kV transmission line. Thus, the system is constrained by this thermal overload when local Phoenix area generation is above 1600 MW.

3. 2012

The analysis determined that the critical single contingency for the Phoenix load area at all load and generation levels is the loss of the Palo Verde-to-Rudd 500-kV transmission line. The loss of this major 500-kV line results in significantly higher flows on the underlying 230-kV transmission system and causes a thermal overload on the Westwing-to-Surprise 230-kV transmission line. Thus, the system is constrained by this thermal overload for the loss of the Palo Verde-to-Rudd 500-kV transmission line.

The voltage stability analysis was performed using Q-V analysis on the most reactive deficient buses in the Phoenix area. These buses were the Kyrene 500-kV, Kyrene 230-kV, Browning 230-kV, Westwing 230-kV, and the Pinnacle Peak 230-kV buses.

C. Phoenix Area – SIL for 2005, 2008, and 2012

Analysis of the Phoenix area transmission network resulted in area import limits based on the limits discussed above. Operation of the Phoenix system within these limits ensures that the area does not experience voltage instability or thermal overloading of a system element after a critical contingency. Voltage instability is characterized by a progressive fall in voltage magnitude at a particular location of the power system that may spread throughout the network causing a complete area voltage collapse and blackout. A thermal overload occurs when more power flows through an element than the emergency rating of that element. The Phoenix area SIL for the years 2005, 2008, and 2012 are outlined in Table 1.

Table 2
2005, 2008, and 2012 Phoenix area Simultaneous Import Limit

Year	SIL (MW)
2005	8,617
2008	10,511
2012	11,103

The maximum Phoenix area load-serving capability for various generation levels is shown in Figures 4, 5, and 6.

Figure 4

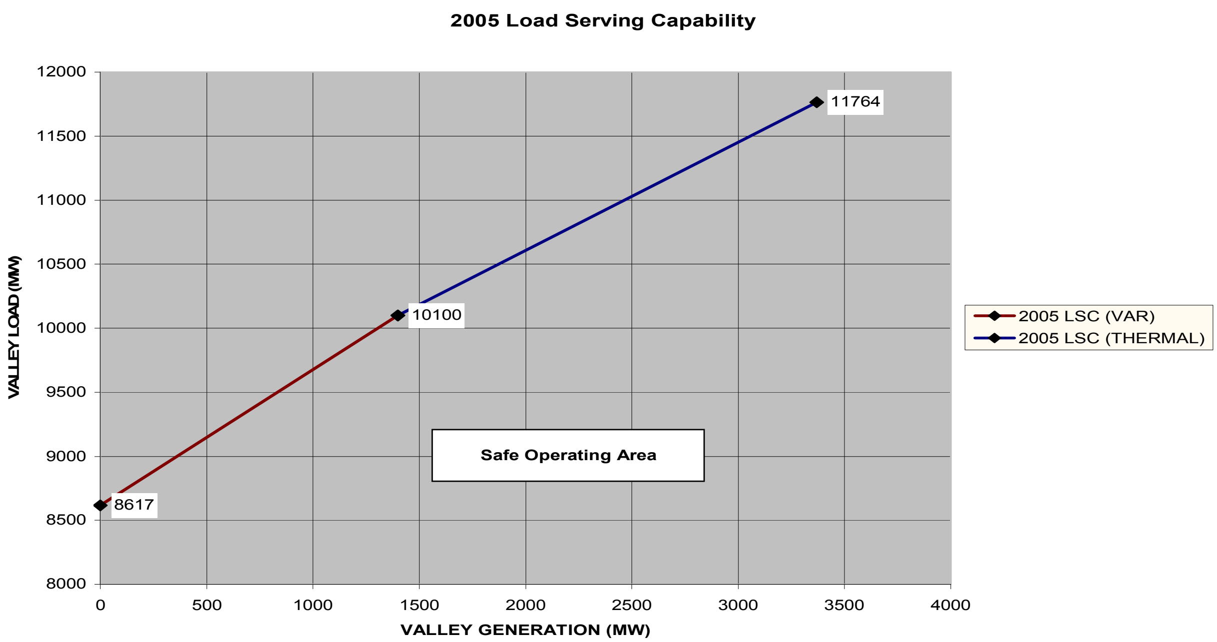


Figure 5

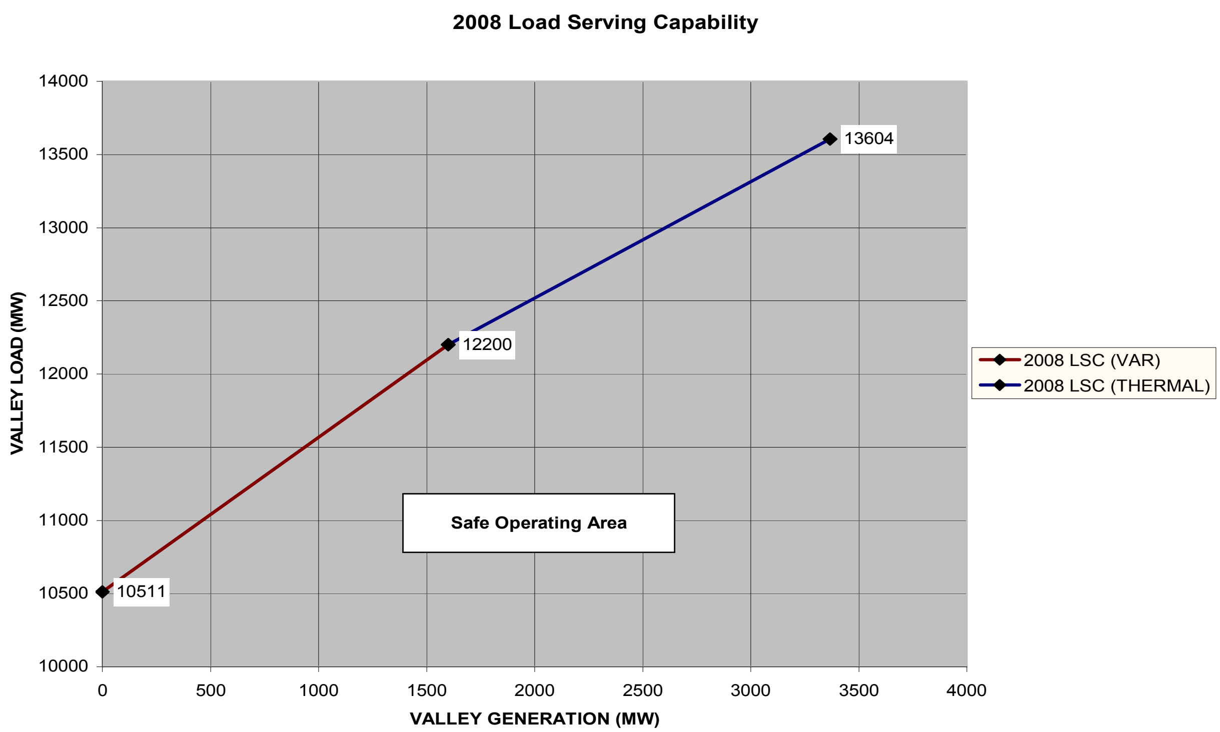
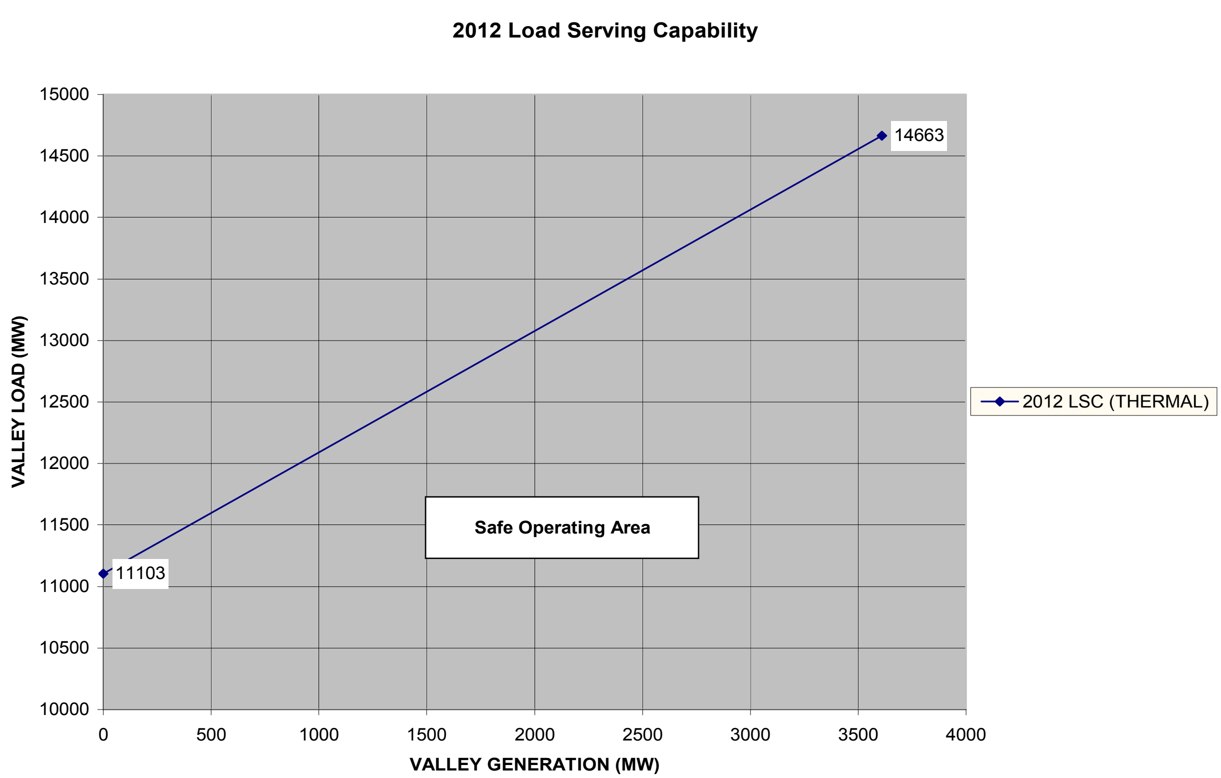


Figure 6



D. Generation Sensitivities

Sensitivity analyses of generation impact on load-serving capability were also conducted. These sensitivities were done with the maximum level of local generation. The following tables provide the results of these analyses for units that are both within and outside the Phoenix area.

Generation sensitivities inside the Phoenix area are listed in Table 2.

Table 3
Generation Sensitivities Inside Phoenix

Generation Source Increase by 100 MW	2005 Load Serving Capability Increase (MW)	2008 Load Serving Capability Increase (MW)	2012 Load Serving Capability Increase (MW)
Agua Fria Generation	25	0	115
Kyrene Generation	170	56	58
Ocotillo Generation	62	257	83
Santan Generation	144	50	61
West Phoenix Generation	12	0	117

Generation sensitivities outside of the Phoenix Metro area are listed in Table 3.

