BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of the Application of The Empire District Electric Company for a Certificate of Convenience and Necessity Related to its Customer Savings Plan	))))	File No. EA-2019-0010

MOTION TO OPEN THE EVIDENTIARY RECORD AND ADMIT EXHIBITS

COMES NOW the Office of the Public Counsel (OPC), by and through counsel, and, for the grounds following, moves the Commission to open the evidentiary record and admit into evidence in this case the two new exhibits described below and attached to this pleading as Exhibits 207, and 208, respectively, which OPC offers on the grounds that follow:

1. The two exhibits are: Exhibit 207, a copy of SPP's transmittal letter and proposed revisions to its open access transmission tariff that SPP filed at the FERC "to require that all Variable Energy Resources ("VER") register as and convert to Dispatchable Variable Energy Resources ("DVER") by the later of January 1, 2021, or the 10-year anniversary of the Resource's original Commercial Operation Date"; and Exhibit 208, a copy of the order the FERC issued April 12, 2019, in response to SPP's proposed revisions to its open access tariff.

2. The Office of the Public Counsel was unaware of SPP's tariff pending before the FERC or of the FERC's order regarding it until yesterday April 17, 2019, when it learned from an S&P Global article dated April 16, 2019, that FERC had issued the order attached hereto, and the Office of the Public Counsel is filing this motion as promptly as practicable in the circumstances. If these two exhibits were not so material to the issues before the Commission in this proceeding, the Office of the Public Counsel would not be offering them now.

3. The FERC-approved changes to the SPP's open access transmission tariff are relevant and material to this proceeding because they require that for new wind generation resources

the SPP must be able to control how much of the available wind resource is dispatched, *i.e.*, the SPP must be able to restrict (curtail) the generation output of new wind resources that is delivered to the transmission grid that the SPP controls. This change to the SPP's open access transmission tariff that requires new additions of wind generation to be dispatchable materially impacts the cost/benefit analysis of Empire's wind projects. Empire's analysis of its proposed new wind projects is based on the assumption that there are no restrictions on them generating electricity when the wind blows, *i.e.*, if the wind blows, the projects produce electricity. SPP-imposed curtailments or other restrictions on the generation output of these wind projects being transmitted across the SPP transmission grid will reduce the realization of production tax credits, tax credits that Empire's analysis relies on as part of its tax equity partner's(s') return of and on its(their) investment in these projects. To the extent Empire's tax equity partner(s) do not realize all of their return of and on its (their) investment through production tax credits and accelerated depreciation, then, ultimately, Empire's retail customers will bear the difference, *i.e.*, more of the SPP project revenues will go to Empire's tax equity partner(s); therefore Empire's retail customers will realize fewer benefits from the SPP market meaning that their rates will be higher than they would have been otherwise.

4. While the Office of the Public Counsel is not requesting in this pleading that the Commission extend the briefing schedule in this case, it would not oppose the Commission doing so should the Commission or any party wish more time to address in their briefs the two exhibits that are attached to this pleading.

WHEREFORE, the Office of the Public Counsel respectfully moves the Commission to admit the following exhibits into the evidentiary record in this case:

Exhibit 207, a copy of SPP's tariff filing at the FERC by which it proposed revisions to its open access transmission tariff "to require that all Variable Energy Resources ("VER") register as and convert to Dispatchable Variable Energy Resources ("DVER") by the later of January 1, 2021, or the 10-year anniversary of the Resource's[1]; and

Exhibit 208, a copy of the order the FERC issued April 12, 2019, in response to SPP's proposed revisions to its open access tariff.[2]

Respectfully,

OFFICE OF THE PUBLIC COUNSEL

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CERTIFICATE OF SERVICE

I hereby certify that a true and correct copy of the foregoing was served, either electronically or by hand delivery or by First Class United States Mail, postage prepaid, on this 19th day of April 2019, with notice of the same being sent to all counsel of record.

/s/ Nathan Williams

[1] Found at https://elibrary.ferc.gov/idmws/file_list.asp?document_id=14721022, accessed April 18, 2019.
[2] Found at https://elibrary.ferc.gov/idmws/file_list.asp?document_id=14760572 and https://www.ferc.gov/CalendarFiles/20190412150632-ER19-356-000.pdf, both accessed April 18, 2019.

November 16, 2018

The Honorable Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426

Re: *Southwest Power Pool, Inc.*, Docket No. ER19-____
Submission of Tariff Revisions to Require that All Variable Energy Resources Register as and Convert to Dispatchable Variable Energy Resources

Dear Secretary Bose:

Pursuant to Section 205 of the Federal Power Act ("FPA"), 16 U.S.C. § 824d, and Section 35.13 of the Federal Energy Regulatory Commission's ("Commission") Regulations, 18 C.F.R. § 35.13, Southwest Power Pool, Inc. ("SPP"), as authorized by its independent Board of Directors, submits revisions to Sections 1.1 and 2.2 of Attachment AE of the SPP Open Access Transmission Tariff ("Tariff")[1] to require that all Variable Energy Resources ("VER") register as and convert to Dispatchable Variable Energy Resources ("DVER") by the later of January 1, 2021, or the 10-year anniversary of the Resource's original Commercial Operation Date.

SPP requests that the Commission accept the proposed revisions as just and reasonable effective January 16, 2019.

I. BACKGROUND

A. SPP

SPP is a Commission-approved Regional Transmission Organization ("RTO").[2] It is an Arkansas non-profit corporation with its principal place of business

[1] Southwest Power Pool, Inc., Open Access Transmission Tariff, Sixth Revised Volume No. 1. References in this filing to "Tariff" refer to the version of SPP's Tariff currently in effect. "Proposed Tariff" refers to a version reflecting the revisions proposed in this filing. All capitalized terms not otherwise defined in this filing shall have the definitions assigned by the Tariff.

[2] *Sw. Power Pool, Inc.*, 109 FERC ¶ 61,009 (2004), *order on reh'g*, 110 FERC ¶ 61,137 (2005).

in Little Rock, Arkansas. SPP currently has 96 members, including 16 investor-owned utilities, 14 municipal systems, 19 generation and transmission cooperatives, 8 state agencies, 14 independent power producers, 12 power marketers, 11 independent transmission companies, 1 federal agency, and 1 large retail customer. As an RTO, SPP: (1) administers, across the facilities of SPP's Transmission Owners, open access transmission service over approximately 66,500 miles of transmission lines covering portions of Arkansas, Iowa, Kansas, Louisiana, Minnesota, Missouri, Montana, Nebraska, New Mexico, North Dakota, Oklahoma, South Dakota, Texas, and Wyoming; and (2) administers the Integrated Marketplace, a centralized day-ahead and real-time Energy and Operating Reserve market with locational marginal pricing and market-based congestion management.[3]

B. Stakeholder Approval

The proposed revisions were reviewed and approved through the SPP stakeholder process, including: (1) a meeting of the Market Working Group ("MWG") on July 10, 2018;[4] (2) a meeting of the Regional Tariff Working Group ("RTWG") on July 26, 2018;[5] and (3) a meeting of the Markets and Operations Policy Committee on July 17, 2018.[6] The revisions were approved for filing with the Commission at a

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3 *Sw. Power Pool, Inc.*, 146 FERC ¶ 61,130 (2014) (order approving the start-up and operation of the Integrated Marketplace effective March 1, 2014).

4 *See* MWG Minutes dated July 10, 2018, at Agenda Item 8 posted at: https://www.spp.org/documents/58343/mwg%20minutes%20&%20attachments%2020180710.pdf. The MWG is responsible for the development and coordination of the changes necessary to support any SPP administered wholesale market(s), including energy, congestion management, and market monitoring, consistent with direction from the SPP Board of Directors.

5 *See* RTWG Minutes dated July 26, 2018, at Agenda Item 11 posted at: https://www.spp.org/documents/58381/rtwg%20july%2026%202018%20minutes.pdf. The RTWG is responsible for development, recommendation, overall implementation, and oversight of SPP's Tariff. The RTWG also advises SPP staff on regulatory and implementation issues not specifically covered by the Tariff or issues where there may be conflicts or differing interpretations of the Tariff.

6 *See* MOPC Minutes dated July 17-18, 2018, at Agenda Item 7 posted at: https://www.spp.org/documents/58436/mopc%20minutes%20and%20attachments%20july%202018.pdf. The MOPC consists of a representative officer or employee from each SPP Member and reports to the SPP Board of Directors. Its responsibilities include recommending modifications to the SPP Tariff. *See*

meeting of the SPP Members Committee[7] and Board of Directors on July 31, 2018.[8] While SPP recognizes that stakeholder approval does not by itself cause a filing to be just and reasonable, SPP requests that the Commission extend appropriate deference to the wishes of SPP's stakeholders, consistent with Commission precedent.[9]

II. PURPOSE AND JUSTIFICATION FOR PROPOSED TARIFF REVISIONS

SPP's proposed revisions to Sections 1.1 and 2.2 of Attachment AE of the Tariff require, with limited exceptions as described herein, that all VERs register as and convert to DVERs by the later of January 1, 2021, or the 10-year anniversary of the Resource's original Commercial Operation Date.

Southwest Power Pool, Inc., Bylaws, First Revised Volume No. 4 ("Bylaws") at Section 6.1.

7 The Members Committee currently consists of up to 24 representatives of the Transmission Owning Member and Transmission Using Member sectors of SPP's Membership. This committee provides input to and assists the SPP Board of Directors with the management and direction of the general business of SPP. *See* Bylaws at Section 5.1.

8 *See* Board of Directors/Members Committee Meeting Minutes No. 180, dated July 31, 2018, at Agenda Item 4 posted at: https://www.spp.org/documents/58412/bod-mc%20minutes%20&%20attachments%2020180731.pdf.

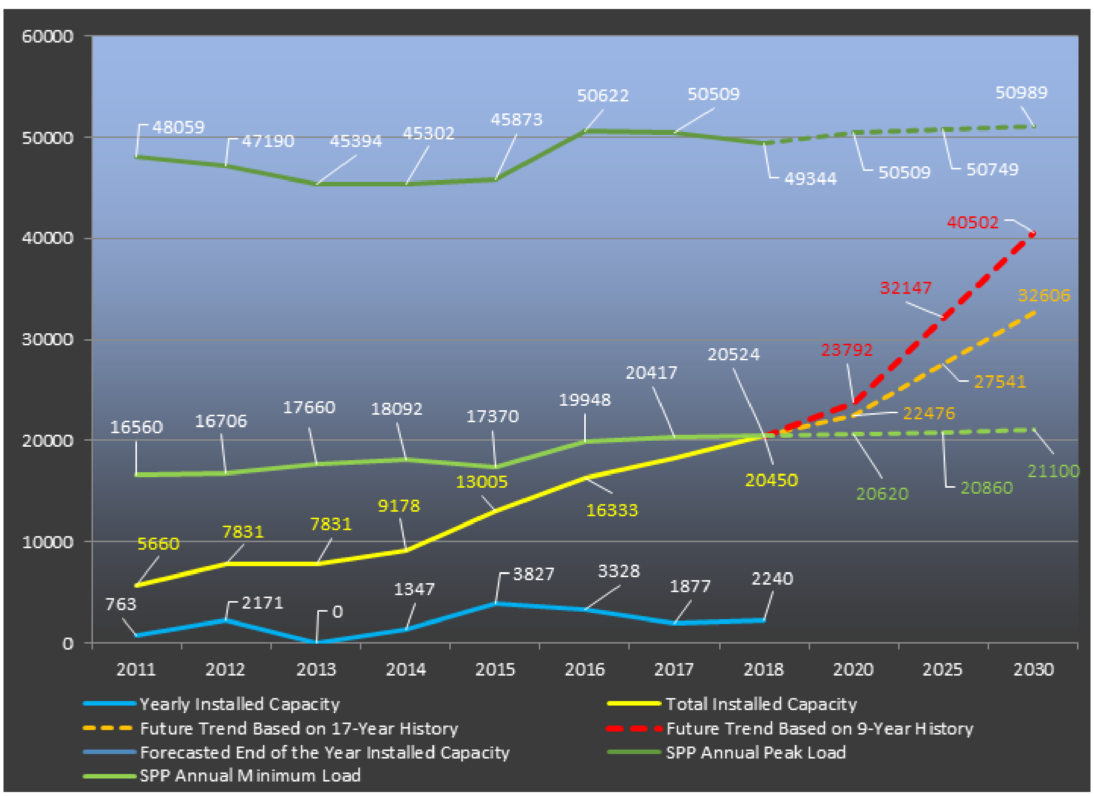
9 The Commission has previously recognized that provisions approved through RTO stakeholder processes are due deference. *See Sw. Power Pool, Inc.*, 127 FERC ¶ 61,283, at P 33 (2009) (noting that the Commission "accord[s] an appropriate degree of deference to RTO stakeholder processes"); *New Eng. Power Pool*, 105 FERC ¶ 61,300, at P 34 (2003) (Commission approval of transmission cost allocation proposal based upon an extensive and thorough stakeholder process); *Policy Statement Regarding Regional Transmission Groups*, 1991-1996 FERC Stats. & Regs., Preambles ¶ 30,976, at 30,872 (1993) (the Commission will afford the appropriate degree of deference to the stakeholder approval process). The Commission's deference to RTO stakeholder processes has been upheld by the courts. *See Pub. Serv. Comm'n of Wis. v. FERC*, 545 F.3d 1058, 1062-63 (D.C. Cir. 2008) (noting the Commission often gives weight to RTO proposals that reflect the position of the majority of the RTO's stakeholders) (quoting *Am. Elec. Power Serv. Corp. v. Midwest Indep. Transmission Sys. Operator, Inc.*, 122 FERC ¶ 61,083, at P 172 (2008)).

