UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Arizona Public Service Co. **Docket No. ER13-82**

MOTION TO INTERVENE AND COMMENTS OF INTERSTATE RENEWABLE ENERGY COUNCIL INC.

Pursuant to Rules 212 and 214 of the Rules of Practice and Procedure of the Federal Energy Regulatory Commission ("FERC" or the "Commission"), 18 C.F.R. §§ 385.212, 385.214, the Interstate Renewable Energy Council Inc. (IREC) hereby moves to intervene and provide comments in the above-captioned proceeding.

I. COMMUNICATIONS

Communications regarding this matter should be addressed to the signatory listed at the end of this filing.

II. SUMMARY OF COMMENTS

Arizona Public Service Company's (APS) compliance filing meets some but not all requirements of FERC Order 1000. While the filing is an improvement over past practices, it falls short in regard to consideration of public policy requirements, comparable treatment of non-transmission alternatives (NTA), public participation and governance. These deficiencies are especially important for removing barriers to the expansion of distributed renewable generation.

IREC requests FERC require APS to modify its procedures for considering Public Policy Requirements (PPR) to:

- Establish a procedure by which APS and stakeholders will choose the PPRs that will be incorporated into local load forecasting and modeling to determine PPR-driven needs;
- Establish at the regional level a process by which regional transmission needs driven by PPRs will be identified.

IREC requests FERC to require APS to modify its procedures by which it affords comparable treatment to Non-Transmission Alternatives (NTAs) to:

- Develop a set of detailed guidelines that inform stakeholders clearly and precisely how to present NTA options and how APS will assess such requests;
- Specify, after stakeholder consultation, how costs and benefits of NTAs will be measured and how up-to-date information on costs and benefits will be gathered and applied;
- Eliminate the APS's refusal to conduct and pay for only three (3) local economic planning studies per calendar year, in the next transmission planning process, conduct a study of at least one NTA alternative involving targeted packages of distributed

renewable generation (DG), demand response (DR) and energy efficiency (EE) as an alternative to a transmission improvement case;

- Eliminate the $25,000 filing fee for non-government organizations and NTA service companies who propose NTAs as solutions to identified transmission issues and clarify that fees for NTA solution proposals will not be applied at the regional level; and,
- Require APS to add clarifying language adding flexibility in instances that NTAs cannot provide all of the same or equivalent information, where the information is unnecessary for consideration of the NTA or where APS is in the best position to provide equivalent information.

IREC requests that FERC require APS to modify its compliance filing in regard to stakeholder participation and governance to:

- Direct APS and the other WestConnect members to finalize the details of the new governance structure and participation agreement as part of their Order 1000 compliance process, and not after the fact, and
- Require APS to establish criteria for fee waivers that allow for broad participation by all interested public interest organizations.

III. MOTION TO INTERVENE

IREC is a non-profit organization that has worked for three decades to expand consumer access to renewable energy resources through the development of programs and policies that reduce barriers to renewable energy deployment and increase consumer access to renewable technologies. IREC has participated in regulatory proceedings or provided technical assistance to over 40 state utility commissions on net metering and interconnection issues. IREC has a national reputation for its technical expertise in interconnection policy and leverages its inter-jurisdictional experience to promote best practices in interconnection policy in proceedings across the country. Among the primary goals of IREC is the facilitation of wider deployment of DG, especially residential and smaller-scale commercial solar photovoltaic (PV) systems. Because transmission system planning is a critical element of efficient and cost-effective deployment of renewable and demand-side technologies, IREC has participated in regional stakeholder processes on grid planning, most recently providing up-to-date figures on solar PV generation costs for WECC transmission planning.[1] Reforming the processes for assessing grid needs, including those driven by public policies, and evaluating solution alternatives on a comparable basis, including renewable energy resources and demand-side options, have long been priority IREC goals. Thus, the Project has a strong interest to ensure transmission provider compliance with the reforms required by Order No. 1000.

IV. BACKGROUND

In July 2011, FERC issued Order No.1000 in which it revised several non-rate terms and

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[1] *See*, Western Electricity Coordinating Council (WECC), Transmission Expansion Planning Policy Committee (TEPPC) Technical Advisory Subcommittee (TAS), *Comments Of The Interstate Renewable Energy Council, Inc*. September 3, 2012.

conditions of its *pro forma* Open Access Transmission Tariff ("OATT") and ordered public utility transmission providers to submit compliance filings reflecting the Order's requirements.[2] Pursuant to the Final Rule, APS submitted its compliance filing on October 11, 2012. [3]

IREC commends the Commission for adopting and affirming Order No. 1000[4] and strongly supports the Commission's requirements that public utility transmission providers adopt planning processes that incorporate the consideration of transmission needs driven by public policy requirements, provide for comparable consideration of non-transmission alternatives, and ensure opportunities for timely and meaningful stakeholder participation throughout the planning process. These provisions will make regional transmission planning more cost-effective and efficient, while providing for the integration of public policy-driven resources and non-transmission alternatives. Thus, Order No. 1000's requirements are an important step toward creating a more sustainable transmission grid.