Table 4
Generation Sensitivities Outside Phoenix

Generation Source Increase by 100 MW	2005 Load Serving Capability Increase (MW)	2008 Load Serving Capability Increase (MW)	2012 Load Serving Capability Increase (MW)
Sundance Generation	94	26	54
Desert Basin Generation	114	28	32
Hassayampa Area Generation	0	0	0
Panda Gila River Generation	0	0	11

The results indicate that the effectiveness of a generator is dependant upon the critical outage, whether the limitation is thermal or voltage, the critical element, and the location of the generator in respect to the direction the power is flowing through the critical element. For example, in 2005 with the critical outage being the Jojoba-Kyrene 500-kV line and the critical element being the Rudd-Orme 230-kV line, the generators that will allow the load-serving capability to increase the greatest are those that inject their power to the east of the Orme substation. And, in 2008, with the critical outage being the Agua Fria-Glendale 230-kV line and the critical element being the West Phoenix-Lincoln Street 230-kV line, because they inject power east of Lincoln Street the Ocotillo generators are most effective in increasing the load-serving capability. In contrast, with the West Phoenix generators injecting power immediately upstream of the critical element, they will be least effective in increasing the load-serving capability.

IV. YUMA AREA

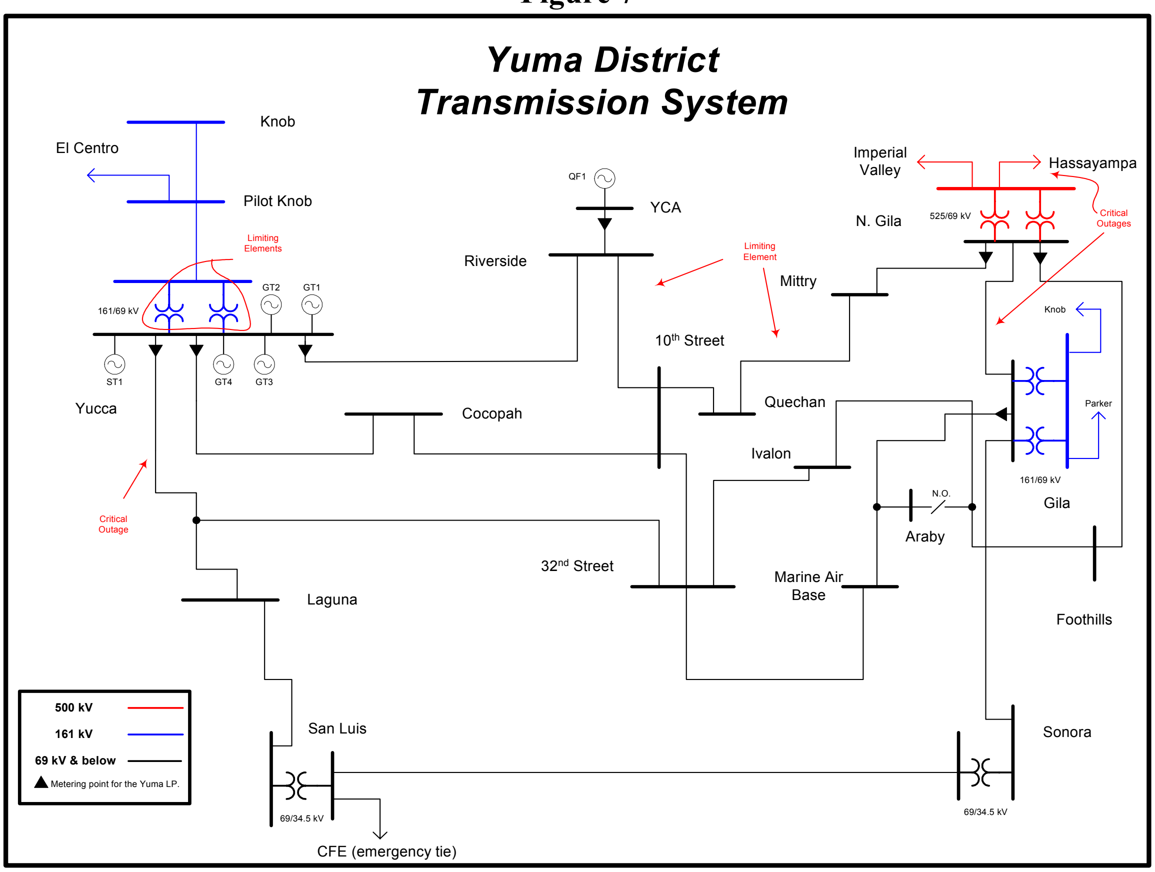
A. Description of Yuma Area

Currently the Yuma area is served from three transmission sources:

- APS' North Gila 500/69-kV substation, which is located east of Yuma. Two 69-kV lines extend west and southwest from this substation into Yuma to serve Yuma area load. A third 69-kV line interconnects into WAPA's Gila substation.
- WAPA's Gila 161/69-kV station, which is also located east of Yuma. From this station, APS has one 69-kV line into the Yuma load area and one 69-kV tie to APS' North Gila substation.
- APS' Yucca 69-kV station, which is located on the west side of Yuma near the Colorado River. APS' local generation is located at this station, along with three 69-kV lines into the load area and an interconnection to IID's 161-kV system through two 161/69-kV transformers. The IID 75 MW steam-generating unit is also located at this substation.

Figure 7 shows the transmission system in 2005 and the metering points for the Yuma area load pocket.

Figure 7



B. Yuma Area Critical Outages

Several critical contingencies exist affecting the determination of the system import limit for the Yuma area during the 2004-2013 time frame. For the 2004-2011 time frame, these include the Hassayampa-N.Gila 500-kV line, the Yucca-Laguna tap 69-kV line, and the N. Gila-Gila 69-kV line. In 2012 and beyond, the loss of the new TS8-Gila Bend 230-kV line also becomes a critical contingency.

A loss of the Hassayampa-N.Gila 500-kV line typically overloads the Yucca 161/69-kV transformers, while the N.Gila-Gila 69-kV outage results in overloading the N.Gila-Mittry 69-kV line or the Mittry-Quechan 69-kV line. An outage of the Yucca-Laguna tap 69-kV line causes an overload on the Riverside-10th Street 69-kV line. In 2012, a loss of the Gila Bend-TS8 230-kV line causes the flows on the Mittry-Quechan 69-kV line and Yucca-Laguna tap 69-kV line to overload.

C. Yuma Area - SIL for 2005, 2008 and 2012

With planned system additions for the Yuma area, along with some accelerated projects (see Table 2), the SIL for the Yuma area will increase each study period. For 2005, 2008, and 2012 the SIL will be 265 MW, 292 MW and 410 MW, respectively. Results of these studies are shown in Figures 8 through 10.