As SPP's operational experience and analysis has demonstrated, Non-Dispatchable Variable Energy Resources ("NDVER") in SPP's market create reliability risks and market inefficiencies that other SPP Resources and systems must mitigate. Conversely, the proposed revisions herein will result in reduced reliability risks and more equitable and efficient market outcomes for the SPP Integrated Marketplace.

Reliability:

As SPP's resource mix has evolved and its renewable energy portfolio has grown, the dynamics of managing the Transmission System have become more challenging. In April 2018, the SPP Balancing Authority ("SPP BA") set a new wind penetration peak of almost 65%, and this peak was only the latest in a string of new wind penetration peaks that SPP has experienced over the last several years. Recent information from SPP's generator interconnection queue indicates that these trends are likely to continue for the foreseeable future. By the end of 2018, SPP expects to have 20,450 MWs of installed wind capacity online, see Figure 1 below, which is nearly as much as SPP's annual minimum load level of approximately 20,500 MWs.

Figure 1: SPP Projected Wind Installation Capacity



As the installed levels of VERs have continued to increase, the inherent variability, and sometimes unpredictability, of these Resources have similarly increased the need for Resources within the market to be dispatchable and flexible. With 7,833 MWs of NDVERs registered in the market, during minimum load conditions 30% of load-serving Resources are of a non-dispatchable type – meaning they are not available to be dispatched by the market in response to congestion on the Transmission System. Instead, the market must first attempt to utilize dispatchable Resources that may be less effective or less efficient prior to taking out-of-market action to manually control NDVERs.

Currently, the only means SPP operators have to control the output of an NDVER Resource is through the use of an Out-of-Merit Energy ("OOME") instruction.[10] By definition, an OOME may only be issued by SPP to address an Emergency Condition or a reliability issue that the market systems cannot resolve.[11] Therefore, SPP must first utilize dispatchable Resources within the market, even if those Resources have a lower impact on the constrained facility or cannot adequately reduce constraint loading, before issuing an OOME to an NDVER.[12] As such, NDVERs make up 69% of the Resources within the SPP Integrated Marketplace to which OOMEs are issued (see Figure 2). The need to issue an OOME inherently represents a physical reliability issue that has risen to the attention of the Reliability Coordinator ("RC") and requires the RC, by definition, to take out-of-market action to maintain reliability. These out-of-market actions take longer to implement and are less efficient than re-dispatching Resources automatically based on the market's Security Constrained Economic Dispatch ("SCED") engine. Although, to this point, SPP has been able to successfully manage these reliability issues through out-of-market actions, converting NDVERs to DVERs would help to ensure these issues are addressed quickly and efficiently within the market.

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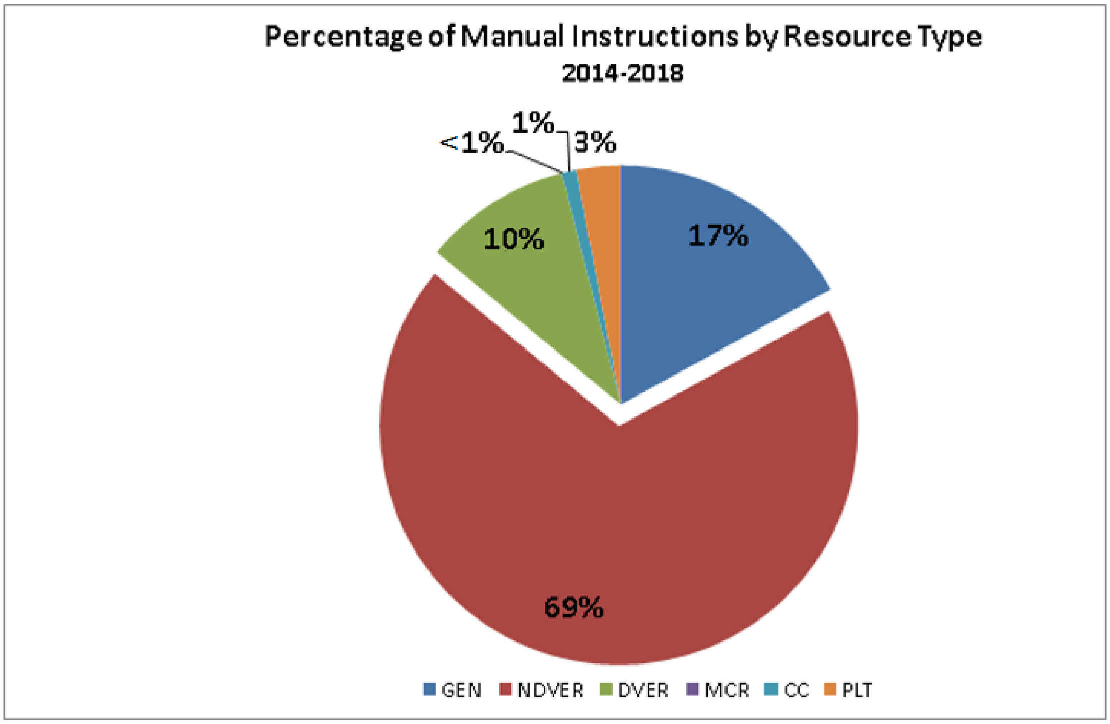
10 *See* Tariff at Attachment AE, Section 6.2.4.

11 *See* Tariff at Attachment AE, Section 1.1 Definitions O.

12 The dispatchable Resources include other VERs that have been registered as DVERs. These DVERs will be dispatched to reduce output *prior to* the NDVERs even if the DVERs are more economical and more effective than the NDVERs.

Figure 2: OOME Instructions by Resource Type



Although, by definition, an NDVER is not capable of being economically dispatched by SPP, a number of NDVERS have been observed to be reacting to Locational Marginal Price ("LMP") signals from the market - dropping offline when the LMP drops and responding to increased LMPs by generating at the same prior output. This price-following behavior presents reliability and operational challenges as more or less relief occurs than was requested by the SCED solution used in the Real-Time Balancing Market ("RTBM"). RTBM is less effective at ensuring reliability for transmission constraints and positioning the SPP BA to perform its responsibilities when NDVERs behave in this manner.

Additionally, this price chasing behavior can lead to reliability issues due to power system oscillations resulting from the quick unloading and reloading of transmission constraints. This phenomenon puts the RC in a position wherein it may be necessary to issue an OOME to NDVERs that are responding to LMP changes, i.e., price-chasing, in order to mitigate transmission constraints becoming unstable from the unexpected oscillations caused by the price-chasing NDVERs. The examples below illustrate actual observed price-chasing behavior and the resulting oscillations on transmission constraints.

Price-Chasing Volatility Example

Figure 3 below shows transmission constraint loading, a DVER following market dispatch instructions, an NDVER that is following price, and the corresponding swings on the Transmission System due to this behavior. As RTBM solves for this congestion, the NDVER is dispatched at the observed MW output at the start of the study due to its non-dispatchable nature while the DVER is dispatched down economically. In Real-Time, both the DVER (following its dispatch set by RTBM) and the NDVER (following the RTBM price) reduce output. This causes the transmission constraint loading to drop off sharply due to NDVER reduction being unaccounted for in the RTBM solution. Seeing the reduced NDVER output and presuming the current MW output will persist, the next RTBM solution begins to restore the DVER output. Once again, in Real-Time, the NDVER follows price and ramps up at the same time as the DVER. This unforeseen increase in DVER output leads to increased flowgate loading and can contribute to system operating limit ("SOL") exceedances.