Order 1000 is the latest in a series of orders directed at improving federal transmission access, planning, and coordination.[5] Order 1000 has potential to expand the range of options for meeting reliability and economic efficiency needs of the national transmission grid and to accommodate renewable energy requirements contained in state policies. Order 1000 can help ensure more thoughtful consideration of DG, EE and DR as means of meeting transmission reliability needs. These comments describe how APS should modify its compliance filing to better integrate DG into transmission planning and describe elements it should add its transmission plans to comply with Order 1000.

Order 1000, for the first time, requires transmission owners and authorities to consider DG as a transmission resource. Compliance with Order 1000 requires a serious effort to gain a better understanding of the costs and benefits of DG. This inquiry comes at a very good time since a number of trends have dramatically changed the profile of DG, such that today it is no longer possible to properly plan transmission system investment without a updated and careful review of DG options.

Costs to install solar and other DG power systems have fallen so rapidly that many key decision makers in utilities, transmission authorities and regulatory commissions do not understand the current value proposition. It is not possible to give equal consideration to solar DG options or to properly plan transmission system investment if the transmission planners use outdated information about solar prices or fail to account for significant public policy initiatives to increase solar energy deployment.

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[2] *Transmission Planning and Cost Allocation by Transmission Owning and Operating Pub. Utils.*, Order No. 1000, 136 FERC ¶ 61,051 (2011), 76 Fed. Reg. 49842 (August 11, 2011), (hereinafter "Order 1000"); *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, Order No. 1000-A ¶ 336, 77 Fed. Reg. 32,184 (May 31, 2012), 139 FERC Stats. & Regs. ¶ 61,132 (2012) (Order on Rehearing and Clarification) (hereinafter "Order 1000-A").

[3] Electronic filing, by Raymond C. Myford, Federal Regulation Supervisor Arizona Public Service.

[4] *See also*, *Transmission Planning and Cost Allocation by Transmission Owning and Operating Pub. Utils.*, Order No. 1000-B, 141 FERC ¶ 61,044 (2012) (Order 1000-B).

[5] *See*, Welton and Gerrard, Columbia University *Center for Climate Change Law Working Paper* (Summer 2012) *FERC Order 1000 as a New Tool for Promoting Energy Efficiency and Demand Response.*

Distributed generation, particularly from solar PV, has matured to the point where it has both the scale and price characteristics to help solve transmission system needs.

According to a FERC report released October 16, 2012, 1,400 MW of new solar generation was installed in the US during 2011 and the first three quarters of 2012. Nearly 8% of new generation in this period was solar, most of it in the form of DG.[6] In light of this growth, DG is significant enough to matter in transmission planning, and its scale is likely to increase. No transmission plan can be effective if there is not an explicit mechanism to consider DG options to system reliability, efficiency and cost-control needs.

As a result of the growth in DG procurement programs, many utilities across the nation have

Figure 2: Annual Installed Grid-Connected PV Capacity by Sector (2002-2011)

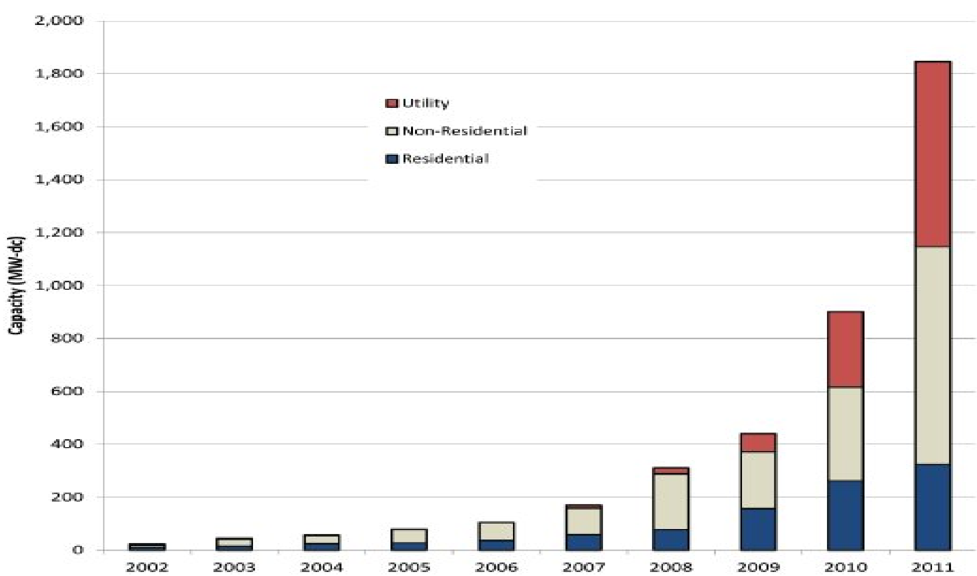

Figure 3: Number of Annual U.S. Grid-Connected PV

experienced an increasingly high volume of interconnection applications, both for large and small generators.[7] In 2005, only 79 MW of grid-connected PV capacity was installed across the United States. Five years later, the grid-connected solar PV capacity installed in just one year totaled 878 MW,[8] over ten times the cumulative amount installed just five years earlier and double the capacity that had been installed the prior year. Annual grid-connected PV capacity more than doubled again in 2011 to 1,845 MW (see figure above), which brought the grid-

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[6] This compares to a total of 17, 900MW total new generation for all generation types. Over 41% (7400 MW) was wind – making renewable energy nearly 50% of newly installed power generation. Coal was 4200MW over the seven quarter period; with natural as at 13800MW. http://www.reuters.com/article/2012/10/18/us-utilities-ferc-generation-idUSBRE89H10E20121018.

