Seventh Biennial Transmission Assessment (2012-2021) Staff Report

Docket No. E-00000D-11-0017.

Appendices

October 30, 2012

Appendices

A. Guiding Principles for Determination of System Adequacy and Reliability[67]

This document serves the dual purpose of providing the guiding principles for acc Staff determination of electric system adequacy and reliability in the two areas of transmission and generation.

Transmission

A.R.S §40-360.02E obligates the Arizona Corporation Commission (ACC) to biennially make a determination of the adequacy and reliability of existing and planned transmission facilities in the state of Arizona. Current state statutes and ACC rules do not establish the basis upon which such a determination is to be made. Therefore, ACC Staff will use the following guiding principles to make the required adequacy and reliability determination until otherwise directed by state statutes or ACC rules.

1. Transmission facilities will be evaluated using Western Systems Coordinating Council (WECC), or its successor's, Reliability Criteria for System Planning and Minimum Operating Reliability Criteria.
2. Transmission planning and operating practices traditionally utilized by Arizona electric utilities will apply when more restrictive than WECC criteria.
3. Compliance with A.C.C. R14-2-1609.B[68] will be established by analysis of power flow and transient stability simulation of single contingency outages (n-1) of generating units, EHV and local transmission lines of greater than 100 kV

[67] Guiding Principles for acc Staff Determination of Electric System Adequacy and Reliability: Arizona's Best Engineering Practices, Jerry D. Smith, acc, pre-filed comments for the Gila Bend Power Plant Hearing, Docket No. E-00000V-00-0106, November 9, 2000.

[68] R14-2-1609.B refers to the obligation of Utility Distribution Companies to assure that adequate transmission import capability and distribution system capacity are available to meet the load requirements of all distribution customers within their service area.

nominal system voltage, and associated transformers. Relying on remedial actions such as generator unit tripping or load shedding for single contingency outages will not be considered an acceptable means of complying with this rule.

Generation

Pursuant to A.R.S. §40-360.07, the ACC must balance, in the broad public interest, the need for adequate, economical, and reliable supply of electric power with the desire to minimize the effect on the environment and ecology of the state when considering the siting of a power plant or transmission line. The laws of physics dictate that generation and transmission facilities are inextricably linked when considering the reliability of service to consumers. Therefore, it is appropriate that both components must be considered when siting a power plant. ACC Staff will use the following guiding principles to make the required adequacy and reliability determination for siting generation until otherwise directed by state statutes or ACC rules.

The best utility practices historically exhibited in the evolution of Arizona's generation and transmission facilities should be continued in order to promote development of a robust energy market. Non-discriminatory access to transmission and fair and equitable business practices must also be maintained and the service reliability to which the state is accustomed must not be compromised. Therefore, Staff support of power plant Certificate of Environmental Compatibility applications will be conditioned as set forth below.

ACC Staff support of power plant Certificate of Environmental Compatibility applications will be contingent upon the applicant providing, either in the application or at the hearing, evidence of items 1-3 below:

1. Two or more transmission lines must emanate from each power plant switchyard and interconnect with the existing transmission system. This plant interconnection must satisfy the single contingency outage criteria (n-1) without reliance on remedial action such as generator unit tripping or load shedding.

2. A power plant applicant must provide technical study evidence that sufficient transmission capacity exists to accommodate the plant and that it will not compromise the reliable operation of the interconnected transmission system.
3. All plants located inside a transmission import limited zone “must offer” all Electric Service Providers and Affected Utilities serving load in the constrained load zone, or their designated Scheduling Coordinators, sufficient energy to meet load requirements in excess of the transmission import limit.

ACC Staff support of power plant Certificate of Environmental Compatibility applications will further be contingent upon the Certificate of Environmental Compatibility being conditioned as provided in items 4-6 below:

4. The Certificate of Environmental Compatibility is conditioned upon the plant applicant submitting to the ACC an interconnection agreement with the transmission provider with whom they are interconnecting.
5. The Certificate of Environmental Compatibility is conditioned upon the plant applicant becoming a member of WECC, or its successor, and filing a copy of its WECC Reliability Criteria Agreement or Reliability Management System (“RMS”) Generator Agreement with the ACC.
6. The Certificate of Environmental Compatibility is conditioned upon the plant applicant becoming a member of the Southwest Reserve Sharing Group, or its successor, thereby making its units available for reserve sharing purposes.