Figure 3: Price-Chasing Volatility

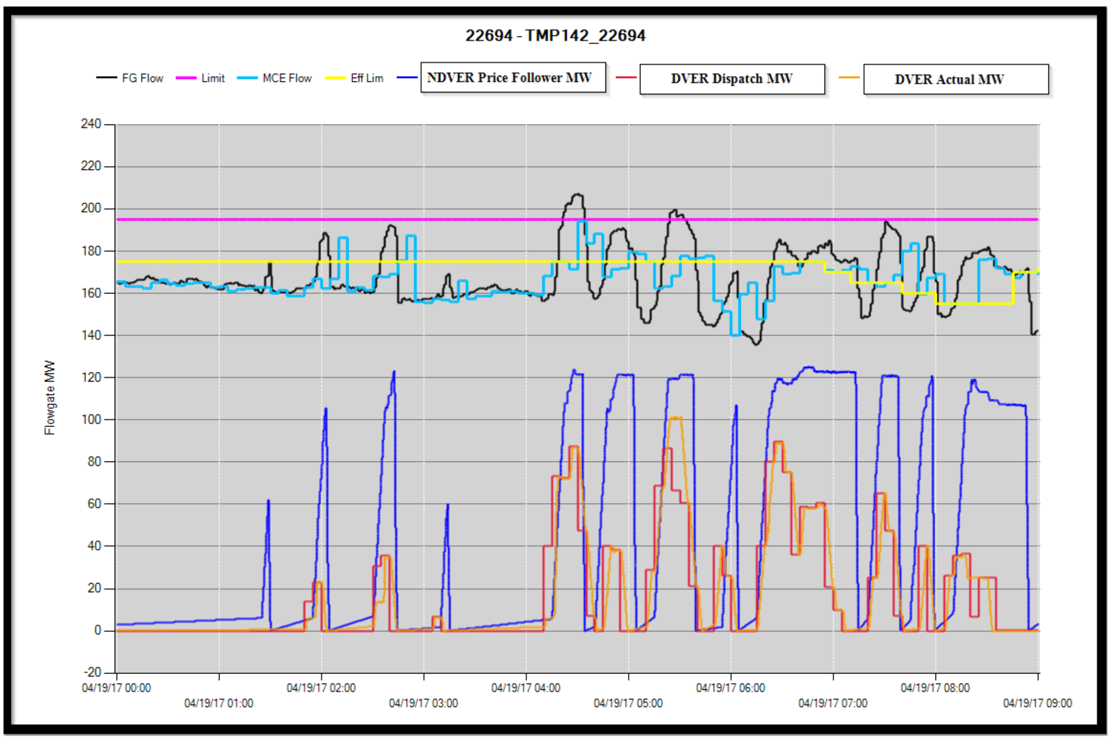
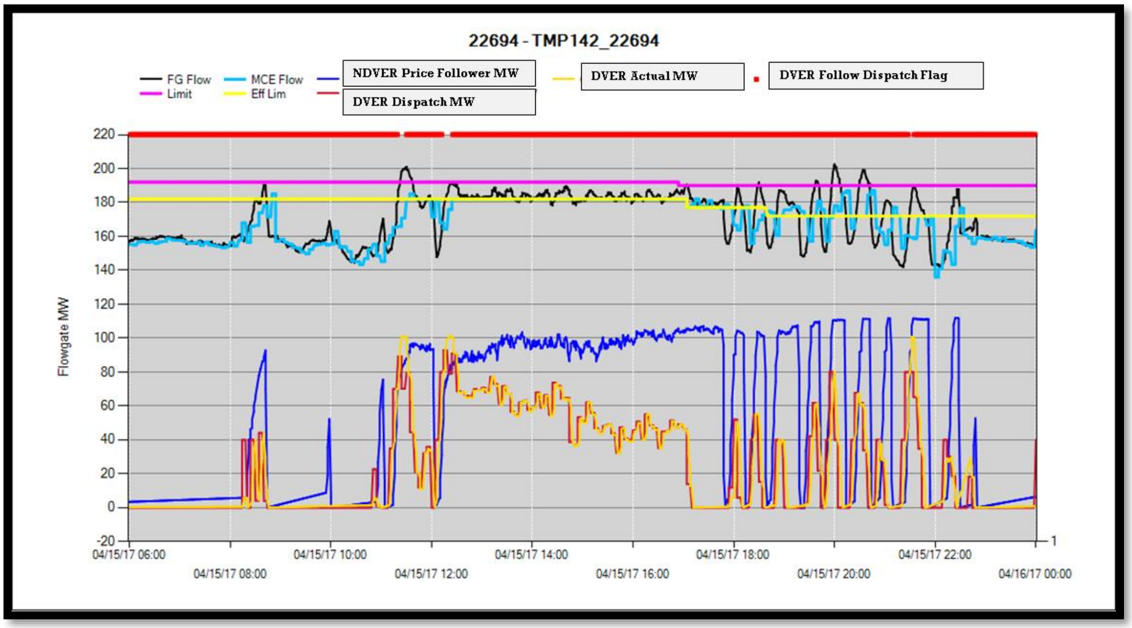


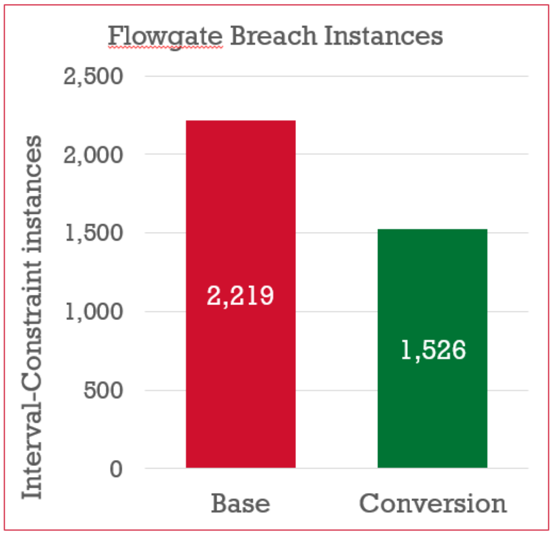
Figure 4 below illustrates the steady control of the same transmission constraint when only the DVER is moving due to RTBM dispatch between the hours of 12:00 and 18:00. Once the NDVER begins price-chasing around 18:00, the transmission constraint loading begins to oscillate and the constraint exceeds its SOL on several occasions.

Figure 4: Price-Chasing Volatility (DVER example)



SPP conducted a study demonstrating the reliability and market efficiency benefits that would result from the proposed conversion of NDVERs to DVERs. A full month of RTBM solutions (i.e., 8,064 five-minute RTBM cases) were simulated with the NDVERs converted to DVERs. The results, illustrated in Figure 5 below, demonstrate increased reliability security and efficiency. In the simulated cases, the market was able to reduce the number of constraint breaches by 31%. A reduction in constraint breaches of that magnitude equates to reduced reliability risk resulting from a significant reduction of time wherein equipment may be over the limit set by the transmission operator.

Figure 5: Reduction in Flowgate Breaches



The primary driver of this reduction in breaches is the ability for the RTBM to utilize more dispatchable Resources, some with large impacts on transmission constraints. As mentioned previously, without the conversion of NDVERs to DVERs, RTBM must re-dispatch Resources that may have less impact to the loaded transmission constraint. It should be noted that this increase in dispatchable Resources also reduces the volatility of prices in the market (see Figure 6) and, in turn, the volatility of the Transmission System as a whole. When re-dispatching for a constraint using Resources with a low impact, the market solution will tend to have more volatility due to the fact that a larger amount of MWs are needed to be re-dispatched to get the same amount of relief than could be achieved from Resources that have a large impact on the constraint. Ultimately, more dispatchable Resources with larger impacts to the constraints on the Transmission System allows for more efficient control of the Transmission System and increases the security and resiliency of the Transmission System as a whole.

Market Efficiency:

While the immediate increase in Transmission System security and resiliency alone presents a compelling case for the proposed change, the increases in overall market efficiency further support the proposal. Converting a significant majority of the NDVERs to DVERs creates a multitude of market efficiencies including a reduction in the cost to resolve congestion, a decrease in the price separation between the Day-Ahead Market and the RTBM, an increase in revenue for Resource owners, a decrease in charges to loads, and a reduction in the amount of negative pricing in the SPP Integrated Marketplace.

As discussed previously, SPP has conducted studies regarding the reliability and market efficiency impacts of the proposed change. The results from SPP's analysis demonstrate a reduction in shadow price, i.e., the cost per MWh to resolve a constraint, of over $15 per MWh. This more efficient dispatch solution with regard to congestion decreases the cost to serve the aggregate load throughout the SPP footprint, as illustrated in Figure 6 below.

Figure 6: Average Constraint Shadow Price during Congestion

Pricing Indicator	Base Case	Conversion Case
Average constraint Shadow Prices during congestion	$122	$107

An area of particular importance that would be improved by the conversion of NDVERs is price convergence between the Day-Ahead Market and the RTBM. Currently, SPP's Day-Ahead Market dispatches NDVERs as if they were dispatchable Resources. This design rule allows Market Participants with NDVERs to more efficiently secure a financial position and hedge themselves consistent with other Resources. As discussed previously, NDVERs are treated differently in the RTBM and are considered non-dispatchable leading to a disparate treatment of NDVERs between the Day-Ahead Market and the RTBM.

Based on the results of SPP's studies of the proposed change, the average difference between the marginal energy cost between the Day-Ahead Market and the RTBM decreased by 49% from ($0.97 to $0.50; see Figure 7). There was a similar decrease in the difference between the average LMP between the Day-Ahead Market and the RTBM. Additionally, the price spread (difference between the minimum and maximum LMP) in the RTBM decreased by over $14. This demonstrates that having non-dispatchable Resources convert to dispatchable would create greater price convergence between the SPP Day-Ahead Market and the RTBM, better price assurance for Market Participants, and more stable pricing throughout the SPP footprint.

Figure 3: DA vs RT Pricing from SPP Study

Pricing Indicator	Base Case	Conversion Case
Average RT-DA MEC Difference	-$0.97	-$0.50
Average RT-DA LMP Difference	-$0.52	+$0.11
Average (absolute) RT-DA LMP Difference	$7.98	$7.39
Change from Base Case	-	-$0.59
Volatility (Std Deviation) RT-DA LMP Difference	$18.16	$17.44
Change from Base Case	-	-$0.72
Average RT LMP Spread (Max LMP – Min LMP)	$170.07	$155.41
Change from Base Case	-	-$14.65

A key discussion during the extensive stakeholder process centered upon the impacts of NDVERs becoming dispatchable on Resource revenues and load payments. SPP's analysis showed that, for the one month study period, there was an increase of over $2 million in revenue for Resources registered in the SPP market. Of that increase, $881,000 was projected to go to the converted NDVERs, $713,000 went to existing DVERs, and $472,000 went to other Resource types (Coal, Gas, Hydro) registered in the market. Additionally, the study indicated that load assets in the market would be expected to pay $134,000 less to meet their load obligations. This change in the Resource revenues and load payments is primarily a result of the increased dispatchability of NDVERs in the market and the resulting convergence between the Day-Ahead Market and the RTBM.

With the increased dispatchability, the market is able to re-dispatch Resources at closer electrical distances that have higher impact to congested constraints rather than depending on Resources at greater electrical distances that have a lower impact. This, in turn, decreases the cost of congestion and raises the previously depressed LMPs at Resource locations impacted by NDVERs. This more efficient solution, from a revenue perspective, is in line with the decrease in shadow prices for constraints mentioned previously. When the market is able to resolve congestion at a lower cost, the LMPs and, therefore, the Resource revenues will also reflect this more efficient solution.

In SPP's analysis, Resource revenues increased while load payments decreased. While this may appear counterintuitive, the study highlighted that Market Participants participating in virtual transactions in the market currently take advantage of the dispatchability difference of NDVERs between the Day-Ahead Market and the RTBM. When NDVERs were converted and became dispatchable in both the Day-Ahead Market and the RTBM, the arbitrage opportunities decreased for the virtual participants. The subsequent decrease of revenue for virtual participants funded the increased Resource revenues and decreased load payments.[13] SPP believes this is a natural progression in energy markets. As the markets mature, inconsistencies that are highlighted by virtual participation are removed, bolstering price convergence and assurance.

A topic of discussion in organized markets that have a large penetration of renewable energy with respect to load is negative pricing. In 2017,SPP saw its largest increase in negative pricing since the start of the Integrated Marketplace in 2014, having over 4,848 intervals in the Day-Ahead Market and the RTBM with negative marginal energy costs. SPP's analysis of converting NDVERs to become dispatchable showed more than a 90% reduction (see Figure 8) in the number of intervals with a negative marginal cost of energy from the base case, in which NDVERs were not dispatchable, to the conversion case, in which NDVERs were dispatchable. This is, again, mostly attributable to a more efficient dispatch of Resources to resolve congestion resulting in increased transmission system security and resiliency.

Figure 4: Instances of Negative Marginal Energy Cost

MEC Bucket	Base	Conversion	# Change	% Change
<$0	148	14	-134	-90.5%
$0 to $10	549	519	-30	-5.5%
$10 to $20	3,926	4,074	148	3.8%
$20 to $30	2,673	2,703	30	1.1%
$30 to $40	354	347	-7	-2.0%
$40 to $50	80	78	-2	-2.5%
>=$50	333	328	-5	-1.5%

13 A modeling inefficiency exists and creates a spread between the Day-Ahead Market and the RTBM. This spread has allowed virtual transactions to arbitrage pricing differences with little risk. The proposed changes would decrease the availability of these arbitrage opportunities and direct the increased efficiency to Resources and load.