[7] The figure embedded in text is from IREC, *Solar market Trends*, August 2012, by Larry Sherwood, page 5 available at www.irecusa.org/wp-content/uploads/IRECSolarMarketTrends-2012-Web-8-28-12.pdf.

[8]See Solar Energy Industries Association Petition for Rulemaking to Update Small Generator Interconnection Rules and Procedures for Solar Electric Generation, FERC Docket No. RM12-10-000 (SEIA Petition) (February 16, 2012).

connected PV capacity in the United States to 4,000 MW by the end of that year.[9] That is a 500% increase in 7 years.

Solar Electric Power Association (SEPA)'s 2011 Utility Solar Rankings Report describes the significance of these developments:

> Utilities are adapting to solar as their fastest growing electricity source. In 2011, utilities interconnected over 62,500 PV systems, 89% of which were residential homes, and which was a 38% growth over 2010. Thirteen utilities interconnected more than 1,000 PV systems and 22 interconnected more than 500 systems. To put this in perspective, about 350 non-solar power plants (> 1 MW) were expected across the entire U.S. in 2011. This annual volume of smaller, distributed solar interconnections is unlike anything the utility industry has previously managed, and conservative forecasts indicate that this number will grow to more than 150,000 interconnections in 2015.[10]

The solar industry installed 772 megawatts (MW) of solar electric (PV and CPV) capacity in Q2 2012, representing a 125 percent increase in deployment over the second quarter of 2011. The utility scale market had its best quarter on record in Q2 2012, with over 477 MW installed. SEIA forecasts that the industry will maintain its rapid growth, as an additional 2,100 MW of solar electric (PV, CPV and CSP) capacity is projected to be installed in the second half of 2012. [11]

It is also clear that these high penetration solar regions have expanded beyond just California in to Southwest, Rocky Mountain and Eastern states. In 2008, 93% of the nation's total annual solar capacity was installed in the Western region. By 2011, however, Western states held only 61% of the nation's solar capacity,[12] and only two California utilities were among the top ten for Cumulative Solar Watts-per-Customer. [13]

A study by E3 projected 24,370 MW of distributed PV in SPSC region by 2022, slide 10, and 8125 MW of CHP slide 15 & 19, 9800 MW by 2032.[14] A February ICF report projected a high case in which CHP additions in CA = >6000MW in California alone (Slide 17) by 2030.[15]

This experience is due in part to rapidly declining cost of solar PV systems. For an example of how fast costs can change, recent data shows that blended module prices for Q1 2012 were down

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[9] See *U.S. Solar Market Trends 2011*, p.5, *supra*, note 6.

[10] Becky Campbell & Mike Taylor, *2011 SEPA Utility Solar Rankings*, p. 6 ("Utility Solar Rankings") (May 2012), *available at* www.solarelectricpower.org/media/257582/final%202011%20utility%20solar%20rankings%20report.pdf.

[11] Solar Energy Industry Association (SEIA), Solar Industry Data http://www.seia.org/research-resources/solar-industry-data.

[12] *Id.* at 22.

[13] Id at 14.

[14] E3 and LBLN, *Estimating DG Potential for the 2032 High DG/DSM Case*, September 25, 2012, by Arne Olson, Nick Schlag.

[15] ICF, *Combined Heat and Power: Policy Analysis and 2011-2030 Market Assessment*, February 2012,.

to $0.94/W, a staggering 47% lower than Q1 2011 levels of $1.78/W.[16] In June 2012, Bloomberg New Energy Finance predicted installed cost for large scale PV project would drop to $1.44/watt by 2020.[17]

DG has reached a scale clearly capable of reducing transmission costs and supporting reliability. A recent report evaluating the impacts of the California Solar Initiative (CSI) found that currently installed capacity under the CSI program is providing transmission capacity benefits comparable to a 230-kV transmission line.[18] Past impact evaluation reports for the CSI, prepared by Itron for the California Public Utility Commission (CPUC), have shown that CSI systems reduce peak transmission system loadings, make additional capacity available on the transmission system, and avoid transmission expansion costs.[19] The CPUC has adopted avoided costs for use in DG cost effectiveness calculations that include avoided transmission and distribution (T&D) costs.[20] The avoided T&D costs used in the CSI Study average about 1 – 2 cents per kWh. More recently, E3 has developed a new approach to calculating avoided T&D costs that makes use of the IOUs' T&D investment plans.[21]

This experience is consistent with that in other states where PV, EE and/or DR have helped avoid transmission upgrades or lower system costs. Examples of how EE, DR, and DG can successfully defer transmission investment include:

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[16] *See* Executive Summary of the Solar Energy Industries Association (SEIA) Q1 2012 "Solar Market Insight" report, at page 3. The document is available at www.seia.org/research-resources for free after submitting contact information. Recent data provided in this publicly available report points out that residential solar PV system prices fell by 4.8 percent from Q4 2011 to Q1 2012, with the national average installed price falling from $6.18/W to $5.89/W (all figures DC) in that one quarter alone. The SEIA Report also shows that year-on-year from 2011 to 2012, solar PV system installed costs declined by 7.2 percent. The SEIA Report (whose numbers are quite conservative) points out that system prices for non-residential solar PV systems fell by 6 percent quarter-to-quarter from the last quarter of 2011 to the first quarter of 2012 (from $4.92/W to $4.63/$W_{DC}$), and that year-over-year, the installed costs of such systems declined by 11.4 percent. The SEIA Report also notes that for projects in excess of a few hundred kilowatts, EPC costs have fallen to the mid-$2-to-$3-per-watt range. See, Page 7 and Figure 2-3 on that page. Also, system sizes continue to grow in the commercial sector, pushing average prices lower. In 2011 alone, the average size of a non-residential distributed solar installation grew by an astounding 43% according to IREC's own Solar Market Trends report. U.S. Solar Market Trends 2011, August, 2012, p. 7. Available at http://www.irecusa.org/wp-content/uploads/IRECSolarMarketTrends-2012-Web-8-28-12.pdf

[17] Power Point Presentation by BNEF staff Nathaniel Bullard and Jenny Chase to ClimateWorks Foundation, June 2012, San Francisco.

[18] *See, e.g.*, CPUC California Solar Initiative 2009 Impact Evaluation § 6.2 (June 2010), available at http://www.cpuc.ca.gov/NR/rdonlyres/70B3F447-ADF5-48D3-8DF0-5DCE0E9DD09E/0/2009_CSI_Impact_Report.pdf.

[19] Itron, *2009 CSI Impact Evaluation Report*, at page ES-17. Also, Itron, "CPUC Self-Generation Incentive Program – Sixth Year Impact Evaluation Report" (August 30, 2007), at 5-29 to 5-33. These Itron reports are available on the CPUC website at http://www.cpuc.ca.gov/PUC/energy/Solar/evaluation.htm and http://www.cpuc.ca.gov/PUC/energy/DistGen/sgip/sgipreports.htm November 5, *2012* Page 7.

[20] *See* D. 09-08-026, Decision Adopting Cost-Benefit Methodology for Distributed Generation, R.08-03-008, at pages 34-36 (Aug. 21, 2009), available at http://docs.cpuc.ca.gov/word_pdf/FINAL_DECISION/105926.pdf. Since 2005, the Commission has included avoided T&D costs in its evaluation of energy efficiency programs.

[21] *12,000 MW of Renewable Distributed Generation by 2020* Benefits, Costs and Policy Implications by Joseph F. Wiedman, Erica M. Schroeder Keyes, Fox & Wiedman LLP, R. Thomas Beach Crossborder Energy, July 2012, pages 4, 10-11. E3's workshop presentation on avoided T&D costs can be found at http://www.cpuc.ca.gov/NR/rdonlyres/90AA83C6-1AAC-4D7E-966E-299436C4A6BD/0/E3FITAvoidedCosts 9262011.pdf

- Con Edison in New York has successfully apply targeted EE services to help reduce need for capital investment in T&D systems.[22]
- A paper by Plunkett and Bentley (2008 ACEEE summer study) describes efforts by Central Vermont Public Service Company to avoid transmission costs via targeted EE and Combined Heat and Power (CHP) systems.[23]
- The California Solar Initiative has reduced the need for transmission investment.[24]

Methodologies for assessing the cost and benefits of PV have been developed and applied in California and elsewhere. The E3 methodology calculates marginal transmission and distribution capacity values using utility rate case capital expenditure data. These costs are then allocated across different hours using weather data as a proxy for distribution loads. The allocation is determined separately for each climate zone.[25] Hence there is sufficient experience and tools available by which to measure costs and benefits of solar distributed generation in transmission planning.

V. COMMENTS

a. Public Policy Requirements (PPRs)

By 2015, the United States will need to interconnect more than 30,000 MW of new renewable generating capacity to meet existing state and federal renewable energy policy goals.[26] By 2035, the additional capacity needed to satisfy existing policy goals increases to 100,000 MW.[27] Already, state and federal policies are promoting nearly 1,900 MW of solar PV installations annually.[28]

Wholesale policies aimed at distributed generation have expanded rapidly over the past 5 years, and include feed-in tariffs (FIT) and competitive solicitations. By 2010, seven of the top 10

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[22] *See* PowerPoint by Madlen Massarlian and Michael Harrington, Con Edison, *Integrated Planning and Targeted DSM*, June 2012 Webinar on EE as a T&D Resource, available at http://www.raponline.org/. See also, *US Experience with Energy Efficiency as a Transmission and Distribution Resource,* February 2012, *www.raponline.org/document/download/id/4765*

[23] Walking the Walk: Considering Non-Transmission Alternatives in Utility Planning, Part Deux, 2008 ACEEE Summer Study Proceedings Paper. "Geo-targeted energy efficiency and CHP projects continue to hold the promise to defer Southern Loop 46 kV transmission upgrades … Vermont's public preference for energy efficiency and small distributed resources, particularly renewable and sustainable generation units, may result in more non-transmission alternatives to further defer the Southern Loop upgrade." The paper describes screening tools and detailed benefit cost metrics available to assess EE as alternative to transmission upgrade investments. Available at: http://www.aceee.org/proceedings?page=12&date_filter[value][year]=2008&date_filter[value][month]=0&date_filter[value][day]=0&date_filter[value][hour]=0&date_filter[value][minute]=0&date_filter[value][second]=0&abstract=&author=. [I don't think this link gets you there]

[24] *See* footnotes 13, 14, 15and 19 above.