Figure 8

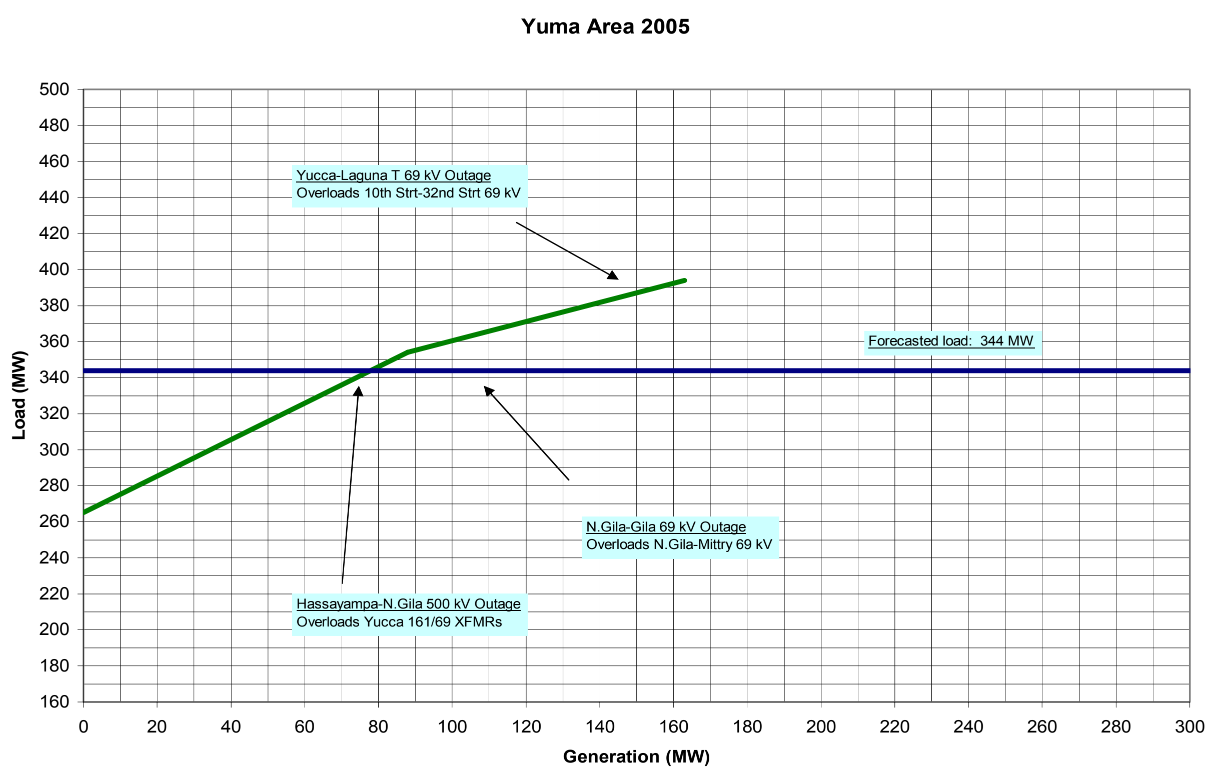


Figure 9

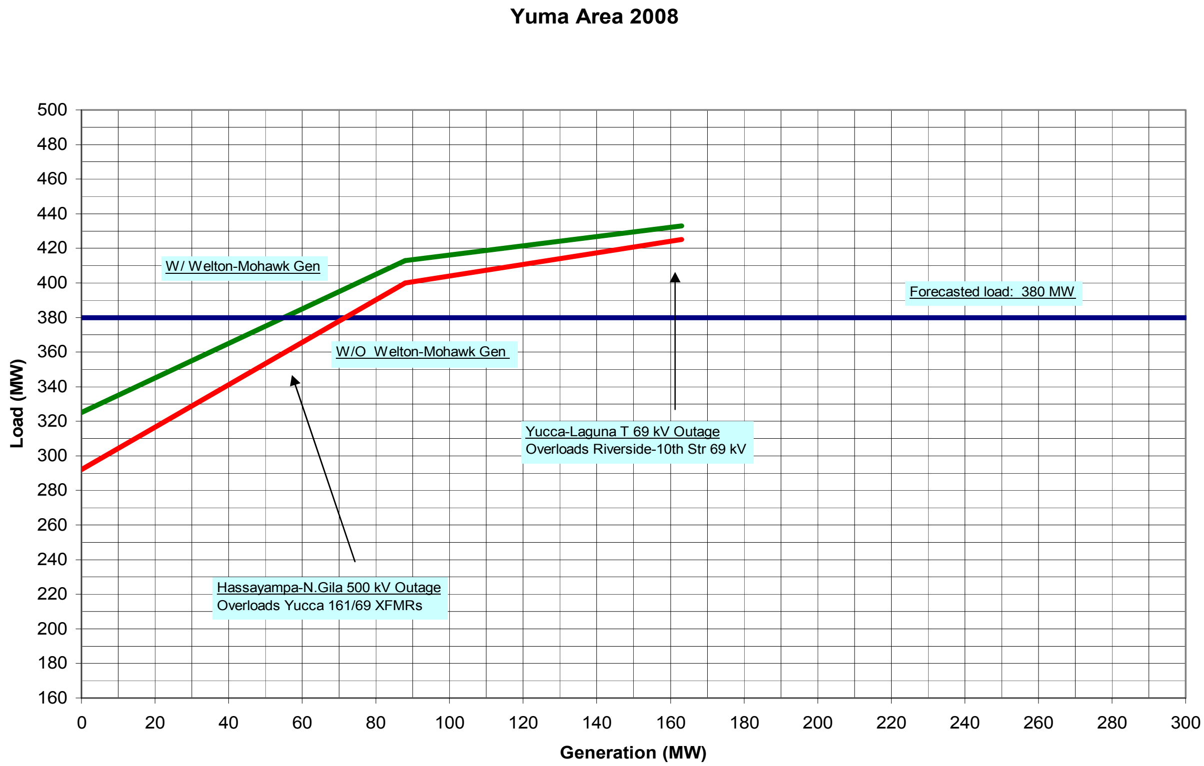
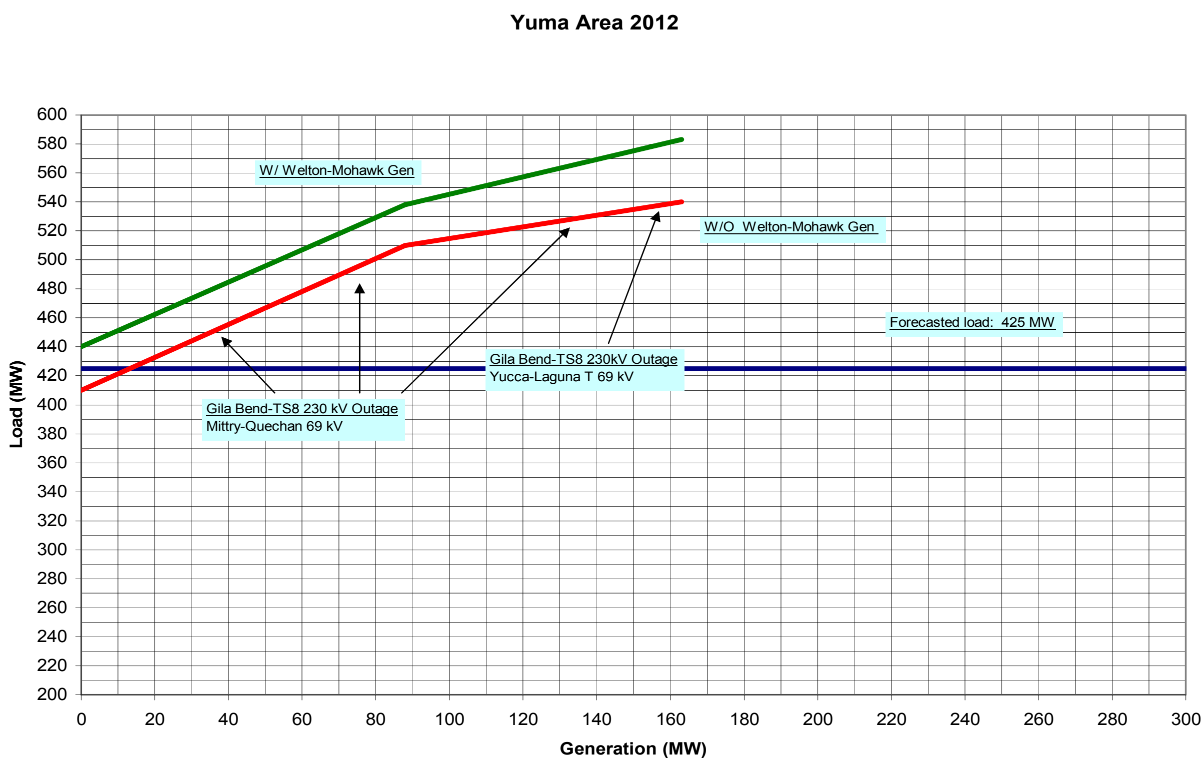


Figure 10



Also, the load listed along the vertical axis is the sum of the entire load within the Yuma area. In performing this analysis, all planned projects were included in the model as well as some new projects. Also, several planned shunt capacitor banks were accelerated and several new banks were added to maximize the capability of the transmission system by ensuring that the area was not severely voltage limited. These projects are listed in Table 4.

Table 5
Yuma Projects

Study Case	Case Description	
	System	Projects Added
2005 base case	Existing	Foothills 69-kV, 32Mvar cap banks (advanced from 2006) Gila cap bank (new) Laguna cap bank (planned 2005) 2nd N.Gila 500/69-kV transformer (planned 2005)
2008 base case	2005 base case	32nd Street-10th Street 69-kV reconductor (new) N.Gila-Mittry 69-kV reconductor (new) 32nd Street-Ivalon 69-kV reconductor (planned 2006)
2012 base case	2008 base case	Gila Bend-TS8 230-kV line (planned 2012) TS8 cap banks (planned 2012)

D. Generation Sensitivities

Welton-Mohawk is a planned generating facility located east of Yuma that is scheduled for commercial operation during 2006. The net capacity of this planned facility is 310 MW. Figures 9 and 10 show import limits for the Yuma area for 2008 and 2012 with and without the Welton Mohawk plant modeled. For each of these years the case with Welton-Mohawk includes the generation modeled at full output. From Figure 10 it is seen that Yuma area import increases approximately 10 MW for each 100 MW of Welton-Mohawk generation. However, the effect of the Welton-Mohawk on Yuma import capability is somewhat less in the 2008 timeframe, as seen in Figure 9. The remaining generation in the Yuma area is located at or near the Yucca power plant and has equal impact on the import limit into the Yuma area.

V. ANALYSIS OF RMR CONDITIONS

A. Phoenix Area

1. Annual RMR Conditions

An RMR condition exists when the local load is greater than the SIL. In such cases, the RMR condition is the amount of generation that must be located inside of the constrained load area to meet the utility's peak load. RMR conditions for the Phoenix area are shown in Table 5 and are represented in the load-duration curves in Figures 9, 10, and 11.

Table 6

Phoenix RMR Conditions Without Valley Generation

(MW)

	PHOENIX		
	2005	2008	2012
Peak Load	11,141	12,425	14,406
Generation	-	-	-
Reserves	-	-	-
Net Valley Generation	-	-	-
Import Capability	8,617	10,511	11,103
Net Gen + Import	8,617	10,511	11,103
Must-Run Generation	2,524	1,914	3,303
Hours Load Exceeds Gen + Imp	678	338	758
Energy - GWH	550	222	805
Energy Percent of Valley Load	1.2%	0.4%	1.3%