<u>Recommendations from the MMU Annual State of the Market Report</u>:

In the 2015 Annual State of the Market ("ASOM") Report,[14] the SPP Market Monitoring Unit ("MMU") expressed their concern with the market design for NDVERs due to their adverse impact on market prices. The SPP MMU stated that when prices are depressed in high wind production regions, NDVERs have an adverse impact on prices based on two observed behaviors.[15] Some Resources chase price, ignoring the system dispatch and self-dispatching to a lower level in an attempt to avoid the cost associated with producing when prices are very low. This price-chasing behavior, as discussed earlier, may cause unexpected volatility on the system and distorts market prices. The alternative behavior is for NDVER units to continue producing as expected even when prices are below what would be an appropriate market-clearing price. Both cases result in sub-optimal market results. The SPP MMU recommended that SPP transition NDVERs to DVERs to lessen the negative impact of such Resources on the market. The SPP MMU reiterated this recommendation in the 2016, and 2017 ASOM reports.[16]

<u>Summary</u>:

The revisions proposed will require that all existing NDVERs, with the exception of Qualifying Facilities exercising their rights under the Public Utility Regulatory Policies Act of 1978 ("PURPA")[17] and run of the river hydroelectric Resources that are incapable of following Dispatch Instructions, become dispatchable to the market. As illustrated above and as indicated by SPP's analysis, there are numerous reliability and market efficiency benefits from this proposed change:

- Increased reliability realized through collective dispatchable Resources mitigating multiple constraints simultaneously;
- Increased economic efficiency through reduction of manual OOME instructions;
- Reduction of price volatility (reliability and economic benefit);

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[14] The 2015 ASOM is posted at: https://www.spp.org/documents/41597/spp_mmu_state_of_the_market_report_2015.pdf.

[15] *See* 2015 ASOM at Section 7.10.

[16] *See* 2016 ASOM at Section 7.2.1 (https://www.spp.org/documents/53549/spp_mmu_asom_2016.pdf). *See also* 2017 ASOM at Section Section 7.4.1 (https://www.spp.org/documents/57928/spp_mmu_asom_2017.pdf).

[17] https://www.ferc.gov/industries/electric/gen-info/qual-fac/what-is.asp

- Fewer instances of negative marginal energy prices;
- Having more DVERs controllable by the market and not subject only to variable fuel and external control behaviors leads to less pricing uncertainty as a result of:
    - Reduction of ramp scarcity events by having more Resources controllable within SCED
    - Increased pricing convergence between the Day-Ahead Market and the RTBM due to larger set of controllable Resources
    - Further potential optimization of Operating Reserves with potentially more VERs participating in the offering of certain ancillary services (e.g. regulation down).
    - Increased reliability by reducing system oscillations from unexpected price-following behavior of certain NDVERs
- Market efficiencies are gained by adding dispatchable generation to resolve congestion in load pockets, rather than redispatching less effective generation due to the NDVERs not being dispatchable by the market. This has the potential to reduce congestion costs from less effective generation redispatch; and
- Potentially disparate treatment between DVERs and NDVERs is reduced.

Accordingly, SPP respectfully requests that the Commission accept the Tariff revisions proposed herein as just and reasonable.

III. DESCRIPTION OF TARIFF REVISIONS

A. Section 1.1 of Attachment AE (Definitions and Acronyms)

The revisions to current Tariff language in Section 1.1 of Attachment AE add the phrase "registered in the market" to the definitions of the terms Dispatchable Variable Energy Resource[18] and Non-Dispatchable Variable Energy Resource.[19]

The purpose of the revision is to make it clear that the proposed revisions to Section 2.2 of Attachment AE regarding registration and conversion *only* apply to VERs that are registered in SPP's market. The requirements do not apply to VERs that

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18 Proposed Tariff at Attachment AE, Section 1.1 Definitions D. SPP is also submitting an additional tariff sheet with an effective date of May 1, 2019 in order to carry forward the changes included herein into the Tariff dated May 1, 2019. The Commission previously accepted unrelated revisions to the Tariff, to be effective May 1, 2019, in Docket No. ER18-2058-000. *See Sw. Power Pool, Inc.*, Letter Order, Docket No. ER18-2058-000 (September 7, 2018).

19 Proposed Tariff at Attachment AE, Section 1.1 Definitions N.

are not required to be registered in the market such as those behind the meter and less than 10 MW.

B. Section 2.2 of Attachment AE (Application and Asset Registration)

Proposed revisions to Section 2.2 of Attachment AE provide dates certain by which VERs currently registered as NDVERs must register as and convert to DVERs.[20]

VERs that are currently registered as NDVERs must register as and convert to DVERs by the later of January 1, 2021, or the 10-year anniversary of the Resource's original Commercial Operation Date. This requirement does not extend to a VER that is either (1) a Qualifying Facility exercising its rights under PURPA or (2) a Resource having a primary fuel source of run of the river hydroelectric that is incapable of following Dispatch Instructions.

The requirement that the VER be registered as and convert to a DVER on the later of January 1, 2021, or the 10-year anniversary of the Resource's original Commercial Operation Date, was chosen after significant stakeholder input regarding the time and expense that may be required to physically modify certain Resources to become capable of being dispatched by SPP. Some stakeholders represented that very little time and expense would be required, while others expressed that 18 months or longer would be necessary. Additionally, some stakeholders desired to tie the requirement to convert to the expiration of production tax credits ("PTCs") associated with a particular Resource. As such, the later of January 1, 2021, or the 10-year anniversary of the Resource's Commercial Operation Date is intended to strike an appropriate balance between the many stakeholder interests and concerns related to the timing of the conversion.

During the extensive stakeholder discussions regarding the proposed revisions, there were many requested exclusions from the requirement to convert for a multitude of reasons including cost, age of resources, contract complexities, PTC implications, etc. Ultimately, SPP and a majority of its stakeholders agreed that only two exclusions to the proposed conversion requirements were appropriate.

First, non-dispatchable Qualifying Facilities exercising their rights under PURPA are excluded from the requirement to change registration and convert to be dispatchable under the proposed revisions. Market Participants, except Behind-The-Meter Generation less than 10 MW, are required to register their loads and Resources.[21]

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[20] Proposed Tariff at Attachment AE, Section 2.2(10).

[21] Tariff at Attachment AE, Section 2.2(6).

This requirement removes a Qualifying Facility's option to not register as a Resource if they are greater than 10 MW.

In Docket No. ER17-68,[22] the Commission considered changes for ISO New England Inc. ("ISO-NE") regarding conversion of non-dispatchable resources, similar to those proposed here by SPP, and found that the changes proposed were just and reasonable.[23] In determining whether the inclusion of Qualifying Facilities in the requirement to convert was reasonable, the Commission noted that the Qualifying Facilities did not have to register in ISO-NE's market in order to participate, and, as such, the changes were just and reasonable as applied to Qualifying Facilities. The Commission stated that "if [Qualifying Facilities] prefer not to comply, they have the option to not register, or to deregister, as Market Participants and act as behind-the-meter resources without impacting their PURPA obligations and rights."[24]

In SPP's Integrated Marketplace, that would not be the case. Qualifying Facilities greater than 10 MW in SPP's Integrated Marketplace are required to register and would, therefore, be required to convert to dispatchable absent an exception. As such, it was determined by SPP and its stakeholders that these Resources should not be required to convert.

Second, run of the river hydroelectric Resources that are incapable of following Dispatch Instructions are also excluded from the requirement to convert. While some stakeholders who own or operate run of the river hydroelectric indicated they could become dispatchable, others indicated that they could not convert due to their limited authority to influence how the U.S. Army Corps of Engineers physically operates the Resource.

Under existing registration provisions in Attachment AE, the relevant Market Participant is responsible for updating a generator's *registration* status. Under the revised language, the Market Participant will continue to be responsible for registration functions, including changes of status from NDVER to DVER. However, the revisions specify that the Generation Interconnection Customer associated with a generator is the party responsible for facilitating the generator's physical conversion. SPP and its stakeholders determined that the Generation Interconnection Customer, as the entity

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22 *See* ISO New England, Inc. and New England Power Pool Market Rule 1 Revisions to Increase Resource Dispatchability, Docket No. ER17-68-000 (October 12, 2016.

23 *ISO New England Inc., et al.*, 157 FERC ¶ 61,189 (2016) ("ISO-NE Order").

24 ISO-NE Order at P 25.

that owns the Resource, would be best suited to handle any necessary modifications and other steps required for conversion.[25]

IV. ADDITIONAL INFORMATION

A. Information Provided Per Commission Regulations[26]

1. Documents submitted with this filing:

In addition to this Transmittal Letter, Clean and Redlined Tariff revisions under the Sixth Revised Volume No. 1.

2. Service:

SPP has electronically served a copy of this filing on all its Members, Transmission Customers and Market Participants. A complete copy of this filing will be posted on the SPP web site, www.spp.org, and is also being served on all affected state commissions.

3. Requisite agreements:

Not applicable.

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25 SPP is not privy to contracts between the Generation Interconnect Customer and other parties. These contracts may delegate the legal financial responsibility for converting an NDVER to a DVER to a party other than the Generation Interconnection Customer and with whom SPP has no contractual privity. In such a circumstance, the Generation Interconnection Customer is the party upon whom the responsibility rests, and to whom SPP will look, for ensuring conversion is completed by the specified dates.

26 Because the revisions to the Tariff submitted herein do not involve any changes in rates, the use of the abbreviated filing procedures as set forth in 18 C.F.R. § 35.13(a)(2)(iii) is appropriate.

B. Communications

Correspondence and communications with respect to this filing should be sent to, and SPP requests the Secretary to include on the official service list, the following:

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V. CONCLUSION

For all of the foregoing reasons, SPP respectfully requests that the Commission issue an order accepting the Tariff revisions proposed herein, to be effective on January 16, 2019.

Respectfully submitted,

*/s/ **Christopher M. Nolen***

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1.1 Definitions D

Day-Ahead

The time period starting at 0001 and ending at 2400 on the day prior to the Operating Day.

Day-Ahead Market

As defined in Section 1 of the Tariff.

Day-Ahead Market Commitment Period

The contiguous period of time between a Resource's Day-Ahead Market Commit Time and Day-Ahead Market De-Commit Time.

Day-Ahead Reliability Unit Commitment ("Day-Ahead RUC")

The process performed by the Transmission Provider following the close of the Day-Ahead Market and prior to the Operating Day to assess Resource and Operating Reserve adequacy for the Day-Ahead period and the remainder of the current Operating Day, commit or de-commit Resources as necessary, and communicate commitment or de-commitment of Resources to the appropriate Market Participants as necessary.

De-Commit Time

The time specified by the Transmission Provider or a local transmission operator in a Commitment Instruction at which a Resource is to begin de-synchronization procedures.

Demand Bid

A proposal by a Market Participant associated with a physical load to purchase a fixed or price sensitive amount of Energy at a specified location and period of time in the Day-Ahead Market.

Demand Bid Curve

A Demand Bid specified as Megawatt and dollars per Megawatt hour with up to ten (10) price/quantity pairs.

Demand Curve

A series of quantity/price points used to set Locational Marginal Prices and Market Clearing Prices when there is a shortage of Energy or Operating Reserve.

Demand Response Load

A registered measurable load that is capable of being reduced at the instruction of the Transmission Provider and subsequently may be increased at the instruction of the Transmission Provider.

Demand Response Resource

A Dispatchable Demand Response Resource or a Block Demand Response Resource.

Designated Resource

As defined in Section 1 of the Tariff.

Dispatch Interval

The five (5) minute interval for which the Transmission Provider issues Dispatch Instructions for Energy and clears Operating Reserve in the Real-Time Balancing Market.

Dispatch Instruction

The communicated Resource target Energy Megawatt output level at the end of the Dispatch Interval.

Dispatchable Demand Response Load Settlement Location

A registered load Settlement Location that contains the Demand Response Load associated with a Dispatchable Demand Response Resource.

Dispatchable Demand Response Resource

A Resource created to model Demand Response Load reduction associated with controllable load or a Behind-The-Meter generator that is dispatchable on a five (5) minute basis.

Dispatchable Resource

A Resource for which an Energy Offer Curve has been submitted and that is available for dispatch by the Transmission Provider on a Dispatch Interval basis.