[25] *See*, E3, Draft Methodology for Assessing Benefit-Costs of Net Energy Metering, September 2012.

[26] *An Examination of the Regional Supply and Demand Balance for Renewable Electricity in the United States through 2015*, National Renewable Energy Laboratory, Technical Report NREL/TP-6A2-45041 (March 2009).

[27] *See* 2011 National Summit on RPS, Presentation of Lawrence Berkeley National Laboratory, Oct. 26-27, slide 22: http://www.cleanenergystates.org/assets/Uploads/2011-RPS-Summit-Combined-Presentations-File.pdf

[28] Larry Sherwood, *U.S. Solar Market Trends 2011* (Interstate Renewable Energy Council), p. 5 (July 2012).) *available at* http://www.irecusa.org/news-events/publications-reports/.

states for installed solar capacity had one or more types of wholesale DG programs.[29] In the last few years alone, California has authorized almost 3 GW of DG procurement programs, mostly through RFPs and auctions.[30]

Order No. 1000 requires transmission providers to establish procedures for identifying transmission needs driven by PPRs and for determining which PPR-driven needs will be evaluated for potential solutions.[31]

The range of public policies that might prove relevant to this endeavor clearly includes a number that are relevant to DG, including solar PV. The federal government and states have an expansive—and expanding—body of laws, regulations, executive orders, plans, and incentives to promote solar energy. These include:

- Federal agency procurement of PV for defense department and other government facilities
- Net Energy Metering rules
- Stimulus funding for PV
- R&D funding for PV
- State PV carve outs in RPS statutes and rules
- Public benefit funds devoted to PV
- Policies requiring state-owned buildings to reduce employ on site renewable energy
- State building codes requiring or crediting PV
- State energy and climate plans; and
- Many additional local laws, regulations, and initiatives.

Effective implementation of Order 1000's call for consideration of public policy driven transmission necessarily involves a serious look at DG not as incidental considerations, but as a central driver of the transmission planning process.

An integral component of such a process must be stakeholder participation because stakeholder input into the identification and evaluation of PPR-driven needs is critical to ensuring just and reasonable rates and avoiding undue discrimination.[32] IREC appreciates the challenge that APS faced in attempting to develop consensus among stakeholders for procedures to incorporate public policy considerations into the planning process. Although IREC believes that APS's compliance filing meets some of Order No. 1000's mandates for PPR identification and evaluation, we conclude that it fails to comply with other significant aspects.

First, while APS's compliance filing mentions that public policy requirements are incorporated into the load forecasts and or modeled in local planning studies, it lacks any process or guidance as to how APS and stakeholders will choose the PPRs that will be incorporated into local load

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[29] Kevin Fox & Laurel Varnado, Solar America Board for Codes and Standards, *Sustainable, Multi-Segment Market Design for Distributed Solar Photovoltaics*, p. 31 (October 2010), *available at* http://www.solarabcs.org/about/publications/reports/market-design/pdfs/ABCS-17_studyreport.pdf.
[30] CPUC, RPS Procurement website, available at http://www.cpuc.ca.gov/PUC/energy/Renewables/procurement.htm (last visited June 28, 2012).
[31] Order 1000, *supra* note 1 at ¶205.
[32] *Id.* at ¶¶ 207-208

forecasting and modeling to determine PPR-driven needs (there is no guidance as to what "as applicable" means). Instead the tariff filing simply states that the needs will, in fact, be identified. At the regional level, the proposal does not include a process by which regional transmission needs driven by PPRs will be identified; it only states that those needs identified will be included in modeling underlying the Regional Plan. These elements fail to meet the Order 1000 requirement that Transmission Provider must "affirmatively consider transmission needs driven by Public Policy…" and "…demonstrate compliance with these requirements."[33]

Second, the tariff proposal lacks a process at either the local or regional level by which APS (and other WestConnect members at the regional level), in consultation with stakeholders, will determine which PPR-driven needs that result from the modeling will be evaluated for solutions. The local tariff language says only that PPRs, as applicable, will be modeled in the local planning studies. A logical assumption would be that all PPR-driven needs then feed into the solutions evaluation process outlined in the tariff,[34] but the tariff does not state whether APS will evaluate solutions for all identified PPR-driven local needs. At the regional level, APS states that "at a minimum, any regional transmission needs driven by enacted state or federal public policy requirements will be included in the transmission system models underlying the development of the Regional Plan."[35] However, again, neither the tariff language nor the BPM makes explicit that all identified regional PPR-driven needs will be evaluated for solutions or provide criteria by which APS and other WestConnect stakeholders can choose which needs merit solutions evaluation.