Figure 11

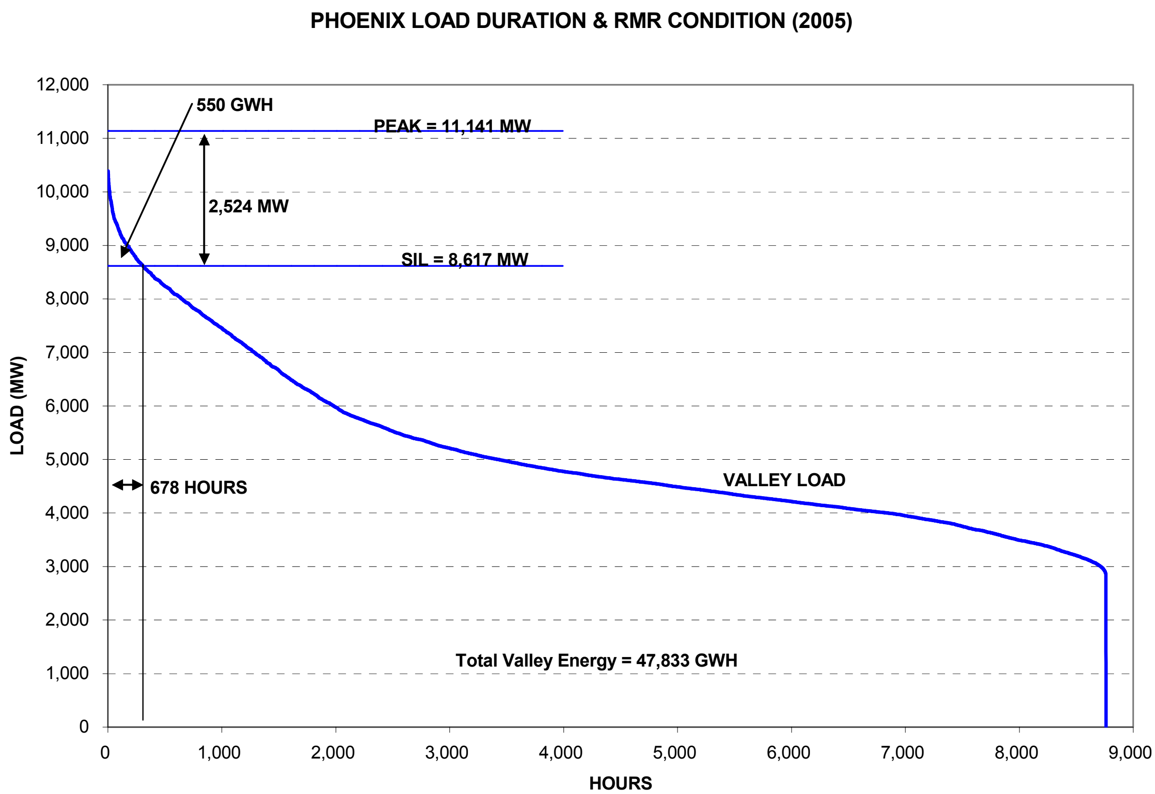


Figure 12

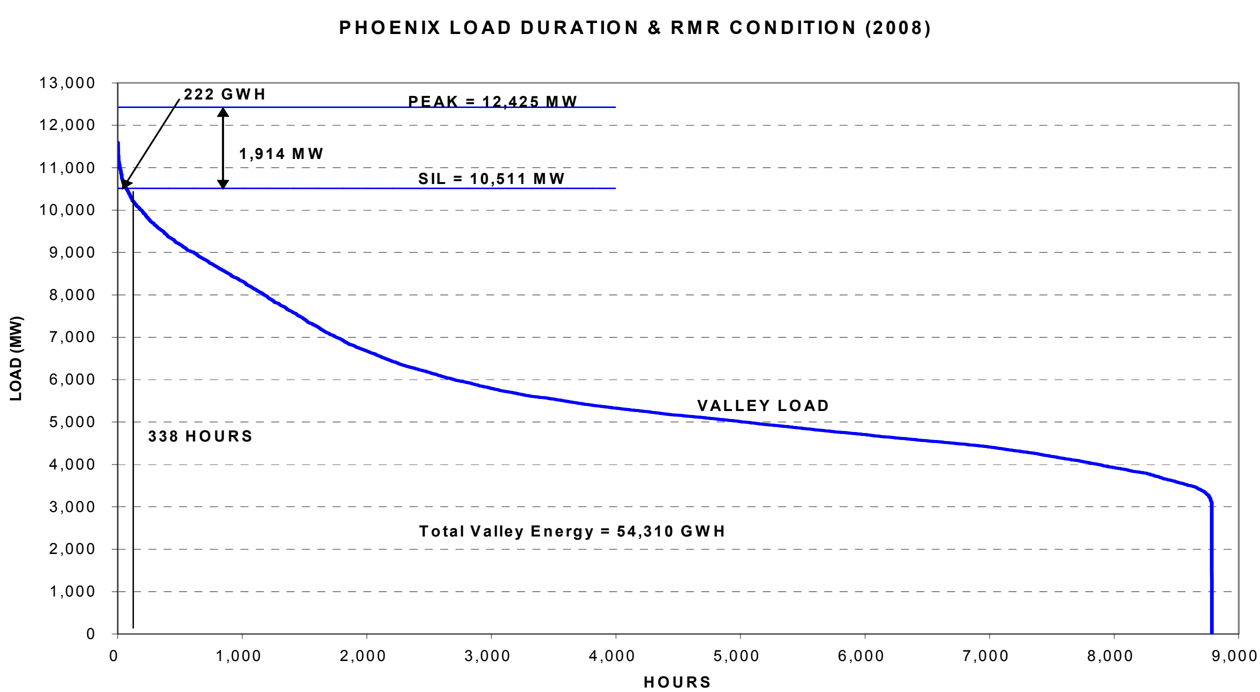


Figure 13

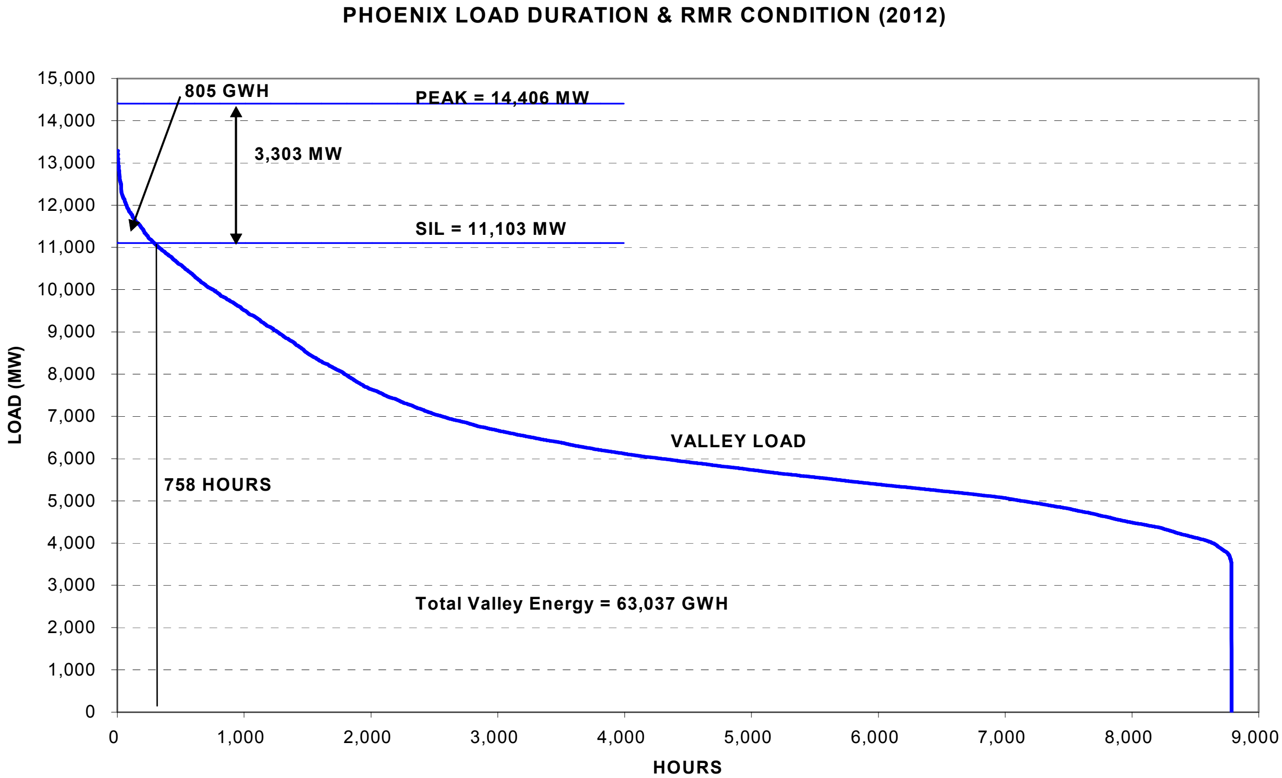


Table 5 shows that Phoenix is expected to require from 2,524 MW to 3,303 MW of local generation resources over and above its import capability to meet peak load. These resources can be located inside the Phoenix area constraint. For Phoenix, generation is estimated to be in a must-run condition for between 678 to 758 hours per year. However, because RMR occurs only at peak, the amount of associated energy is only approximately one percent of the total Phoenix area energy requirements, as shown in Figures 9, 10, and 11 above.

2. Maximum Load Serving Capability (MLSC)

MLSC is the maximum load that can be reliably served in the load pocket. It is the import capability plus the generation capability located inside the load pocket, minus a reserve margin allowance for generation reliability. Based on the load forecast and SIL presented in this analysis, and existing and planned local generation, the following MLSCs for Phoenix were developed. The approach used also shows how much generation or transmission may be needed to reliably meet load.

These results along with the generation and transmission assumptions are depicted in Table 6. As shown on this table, additional resources are not required in years 2005 and 2008, but in 2012, 519 MW of either additional transmission import capability or local generation is necessary to serve the Phoenix area load reliably. However, the energy associated with this capacity need is very small — 6 GWH.

Table 7

Phoenix Area Maximum Load Serving Capability
(MW)

	PHOENIX		
	2005	2008	2012
Peak Load	11,141	12,425	14,406
Valley Generation	3,374	3,649	3,649
Required Reserves	(809)	(865)	(865)
Net Valley Generation	2,565	2,784	2,784
SIL	8,617	10,511	11,103
MLSC	11,182	13,295	13,887
Projected Reserves	850	1735	346
Hours Load Exceeds MLSC	-	-	26
Energy - GWH	-	-	6
Energy Percent of Valley Load	0.0%	0.0%	0.0%

3. Area Load Forecast

The actual peak load within the Phoenix area constraint is shown in Table 7 for 1999-2003, along with projected peak load for 2005, 2008 and 2012. Projected peak load is based on the same assumptions embodied in APS' total system load forecast used for budgeting and planning. This peak load is the load measured just inside the defined Phoenix area constraint. The peak load is net of EHV transmission losses of about 3.8 percent.

Table 8

Phoenix and Yuma Load and Energy Forecast
(MW / GWH)

	HISTORICAL					FORECAST		
	1999	2000	2001	2002	2003	2005	2008	2012
PHOENIX								
LOAD	7,854	8,688	9,179	9,290	9,663	11,141	12,425	14,406
ENERGY	35,232	38,711	39,654	40,426	42,140	47,833	54,310	63,037
Load Factor	51.2%	50.7%	49.3%	49.7%	49.8%	49.0%	49.8%	49.8%
APS YUMA								
LOAD	270	273	296	292	321	344	380	425
ENERGY	1,197	1,262	1,330	1,332	1,394	1,517	1,663	1,869
Load Factor	50.6%	52.6%	51.2%	52.0%	49.6%	50.4%	49.8%	50.0%

The Phoenix area has historically had about a 50 percent load factor. Phoenix area APS load forecasts were developed by estimating a multiple regression model using historic hourly load data, weather, and number of retail customers. These historic relationships (correlations) were used against the metro area customer forecast, and a forecast of Phoenix weather to produce the APS Phoenix area load. The same process was followed to develop the hourly forecast load for SRP. The SRP forecast was then added to the APS forecast to obtain a total valley load forecast.

4. Generation

There are currently three owners of generation electrically located inside the Phoenix area — APS with 660 MW, SRP with 1,523 MW, and PWEC with 641 MW. Load serving entities (i.e., APS and SRP) own a combined total of 2,183 MW of local generation that is currently in service. Table 8 shows operational data associated with each unit.

Table 9

PHOENIX AREA GENERATION

OWNER	PLANT	TYPE	SUMMER CAPABILITY	MINIMUM LOAD	MINIMUM UP TIME	MINIMUM DOWN TIME	FOR	EFOR	FUEL TYPE
APS	Ocotillo 1	ST	110	30	8	8	4%	6%	NG
APS	Ocotillo 2	ST	110	30	8	8	4%	6%	NG
APS	Ocotillo GT1	GT	50	4	1	8	10%	12%	NG
APS	Ocotillo GT2	GT	50	4	1	8	10%	12%	NG
APS	West Phoenix GT1	GT	50	4	1	8	10%	12%	NG
APS	West Phoenix GT2	GT	50	4	1	8	10%	12%	NG
APS	West Phoenix CC1	CC	80	30	3	8	3.5%	7%	NG
APS	West Phoenix CC2	CC	80	30	3	8	3.5%	7%	NG
APS	West Phoenix CC3	CC	80	30	3	8	3.5%	7%	NG
PWEC	West Phoenix CC4	CC	112	84	6	4	4%	4%	NG
PWEC	West Phoenix CC5	CC	529	178	4	4	8%	8%	NG
SRP	Agua Fria 1	ST	113	57	8	8	4%	6%	NG
SRP	Agua Fria 2	ST	113	57	8	8	4%	6%	NG
SRP	Agua Fria 3	ST	181	92	8	8	4%	6%	NG
SRP	Agua Fria 4	GT	73	35	1	8	10%	12%	NG
SRP	Agua Fria 5	GT	73	32	1	8	10%	12%	NG
SRP	Agua Fria 6	GT	73	32	1	8	10%	12%	NG
SRP	Crosscut HY1	HY	3	N/A	N/A	N/A	0%	0%	WAT
SRP	Kyrene 1	ST	34	14	8	8	4%	6%	NG
SRP	Kyrene 2	ST	72	29	8	8	4%	6%	NG
SRP	Kyrene GT4	GT	59	25	1	8	10%	12%	NG
SRP	Kyrene GT5	GT	53	24	1	8	10%	12%	NG
SRP	Kyrene GT6	GT	53	24	1	8	10%	12%	NG
SRP	Kyrene CC1	CC	250	161	4	4	8%	8%	NG
SRP	Santan 1	CC	92	35	3	8	3.5%	7%	NG
SRP	Santan 2	CC	92	35	3	8	3.5%	7%	NG

SRP	**Santan 3**	**CC**	**92**	**36**	**3**	**8**	**3.5%**	**7%**	**NG**
SRP	**Santan 4**	**CC**	**92**	**35**	**3**	**8**	**3.5%**	**7%**	**NG**
SRP2	**Santan 5**	**CC**	**550**	**330**	**4**	**4**	**8%**	**8%**	**NG**
SRP2	**Santan 6**	**CC**	**275**	**165**	**6**	**4**	**8%**	**8%**	**NG**
SRP	**South Consolidated 1**	**HY**	**1**						**WAT**
SRP	**Transport GT1**	**GT**	**4**						**NG**
PHOENIX TOTAL			**3,649**						

NOTES:
1) Based on WECC data as of 1/1/2003
2) Santan expansion assumes an in-service date of 5/2005 (ST5) & 5/2006 (ST6)

APS owns West Phoenix CC 1-2-3, West Phoenix CT 1-2, Ocotillo ST 1-2, and Ocotillo CT 1-2. These units collectively have a 660 MW summer rating. These units have historically operated at capacity factors in the 3-30 percent range, and are expected to operate at lower capacity factors for the next few years as new high-efficiency plants come on line in Arizona and the Southwest.