Dispatchable Variable Energy Resource

A Variable Energy Resource registered in the Integrated Marketplace that is capable of being incrementally dispatched by the Transmission Provider.

1.1 Definitions D

Data Error

A data error shall be the following:

(i) Data received by the Transmission Provider from an independent source, including data produced by a system or submitted by a third party, that is inaccurately modified by the Transmission Provider during the execution of a market function; or

(ii) Data received by the Transmission Provider from an independent source, including data produced by a system or submitted by a third party, that is patently incorrect and is used by the Transmission Provider during the execution of a market function; or

(iii) Incorrect data produced and used by the Transmission Provider during the execution of a market function.

Day-Ahead

The time period starting at 0001 and ending at 2400 on the day prior to the Operating Day.

Day-Ahead Market

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The contiguous period of time between a Resource’s Day-Ahead Market Commit Time and Day-Ahead Market De-Commit Time.

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Demand Curve

A series of quantity/price points used to set Locational Marginal Prices and Market Clearing Prices when there is a shortage of Energy or Operating Reserve.

Demand Response Load

A registered measurable load that is capable of being reduced at the instruction of the Transmission Provider and subsequently may be increased at the instruction of the Transmission Provider.

Demand Response Resource

A Dispatchable Demand Response Resource or a Block Demand Response Resource.

Designated Resource

As defined in Section 1 of the Tariff.

Dispatch Interval

The five (5) minute interval for which the Transmission Provider issues Dispatch Instructions for Energy and clears Operating Reserve in the Real-Time Balancing Market.

Dispatch Instruction

The communicated Resource target Energy Megawatt output level at the end of the Dispatch Interval.

Dispatchable Demand Response Load Settlement Location

A registered load Settlement Location that contains the Demand Response Load associated with a Dispatchable Demand Response Resource.

Dispatchable Demand Response Resource

A Resource created to model Demand Response Load reduction associated with controllable load or a Behind-The-Meter generator that is dispatchable on a five (5) minute basis.

Dispatchable Resource

A Resource for which an Energy Offer Curve has been submitted and that is available for dispatch by the Transmission Provider on a Dispatch Interval basis.

Dispatchable Variable Energy Resource

A Variable Energy Resource registered in the Integrated Marketplace that is capable of being incrementally dispatched by the Transmission Provider.

1.1 Definitions N

Net Benefits Test

A calculation that measures the threshold price at which the benefits of dispatching Demand Response Load outweigh the costs.

Network Integration Transmission Service

As defined in Section 1 of the Tariff.

Network Integration Transmission Service Auction Revenue Right Nomination Cap

The maximum amount of Network Integration Transmission Service Candidate Auction Revenue Rights that an Eligible Entity may nominate in each month and season in the annual Auction Revenue Right allocation process and the monthly Auction Revenue Right allocation process.

Network Integration Transmission Service Candidate Auction Revenue Right

The Megawatt quantity associated with Network Integration Transmission Service from Network Resources that the holder of the Network Integration Transmission Service can nominate for conversion into an Auction Revenue Right, subject to the Network Integration Transmission Service Auction Revenue Right Nomination Cap.

Network Integration Transmission Service Candidate Long-Term Congestion Right

The Megawatt quantity associated with Network Integration Transmission Service with rollover rights from Network Resources that is used by the Transmission Provider to determine available rights that the holder of the Network Integration Transmission Service can select for conversion into a Long-Term Congestion Right during the Long-Term Congestion Right allocation process.

Network Model

A representation of the transmission, generation, and load elements of the interconnected Transmission System and the transmission systems of other regions in the Eastern Interconnection.

No-Load Offer

The compensation request in a Resource Offer, in dollars, by a Market Participant representing the hourly fee for operating a synchronized Resource at zero (0) Megawatt output. For a generating unit, No-Load Offers are generally representative of the fuel expense required to maintain synchronous speed at zero (0) Megawatt output. For a Dispatchable Demand Response Resource or Block Demand Response Resource, No-Load Offers are generally representative of a combination of the fuel expense required to maintain synchronous speed at zero (0) Megawatt output for Behind-The-Meter Generation and the ongoing hourly costs associated with manufacturing process changes associated with a reduction in load consumption.

Non-Conforming Load

Load that is process driven that does not follow a predictable pattern.

Non-Dispatchable Variable Energy Resource

A Variable Energy Resource registered in the Integrated Marketplace that is not capable of being incrementally dispatched by the Transmission Provider.

2.2 Application and Asset Registration

(1) Applications for a Market Participant to provide services in the Integrated Marketplace must be submitted to the Transmission Provider prior to the expected date of participation consistent with Section 6.4 of the Market Protocols. Applications must conform to the procedures specified in the Market Protocols and may be rejected if not complete. New Market Participants will follow the timeframe as specified in Section 6.4 of the Market Protocols in addition to the detailed model update timing requirements in Appendix E of the Market Protocols.

(2) As part of the application process, Market Participants must register all Resources and load, including applicable load associated with Grandfathered Agreements ("GFAs"), Non-Conforming Load and Demand Response Load with the Transmission Provider in accordance with the registration process specified in the Market Protocols. As part of Resource registration, Market Participants must specify whether settlement meter data will be submitted on a gross basis or net basis, where gross meter data does not include reductions for auxiliary load and net meter data is gross meter data reduced by auxiliary load. Both Non-Conforming Load and Demand Response Load may only be associated with a single Price Node except that Non-Conforming Load and Demand Response Load may be associated with an aggregated Price Node that contains multiple electrically equivalent Price Nodes. Non-participating embedded load and/or generation must either: (i) register its load and/or generation in the Integrated Marketplace; or (ii) transfer its load and/or generation to an external Balancing Authority.

(3) Market Participants may elect to define a single Settlement Location that aggregates multiple Meter Data Submittal Locations associated with their load assets. Market Participants may not aggregate multiple Resource Meter Data Submittal Locations into a single Resource Settlement Location unless the Resources are at the same physical and electrically equivalent injection point to the Transmission System.

(4) In addition to the responsibilities described in Section 4.1.2 of this Attachment AE and under the Market Protocols, Market Participants wishing to model each participant's share of a Jointly Owned Unit as a separate Resource must choose one of the two options described below and provide the specified additional information. A Resource registered as a combined cycle Resource may not register as a Jointly Owned Unit.

(a) Individual Resource Option

Under the individual Resource option, each participant's share is modeled as a separate Resource for the purposes of commitment and dispatch and each Resource may be committed independent of the other Resource shares.

The operating owner's Meter Agent will be the Meter Agent for that Jointly Owned Unit unless each individual Jointly Owned Unit participant registers a Meter Agent for its share of the Resource.

Unless otherwise agreed to by the Jointly Owned Unit participants, the operating owner will be responsible for submitting the following data:

- Jointly Owned Unit maximum physical capacity operating limit;
- Jointly Owned Unit minimum physical capacity operating limit;
- Jointly Owned Unit minimum physical regulation capacity operating limit; and
- Maximum physical ten (10) minute response from an off-line state.

(b) Combined Resource Option

Under the combined Resource option each participant's share is modeled and must be registered as a separate Resource. Under this option, the commitment decision is made assuming that all Resource shares must be committed or none at all. Each Asset Owner of a Jointly Owned Unit under the combined Resource option must submit a zero for the Minimum Emergency Capacity Operating Limit, Minimum Normal Capacity Operating Limit, Minimum Regulation Capacity Operating Limit, and

Minimum Economic Capacity Operating Limit. The Jointly Owned Unit minimum physical capacity operating limit and minimum physical regulation capacity operating limit when the Jointly Owned Unit is selected to Regulate, can be achieved by any combination of Jointly Owned Unit shares during the commitment period. A Jointly Owned Unit under the combined Resource option will be dispatched using an aggregated Energy Offer Curve. Once committed, each Jointly Owned Unit share is dispatched independently and is eligible for recovery of Start-Up Offer and No-Load offer costs as described under Sections 8.5.9 and 8.6.5 of this Attachment AE. This option must be selected if the eligibility criteria stated under the individual Resource option cannot be met.

The operating owner's Meter Agent will be the Meter Agent for that Jointly Owned Unit unless each individual Jointly Owned Unit participant registers a Meter Agent for its share of the Resource.

Unless otherwise agreed to by the Jointly Owned Unit participants, the operating owner will be responsible for submitting the following data:

- Jointly Owned Unit maximum physical capacity operating limit;
- Jointly Owned Unit minimum physical capacity operating limit;
- Jointly Owned Unit minimum physical regulation capacity operating limit;
- Maximum physical ten (10) minute response from an off-line state; and
- Participant share percentage by Market Participant.

(5) Market Participants may modify their registered assets in accordance with the asset registration procedures specified in the Market Protocols.

(6) All loads and all Resources, excluding Behind-The-Meter Generation less than 10 Megawatts ("MWs"), must register. Failure or refusal to register a load will result in the Transmission Provider filing an unexecuted version of the service

agreement as specified in Attachment AH of this Tariff for that load with the Commission under the name of the (i) Network Customer, (ii) Transmission Customer, or (iii) Transmission Owner serving load under a Grandfathered Agreement for which the Transmission Owner is neither taking Network Integration Transmission Service nor Firm Point-To-Point Transmission Service. Failure or refusal to register a Resource will result in the Transmission Provider filing an unexecuted version of the service agreement as specified in Attachment AH of this Tariff for that Resource with the Commission under the name of the generation interconnection customer under an interconnection agreement with the Transmission Provider or the applicable Transmission Owner. In the case of a Qualifying Facility exercising its rights under PURPA to deliver all of its net output to its host utility, such registration will not require the Qualifying Facility to participate in the Energy and Operating Reserve Markets or subject the Qualifying Facility to any charges or payments related to the Energy and Operating Reserve Markets. Any Energy and Operating Reserve Market charges or payments associated with the output of the Qualifying Facility will be allocated to the Market Participant representing the host utility purchasing the output of the Qualifying Facility under PURPA, and the Market Participant will be provided the settlement data required to verify the settlement charges and payments.

(7) A Market Participant wishing to Offer an External Resource in the Energy and Operating Reserve Markets will utilize an External Resource Pseudo-Tie in accordance with Attachment AO. In addition to the responsibilities outlined in Attachment AO, the Market Participant registering the External Resource will be responsible for registering and performing all responsibilities that are required of Resources in the Energy and Operating Reserve Markets.

(8) A Market Participant wishing to offer Demand Response Load as a Demand Response Resource in the Energy and Operating Reserve Markets must include in its application and registration a certification that participation in the Energy and Operating Reserve Markets by its Demand Response Resource is not precluded under the laws or regulations of the relevant electric retail regulatory authority. Consistent with Section 2.8.1 of this Attachment, an aggregator of retail

customers wishing to offer Demand Response Load in the form of a Demand Response Resource on behalf of one or more retail customers must also include in its application and registration a certification that participation of each retail customer is either: (1) not precluded by the laws or regulations of the relevant electric retail regulatory authority if the customer is served by a utility that distributed more than 4 million MWh in the previous fiscal year; or (2) affirmatively permitted by the laws or regulations of the relevant electric retail regulatory authority if the customer is served by a utility that distributed 4 million MWh or less in the previous fiscal year. Demand Response Resources must meet all application, registration and technical requirements applicable to the Energy and Operating Reserve Markets. The Transmission Provider is not responsible for interpreting the laws or regulations of a relevant electric retail regulatory authority and shall be required only to verify that the Market Participant has included such a certification in its application materials. The Transmission Provider is not liable or responsible for Market Participants participating in the Energy and Operating Reserve Markets in violation of any law or regulation of a relevant electric retail regulatory authority including state-approved retail tariff(s).

(9) An aggregator of retail or wholesale customers offering Demand Response Load of one or more end-use retail customers or wholesale customers as a Demand Response Resource in the Energy and Operating Reserve Markets must be a Market Participant, satisfying all registration and certification requirements applicable to Market Participants as well as certification consistent with Section 2.8 of this Attachment, as required.