Without increased specificity as to the procedures for the identification of PPR-driven grid needs and the process by which APS will determine which PPR-driven grid needs for which solutions will be evaluated, IREC concludes that the proposed tariff language violates Order 1000's requirements and does not provide sufficient assurance that opportunity for meaningful stakeholder input on PPR-driven grid needs will be provided. Without such detailed assurance, the tariff fails to ensure just and reasonable rates.

b. Planning & Non-Transmission Alternatives

Order No. 1000 requires transmission providers to address grid needs by establishing procedures to ensure comparable consideration of transmission and non-transmission solution alternatives.[36] In some cases, DG (sometimes in combination with energy efficiency and demand response) may prove to be a more cost-effective and socially desirable way of addressing forecasted demand growth.

Complying with this requirement requires an explicit recognition that major changes have occurred in the price and availability of DG in recent years, and procedures to track future changes. The Order requires procedures to ensure *comparable consideration* of transmission and non-transmission solutions to address grid needs, including the *process & metrics* for evaluating and selecting alternative solutions. IREC believes that this language requires:

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[33] Order 1000, *supra* note 1 at ¶222.
[34] Attachment K, *supra* note 3 at (I)(A)(9)(b).
[35] *Id.* at (III)(C)(14)(a).
[36] *Id.* at 80, ¶¶154-155.

- Transmission Providers (TPs), in consultation with stakeholders, *must evaluate* alternative solutions that might meet grid needs (whether reliability, economic or PPR-driven) more efficiently or cost-effectively and *must consider* proposed NTAs on a comparable basis. (Order 1000 at ¶ 148)
- TPs must specify when and how stakeholder solution proposals will be evaluated in the regional plan development process;
- TPs must have clear procedures for responding to stakeholder study requests in a timely manner;
- TPs must establish procedures and metrics to be used to evaluate on a comparable basis all solution options and to select solutions that are more efficient or cost-effective for inclusion in its regional plan;[37]
- TPs must collect cost and benefit data on NTA's, including DG, in a manner equally comprehensive to the way data is collected for fossil generation;
- TPs must provide access to modeling inputs and assumptions such as expected load growth, the impact of DR and EE;
- Identify clear parameters for how transmission and non-transmission alternatives are compared side-by-side and how one resource is ultimately chosen over another competing alternative.

TPs need to develop some means of paying for the DG alternatives if none exist. A transmission owner or ISO should, on its own initiative, include provisions in its tariff establishing cost allocation for some non-transmission alternatives.[38]

IREC supports APS's and WestConnect members' agreement to start the regional planning process with WECC-provided data as the baseline. The use of interconnection-wide data will provide a starting point for the consistency and coordination necessary to ensure efficient and cost-effective outcomes and will lead to more effective interregional coordination. By itself, however, this does not ensure that NTAs will receive a fair hearing throughout the process of selecting transmission solutions. IREC does not believe that APS's compliance filing satisfies Order No. 1000's mandate for comparable consideration of NTA solutions.

While the APS filing meets some of the FERC requirements, the treatment of NTA's is often very brief, simply repeating phrases from the Commission order without an explanation of how comparability will be achieved. Procedures are vague and decision-making responsibility is spread across a wide range of actors, casting doubt on whether APS's ultimate choice of transmission solutions will fully reflect actual benefit/cost data.

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[37] FERC declined to establish particular metrics for how this comparison should operate, but clearly expects Transmission Owners to define these metrics and processes. *See* Order 1000-A, *supra* note 9, at ¶ 745.

[38] Order 1000 notes that "in appropriate circumstances, alternative technologies may be eligible for treatment as transmission for ratemaking purposes." *Id.* ¶ 779 n.563 (citing Proposed Rule, FERC Stats. & Regs. ¶ 32,660 at n.58 and *Western Grid Development, LLC*, 130 FERC ¶ 61,056 (2010)). In *Western Grid*, FERC held that certain sodium sulfur battery storage projects qualified as "wholesale transmission facilities" because the projects interacted with the relevant ISO in a manner similar to transmission and shared important characteristics with transmission equipment. *See Western Grid Development, LLC*, 133 FERC ¶ 61,029 (2010) (Order Denying Rehearing).

Moreover, cost/benefit metrics are either missing or so deeply buried in cross-referenced documents as to obscure how DG systems will be evaluated. The costs and benefits of DG are changing rapidly, in the direction of lower costs and rising benefits – yet many utilities continue to use outdated information. FERC should require APS to describe how it assesses benefits and costs of NTA's and how that information will be updated regularly to account for cost reductions DG systems.[39] Without this, entities proposing NTA may find themselves in an endless round of "bring me a rock…not that rock" which will frustrate the purpose of FERC's NTA comparability requirement.