SRP owns the Agua Fria, Kyrene and Santan generating stations inside the Phoenix area, totaling 1,523 MW of generation. These units were mostly built in the late 1950s to the mid-1970s. The new Kyrene CC unit went into service in 2002. SRP plans to construct another 825 MW of combined-cycle generation at the Santan plant. For this study, it is assumed the new Santan units will go into service in 2005 (Santan 5) and 2006 (Santan 6).

PWEC has constructed West Phoenix CC 4 (112 MW), which went into service in June 2001, and the West Phoenix CC 5 (529 MW) unit, which came on-line in July 2003. These units improve reliability to the Phoenix area.

5. Reserves

Reliability within a load pocket such as Phoenix must be evaluated differently than for an unconstrained system. For example, although a 15 percent reserve margin or a largest hazard margin may be adequate for unconstrained total system loads, it does not provide adequate reliability to load pockets that cannot access all reserves present in the WECC interconnected system. APS performs an analysis that considers the size, forced outage rate, and effective forced outage rate of each unit in the load pocket to determine the probability that enough generation will be available when needed. The required reserve values used for this study were based on a 99% probability that all load can be served.

This analysis results in a reserve requirement in 2005 of 809 MW for Phoenix generating units. Specifically, the reserve analysis considers 2,565 MW of local generation as effectively firm (i.e., 3,374 MW minus 809 MW). The reserve requirement will change as resources are installed and/or retired. The reserve requirement is 865 MW once the Santan unit 6 is in-service.

The reserve values are used in calculating the load serving capability for the Phoenix load area. In addition, the loads used in this analysis are based on Phoenix experiencing average weather. If the Phoenix area has a hot summer, the load would be higher than projected, and the gas turbine and combined-cycle units' output would be reduced due to the hotter weather.

B. Yuma Area

1. Annual RMR Conditions

RMR conditions for the Yuma constrained area are shown in Table 9 and pictorially represented in a load-duration curve in Figures 12, 13, and 14. Table 9 shows that APS requires 88 MW (2008) of resources over and above its transmission import capability to meet peak load in Yuma. These resources can be APS-owned generation or non-APS owned generation located inside the constrained area. APS is in a must-run condition for between 714 to 12 hours per year in Yuma and the amount of associated energy is approximately 1.0 percent of APS' total Yuma energy requirement.

Table 10

Yuma RMR Conditions Without Generation
(MW)

	YUMA		
	2005	2008	2012
Peak Load	344	380	425
Generation	-	-	-
Reserves	-	-	-
Net Generation	-	-	-
Import Capability	265	292	410
Net Gen + Import	265	292	410
Must-Run Generation	79	88	15
Hours Load Exceeds Gen + Imp	714	676	12
Energy - GWH	20	21	0
Energy Percent of Yuma Load	1.3%	1.2%	0.0%

Figure 14

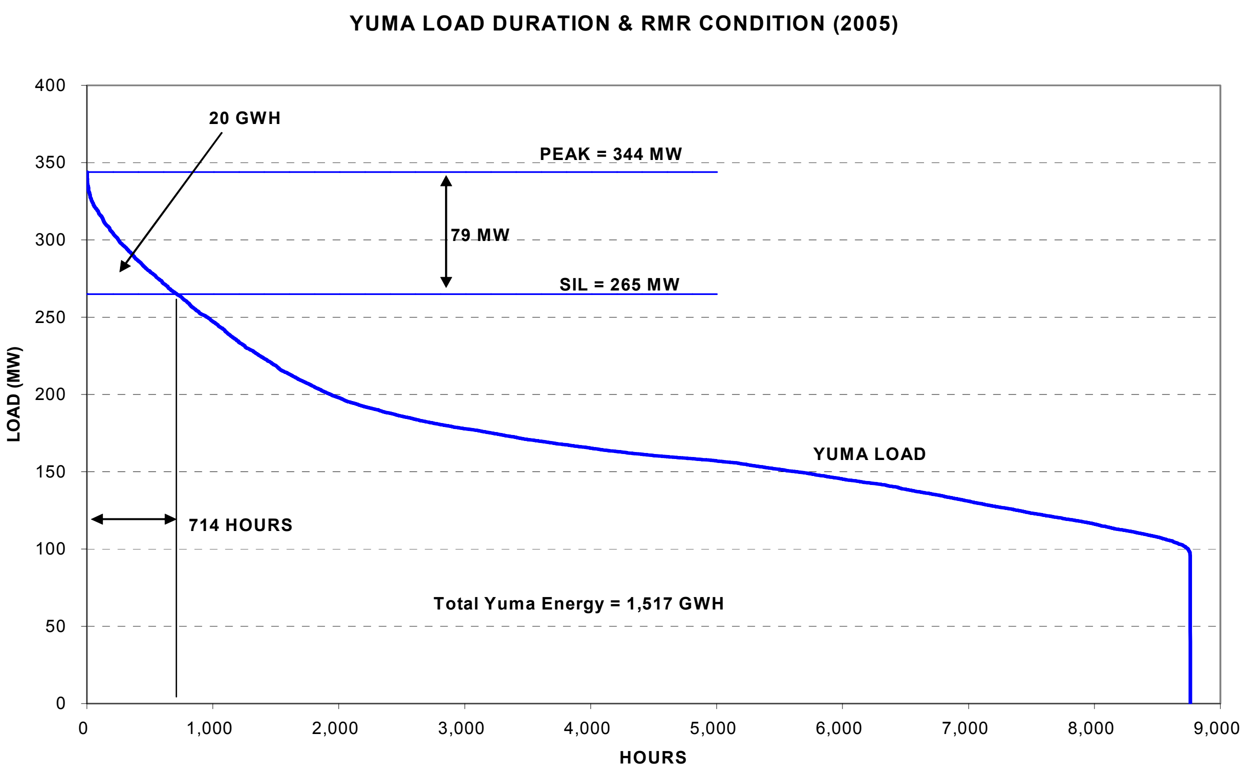


Figure 15

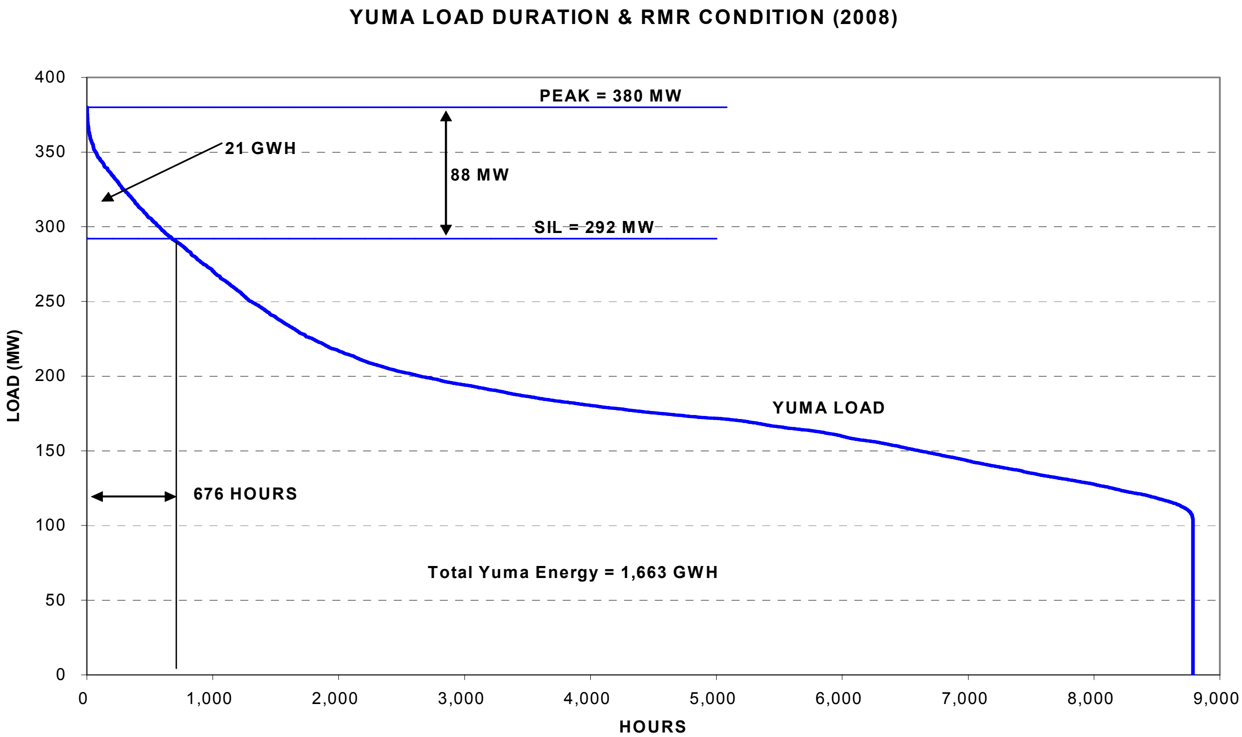
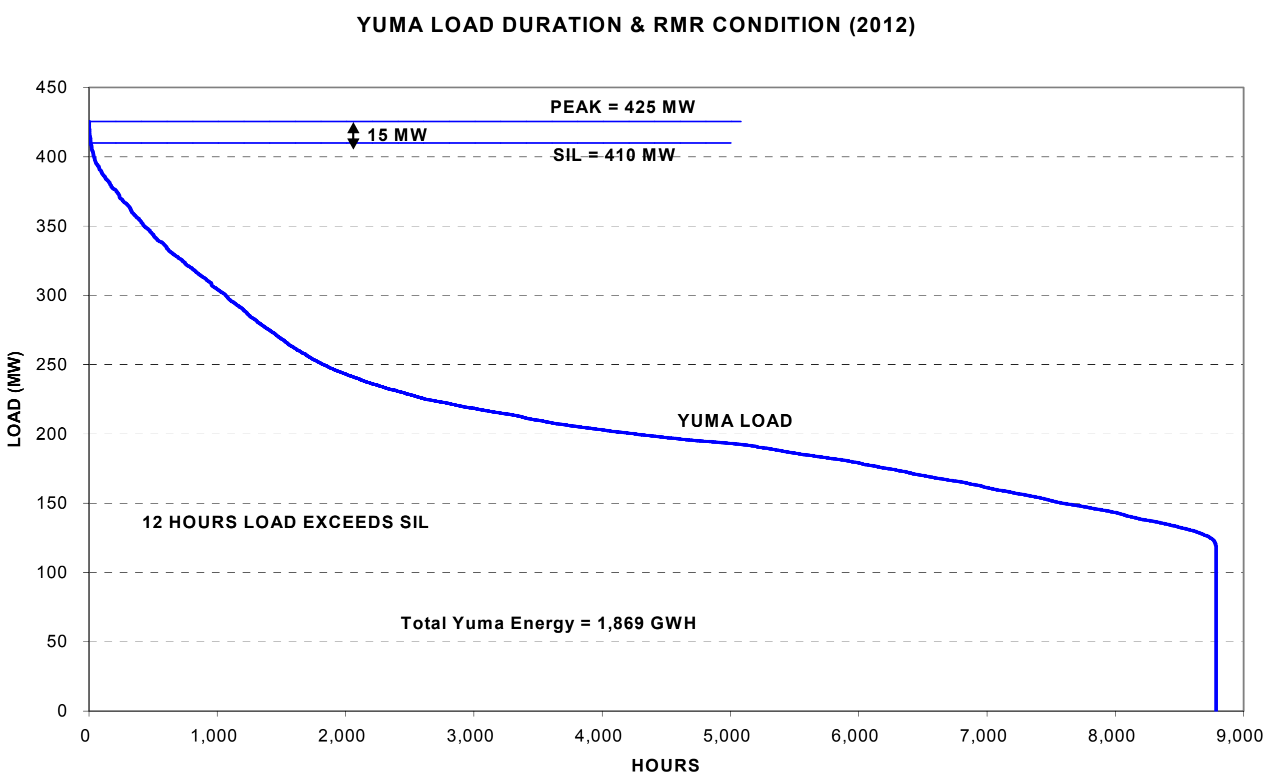


