COMPARATIVE REGULATION OF PURPA QUALIFYING FACILITIES IN WESTERN STATES
Background for the Legislative Service Office

As requested, the following is summary background information for LSO in preparation for the forth coming joint meetings of the Corporations, Elections and Political Subdivisions Committees on May 18-19. The document simply supplies a summary of the different approaches to this topic take in certain western states. It is intended to provide information for LSO's use in briefing legislators and does not, therefore, advance nor take a position with respect to any particular proposal for legislation.

1. The Public Utility Regulatory Policies Act and the "Qualifying Facilities" Industry

In 1978, in the immediate aftermath of the Arab oil embargo earlier in that decade, the U.S. Congress adopted the Public Utility Regulatory Policies Act ("PURPA") in an effort to encourage development of domestic sources of energy and reduce what then was perceived as an excessive dependency on imported energy resources. PURPA was enacted prior to the deregulation of the public utility industry in the United States, at a time when the generation, transmission and distribution of electric energy was conducted by vertically integrated monopolies.

The "must-take" provision of PURPA. One of PURPA's main objectives, therefore, was to compel these monopoly utilities to purchase energy from independent power producers generating electricity from domestic resources. These include, for example, businesses that generated electricity incidental to their main activity ("cogenerators", such as natural gas producers), as well as renewable energy producers generating electricity from solar and wind. Accordingly, PURPA includes a clause, often referred to as its "must-take" provision, requiring public utilities to purchase energy generated by "qualifying facilities" ("QFs"), which the statue and regulations define as plants generating 80 mw or less of electricity via specified technologies.

The "avoided cost" limitation and PURPA contract terms. PURPA contains, however, a crucial limitation on the "must-take" obligation: Utilities are not to pay more for energy from QFs than it would cost them to acquire the energy from other sources. The statute and regulations are clear in this regard. However, determination of this "avoided cost", and the other financial/contractual terms on which utilities purchase QF energy, has been left to the states. Not surprisingly, practice has varied widely, and it has evolved over time. In some states the price utilities pay for QF energy is determined on a fully competitive basis. In others (including Wyoming) it is determined by contract negotiations between the utility and the QF. Inevitably, efforts by utilities to bring competition into these situations – and thereby bring down costs to ratepayers - encounters heavy lobbying by the QF industry that benefits from the lack of competition.

Major changes in the public utility industry since PURPA's enactment. Meanwhile, the overall structure of the utility industry across the United States has changed dramatically. In 1978, the industry was comprised largely of vertical monopolies. Today, in many states, deregulation has created open, competitive markets for electricity generation (commonly known as regional transmission organizations, or “RTOs” and independent system operators, or “ISOs”. These RTOs and ISOs operate in all or parts of 36 states and the District of Columbia.[1] In 2005, Congress amended PURPA to end the “must-take” provision in these RTO and ISO jurisdictions for industrial-scale QF energy, and prices have responded accordingly. As a result, states in the West where there is no RTO or ISO (such as Wyoming) are experiencing increased interest on the part of QF developers under PURPA due to the persistence of the “must-take” provision and lack of competition in the determination of “avoided cost”.[2]

The QF business model. Notwithstanding these major changes in the public-utility landscape, there remains an established industry of non-utility QF developers pursuing a business model dependent on the must-take provision of PURPA. Typically, these promoters seek to take a proposed QF development through the stage of identifying a site, obtaining the requisite property rights and permits, using the must-take provision to obtain a power-purchase agreement from a public utility on terms that will afford an attractive return (typically, an internal rate of return of 10-20% annualized) for the private equity or hedge funds that specialize in backing this early-stage development and, then, obtaining “take-out” financing from a provider of construction financing. These latter transactions commonly are called “tax equity financing” because the funding is provided by companies with federal tax liabilities that they can reduce by “harvesting” tax credits that the federal government has had in place for wind and solar energy for the past 25 years (with a few brief interruptions). Finally, when the period of the tax credits has ended, these tax-equity investors typically sell the project to tax-exempt investors such as pension funds or insurance companies who require cash flows similar to bond investments, but at significantly higher returns.

2. State Policies Compared

The following table compares practices in Wyoming and neighboring western states that do not participate in an ISO or RTO and where, accordingly, utilities remain subject to the must-take

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[1] Southern Power Pool “operates in an eight-state area including all or parts of Arkansas, Kansas, Louisiana, Mississippi, Missouri, New Mexico, Oklahoma and Texas.” (https://www.spp.org/about-us/footprint/); “PJM Interconnection coordinates the movement of electricity through all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia.” (http://www.pjm.com/about-pjm/who-we-are/territory-served.aspx); Midwest ISO operates in all or parts of 15 states. (https://www.misoenergy.org/AboutUs/Pages/AboutUs.aspx); New York ISO; New England ISO operates across all or parts of 6 states. (https://www.iso-ne.com/about); and California ISO. *See also* map of RTO and ISO territories at http://www.isorto.org/about/default.