Approved by:

(Original Signed by Deborah R. Scott)

Deborah R. Scott
Director
Utilities Division

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B. History of Commission Ordered Studies

Local Area Transmission Import Study Requirements

In the First BTA, Staff identified five load pockets in Arizona that should be monitored for transmission import constraints: Phoenix, Tucson, Yuma, Mohave County and Santa Cruz County. The 2002 BTA added a sixth area located in Southeastern Arizona (Cochise County). The Cochise County area was added to the Commission's areas of concern due to a major blackout of the area in 2001. The 2004 BTA added Pinal County as a local area that needed to be monitored as well. Inclusion of Pinal County was prompted by the necessity of transmission providers to implement a remedial action scheme ("RAS") or special protection scheme ("SPS") for single contingencies with operation of the new Desert Basin and Sundance power plants and additional gas turbines at Saguaro Power Plant.

Cochise County and Santa Cruz County are served by radial transmission lines that result in interruption of service to significant numbers of customers for the outage of any one of the radial transmission lines serving these two counties. A study of the Cochise County Area was documented in the Second BTA. At that time no Commission action was deemed necessary because local transmission switching capability was sufficient to minimize the outage time for customers. The Fourth BTA granted Southwest Transmission Cooperative ("SWTC") a time extension until January 2008 to resolve n-1 contingency violations for loss of the Apache to Butterfield or the Butterfield to San Rafael 230 kV line in its 2015 planning study and to file expansion plans to resolve those issues as part of its 2008-2017 ten year plan. During the Fifth BTA the Commission proposed replacing the restoration of service paradigm with a "continuity of service" paradigm intended to automatically restore customer loads within seconds or minutes of any n-1 transmission outage. The Commission ordered the respective utilities (e.g., the Cochise County Study Group) to identify a system expansion plan that could accomplish this objective, which was reviewed as part of the Sixth BTA.

Santa Cruz County is served by a single transmission line. The customer service and system impacts and risks associated with the loss of a single 115 kV line serving Santa Cruz County are well chronicled over prior BTA assessments and siting of the Gateway 345 kV transmission project.[69] UNS Electric analyzed transmission needs in Santa Cruz County in 2009 to develop transmission plans that address the recommendations in the Fifth BTA related to continuity of service. A Santa Cruz County Continuity of Service Summary Report and Reference Filing was made by UNS Electric in February, 2010.

Reliability Must-Run Study Requirements

Previous BTAs also identified several of the local load pockets in Arizona where the load cannot be served using a normal economic merit order generation dispatch due to transmission limitations. During some portions of the year, generation units within the load pocket must be operated out of merit order to serve a portion of the local load. Such a resource requirement is often referred to as Reliability-Must-Run ("RMR") generation. The RMR power generated from local generation may be more expensive than the power from outside resources; and may be environmentally less desirable. During RMR conditions, transmission providers must dispatch RMR generation to relieve the congestion on transmission lines.

The Commission's generic electric restructuring docket established that existing Arizona transmission constraints would limit APS' and TEP's ability to deliver competitively procured power to less than the required 50% of Standard Offer Service's load.[70] The Commission stayed this requirement in its Track B proceedings. However, each Utility Distribution Company ("UDC") is still obligated to assure that adequate transmission import capability is available to meet the load requirements of all distribution customers within its service area.[71] Known transmission constraints result in APS and TEP being dependent upon local RMR generation to serve their peak load during certain hours of the year.

In order to provide the Arizona load pockets access to potentially less costly power, the ACC Track A Decision No. 65154 ordered the Arizona utilities to work with Staff to develop a plan to

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69 ACC Decision #64356.

70 Direct Testimony of Jerry D. Smith and rebuttal testimony of Cary Deise, Docket No. E-00000A-02-0051.

71 A.A.C. R14-2-1609.B.

resolve RMR concerns, and include the results of such a plan in the 2004 BTA. The same Decision ordered APS and TEP to file annual RMR study reports with the Commission in concert with their January 31 ten-year plan, for review prior to implementing any new RMR generation strategies, until the 2004 BTA is issued. The utilities readily responded and began providing RMR studies in 2003.