Figure 16



2. Maximum Load Serving Capability (MLSC)

Based on the load forecast and SIL presented in this report, and the 267 MW of local generation, the following MLSCs were developed. This approach also shows how much generation or transmission may be needed to reliably meet load. As shown in Table 10, from 2005 to 2012 APS could serve 394 to 539 MW of load without additional resources. With a load forecast of between 344 MW to 425 MW, this resource need can be met from non-APS owned generation (Yucca steam and YCA units) within the load pocket. Also, when the Yucca steam and YCA units are running, APS' requirement for generation inside the load pocket is reduced on a one-for-one basis.

Table 11

Yuma Area Maximum Load Serving Capability
(MW)

	YUMA		
	2005	2008	2012
Peak Load	344	380	425
Local Generation	267	267	267
Required Reserves	(138)	(138)	(138)
Net Local Generation	129	129	129
SIL	265	292	410
MLSC	394	421	539
Projected Reserves	188	179	252
Hours Load Exceeds MLSC	-	-	-
Energy - GWH	-	-	-
Energy Percent of Yuma Load	0.0%	0.0%	0.0%

3. Area Load Forecast

Table 7 shows APS' Yuma peak load for 1999-2003, and projected peak for 2005, 2008 and 20012. Projected peak is based on the same assumptions used in APS' total system load forecast used for budgeting and planning. This peak is the load measured just inside the Yuma area. It is net of EHV transmission losses of about 3.8 percent. Yuma load represents approximately 5 percent of APS' total system load. Yuma has historically had a slightly higher load factor than that of the Phoenix area — 52 percent compared to 50 percent. Yuma area APS load forecasts were developed by estimating a multiple regression model using historic hourly load data, weather, and number of retail customers. These historic relationships (correlations) were used against the Yuma area customer forecast, and a forecast of Yuma weather to produce the Yuma area load.

4. Generation

APS, IID and YCA own generation inside the Yuma load pocket. These plants have a summer capacity rating of 267 MW. Five of the six units run on natural gas while the other plant (Yucca CT 4) runs on oil. Additional power plant data for this generation is provided in Table 11. Of these plants, only the combustion turbines are owned by APS.

Although operated by APS, IID dispatches its steam plant to meet its load and spinning reserve needs. YCA is a cogeneration plant that has a contract with San Diego Gas & Electric (SDG&E). Although APS has no dispatch rights to these units, whenever the units are running they provide internal generation in the Yuma area for purposes of using the import nomogram.

Table 12

YUMA AREA GENERATION

OPERATOR	PLANT	TYPE	SUMMER CAPABILITY[1]	MINIMUM LOAD	MINIMUM UP TIME	MINIMUM DOWN TIME	FOR	EFOR	FUEL TYPE
APS	Yucca GT1	GT	18	2	1	2	10%	10%	NG
APS	Yucca GT2	GT	18	2	1	2	10%	10%	NG
APS	Yucca GT3	GT	52	5	1	2	10%	10%	NG
APS	Yucca GT4	GT	51	5	1	2	10%	10%	FO2
APS SUBTOTAL			139						
IID	Yuma Axis 1	ST	75	18	8	8	4%	6%	NG
YCA	Yuma Cogen 1	CC	36	14	N/A	N/A	3.5%	7%	NG
YCA	Yuma Cogen 2	CC	17	7	N/A	N/A	3.5%	7%	NG
YCA SUBTOTAL			53						
YUMA TOTAL			267						

NOTES: 1) Based on WECC data as of 1/1/2003

5. Reserves

Using a probabilistic generation analysis, the reserve margin for Yuma was calculated to be 138 MW.

VI. ECONOMIC ANALYSIS OF RMR

A. Introduction

To consider potential economic effects resulting from using local generation or arising from RMR conditions, an economic analysis was performed using a regional dispatch model. For this economic analysis, the production cost of meeting Phoenix loads was determined with the existing transmission import limitations in place. Next, a second hypothetical case was built in which the transmission import limits were removed. Comparing the two cases shows the economic costs of the transmission constraint.

These two cases were simulated with GE MAPS and their outputs were compared to determine the cost of transmission constraints. GE MAPS is a detailed regional production-costing model that includes the generation and transmission system of the entire WECC. In its dispatch, the model meets a company's load requirements by generating from the company's own units or buying available more economic generation from the market. The GE MAPS model also shows sales of economic generation to other utilities in the region subject to regional transmission constraints.

Much of the data used in modeling comes from public sources, however some of GE MAPS assumptions have been developed by APS. The GE MAPS database on existing generation was initially developed by several utilities in the West in the early 1990s to evaluate the economics of interregional transmission projects. It has been enhanced by the WECC in the mid-1990s and, like many other users of the model, APS continues to enhanced it to reflect system improvements and resources. This model includes all new generation expected to be built in the West, including the plants under construction or in operation near Hassayampa.

The transmission modeling in GE MAPS are based on the WECC's bulk power flow cases, and was updated to reflect expected system enhancements for 2005, 2008, and 2012. Transmission modeling of Yuma was enhanced by APS to accurately model the transmission constraints in that load pocket, based on APS' operational experience. The transmission model is an electrical flow model as opposed to a transport model. That means that transmission flows are subject to physical electrical constraints as well as scheduling constraints. Electrical constraints of the system are based on the WECC's path rating catalog, with additional local constraints such as the Phoenix import constraints. A description of GE MAPS (Appendix B) as well as some of its output is provided in Appendices C and D to this report.

The following items were quantified based on the GE MAPS simulations:

- Number of hours per year the Phoenix and Yuma area transmission system is expected to be constrained by the import limits;
- Phoenix and Yuma generation capacity factors;
- Cost to serve the Phoenix system, including fuel, variable O&M, purchase power cost and wholesale interchange sales margins; and
- Phoenix and Yuma generation emissions.

West Phoenix CC 4 and 5 and Santan CC 5 and 6 were included in the simulation. West Phoenix units were not assumed to be under the dispatch control of APS, though they may be selling to APS as may any of the other new generators. When the new West Phoenix combined cycles are operating, whether or not they are selling to APS or SRP, they mitigate must-run conditions in the Phoenix area because the plants are electrically located inside the Phoenix area constraint. Thus, if these units are scheduled outside the Phoenix area, a like-amount of power can be counter-scheduled back into the Phoenix area without affecting the transmission import limits. Due to the high efficiency of new combined cycle units, it is anticipated that older existing generation within the Phoenix area will operate less than it has historically. This older existing generation, however, remains particularly valuable as inexpensive capacity reserves.

B. Phoenix

1. Phoenix Imports

Table 12 shows that under economic dispatch conditions for Phoenix area generation, Phoenix approached its transmission import limits less than 0.5% of the hours in a year.

Table 13

IMPACT OF ELIMINATING PHOENIX IMPORT LIMITS

	With Import Limits			Without Import Limits			Difference (With minus Without)		
	2005	2008	2012	2005	2008	2012	2005	2008	2012
Hours Limiting	18	0	14	0	0	0	18	0	14
Phx Plant Generation (GWH)	3,330	4,808	8,164	3,323	4,808	8,163	6	0	1
Phx Plant Capacity Factor	11.3%	15.0%	25.5%	11.3%	15.0%	25.5%	0.0%	0.0%	0.0%
Cost of Constraints ($M)							0.0	0.0	0.1

2. Operation of Phoenix area Generating Units

Historically the Phoenix area's combined-cycle power plant capacity factors have ranged from 10 to 46 percent, with an average of about 24 percent. Capacity factors for steam-fired plants ranged from 6 to 42 percent, averaging about 15 percent. Capacity factors for simple-cycle combustion turbines ranged 0 to 22 percent, averaging about 4 percent. Historical capacity factors are shown in the Table 13 by plant type for the period 1993 to 2002.

Operation of these units in 1999-2002 was higher than the historical average because the Western Interconnection and the Phoenix area both experienced high price volatility, high load growth, and few new generation resources had been added since the 1980s. With new higher-efficiency power plants coming on line, as well as the presence of the new Palo Verde-Rudd 500 kV transmission line, the older Phoenix area units are expected to run at lower capacity factors. As noted above, however, these units remain critical to maintaining Phoenix area reliability.

Even if the Phoenix area transmission import limits were totally eliminated, these older units would still be needed to economically meet summer peak loads. Elimination of the constraints has a minor impact on the capacity factors of all Phoenix area plants. Removing the transmission constraint reduces local generation by less than 6 GWH per year. Table 12 summarizes the results of the simulation analysis.

Table 14

PHOENIX AREA POWER PLANT HISTORICAL CAPACITY FACTOR (%)

	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002
TOTAL PHOENIX										
STEAM	6.6	6.3	6.5	6.7	7.1	10.0	21.2	26.5	42.0	14.2
COMBINED CYCLE	16.5	19.3	17.2	12.9	10.6	17.0	27.7	36.3	46.0	34.3
COMBUSTION TURBINE	0.6	0.9	0.4	0.5	1.0	1.8	2.6	5.8	21.9	4.2

3. *Cost Impacts*

An estimate of the cost of the transmission import constraints can be determined by comparing the system cost to serve Phoenix customers with and without constraints. Costs included in the analysis are fuel, variable O&M, purchased power and wholesale sale margin credits. The results of this analysis showed no measurable savings. See Table 12.

4. *Emissions Impact*

In addition to economic modeling, the GE MAPS analysis evaluated the change in plant air emissions that would result from removing the transmission constraint. Specifically, the emission impact to the Phoenix area from removing transmission constraints and "moving" generation outside the Phoenix area was calculated. Four criteria pollutants are routinely tracked for power plants: NO_X, CO, VOCs and PM_{10}. Maricopa County is a non-attainment area for CO and PM_{10}. NO_X and VOCs are precursors for ozone and therefore are included.