(10) All Variable Energy Resources in the Integrated Marketplace must be registered as a Dispatchable Variable Energy Resource except for (1) a Qualifying Facility exercising its rights under PURPA to deliver its net output to its host utility or (2) a Resource having a primary fuel source of run of the river hydro-electric that is incapable of following Dispatch Instructions. A Generation Interconnection Customer with Variable Energy Resources that are not Qualifying Facilities exercising their rights under PURPA previously registered as a Non-Dispatchable Variable Energy Resource must convert to a Dispatchable Variable Energy Resource

by the later of January 1, 2021 or the 10 year anniversary of a Resource's original Commercial Operation Date. A Qualifying Facility exercising its rights under PURPA to deliver its net output to its host utility may register as a Dispatchable Variable Energy Resource if it is capable of being incrementally dispatched by the Transmission Provider and will be subject to the Dispatchable Variable Energy Resource market rules including Uninstructed Resource Deviation charges. Any Resource that has previously registered as a Dispatchable Variable Energy Resource shall not subsequently register as a Non-Dispatchable Variable Energy Resource.

(11) A Market Participant that is selling firm power to the load asset under a bilateral contract may, with the agreement of the buyer, register all or a portion of the buyer's load as its load asset. For purposes of this Section 2.2(11) of this Attachment AE, the sale of firm power shall refer to power sales deliverable with firm transmission service, with the supplier assuming the obligation to serve the buyer's load with both capacity and energy. For the purposes of Section 2.11.1 of this Attachment AE, such registration of the buyer's load by the seller shall be accounted for by including such load in the seller's Reported Load and not including such load in the buyer's Reported Load, as described under Section 2.11.1(A)(1) of this Attachment AE, and such associated bilateral contracts shall not be included in either the buyer's or seller's net resource capacity described under Section 2.11.1(A)(4) of this Attachment AE.

(12) A Transmission Owner providing firm transmission service under a GFA eligible for GFA Carve Out must request removal of congestion and marginal loss charges and designate the GFA Responsible Entity within the timeframe set forth in Section 2.2 (1) of Attachment AE.

(13) A GFA Responsible Entity shall provide to the Transmission Provider the information necessary to administer the GFA Carve Out. The required information shall include the following:

(a) Resource Settlement Location;

(b) Load Settlement Location;

(c) The maximum MW capacity contracted under the GFA Carve Out;

(d) The identification of the GFA in Attachment W; and

(e) Any other information reasonably required by the Transmission Provider.

(14) Market Participants with assets interconnected to the Transmission System that are not participating in the Energy and Operating Reserve Markets must pseudo-tie the Resource or load out of the SPP Balancing Authority Area in accordance with Attachment AO. Such assets shall continue to be registered in the Integrated Marketplace for the purposes of accounting for congestion and loss charges between the Resource Price Node and the applicable External Interface Settlement Location as described under Sections 8.6.23 and 8.6.24 of this Attachment AE.

(a) To the extent that the SPP Balancing Authority or associated external Balancing Authority can no longer maintain the Resource pseudo-tie for reliability reasons, the Market Participant representing the pseudo-tied Resource must immediately reduce the output of the pseudo-tied resource to the available pseudo-tie capability after receiving notification from the affected Balancing Authority of the reduced capability. A Market Participant shall not generate any energy in excess of the available pseudo-tie capability after receiving such notification and shall not be compensated in the Energy and Operating Reserve Markets settlement for any energy generated in excess of the available pseudo-tie capability.

(15) Western-UGP shall provide to the Transmission Provider the information necessary to administer the FSE. The required information shall include the following:

(a) Resource Settlement Locations;

(b) Load Settlement Locations;

(c) The maximum MW capacity contracted under the FSE;

(d) The identification of the FSE Statutory Load Obligations as described in the SPP-Western-UGP NITSA; and

(e) Any other information reasonably required by the Transmission Provider.

(16) The Transmission Provider shall establish FSE Transfer Points consistent with the FSE transmission service power flow impacts.

(17) A Market Participant registering a Staggered Start Resource shall attest that the Resource meets the Staggered Start Resource definition in this Attachment AE. The attestation shall contain sufficient detail regarding the specific circumstances of the Resource to demonstrate that it meets the definition of a Staggered Start Resource. A Market Participant that has registered a Staggered Start Resource shall change the registration status no later than thirty (30) business days from the date the Resource ceases to meet the Staggered Start Resource definition.

1.1 Definitions D

Day-Ahead

The time period starting at 0001 and ending at 2400 on the day prior to the Operating Day.

Day-Ahead Market

As defined in Section 1 of the Tariff.

Day-Ahead Market Commitment Period

The contiguous period of time between a Resource's Day-Ahead Market Commit Time and Day-Ahead Market De-Commit Time.

Day-Ahead Reliability Unit Commitment ("Day-Ahead RUC")

The process performed by the Transmission Provider following the close of the Day-Ahead Market and prior to the Operating Day to assess Resource and Operating Reserve adequacy for the Day-Ahead period and the remainder of the current Operating Day, commit or de-commit Resources as necessary, and communicate commitment or de-commitment of Resources to the appropriate Market Participants as necessary.

De-Commit Time

The time specified by the Transmission Provider or a local transmission operator in a Commitment Instruction at which a Resource is to begin de-synchronization procedures.

Demand Bid

A proposal by a Market Participant associated with a physical load to purchase a fixed or price sensitive amount of Energy at a specified location and period of time in the Day-Ahead Market.

Demand Bid Curve

A Demand Bid specified as Megawatt and dollars per Megawatt hour with up to ten (10) price/quantity pairs.

Demand Curve

A series of quantity/price points used to set Locational Marginal Prices and Market Clearing Prices when there is a shortage of Energy or Operating Reserve.

Demand Response Load

A registered measurable load that is capable of being reduced at the instruction of the Transmission Provider and subsequently may be increased at the instruction of the Transmission Provider.

Demand Response Resource

A Dispatchable Demand Response Resource or a Block Demand Response Resource.

Designated Resource

As defined in Section 1 of the Tariff.

Dispatch Interval

The five (5) minute interval for which the Transmission Provider issues Dispatch Instructions for Energy and clears Operating Reserve in the Real-Time Balancing Market.

Dispatch Instruction

The communicated Resource target Energy Megawatt output level at the end of the Dispatch Interval.

Dispatchable Demand Response Load Settlement Location

A registered load Settlement Location that contains the Demand Response Load associated with a Dispatchable Demand Response Resource.

Dispatchable Demand Response Resource

A Resource created to model Demand Response Load reduction associated with controllable load or a Behind-The-Meter generator that is dispatchable on a five (5) minute basis.

Dispatchable Resource

A Resource for which an Energy Offer Curve has been submitted and that is available for dispatch by the Transmission Provider on a Dispatch Interval basis.

Dispatchable Variable Energy Resource

A Variable Energy Resource registered in the Integrated Marketplace that is capable of being incrementally dispatched by the Transmission Provider.

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Data Error

A data error shall be the following:

(i) Data received by the Transmission Provider from an independent source, including data produced by a system or submitted by a third party, that is inaccurately modified by the Transmission Provider during the execution of a market function; or

(ii) Data received by the Transmission Provider from an independent source, including data produced by a system or submitted by a third party, that is patently incorrect and is used by the Transmission Provider during the execution of a market function; or

(iii) Incorrect data produced and used by the Transmission Provider during the execution of a market function.

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The contiguous period of time between a Resource's Day-Ahead Market Commit Time and Day-Ahead Market De-Commit Time.

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A Variable Energy Resource registered in the Integrated Marketplace that is capable of being incrementally dispatched by the Transmission Provider.

1.1 Definitions N

Net Benefits Test

A calculation that measures the threshold price at which the benefits of dispatching Demand Response Load outweigh the costs.

Network Integration Transmission Service

As defined in Section 1 of the Tariff.

Network Integration Transmission Service Auction Revenue Right Nomination Cap

The maximum amount of Network Integration Transmission Service Candidate Auction Revenue Rights that an Eligible Entity may nominate in each month and season in the annual Auction Revenue Right allocation process and the monthly Auction Revenue Right allocation process.

Network Integration Transmission Service Candidate Auction Revenue Right

The Megawatt quantity associated with Network Integration Transmission Service from Network Resources that the holder of the Network Integration Transmission Service can nominate for conversion into an Auction Revenue Right, subject to the Network Integration Transmission Service Auction Revenue Right Nomination Cap.

Network Integration Transmission Service Candidate Long-Term Congestion Right

The Megawatt quantity associated with Network Integration Transmission Service with rollover rights from Network Resources that is used by the Transmission Provider to determine available rights that the holder of the Network Integration Transmission Service can select for conversion into a Long-Term Congestion Right during the Long-Term Congestion Right allocation process.

Network Model

A representation of the transmission, generation, and load elements of the interconnected Transmission System and the transmission systems of other regions in the Eastern Interconnection.

No-Load Offer

The compensation request in a Resource Offer, in dollars, by a Market Participant representing the hourly fee for operating a synchronized Resource at zero (0) Megawatt output. For a generating unit, No-Load Offers are generally representative of the fuel expense required to maintain synchronous speed at zero (0) Megawatt output. For a Dispatchable Demand Response Resource or Block Demand Response Resource, No-Load Offers are generally representative of a combination of the fuel expense required to maintain synchronous speed at zero (0) Megawatt output for Behind-The-Meter Generation and the ongoing hourly costs associated with manufacturing process changes associated with a reduction in load consumption.

Non-Conforming Load

Load that is process driven that does not follow a predictable pattern.

Non-Dispatchable Variable Energy Resource

A Variable Energy Resource registered in the Integrated Marketplace that is not capable of being incrementally dispatched by the Transmission Provider.

2.2 Application and Asset Registration

(1) Applications for a Market Participant to provide services in the Integrated Marketplace must be submitted to the Transmission Provider prior to the expected date of participation consistent with Section 6.4 of the Market Protocols. Applications must conform to the procedures specified in the Market Protocols and may be rejected if not complete. New Market Participants will follow the timeframe as specified in Section 6.4 of the Market Protocols in addition to the detailed model update timing requirements in Appendix E of the Market Protocols.

(2) As part of the application process, Market Participants must register all Resources and load, including applicable load associated with Grandfathered Agreements ("GFAs"), Non-Conforming Load and Demand Response Load with the Transmission Provider in accordance with the registration process specified in the Market Protocols. As part of Resource registration, Market Participants must specify whether settlement meter data will be submitted on a gross basis or net basis, where gross meter data does not include reductions for auxiliary load and net meter data is gross meter data reduced by auxiliary load. Both Non-Conforming Load and Demand Response Load may only be associated with a single Price Node except that Non-Conforming Load and Demand Response Load may be associated with an aggregated Price Node that contains multiple electrically equivalent Price Nodes. Non-participating embedded load and/or generation must either: (i) register its load and/or generation in the Integrated Marketplace; or (ii) transfer its load and/or generation to an external Balancing Authority.

(3) Market Participants may elect to define a single Settlement Location that aggregates multiple Meter Data Submittal Locations associated with their load assets. Market Participants may not aggregate multiple Resource Meter Data Submittal Locations into a single Resource Settlement Location unless the Resources are at the same physical and electrically equivalent injection point to the Transmission System.

(4) In addition to the responsibilities described in Section 4.1.2 of this Attachment AE and under the Market Protocols, Market Participants wishing to model each participant's share of a Jointly Owned Unit as a separate Resource must choose one of the two options described below and provide the specified additional information. A Resource registered as a combined cycle Resource may not register as a Jointly Owned Unit.

(a) Individual Resource Option

Under the individual Resource option, each participant's share is modeled as a separate Resource for the purposes of commitment and dispatch and each Resource may be committed independent of the other Resource shares.