The Third BTA Decision No. 65476 approved a collaborative RMR study plan agreed to by all Arizona transmission providers.[72] The 2003 RMR study forum included only the transmission providers. In contrast, since 2004 the RMR process has been open to all interested parties through Arizona's subregional study forums. The Fourth BTA required that "RMR studies continue to be performed and filed with ten year plans in even numbered years for inclusion in future BTA reports and that:

- Future RMR studies provide more transparent information on input data and economic dispatch assumptions, and
- Arizona utilities collaborate with the Staff to develop and effectively implement more stringent criteria as appropriate for RMR areas in the 2006 BTA."

The simultaneous import limit ("SIL") and maximum load serving capability ("MLSC") of each of the Arizona load pockets is generally established in conjunction with RMR studies. The Commission approved SIL and MLSC definitions and methodology for performing RMR studies is documented in Appendix C. Arizona's subregional planning forums have also been performing a tenth year snapshot study of the state's transmission system. Those studies have traditionally considered N-0 and N-1 contingencies and provide additional information regarding the transmission capability of each local load pocket.

Ten-Year Snapshot ("n-1-1") Study Requirements

The Ten Year Snapshot (previously called n-1-1) study has been included in the set of Commission ordered studies since the 2nd BTA. The objective of the study is to analyze how the

72 Appendix C.

participants' ten year plans perform as whole in a regional environment and the effect of omitting an individual planned transmission project from the plan. It assesses the performance of the Arizona system in the 10th year of the ten year planning period covered by the BTA and examines system performance for all bulk power single contingency (n-1) outage events in the study area, together with the removal of major planned transmission projects from the expansion plan, removed one at a time ("n-1-1"). It thus provides a "snapshot" of projected system performance in the final year of the BTA ten year planning period, even if any one of the planned major transmission projects is delayed. The study has traditionally been performed by the CATS-EHV Subcommittee of SWAT. As of 2009 and the Sixth BTA, the study was aptly renamed the "Ten-Year Snapshot Study".

The study has historically focused on the central Arizona region (an area bounded by the Phoenix Metropolitan area to the north, the Tucson Metropolitan area to the south, the Palo Verde Generating Station to the west and the Arizona/New Mexico border to the east). However, beginning in 2009, SWAT expanded the assessment into a statewide review of n-1-1 impacts.

Extreme Contingency Study Requirements

Staff's concerns regarding the adequacy and reliability of the Arizona electric system began in 2000 with the rapid development of new generation projects interconnecting with the Palo Verde Nuclear Generating Station. These projects all proposed to interconnect at the new Hassayampa 500 kV switchyard but were not increasing the capacity of the existing transmission lines already connected to the Palo Verde marketing hub. Large quantities of generation capacity and energy were at risk of being interrupted or curtailed for single contingency outages or credible outages of multiple lines. In addition the generation projects were being developed solely for merchant's commercial interest without obligations to assure existing generation reserves were sufficient to cover the outage risks the projects posed.

Therefore the Utilities Division of the Commission developed "Guiding Principles for Determination of System Adequacy and Reliability"[73] for Staff's use in power plant and

[73] Appendix A.

transmission line siting cases. The Commission endorsed this document via its Decision No. 65476 for the Second BTA. Then Condition No. 23 of the CEC was placed on APS and SRP in the Palo Verde to Rudd 500 kV siting case to formally require a study be performed to properly address the risks associated with interconnection developments at the Palo Verde Hub resulting in the Third BTA the adoption of the Palo Verde Hub interconnection criteria,

> "Require all future interconnections proposed at the Palo Verde Hub, either new generation or new transmission lines, must perform a risk assessment of the Hub to ascertain to what degree the proposed project mitigates the pre-existing risks to extreme outage events. This assessment must precede a project's application for a CEC with the Commission. The recommendations of the Palo Verde Risk Assessment report should be followed if a proposed project would otherwise exacerbate the existing risk at the Hub." [74]

Since the initiation of the Commission's first BTA process Arizona has experienced several fire seasons with exposure to loss of multiple lines in a common corridor on forested lands. These events heightened the Commission's awareness of the state's vulnerability to loss of transmission lines in common corridors. These events were then upstaged by the major 500/230 kV transformer and 230/69 kV fires that occurred at Westwing and Deer Valley in 2004 and the Westwing 500/345 kV transformer fire in 2006. Therefore the third BTA required that the fourth BTA address and document extreme contingency outages studied for Arizona's major generation hubs and major transmission stations including identification of associated risks and consequences if mitigating infrastructure improvements were not planned. This extreme contingency study requirement was reinforced further when the Commission ordered the same requirement for the fifth BTA.