[2] For further reference, the following is a recently summary published by the Federal Energy Regulatory Authority on the circumstances described in the text (https://www.ferc.gov/industries/electric/gen-info/qual-fac/benefits.asp): “QFs have the right to sell energy and capacity to a utility (see 18 C.F.R. § 304), provided the purchasing utility has not been relieved from its QF purchase obligation (see 18 C.F.R. § 309-311). With limited exceptions, QFs generally have the option of selling to a utility either at the utility's avoided cost or at a negotiated rate. Avoided cost is the incremental cost to an electric utility of electric energy or capacity which, but for the purchase from the QF, such utility would generate itself or purchase from another source (see 18 C.F.R. § 292.101(b)(6)). QFs also generally have the option to sell energy either "as-available" (i.e., as the QF determines such energy to be available for such purchases) or as part of a legally enforceable obligation for delivery of energy or capacity over a specified term.”

provision (as constrained by the avoided-cost limitation). The details can seem daunting, but the key issues are straightforward:

Avoided cost determination. Is the price that a QF can charge a utility based on competition among potential suppliers (e.g., through an RFP process). If not, is the reference rate for the calculation of "avoided cost" the price the utility would have to pay for energy then available from other sources? Or is it a price determined in a regulatory process? How is the avoided cost determined in instances in which a utility requires no incremental energy

Length of the contract. Is the utility required to enter a long-term contract to buy energy at a fixed price? Some states set limits on the length of a fixed-price contract because they can result in utilities and ratepayers being locked in to high prices. The price of wind energy, for example, has been dropping, but many earlier QF projects have locked in higher costs. In addition, it is often cheaper for the utility to buy energy on the open market hour-by-hour. QF developers typically advocate for long-term, fixed-price contracts on the grounds that such a contract is necessary to secure financing.

Does the state's public utility commission (e.g., the PSC in Wyoming) review the terms of each QF contract to determine if it meets the "avoided cost" limitation? If not, especially in states in which prices are not determined competitively, this prevents consumers from participating in the process for determining avoided cost.

	Avoided cost: How determined?	**Fixed-price contract required? How long?**	**Contract Approval Required?**	**Regulation and/or Tariff**
Wyoming	Fixed price, based on the Partial Displacement Differential Revenue Requirement ("PDDRR") Method (See attached Exhibit 1)	Yes. Fixed price. 20 years	No	Wyoming tariff, Schedule 38, Rocky Mountain Power
Colorado	Competitive bid among QFs (when the utility advertises for power) QFs with a design capacity greater than 100 kW must be successful bidders through the Company's Resource Planning process, as set forth in the Commission's Electric Resource Planning Rules.	No fixed price. Price determined in the competitive bidding process.	?	Colorado tariff, No. 8 Electric, Small Power Production and Cogeneration Facility Policy Electric Purchase, Public Service Company of Colorado, an Xcel Energy company

Idaho	"Highest displaceable incremental cost" ("HDIC") – Production cost model studies are with and without the QF, but no additional market sales are allowed as a result of adding QF (See attached Exhibit 1)	Yes fixed price. 2 years for industrial scale QFs, 20 years for very small QFs such as hydro	Yes	Idaho tariff, Schedule 38, Rocky Mountain Power
Oregon	Partial Displacement Differential Revenue Requirement ("PDDRR") Method but avoided costs can be no less than market prices during sufficiency period (See attached Exhibit 1)	15 years fixed prices + 5 years market as adopted by the Oregon PSC in Order 07-360 in Docket No. UM 1129	No	Oregon tariff, Schedule 38, Pacific Power
Nevada	The rate paid for non-firm energy deliveries shall be calculated for each hour and is defined as the lesser of: The highest hourly system incremental generation cost or the hourly Market Price Qualifying Facilities with rated (nameplate) capacities of more than 100 kW must use time-differentiated rates. Time differentiated refers to the ability to meter and tag hourly energy output levels for use with corresponding hourly pricing data.	No fixed-price. Applicable only to short-term purchases	?	Nevada Tariff No. 1-B, Schedule QF, Nevada Energy, a Pacific Power Company and Nevada Tariff No. Electric No. 2, Schedule No. CSPP, Nevada Energy, a Pacific Power Company
Utah	Partial Displacement Differential Revenue Requirement ("PDDRR") Method (See attached Exhibit 1)	Yes fixed price. 15 years	Yes	Utah tariff, Schedule 38, Rocky Mountain Power
Arizona	Non-firm, Time of Use avoided costs based on	No fixed price.	Yes	Arizona Corporation Commission

	standard rates that may be adjusted or updated any time the tariff is revised.	Successive one-year terms that automatically renew each year.		Decision No. 52345 and 56271; Arizona Public Service Rate Schedule EPR-2; Arizona Corporation Commission Docket No. E-01245A-12-0482 and Docket No. E-01345A-12-0482
Washington	Competitive bid among QFs (when the utility advertises for power)	Yes, 5- year fixed priced contract	?	Chapter 480-107 WAC – Electric Companies—Purchases of Electricity from Qualifying Facilities and Independent Power Producers and Purchases of Electrical Savings from Conservation Suppliers; *Application of Rocky Mountain Power for Modification of Contract Term of PURPA Power Purchase Agreements with Qualifying Facilities*, Docket No. 20000-481-EA-15, Direct Testimony of Kenneth G. Lay, Exhibit 400, page 7, Rocky Mountain Power response to OCA data request 1.3.