The operating owner's Meter Agent will be the Meter Agent for that Jointly Owned Unit unless each individual Jointly Owned Unit participant registers a Meter Agent for its share of the Resource.

Unless otherwise agreed to by the Jointly Owned Unit participants, the operating owner will be responsible for submitting the following data:

- Jointly Owned Unit maximum physical capacity operating limit;
- Jointly Owned Unit minimum physical capacity operating limit;
- Jointly Owned Unit minimum physical regulation capacity operating limit; and
- Maximum physical ten (10) minute response from an off-line state.

(b) Combined Resource Option

Under the combined Resource option each participant's share is modeled and must be registered as a separate Resource. Under this option, the commitment decision is made assuming that all Resource shares must be committed or none at all. Each Asset Owner of a Jointly Owned Unit under the combined Resource option must submit a zero for the Minimum Emergency Capacity Operating Limit, Minimum Normal Capacity Operating Limit, Minimum Regulation Capacity Operating Limit, and

Minimum Economic Capacity Operating Limit. The Jointly Owned Unit minimum physical capacity operating limit and minimum physical regulation capacity operating limit when the Jointly Owned Unit is selected to Regulate, can be achieved by any combination of Jointly Owned Unit shares during the commitment period. A Jointly Owned Unit under the combined Resource option will be dispatched using an aggregated Energy Offer Curve. Once committed, each Jointly Owned Unit share is dispatched independently and is eligible for recovery of Start-Up Offer and No-Load offer costs as described under Sections 8.5.9 and 8.6.5 of this Attachment AE. This option must be selected if the eligibility criteria stated under the individual Resource option cannot be met.

The operating owner's Meter Agent will be the Meter Agent for that Jointly Owned Unit unless each individual Jointly Owned Unit participant registers a Meter Agent for its share of the Resource.

Unless otherwise agreed to by the Jointly Owned Unit participants, the operating owner will be responsible for submitting the following data:

- Jointly Owned Unit maximum physical capacity operating limit;
- Jointly Owned Unit minimum physical capacity operating limit;
- Jointly Owned Unit minimum physical regulation capacity operating limit;
- Maximum physical ten (10) minute response from an off-line state; and
- Participant share percentage by Market Participant.

(5) Market Participants may modify their registered assets in accordance with the asset registration procedures specified in the Market Protocols.

(6) All loads and all Resources, excluding Behind-The-Meter Generation less than 10 Megawatts ("MWs"), must register. Failure or refusal to register a load will result in the Transmission Provider filing an unexecuted version of the service

agreement as specified in Attachment AH of this Tariff for that load with the Commission under the name of the (i) Network Customer, (ii) Transmission Customer, or (iii) Transmission Owner serving load under a Grandfathered Agreement for which the Transmission Owner is neither taking Network Integration Transmission Service nor Firm Point-To-Point Transmission Service. Failure or refusal to register a Resource will result in the Transmission Provider filing an unexecuted version of the service agreement as specified in Attachment AH of this Tariff for that Resource with the Commission under the name of the generation interconnection customer under an interconnection agreement with the Transmission Provider or the applicable Transmission Owner. In the case of a Qualifying Facility exercising its rights under PURPA to deliver all of its net output to its host utility, such registration will not require the Qualifying Facility to participate in the Energy and Operating Reserve Markets or subject the Qualifying Facility to any charges or payments related to the Energy and Operating Reserve Markets. Any Energy and Operating Reserve Market charges or payments associated with the output of the Qualifying Facility will be allocated to the Market Participant representing the host utility purchasing the output of the Qualifying Facility under PURPA, and the Market Participant will be provided the settlement data required to verify the settlement charges and payments.

(7) A Market Participant wishing to Offer an External Resource in the Energy and Operating Reserve Markets will utilize an External Resource Pseudo-Tie in accordance with Attachment AO. In addition to the responsibilities outlined in Attachment AO, the Market Participant registering the External Resource will be responsible for registering and performing all responsibilities that are required of Resources in the Energy and Operating Reserve Markets.

(8) A Market Participant wishing to offer Demand Response Load as a Demand Response Resource in the Energy and Operating Reserve Markets must include in its application and registration a certification that participation in the Energy and Operating Reserve Markets by its Demand Response Resource is not precluded under the laws or regulations of the relevant electric retail regulatory authority. Consistent with Section 2.8.1 of this Attachment, an aggregator of retail

customers wishing to offer Demand Response Load in the form of a Demand Response Resource on behalf of one or more retail customers must also include in its application and registration a certification that participation of each retail customer is either: (1) not precluded by the laws or regulations of the relevant electric retail regulatory authority if the customer is served by a utility that distributed more than 4 million MWh in the previous fiscal year; or (2) affirmatively permitted by the laws or regulations of the relevant electric retail regulatory authority if the customer is served by a utility that distributed 4 million MWh or less in the previous fiscal year. Demand Response Resources must meet all application, registration and technical requirements applicable to the Energy and Operating Reserve Markets. The Transmission Provider is not responsible for interpreting the laws or regulations of a relevant electric retail regulatory authority and shall be required only to verify that the Market Participant has included such a certification in its application materials. The Transmission Provider is not liable or responsible for Market Participants participating in the Energy and Operating Reserve Markets in violation of any law or regulation of a relevant electric retail regulatory authority including state-approved retail tariff(s).

(9) An aggregator of retail or wholesale customers offering Demand Response Load of one or more end-use retail customers or wholesale customers as a Demand Response Resource in the Energy and Operating Reserve Markets must be a Market Participant, satisfying all registration and certification requirements applicable to Market Participants as well as certification consistent with Section 2.8 of this Attachment, as required.

(10) All Variable Energy Resources in the Integrated Marketplace must be registered as a Dispatchable Variable Energy Resource except for (1) ~~a wind-powered Variable Energy Resource with an interconnection agreement executed on or prior to May 21, 2011 and that commenced Commercial Operation before October 15, 2012 or (2)~~ a Qualifying Facility exercising its rights under PURPA to deliver its net output to its host utility or (2~~3~~) a Resource having a primary fuel source of run of the river hydro-electric that is incapable of following Dispatch Instructions~~a non-wind powered Variable Energy Resource registered on or prior to January 1,~~

~~2017 and with an interconnection agreement executed on or prior to January 1, 2017~~. ~~Variable Energy Resources included in (1) and (3) above may register as Dispatchable Variable Energy Resources if they are capable of being incrementally dispatched by the Transmission Provider.~~ A Generation Interconnection Customer with Variable Energy Resources that are not Qualifying Facilities exercising their rights under PURPA previously registered as a Non-Dispatchable Variable Energy Resource must convert to a Dispatchable Variable Energy Resource by the later of January 1, 2021 or the 10 year anniversary of a Resource's original Commercial Operation Date. A Qualifying Facility exercising its rights under PURPA to deliver its net output to its host utility may register as a Dispatchable Variable Energy Resource if it is capable of being incrementally dispatched by the Transmission Provider and will be subject to the Dispatchable Variable Energy Resource market rules including Uninstructed Resource Deviation charges. Any Resource that has previously registered as a Dispatchable Variable Energy Resource shall not subsequently register as a Non-Dispatchable Variable Energy Resource.

(11) A Market Participant that is selling firm power to the load asset under a bilateral contract may, with the agreement of the buyer, register all or a portion of the buyer's load as its load asset. For purposes of this Section 2.2(11) of this Attachment AE, the sale of firm power shall refer to power sales deliverable with firm transmission service, with the supplier assuming the obligation to serve the buyer's load with both capacity and energy. For the purposes of Section 2.11.1 of this Attachment AE, such registration of the buyer's load by the seller shall be accounted for by including such load in the seller's Reported Load and not including such load in the buyer's Reported Load, as described under Section 2.11.1(A)(1) of this Attachment AE, and such associated bilateral contracts shall not be included in either the buyer's or seller's net resource capacity described under Section 2.11.1(A)(4) of this Attachment AE.

(12) A Transmission Owner providing firm transmission service under a GFA eligible for GFA Carve Out must request removal of congestion and marginal loss charges

and designate the GFA Responsible Entity within the timeframe set forth in Section 2.2 (1) of Attachment AE.

(13) A GFA Responsible Entity shall provide to the Transmission Provider the information necessary to administer the GFA Carve Out. The required information shall include the following:

(a) Resource Settlement Location;

(b) Load Settlement Location;

(c) The maximum MW capacity contracted under the GFA Carve Out;

(d) The identification of the GFA in Attachment W; and

(e) Any other information reasonably required by the Transmission Provider.

(14) Market Participants with assets interconnected to the Transmission System that are not participating in the Energy and Operating Reserve Markets must pseudo-tie the Resource or load out of the SPP Balancing Authority Area in accordance with Attachment AO. Such assets shall continue to be registered in the Integrated Marketplace for the purposes of accounting for congestion and loss charges between the Resource Price Node and the applicable External Interface Settlement Location as described under Sections 8.6.23 and 8.6.24 of this Attachment AE.

(a) To the extent that the SPP Balancing Authority or associated external Balancing Authority can no longer maintain the Resource pseudo-tie for reliability reasons, the Market Participant representing the pseudo-tied Resource must immediately reduce the output of the pseudo-tied resource to the available pseudo-tie capability after receiving notification from the affected Balancing Authority of the reduced capability. A Market Participant shall not generate any energy in excess of the available pseudo-tie capability after receiving such notification and shall not be compensated in the Energy and Operating Reserve Markets settlement for any energy generated in excess of the available pseudo-tie capability.

(15) Western-UGP shall provide to the Transmission Provider the information necessary to administer the FSE. The required information shall include the following:

(a) Resource Settlement Locations;

(b) Load Settlement Locations;

(c) The maximum MW capacity contracted under the FSE;

(d) The identification of the FSE Statutory Load Obligations as described in the SPP-Western-UGP NITSA; and

(e) Any other information reasonably required by the Transmission Provider.

(16) The Transmission Provider shall establish FSE Transfer Points consistent with the FSE transmission service power flow impacts.

(17) A Market Participant registering a Staggered Start Resource shall attest that the Resource meets the Staggered Start Resource definition in this Attachment AE. The attestation shall contain sufficient detail regarding the specific circumstances of the Resource to demonstrate that it meets the definition of a Staggered Start Resource. A Market Participant that has registered a Staggered Start Resource shall change the registration status no later than thirty (30) business days from the date the Resource ceases to meet the Staggered Start Resource definition.

167 FERC ¶ 61,028
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Neil Chatterjee, Chairman;
Cheryl A. LaFleur, Richard Glick,
and Bernard L. McNamee.

Southwest Power Pool, Inc. Docket Nos. ER19-356-000
ER19-356-001

ORDER CONDITIONALLY ACCEPTING TARIFF FILING
AND REQUIRING COMPLIANCE FILING

(Issued April 12, 2019)

1. On November 16, 2018, Southwest Power Pool, Inc. (SPP) submitted, pursuant to section 205 of the Federal Power Act (FPA)[1] and section 35.13 of the Commission's regulations,[2] proposed revisions to its Open Access Transmission Tariff (Tariff) to require that certain Non-Dispatchable Variable Energy Resources (NDVERs) register and convert to Dispatchable Variable Energy Resources (DVERs).[3] As discussed below, we accept SPP's filing, subject to condition, effective January 16, 2019, as requested, and direct SPP to submit a compliance filing within 30 days of the date of this order.

[1] 16 U.S.C. § 824d (2012).

[2] 18 C.F.R. § 35.13 (2018).