Renewable Energy Transmission Assessment Requirement

In the Fourth BTA, the Commission ordered a Renewable Energy Assessment stating specifically, "in the next BTA, Commission regulated electric utilities, in consultation with the

[74] ACC Decision No. 67457, December 14, 2004, page 4, section 7.e.

stakeholders, should prepare an assessment of ATC for renewable energy and prepare a plan, including a description of the location, amount and transmission needs of renewable resources in Arizona, to bring available renewable resources to load."[75] This study requirement is focused on exploring transmission delivery obstacles for renewable resources that may choose to develop within the state, and was intended to assure that Arizona utilities can successfully comply with the renewable portfolio standards adopted by the Commission in 2006.

In the Fifth BTA, the Commission significantly expanded the scope of Arizona Renewable Transmission assessment activities and filing requirements, including determination of an initial set of Renewable Transmission Projects ("RTPs") as described in detail in Section 3.0 of the Sixth BTA Staff report. While a separate docket was opened for this activity, discussion regarding the filings in that docket were included in the workshops for the Sixth BTA and Seventh BTA.

The Commission's decision in the Sixth BTA (2010)[76] addressed the ability of the Arizona transmission system to export renewable energy to neighboring states by directing the jurisdictional utilities to jointly conduct or procure a study to identify the barriers to and solutions for enhancing Arizona's ability to export renewable energy. The study was to identify specific transmission corridors that should be built to accomplish this objective. The utilities were also to conduct stakeholder workshops in conjunction with the study.

The study and results were filed as required at the Commission by November 1, 2011, and included as part of the scope of the Staff's assessment performed in the Seventh BTA proceeding.[77]

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75 ACC Decision No. 69389, March 22, 2007, page 8.

76 Commission Decision No. 72031, 10 December 2010.

77 *Enhancing Arizona's Ability to Export Renewable Energy, A Report to Address the Arizona Corporation Commission's Sixth Biennial Transmission Assessment, Commission Decision 72031*, PDS Consulting, PLC, October 2011 (http://images.edocket.azcc.gov/docketpdf/0000130865.pdf).

C. RMR Conditions and Study Methodology

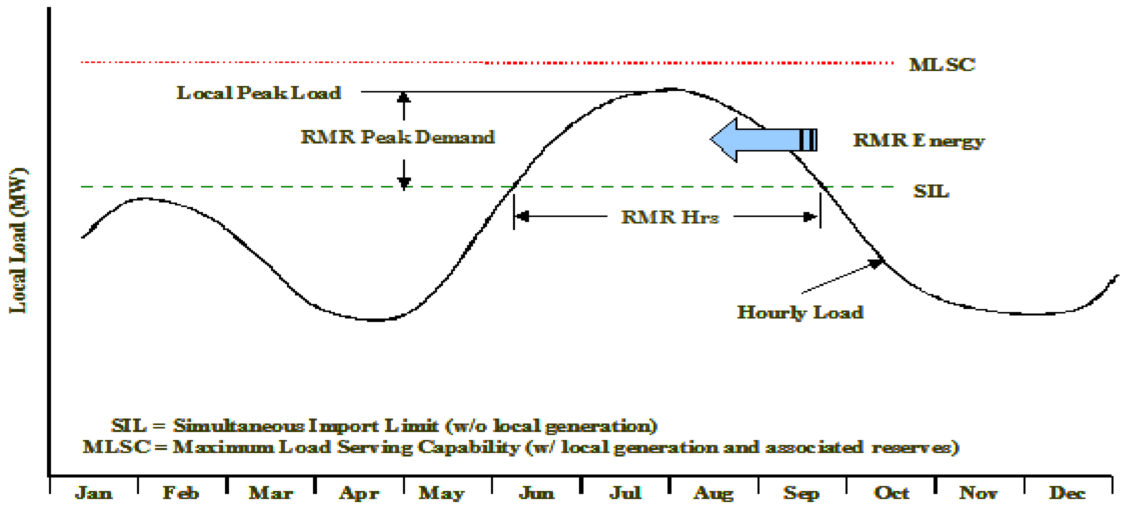
In the 2002 BTA, Staff proposed that any UDC currently relying on local generation, or foreseeing a future time period when utilization of local generation may be required to assure reliable service for a local area, should perform and report the findings of an RMR study as a feature of their Ten-Year Plan filing with the Commission in January, 2003 and 2004. The 2002 BTA defined a Generic RMR Study Plan that required utilities to:

1. Define annual simultaneous import limits (SIL) for each transmission import limited area.
2. Provide a listing of all local generation and associated operational attributes.
3. Define RMR conditions for each year of the Ten-Year Plan.
4. Provide a local generation sensitivity analysis.
5. Identify and study alternative solutions.
6. Perform comparative analysis and present worth analysis of alternative solutions.