The APS filing states that entities proposing NTAs must "adhere to and provide the same or equivalent information and submittal fees as transmission alternatives."[40] This rule could be applied in a manner that is unduly discriminatory. NTA's often have characteristics that are very different from traditional transmission infrastructure. It may not be possible for sponsors of NTAs to submit the same or equivalent information as sponsors of transmission proposals. Transmission Providers should not be able to reject a proposed NTA solution for failure to provide the same or equivalent information if such information does not apply to the NTA, or if such information is unnecessary to evaluate and compare the proposed NTA. The Commission should require APS to add clarifying language adding flexibility in instances that NTA sponsors cannot provide all of the same or equivalent information, or where the information is unnecessary for consideration of the NTA.

The filing and associated documents do not address how combinations of DG resources, DR, and EE would be proposed, evaluated and modeled as potential solutions to transmission system needs. This is a serious flaw since it is likely that many if not most transmission reliability and cost issues can be addressed effectively and at low cost by targeted combinations of DG, EE services and DR.

At several points in the filing APS's commitment to comparable evaluation of NTAs is conditional or half-hearted. For example: "*Where feasible*, identify NTAs, such as demand response resources that could meet or mitigate the need for transmission additions or upgrades. (Emphasis added)."[41]

The filing cross-references a document entitled "Transmission Planning Process Guideline," dated January 2012. While that document briefly refers to DG, it states that it is evaluated on a "case specific basis" not as an integral part of the planning process. The document is clearly oriented around response to growth in electric demand through large generation and transmission

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[39] IREC is unsure what to make of the following language at page 39 of the filing, except to note that is an example of the lack of clarity, uncertain decision making process and potentially unreasonably narrow approach for considering benefits of NTA's.

> In developing a more efficient and cost effective plan, it is possible for the plan to jointly consider multiple types of benefits when approving projects for inclusion in the Regional Plan. The determination to consider multiple types of benefits for a particular project shall be made through the WestConnect stakeholder process; however, *the value of economic benefits may only be considered in response to a WECC Board-approved recommendation to study congestion in the WestConnect footprint*. (Emphasis added)

[40] *See*, Section III.C.6 of Arizona Public Service Company Revisions OATT in accordance with FERC Order No. 1000 Clean Tariff, page 32.

[41] APS filing at page 13, section II.A.4.a.2.

infrastructure. It refers to load forecasts but does not say how DG, EE or DR resources are accounted for in them.

While the filing appears to allow stakeholders to come forward with NTA's, it does not include a commitment by the transmission owner to proactively identify and assess NTA's. These aspects of the filing appear to conflict with the requirements of Order 1000, which places responsibility to assess NTA's with the transmission owner.[42] That responsibility should be shared with, but not entirely shifted to other parties. FERC requires the transmission owner to identify transmission *and* non-transmission alternatives available and to use appropriate and comparable metrics selecting and evaluating solutions. This requires an active commitment by APS to identifying viable distributed generation NTA's, and metrics with which to assess benefits and costs. It is not enough for transmission owners to assume a passive role of simply responding to requests for study.[43]

Moreover, the opportunity for stakeholders to propose NTA occurs under restrictions that discourage proposals and limit the likelihood of receiving attention in the selection of solutions. The APS filing limits the number of solutions that will be studied to three, chosen by APS in its sole discretion.[44]

APS also proposes fees that will discourage public interest groups and small-medium sized businesses from proposing NTA solutions. APS has added additional criteria that project sponsors must satisfy for the submission of NTAs, including a $25,000 flat submittal fee.[45] While a $25,000 submittal fee may not pose a problem for an independent transmission company submitting a transmission project proposal for cost allocation, the fee could prove cost prohibitive to potential sponsors of NTA proposals. In addition, it appears that the WestConnect Business Practice Manual will require fees be charged for proposals at the regional level in addition to the $25,000 flat submittal fee APS has laid out in its tariff. To correct these problems, APS should be required to:

- Develop a set of detailed guidelines that inform stakeholders clearly and precisely how to present NTA options and how APS will assess such requests;
- Specify, after stakeholder consultation, how costs and benefits of NTAs will be measured and how up-to-date information on costs and benefits will be gathered and applied;
- Eliminate the APS's refusal to conduct and pay for only three (3) local economic planning studies per calendar year, in the next transmission planning process, conduct a study of at least one NTA alternative involving targeted packages of distributed renewable generation (DG), demand response (DR) and energy efficiency (EE) as an alternative to a transmission improvement case;

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[42] *Id.* at ¶ 148.
[43] *Id.* at ¶155.
[44] "APS will have no obligation to conduct and pay for more than three (3) priority local economic planning studies per calendar year. " See, Section II.A.5.b.5 of Arizona Public Service Company Revisions OATT in accordance with FERC Order No. 1000 Clean Tariff, page 16.
[45] APS Compliance filing pages 14-15.

- Eliminate the $25,000 filing fee for non-government organizations and NTA service companies who propose NTAs as solutions to identified transmission issues and clarify that fees for NTA solution proposals will not be applied at the regional level; and,
- Require APS to add clarifying language adding flexibility in instances that NTAs cannot provide all of the same or equivalent information, where the information is unnecessary for consideration of the NTA or where APS is in the best position to provide equivalent information.