The emissions impact from power plant emissions in the Phoenix area was estimated by using the average emission rates of APS Phoenix area units along with the modeled change in energy production. Emissions were also estimated for the other non-APS Phoenix area units. Changes in emissions resulting from entirely eliminating the transmission import constraint into Phoenix are shown in Table 14. For comparison purposes, total emissions in Maricopa County were estimated by Maricopa County Environmental Services Department for 1999. Their emissions estimates include all stationary point sources, area sources, non-road mobile sources and on-road mobile and biogenic sources. To put the results into perspective, changes in Phoenix area power plant emissions are shown as a percentage of total Maricopa County emissions.

Table 15
Phoenix Area Air Emissions Reduction

Pollutant	Reduction[1] (tons/year)	Reduction of Phoenix Area Emissions (% of total emissions from all sources)
VOC	0.0	0.000
NO_x	4.0	0.007
CO	1.0	0.000
PM_{10}	0.0	0.000[2]

[1]2005 results, impact for 2008 and 2012 is negligible

[2]Reduction % is based on 1994 actual emissions.

Table 15 shows APS and Phoenix area emissions by type.

Table 16

PHOENIX POWER PLANT EMISSIONS (TONS)

	With Import Limits			Without Import Limits			Difference (With minus Without)		
	2005	2008	2012	2005	2008	2012	2005	2008	2012
NOx	245	339	698	241	339	696	4	0	2
CO	68	101	187	67	101	186	1	0	1
PM_{10}	85	124	214	85	124	214	0	0	0
VOC	31	45	79	31	45	79	0	0	0

C. Yuma

1. Yuma Imports

Transmission imports to the Yuma load pocket are provided in Appendix D. Unlike the Phoenix area, these imports do approach their limits at various times throughout the year. These plots are included in Appendix D for the cases in which the limits were removed.

Table 16 shows that APS could approach its import limits for 336 hours per year. The energy associated with these hours amounts to 8 GWH. During these hours, it would have been more economical to import cheaper power either generated on APS own units outside the Yuma area or purchased from the wholesale market if the import limits were increased.

Table 17

IMPACT OF ELIMINATING YUMA IMPORT LIMITS

	With Import Limits			Without Import Limits			Difference (With minus Without)		
	2005	2008	2012	2005	2008	2012	2005	2008	2012
Hours Limiting	336	2	0	0	0	0	336	2	0
Yuma Generation (GWH)									
APS	8	0	0	0	0	0	8	0	0
Yuma	30	25	23	22	25	23	8	0	0
Yuma Plant Capacity Factor									
APS	0.6%	0.0%	0.1%	0.0%	0.0%	0.1%	0.6%	0.0%	0.0%
Yuma	1.6%	1.3%	1.2%	1.2%	1.3%	1.2%	0.4%	0.0%	0.0%
Cost of Constraints ($M)									
APS							1	0	0

2. Operation of Yuma Units

Historically, the Yucca CTs have operated at capacity factors of between 0.5 up to 18 percent, as shown in Table 17. On average they are in the 1 to 2 percent range.

Table 18

YUMA POWER PLANTS HISTORICAL CAPACITY FACTOR (%)										
	1993	**1994**	**1995**	**1996**	**1997**	**1998**	**1999**	**2000**	**2001**	**2002**
YUCCA										
CT1	0.3	0.6	0.4	0.4	1.1	1.5	1.4	5.0	23.4	4.0
CT2	0.4	0.4	0.5	0.4	1.2	1.5	1.4	6.9	21.8	4.6
CT3	1.5	1.4	1.0	1.4	2.8	3.6	3.5	12.2	22.0	14.4
CT4	0.0	0.2	0.0	0.2	0.2	0.7	0.3	4.8	11.9	0.3
Total Yucca	0.7	0.7	0.5	0.7	1.4	2.0	1.8	7.9	18.4	6.6
YUMA AXIS	18.4	15.9	15.3	33.3	45.2	45.4	53.7	41.3	53.0	48.0
TOTAL YUMA	6.7	5.9	5.5	11.7	16.2	16.7	19.3	19.2	30.1	20.6

3. Cost Impacts

The GE MAPS analysis indicates that the Yuma import limit will be constraining from 336 hours in 2005 and zero hours in 2012. The cost of this constraint in 2005 is $1 million. See Table 16.

4. Emission Impacts

The emission impact on the Yuma area due to a potential relieving of transmission constraints and "moving" generation outside of the Yuma area was determined by GE MAPS similarly to the Phoenix analysis. Unlike Phoenix, however, Yuma County is a non-attainment area for PM_{10} only. Impacts on power plant emissions in Yuma were estimated by using average emission rates of APS units along with the change in energy production. Emissions were also estimated for the other non-APS units. By entirely eliminating the import limits into Yuma, emissions produced by power plants located inside the Yuma load pocket would change as shown in Table 18.

Table 19
YUMA POWER PLANT EMISSIONS (TONS)
(Includes Yucca 1-4 and Yuma Axis)

	With Import Limits			Without Import Limits			Difference (With minus Without)		
	2005	**2008**	**2012**	**2005**	**2008**	**2012**	**2005**	**2008**	**2012**
NOx	37	19	19	17	19	19	20	0	0
CO	10	5	5	5	5	5	5	0	0
PM_{10}	2	2	2	1	2	2	1	0	0
VOC	2	0	0	0	0	0	1	0	0

VII. Conclusions

Phoenix area Conclusions

1. All Phoenix area transmission and local generation are necessary to reliably serve Phoenix area peak load in 2005 with the local generation reserve margin just exceeding the required reserve margin. In 2008, the local generation reserve margin significantly exceeds the required reserve margin. However, in 2012 the reserve margin is 346 MW which is 519 MW less than the required reserve margin of 865 MW. To mitigate this deficiency APS and SRP are presently evaluating both transmission alternatives to increase import capability and alternatives to increase Phoenix area generation.

2. During the summer, Phoenix area load is expected to exceed the available transmission import capability for approximately 680 hours in 2005, 340 hours in 2008, and 760 hours in 2012. These hours represent only approximately one percent of the annual energy requirements for the Phoenix area.

3. From a total Phoenix load, transmission, and resources viewpoint, import limits are expected to cause a minimal amount of local generation to be dispatched out of economic dispatch order in 2005 and 2012, and no impact in 2008.

4. The estimated annual economic cost of Phoenix area RMR generation is negligible, therefore advancement of transmission projects to increase import capability are presently not cost justified.

5. Removing the transmission constraint could reduce total Phoenix area air emissions by the following annual amount for 2005. There is a minimal impact for years 2008 and 2012 due to the increased import capabilities and resources resulting in fewer hours of operating local generation.

Table C1
Phoenix area Air Emissions Reduction

Pollutant	Reduction[1] (tons/year)	Reduction of Phoenix Area Emissions (% of total emissions from all sources)
VOC	0.0	0.000
NO_x	4.0	0.007
CO	1.0	0.000
PM_{10}	0.0	0.000

[1]2005 results, impact for 2008 and 2012 is negligible

6. Removing the import restriction into the Phoenix area has no impact on local generation capacity factor. The capacity factor ranges from approximately 11% in 2005 to 26% in 2012.

Yuma Area Conclusions

7. All existing Yuma area transmission and generation resources are necessary to reliably serve the Yuma area load.

8. The Yuma area load is expected to exceed the available transmission import capability for 714 hours in 2005, 676 hours in 2008 and 12 hours in 2012 although the amount of total load in the Yuma area is approximately 350-425 MW.

9. From a total Yuma load, transmission, and resources viewpoint, the import constraint could cause APS Yuma generation to be dispatched out of economic dispatch order for 336 hours in 2005, 2 hours in 2008, and 0 hours in 2012.

10. The estimated annual economic cost of Yuma area generation required to run out of economic dispatch order is relatively small, therefore advancement of transmission projects to increase import capability are presently not cost justified.

11. Removing the transmission constraint could reduce total Yuma area air emissions by the following annual amount for 2005. There is a minimal impact for years 2008 and 2012 due to the increased import capabilities resulting in fewer hours of operating local generation.

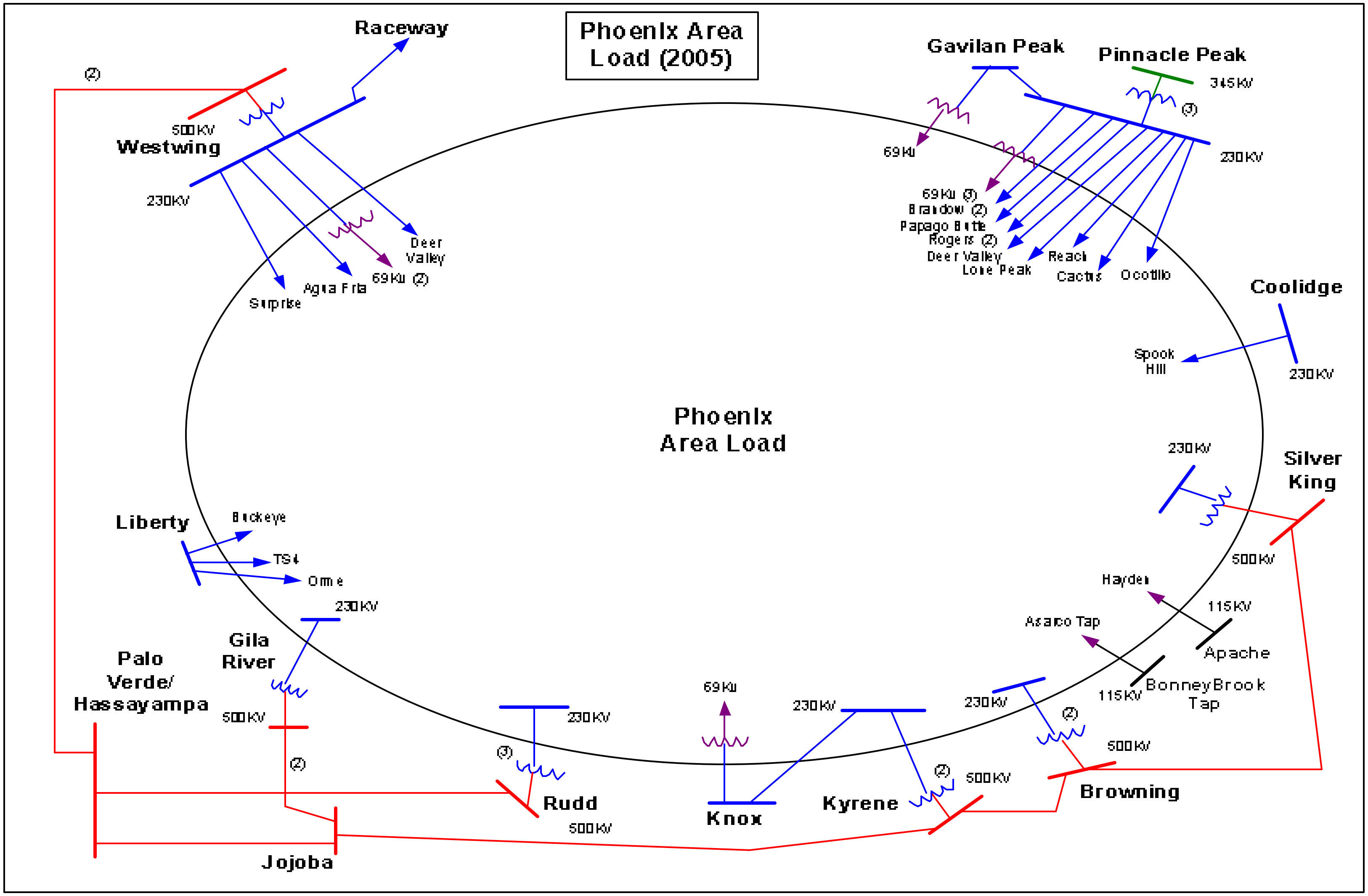
Table C2
Yuma Area Air Emissions Reduction