RMR conditions, required from RMR studies, are defined in the 2002 BTA and graphically presented in the following Figure C-1.[78]

[78] 2002 BTA, Page 74-76.

Figure C-13 – RMR Conditions



Essential RMR indicators that the Commission intends to receive from the RMR studies are:

- RMR hours - The number of hours during which the local load is above the SIL
- RMR energy - The amount of energy served from RMR generation
- RMR peak demand - The maximum RMR amount of capacity that the RMR generators would be required to produce
- RMR costs - The costs of out-of-merit-order dispatch from RMR

The 2002 BTA established specific RMR procedures. The transmission system's simultaneous import limit (SIL) for each local constrained area is established for single contingencies (n-1) with no local generation in operation. An RMR condition exists during those times when the local load served by a UDC, or group of UDCs, exceeds that SIL. If no local generation exists for an RMR condition then the UDC(s) would have to utilize a load-shedding scheme for those contingencies that establish the SIL. This would imply a violation of WECC planning criteria since reliability practices are founded on the principle of continuity of service for single contingency outages.

When local generating units within the local load pocket are owned or under the operational control of the UDC(s), they are viewed as RMR units for the duration of the RMR condition. A local generating unit that is neither owned or under operational control of the UDC(s) may be considered a non-RMR unit. In some instances, a non-RMR unit may have a "must-offer" requirement to assure that system reliability is maintained. A local non-RMR unit that is operational during the hours an RMR condition exists will have the automatic effect of mitigating the constraint to the extent it serves local load or its capacity and energy is scheduled out of the local load pocket.

Local generation, irrespective of its composition of RMR and non-RMR units, may offer an acceptable planning solution to RMR conditions. The local RMR condition is essentially mitigated when local generation capacity and its associated voltage regulation ability is equal to or greater than that required to reliably serve the local RMR peak load. The question that needs to be answered is whether such dependence on local generation is prudent and in the consumers' best interest.

The maximum load serving capability (MLSC) of the local system is established by operating all local units at capacity, less local reserve requirements. The local MLSC equals to the SIL when there is no local generation. When local generation exists, the local MLSC is greater than the SIL but may fail to exceed the RMR peak load requirement. Such an RMR condition would require new transmission improvements or new local generation to assure reliable service to local consumers. When the MLSC is greater than the local peak demand, then the RMR condition is mitigated and there is less risk that local load would be interrupted for local transmission or generation outages.

Utilization of reactive devices such as high voltage shunt capacitors, static or dynamic var compensators, or Flexible AC Transmission System (FACTS) control devices should be considered for voltage and var margin constrained SIL conditions. Similarly, maintaining a unity power factor at the sub-transmission bus of distribution substations and seasonal tap changes for transformers lacking automatic tap changer under load capability should be considered as a means of resolving voltage or var margin deficiencies. Advancing planned transmission lines or construction of previously unplanned lines should be among the alternatives studied for thermal and stability constrained SIL conditions.

A comparative analysis of all alternative solutions, including using local generation that mitigates the local RMR condition is to be documented. The following factors should be considered when documenting the merits of the various alternatives: impact on SIL, system reliability implications, system losses, operational flexibility, environmental effects, implementation requirements and lead-time, and opportunity for consumer benefits from competitive wholesale market. The following should also be identified in the comparative analysis of alternatives:

- The total expected cost, fixed and variable, for the local generation dispatch that results in the lowest local generation dispatch to mitigate annual RMR conditions.
- Total emission pollutants produced by the lowest local generation dispatch mitigating the annual RMR condition.