Having reviewed the compliance filing, amended tariff and numerous cross referenced documents, it is difficult to discern a clear path forward to engage the APS in a dialogue regarding how PV distributed generation (DG) can help meet meeting the utility's future energy and transmission needs. IREC wants to ensure that the opportunities for suggesting non-transmission alternatives, and the methodology for comparable evaluation of non-transmission alternatives are clear. Give the rapidly declining cost of solar PV, the low cost of EE and DR solutions and projected US utility transmission investment of $298 Billion (2010-2030), it is urgent that APS more fully describe how it will consider non-wires alternatives as a solution to local and regional energy and transmission needs.[46]

c. Stakeholder Participation and Governance

Order No. 1000 also mandates that regional planning procedures provide for consultation with stakeholders – procedures that enable stakeholders to express their needs, access data used in the planning process, and identify and evaluate potential solutions.[47] Such stakeholder participation helps to ensure efficient and cost-effective planning. Order No. 1000 also requires that regional transmission planning processes comply with the principles laid out in Order No. 890, including: coordination, openness, transparency, information exchange and comparability.[48] Order No. 1000 does not mandate that transmission providers create a governance structure for compliant regional planning, but the inclusion of the above principles and requirements regarding stakeholder participation highlight the Commission's interest in increasing stakeholder participation in the regional transmission planning process.

As such, IREC supports APS's efforts to draft a governance structure that allows stakeholders better access to the planning process. Specifically, IREC supports the creation of five member classes in the planning governance structure that includes a "key interest group" class to which public interest groups can join. The structure provides a strong model for other regions. Having a role in the governance structure of regional planning provides the transparency and access required for meaningful stakeholder input and maintains the framework for strong stakeholder participation over time.

As part of the voting structure, IREC appreciates that APS has provided for the waiver of membership fees for certain entities. APS's transmittal letter states that "certain" non-profit organizations will not be assessed membership fees for participation in the key interest group

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[46] *See* Order 1000, page 38, ¶ 44, citing an EEI sponsored study by Brattle Group. *Transforming America's Power Industry* at 37, http://www.eei.org/ourissues/finance/Documents/Transforming_Americas_Power_Industry.pdf. *See also*, Regulatory Assistance Project, *US Experience with Efficiency As a Transmission and Distribution System Resource*, Chris Neme, Energy Futures Group, Rich Sedano, Regulatory Assistance Project, February 2012.
[47] *Id.* at ¶¶150-152.
[48] *Id.* at ¶151.

sector, and the current draft of WestConnect's Business Practice Manual (§ 3.2.1.3) refers to criteria for non-profit organization exemption from membership fee requirements. In order to effectuate EPE's intent to enable the broad participation that the waiver of membership fees will allow, IREC asks the Commission to encourage APS to design criteria for fee waivers that allow for broad participation by all interested public interest organizations for which a membership fee could prove prohibitive.

Finally, IREC supports the comment of the Public Interest Intervenors to the effect that the WestConnect governance structure risks undue discrimination and incomplete duplicative organizational structures. IREC requests that the commission direct APS and the other WestConnect members to finalize the details of the new governance structure and participation agreement as part of their Order 1000 compliance process, and not after the fact.

VI. CONCLUSION AND COMMUNICATIONS

For the reasons set forth above, IREC respectfully requests that the Commission 1) grant IREC's motion to intervene and 2) direct APS to modify its tariff language in the following ways:

In regard to Procedures for considering Public Policy Requirements (PPR):

- Establish a procedure by which APS and stakeholders will choose the PPRs that will be incorporated into local load forecasting and modeling to determine PPR-driven needs;
- Establish at the regional level a process by which regional transmission needs driven by PPRs will be identified.

In regard to comparable treatment to NTAs to:

- Develop a set of detailed guidelines that inform stakeholders clearly and precisely how to present NTA options and how APS will assess such requests;
- Specify, after stakeholder consultation, how costs and benefits of NTAs will be measured and how up-to-date information on costs and benefits will be gathered and applied;
- Eliminate the APS's refusal to conduct and pay for only three (3) local economic planning studies per calendar year, in the next transmission planning process, conduct a study of at least one NTA alternative involving targeted packages of distributed renewable generation (DG), demand response (DR) and energy efficiency (EE) as an alternative to a transmission improvement case;
- Eliminate the $25,000 filing fee for non-government organizations and NTA service companies who propose NTAs as solutions to identified transmission issues and clarify that fees for NTA solution proposals will not be applied at the regional level; and,
- Require APS to add clarifying language adding flexibility in instances that NTAs cannot provide all of the same or equivalent information, where the information is unnecessary for consideration of the NTA or where APS is in the best position to provide equivalent information.

In regard to stakeholder participation and governance:

- Direct APS and the other WestConnect members to finalize the details of the new governance structure and participation agreement as part of their Order 1000 compliance process, and not after the fact; and
- Require APS to establish criteria for fee waivers that allow for broad participation by all interested public interest organizations.

Respectfully submitted,

INTERSTATE RENEWABLE ENERGY COUNCIL, INC.

/s/

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CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document upon each person designated on the official service list compiled by the Secretary in this proceeding.

Dated at Oakland, California this 26th day of November, 2012.

/s/

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