Pollutant	Reduction[1] (tons/year)	Reduction of Yuma Area Emissions (% of total emissions from all sources)
VOC	1.0	Unavailable
NO_x	20	Unavailable
CO	5	Unavailable
PM_{10}	1.0	0.001

[1]2005 results, impact for 2008 and 2012 is negligible

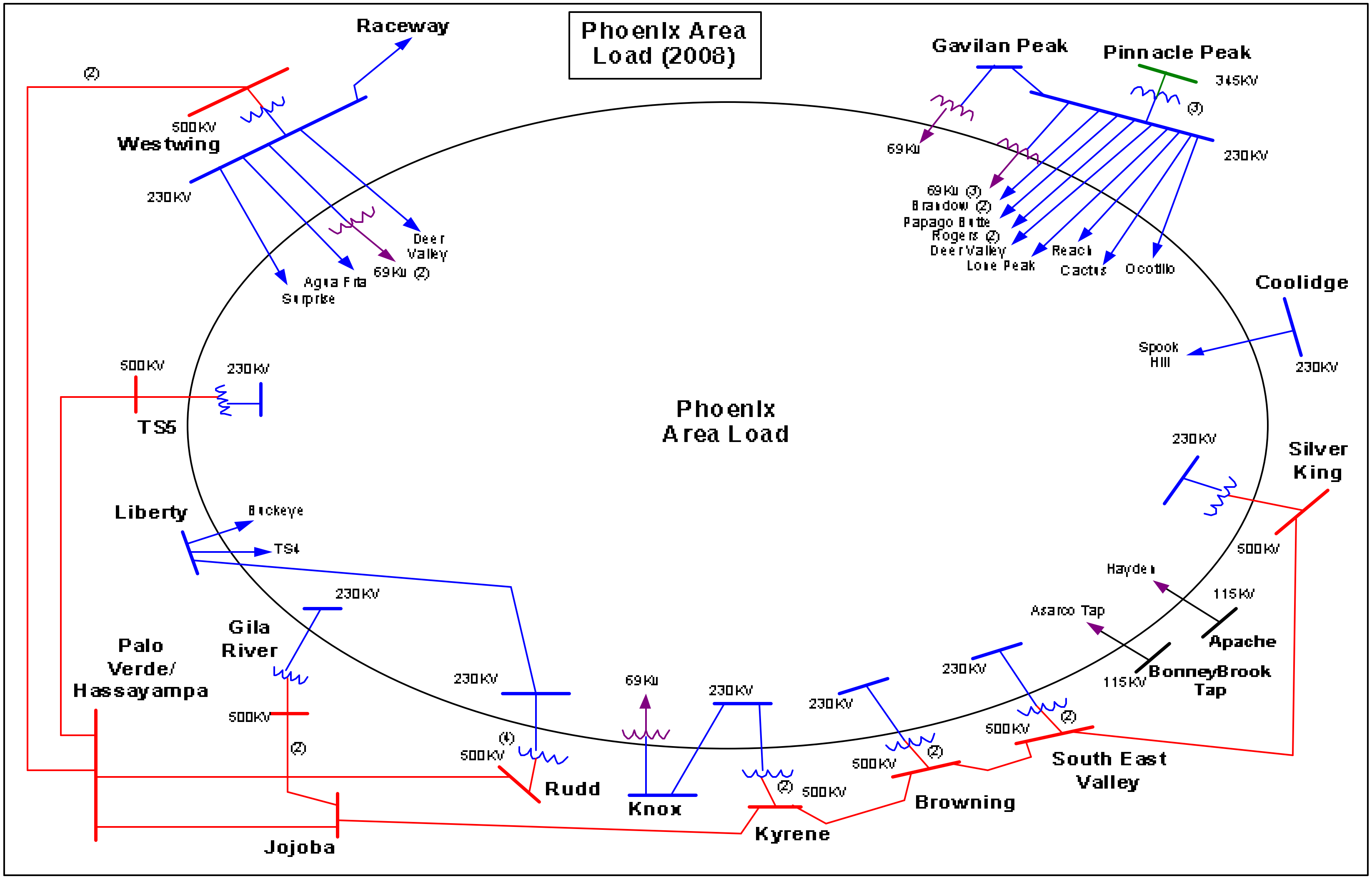
12. Removing the import restriction into the Yuma area could reduce the APS Yuma generation capacity factor from 1.6 percent to 1.2 percent in 2005.

Figure 1



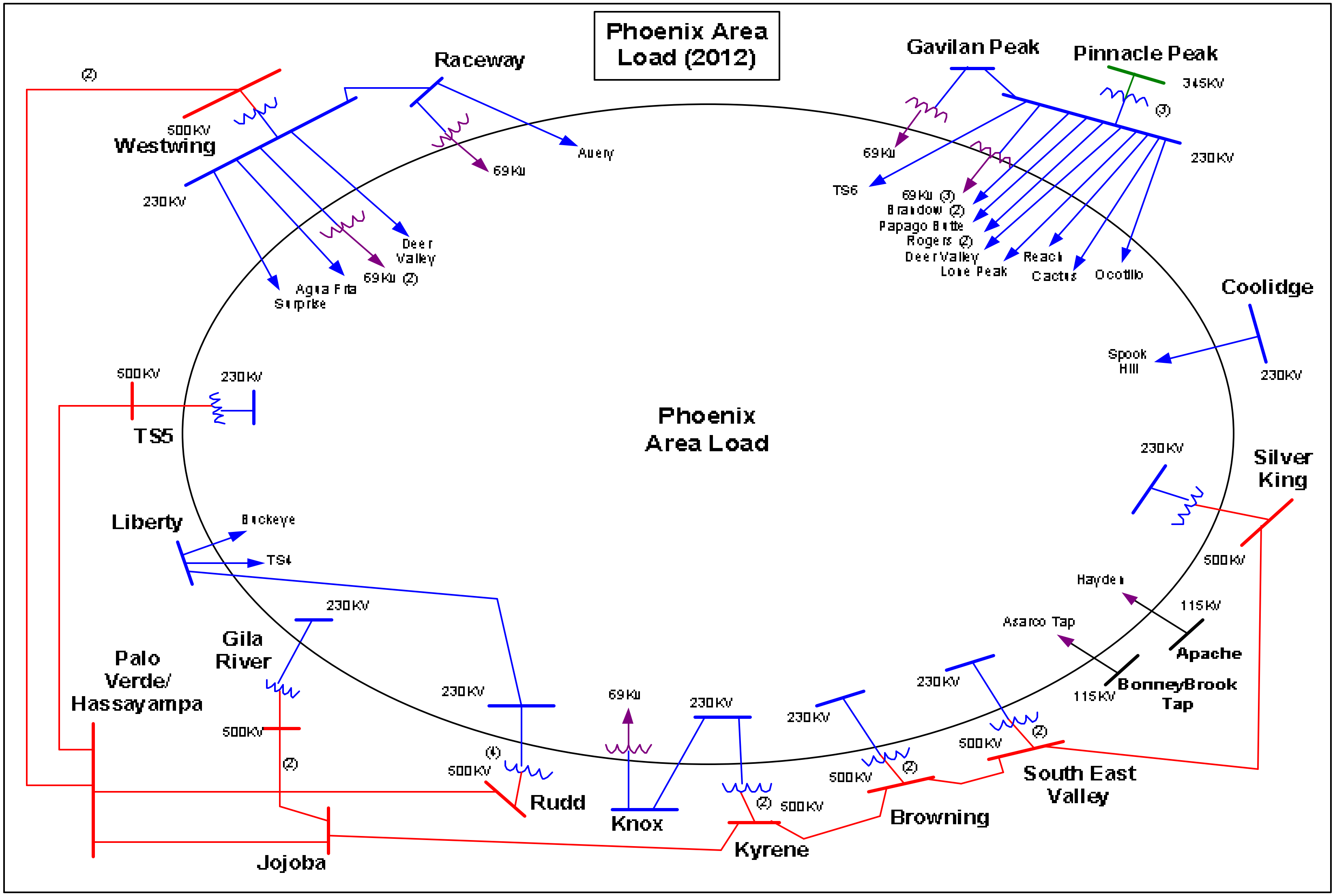
Phoenix Area Load (2005)
Phoenix Area Load
Raceway
Westwing
500KV
230KV
Deer Valley
69Kv (2)
Agua Fria
Surprise
(2)
Gavilan Peak
Pinnacle Peak
345KV
230KV
69Kv
69Kv (3)
Brandow (2)
Papago Butte
Rogers (2)
Deer Valley
Lone Peak
Reach
Cactus
Ocotillo
Coolidge
Spook Hill
Silver King
Liberty
Buckeye
TS4
Orme
Gila River
Palo Verde/ Hassayampa
Rudd
Knox
Kyrene
Browning
Jojoba
Apache
Bonney Brook Tap
Hayden
Asarco Tap
115KV

Figure 2



Phoenix Area Load (2008)
Raceway
Westwing
500 KV
230 KV
Deer Valley
69 Kv (2)
Agua Fria
Surprise
Gavilan Peak
Pinnacle Peak
345KV
(3)
230 KV
69 Kv
69 Kv (3)
Brandow (2)
Papago Butte
Rogers (2)
Deer Valley
Lone Peak
Reach
Cactus
Ocotillo
Coolidge
Spook Hill
230 KV
Phoenix Area Load
TS5
500 KV
230 KV
Liberty
Buckeye
TS4
Silver King
230 KV
500 KV
Hayden
115 KV
Apache
Asarco Tap
BonneyBrook Tap
115 KV
Gila River
230 KV
500KV
(2)
Palo Verde/ Hassayampa
Rudd
230 KV
500 KV
(4)
Knox
69 Kv
230 KV
Kyrene
500 KV
(2)
Browning
230 KV
500 KV
(2)
South East Valley
230 KV
500 KV
(2)
Jojoba

Figure 3


Phoenix Area Load (2012)
Phoenix Area Load
Westwing
500KV
230KV
Raceway
69Kv
Avery
Deer Valley
69Kv (2)
Agua Fria
Surprise
Gavilan Peak
Pinnacle Peak
345KV
(3)
230KV
69Kv
TS6
69Kv (3)
Brandow (2)
Papago Butte
Rogers (2)
Deer Valley
Lone Peak
Reach
Cactus
Ocotillo
Coolidge
Spook Hill
230KV
TS5
500KV
230KV
Silver King
230KV
500KV
Liberty
Buckeye
TS4
Hayden
115KV
Apache
Asarco Tap
BonneyBrook Tap
115KV
Gila River
230KV
500KV
(2)
Palo Verde/ Hassayampa
230KV
(4)
500KV
Rudd
69Kv
Knox
230KV
(2)
500KV
Kyrene
230KV
500KV
(2)
Browning
230KV
500KV
(2)
South East Valley
Jojoba