A present worth analysis of all alternative solutions is also to be performed. The cost analysis is to include an assessment of the total expected cost of operating local units versus remote units in combination with some transmission solution. Local and remote generation cost assumptions must be documented. The accuracy of RMR conditions depends upon technical studies, engineering assumptions and validity of data needed to determine:

1. Hourly load forecast for the future years.
2. SIL by ensuring that:
   - Aggregate local area load is the total substation load actually impacted by the transmission constraint;
   - RMR generation within the local area is accurate; With RMR generation modeled out-of-service, the transmission system meets required normal (n-0) reliability criteria, showing no thermal and/or voltage limit violations;
   - With RMR generation modeled out-of-service, the transmission system meets required reliability criteria for all single contingency outages showing no thermal and/or voltage criteria violations; and
   - With RMR generation modeled out-of-service, the transmission system remains stable and shows no voltage instability.

3. RMR production costs by ensuring that:

- Analysis is done using industry recognized production-cost model.
- Production-cost model database contains projected generation additions as accurate as possible, knowing in advance that future generation additions and unit commitments are dependent on many factors and are subject to change.
- Hydro generation modeling reflects actual operating conditions as accurately as possible.
- Thermal generation modeling reflects the current projection of variable operating and maintenance costs.

Comparison of the present worth of RMR production costs and present worth of transmission alternative costs.

D. 2012 BTA Workshop I and II - List of Attendees[79]

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79 BTA Workshop I was held on July 10, 2012 and BTA Workshop II was held on August 16, 2012.

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Thor	Vincent	Planning Eng	APS	602-250-6647	vincent.thor@aps.com	X	
Trent	Gary	Transmission Planning Engineer	TEP	520-745-3168	gtrent@tep.com	X	X
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Turkelson	LeeAnn	Principal Engineer	SRP	602-236-0973	LeeAnn.Turkelson@srpnet.com		X
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Weinstein	Lauren	Principal	EPG	602-956-4370	lweinstein@epgaz.com		X
Woodall	Laurie	Attorney/Consultant	URS	602-648-2385	laurie.woodall@urs.com	X	
Wray	Tom		SunZia				X

E. Listing of Terminology[80]

Terminology

Arizona Power Plant and Transmission Line Siting Committee: The committee that reviews proposals to construct power plants and transmission lines in Arizona. In 1971, the Arizona Legislature required that the Commission establish a power plant and line siting committee. The Committee provides a single, independent forum to evaluate applications to build power plants (of 100 megawatts or more) or transmission projects (of 115,000 volts or more) in the state. The Committee holds meetings and hearings that are open to the public. More information about the Siting Committee can be found at www.cc.state.az.us/divisions/utilities/electric/linesiting-faqs.asp.

Bundled service: Electric service provided as a package to the consumer including all generation, transmission, distribution, ancillary and other services necessary to deliver and measure useful electric energy and power to consumers.

Certificate of Convenience & Necessity (CC & N): A document granting operating authority to utilities.

Competitive services: All aspects of retail electric service except those services specifically defined as "Noncompetitive Services" pursuant to Corporation Commission Rules R14-2-1601(29) or noncompetitive services as defined by the Federal Energy Regulatory Commission.

Continuity of Service[81]***:*** Each utility shall make reasonable efforts to supply a satisfactory and continuous level of service. With respect to the Fifth BTA, use of this term describes the desire for "continuity of service" following the loss of a transmission line.

Demand: The rate at which power is delivered during any specified period of time. Demand

80 http://www.cc.state.az.us/divisions/utilities/electric/terms.asp.

81 Excerpt from Arizona Administrative Code, R14-2-208(C) http://www.azsos.gov/public_services/Title_14/14-02.pdf.

may be expressed in kilowatts, kilovolt-amperes or other suitable units.

Distribution lines: The utility lines operated at distribution voltage, which are constructed along public roadways or other bona fide rights-of-way, including easements on customer's property.

Distribution service: The delivery of electricity to a retail consumer through wires, transformers, and other devices that are not classified as transmission services subject to the jurisdiction of the Federal Energy Regulatory Commission. Distribution service excludes metering services, meter reading services and billing and collection services, as those terms are used herein.

Electric Service Provider (ESP): A company supplying, marketing or brokering at retail any competitive services pursuant to a Certificate of Convenience and Necessity approved by the Corporation Commission.

Federal Energy Regulatory Commission (FERC): An independent regulatory agency within the US Department of Energy that, among other things, regulates interstate oil, natural gas and power transmission sales.

Generation: The production of the actual megawatts of electricity or purchase of electricity through the wholesale market.

Green pricing: A program offered by an Electric Service Provider where customers elect to pay a rate premium for renewable generated electricity.

Pancaking: **A term used to describe the layering of multiple tariff rates in point to point transactions.**

PV Hub: Palo Verde power plant and switchyard, the Hassayampa switchyard, and the there 500 kV tie lines connecting the two switchyards.

Interruptible electric service: Electric service that is subject to interruption as specified in the utility's tariff.

Kilowatt (kW): A unit of power equal to 1,000 watts.

Kilowatt-hour (kWh): The electric energy equivalent to the amount of electric energy delivered in 1 hour when delivery is at a constant rate of 1 kilowatt.

Megawatt (MW): A unit of power equal to 1,000,000 watts.

Meter service: All functions related to measuring electricity consumption, including installation and repair of meters, but not including meter reading.

Point of Delivery: The point where facilities owned, leased or under license by a customer connects to the utility's facilities.

Power: The quantity of electricity being generated, transferred or used at any instant in time, usually expressed in kilowatts.

Renewable Portfolio Standard (RPS): A ruling by the Commission that requires any company serving electricity to an end-user to generate a portion of that electricity through renewable technologies such as wind, solar, biomass generators or landfill gas recovery.

Renewable Transmission Project: **Refers to any proposed/planned electric transmission project at 115kV or above, designated and sponsored by the jurisdictional utilities in response to the Commission's order in the 5th BTA for projects that facilitate the delivery or integration of renewables in Arizona.**

Service area: The territory in which the utility has been granted a Certificate of Convenience and Necessity and is authorized by the Commission to provide electric service.

Tariffs: The documents filed with the Corporation Commission which list the services and products offered by the utility and which set forth the terms and conditions and a schedule of the rates and charges for those services and products.

Transmission Planning Reliability Standards: **Refers to NERC reliability standards related to electric transmission planning; part of the overall portfolio of NERC mandatory** reliability standards which apply to users, owners and operators of the bulk power system designated by NERC through its compliance registry procedures.

Transmission service: Refers to the transmission of electricity at high voltage to retail electric customers or to electric distribution facilities as defined by the Federal Energy Regulatory

Commission (FERC) or Arizona Corporation Commission.

Utility: The public service corporation providing electric service to the public in compliance with state law, except in those instances set forth in Corporation Commission Rules, R14-2-1612 (A) and (B).

Utility Distribution Company (UDC): The electric utility entity regulated by the Commission that operates, constructs, and maintains the distribution system for the delivery of power to the end user point of delivery on the distribution system.

F. Sources of Information Referenced

Third party reports and other information used to develop the Seventh BTA Staff Report included:

Docket No. E-00000D-11-0017 filings including:

Utilities' ten-year transmission plans

Developers' ten-year transmission plans

Utilities' responses to Staff data requests

APS's Update of Renewable Transmission Action Plan (RTAP) in compliance with Commission Decision No. 72057.[82]

Docket No. E-00000D-09-0020 filings including:

Developers' ten-year transmission plans (if applicable to 2012-2021)

Cochise County Study Group (CCSG) progress reports per Decision No. 73132

Filings related to request for deferral of CCSG progress reports due in 2012

Other Commission Order Studies per Decision No. 73132

Reliability must-run studies

Ten-Year Snapshot Study[83]

Extreme Contingency Study

Utilities' compliance filing on study to identify the barriers to and solutions for enhancing Arizona's ability to export renewable energy [84]

CCSG responses to informal data requests subsequent to July 9, 2012 meeting with Staff/KEMA

Seventh BTA Workshop 1 and 2 Presentations

All can be found in their entirety in the Commission's docket site http://edocket.azcc.gov/

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82 See APS Ten-Year Transmission System Plan, Attachment C, filed 31 January 2012.

83 Filed as *SWAT-CATS Project Outage Study for 2012 Biennial Electric Transmission Assessment 2012-2012* by SRP in Docket No. E-00000D-11-0017 on January 30, 2012.

84 *Enhancing Arizona's Ability to Export Renewable Energy, A Report to Address the Arizona Corporation Commission's Sixth Biennial Transmission Assessment, Commission Decision 72031*, PDS Consulting, PLC, October 2011 (http://images.edocket.azcc.gov/docketpdf/0000130865.pdf).

Prior BTA Reports

These reports can be found on the Commission website
www.cc.state.az.us/utility/electric/index.htm

Federal Energy Regulatory Commission (FERC)

FERC Order 1000 (www.ferc.gov)

North America Electric Reliability Council (NERC)

NERC Reliability Standards (www.nerc.com)