[3] A Variable Energy Resource (VER) is defined by SPP as "[a] device for the production of electricity that is characterized by an energy source that: (1) is renewable; (2) cannot be stored by the facility owner or operator; and (3) has variability that is beyond the control of the facility owner or operator." A DVER is defined as "[a] Variable Energy Resource registered in the Integrated Marketplace that is capable of being incrementally dispatched by the [t]ransmission [p]rovider." An NDVER is defined as "[a] Variable Energy Resource registered in the Integrated Marketplace that is not capable of being incrementally dispatched by the [t]ransmission [p]rovider." SPP, OATT, Att. AE (MPL), § 1.1 Definitions V (0.1.0), D (2.0.0), and N (2.0.0).

I. Background

A. The Instant Filing

2. SPP proposed revisions to Sections 1.1 and 2.2 of Attachment AE (Integrated Marketplace) of the Tariff to require certain NDVERs to register and convert to DVERs by the later of January 1, 2021, or the 10-year anniversary of each resource's original commercial operation date.[4] SPP maintains that this proposed deadline strikes an appropriate balance between many stakeholder interests and concerns related to the timing of the required conversion. As proposed, the requirement to register and convert to DVER status would not extend to (1) qualifying facilities (QFs) exercising their rights under section 210 of the Public Utility Regulatory Policies Act of 1978 (PURPA)[5] to sell their net capacity to their host utility, or (2) run-of-the-river hydroelectric resources that are incapable of following dispatch instructions. SPP also states that behind-the-meter generation of less than 10 MWs is not required to register its loads and resources, and is thus not subject to the proposed Tariff revisions. In addition, SPP proposes that, while the market participant would continue to be responsible for registration functions, the generation interconnection customer associated with a generator would be responsible for facilitating the generating facility's physical conversion.[6]

3. SPP states that the proposed revisions would result in reduced reliability risks and more equitable and efficient market outcomes for the Integrated Marketplace. SPP maintains that, as the installed levels of VERs have increased, the inherent variability, and sometimes unpredictability, of these resources have similarly increased the need for resources to be dispatchable and flexible. SPP states that it currently has 7.8 GW of NDVERs registered in the market, which represents 30 percent of resources during minimum load conditions.[7] SPP states that its ability to control the output of NDVERs is limited to the use of out-of-merit energy instructions, which may only be issued to address emergency conditions or reliability issues that the market systems cannot resolve. SPP further explains that NDVERs make up 69 percent of the resources for which out-of-market actions are taken, and these out-of-market actions take longer to implement and are less efficient than re-dispatching resources automatically based on the market's

[4] Transmittal at 1.

[5] 16 U.S.C. § 824a-3.

[6] Transmittal at 14-16.

[7] *Id.* at 5.

security constrained economic dispatch engine.[8] SPP explains that although by definition an NDVER is not capable of being economically dispatched, a number of NDVERs have been observed to be reacting to pricing signals from the market by going offline when prices drop and re-entering the market at higher prices.[9] SPP states that it conducted a study demonstrating the reliability and market efficiency benefits that would result from the proposed conversion of NDVERs to DVERs by simulating a full month of Real-Time Balancing Market solutions. SPP explains that the simulation showed a reduction of the number of constraint breaches by 31 percent, primarily driven by the ability for the Real-Time Balancing Market to utilize more dispatchable resources.[10] SPP concludes that converting NDVERs to DVERs would create market efficiencies, reduce congestion costs, improve the convergence of day-ahead and real-time prices, increase revenues for resource owners, decrease charges to load, reduce the amount of negative pricing, and stabilize pricing throughout the SPP footprint.[11]

B. Deficiency Letter and Response

4. On January 10, 2019, Commission staff issued a letter informing SPP that its filing was deficient and additional information would be necessary to evaluate its submission (Deficiency Letter). Among other things, Commission staff requested that SPP explain (1) the number of NDVER to DVER conversions that would occur and associated capacity; (2) how the conversion costs for older and newer units compare; (3) whether SPP proposes to exempt *all* run-of-the-river hydroelectric facilities from the DVER registration requirement, and whether such facilities would be exempt from the DVER conversion requirement; and (4) why SPP believes that generation interconnection customers are the party best-suited to facilitate the conversion, and the implications when resources do not have Generation Interconnection Agreements (GIA) with SPP.

5. On February 11, 2019, SPP filed its response (Deficiency Response), as described below.

II. Notices and Responsive Pleadings

6. Notice of the November 16, 2018 filing was published in the *Federal Register*, 83 Fed. Reg. 60,840 (2018), with interventions and protests due on or before

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[8] *Id.* at 5.

[9] *Id.* at 6.

[10] *Id.* at 8-9.

[11] *Id.* at 9-10.

December 7, 2018. Timely motions to intervene were filed by: American Electric Power Service Corporation;[12] Dempsey Ridge Wind Farm, LLC; EDF Renewables, Inc.; Exelon Corporation; E.ON Climate & Renewables North America, LLC; Mid-Kansas Electric Company, Inc.; Nebraska Public Power District; NextEra Energy Resources, LLC; Rolling Thunder I Power Partners, LLC; Sunflower Electric Power Corporation; Westar Energy, Inc., Kansas City Power & Light Company, and KCP&L Greater Missouri Operations Company; Western Area Power Administration; and Xcel Energy Services Inc. (Xcel), on behalf of Southwestern Public Service Company. Timely motions to intervene and comments were filed by American Wind Energy Association and the Wind Coalition (Joint Commenters); Invenergy Energy Management LLC (Invenergy); and the Market Monitoring Unit of Southwest Power Pool, Inc. (SPP Market Monitor). City Utilities of Springfield, Missouri, filed an out-of-time motion to intervene. On December 19, 2018, SPP filed an answer to the comments. On December 21, 2018, Xcel filed an answer to Joint Commenters' comments and, on January 4, 2019, Joint Commenters filed an answer to the answers of SPP and Xcel.

7. Notice of SPP's Deficiency Response was published in the *Federal Register*, 84 Fed. Reg. 4461 (2019), with interventions and protests due on or before March 4, 2019. Western Farmers Electric Cooperative filed a timely motion to intervene. Invenergy filed comments (Invenergy Deficiency Response Comments).

III. <u>Procedural Matters</u>

8. Pursuant to Rule 214 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.214 (2018), the timely, unopposed motions to intervene serve to make the entities that filed them parties to this proceeding.

9. Pursuant to Rule 214(d) of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.214(d) (2018), we grant City Utilities of Springfield, Missouri's late-filed motion to intervene given its interest in the proceeding, the early stage of the proceeding, and the absence of undue prejudice or delay.

10. Rule 213(a)(2) of the Commission's Rule of Practice and Procedure, 18 C.F.R. § 385.213(a)(2) (2018), prohibits an answer to a protest or answer unless otherwise ordered by the decisional authority. We accept the answers filed SPP, Xcel and Joint Commenters because they have provided information that assisted us in our decision making process.

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[12] American Electric Power Service Corporation filed on behalf of Public Service Company of Oklahoma and Southwestern Electric Power Company.

IV. Substantive Matters

11. As discussed below, we find SPP's proposed Tariff revisions to be just and reasonable and not unduly discriminatory or preferential. Accordingly, we accept them, subject to condition, effective January 16, 2019, as requested, and direct SPP to submit a compliance filing within 30 days of the date of this order.[13]

A. Requirement to Convert from NDVER to DVER

1. Comments

12. Invenergy strongly supports SPP's proposal to transition existing NDVERs to DVERs, stating that NDVERs create operational and reliability issues for SPP.[14] Similarly, the SPP Market Monitor strongly supports SPP's filing, stating that it agrees with SPP's analysis that converting NDVERs to DVERs would result in substantial benefits.[15]

2. Commission Determination

13. We find that SPP's proposal to require the conversion of NDVERs to DVERs is just and reasonable. We find that SPP's proposal will produce a variety of benefits, including mitigating the need for SPP to use out-of-merit energy instructions and increasing the reliability and efficiency of the Integrated Marketplace.

B. DVER Conversion Timeline

1. Comments

14. The SPP Market Monitor states that it recommended that SPP require conversion of all NDVERs to DVERs within an 18-month period, but ultimately, the stakeholder process approved language that gave approximately two years for NDVERs to convert to DVERs. The SPP Market Monitor states that, while this approach was not its preferred

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[13] The United States Court of Appeals for the District of Columbia Circuit has held that, in certain circumstances, the Commission has "authority to propose modifications to a utility's [FPA section 205] proposal if the utility consents to the modifications." *NRG Power Mktg., LLC v. FERC*, 862 F.3d 108, 114-15 (D.C. Cir. 2017).

[14] Invenergy Comments at 1.

[15] SPP Market Monitor Comments at 2.

method, it nonetheless believes SPP's proposal is acceptable because the proposal establishes a sufficient timeline for conversion.[16]

15. Invenergy is concerned that SPP's proposed timeline to allow for the conversion of NDVERs to DVERs is unnecessarily long. Invenergy states that wind facilities typically constitute more than 20 percent of SPP's total generation mix, and continuing to allow wind facilities to operate as NDVERs is a significant source of harm to the markets and reliability. Invenergy states that many wind facilities are already capable of operating as DVERs and are choosing to operate as NDVERs by choice, not due to technical limitations. Invenergy maintains that, as an experienced wind developer, it is familiar with the technical capabilities of the equipment that has been available from the major wind turbine manufacturers over the last 10 years, and turbines installed over that period already have the capability to follow dispatch instructions and are likely the NDVERs that SPP has observed chasing market prices.[17] Invenergy maintains that, while this choice may financially benefit the NDVER, it creates reliability risks and market inefficiencies. Invenergy states that the preference allowed to NDVERs, compared to the limitations placed on DVERs, places its wind facilities at a competitive disadvantage. Invenergy maintains that, regardless of relative price and efficiency, DVERs will be curtailed prior to NDVERs, and only DVERs are required to adhere to ramp rate restrictions that limit their ability to take advantage of optimal wind conditions.[18]

16. Invenergy argues that the Commission should eliminate the alternative deadline based on the 10-year anniversary of a resource's original commercial operation date to the extent that it applies to wind facilities, and the Commission should require SPP to adopt a shorter deadline of no later than January 1, 2020 for NDVERs that are already capable of being dispatched.[19] Invenergy states that SPP's concerns about the time and expense of modifying existing wind facilities do not support the longer transition period, asserting that the Commission must balance the interests of market participants that are adversely affected by delaying the elimination of NDVERs with those it believes need more time to register and convert.[20] It asserts that there is no factual or policy basis for an extended deadline based on the 10-year anniversary of resources' original commercial operation dates for resources that achieved commercial operation in 2011 and 2012

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[16] *Id.* at 4.

[17] Invenergy Comments at 2.

[18] *Id.* at 4-5.

[19] *Id.* at 3.

[20] *Id.* at 6-7.

because such resources likely already have the technology necessary to be dispatchable and could easily complete conversions as early as June 1, 2019. Invenergy also maintains that older NDVERs that utilize earlier technologies are instead required to meet the earlier January 1, 2021 deadline. It contends that an earlier deadline for conversion should apply to all units capable of following a dispatch signal.[21]

2. Answers

17. SPP states that the proposed timeline for DVER conversion is just and reasonable and was chosen after significant stakeholder input regarding the time and expense that may be required to physically modify certain resources to become capable of being dispatched by SPP. SPP states that some stakeholders also desired to tie the DVER conversion requirement to the expiration of certain production tax credits. SPP contends that its proposed deadline of the latter of January 1, 2021 or the 10-year anniversary of a resource's original commercial operation date is an attempt to balance the stakeholder interests and concerns.[22] SPP also maintains that it is not in a position to determine whether individual NDVERs may be capable of converting on a shorter timeline. SPP argues that, while Invenergy's proposed timeline might be just and reasonable, it does not mean that SPP's proposal is not also just and reasonable. SPP asserts that its proposed timeline is just and reasonable, warrants no adjustments, and should be accepted by the Commission.[23]

3. Deficiency Response and Comments

18. In its Deficiency Response, SPP maintains that only a limited number of conversions from NDVER to DVER status would occur after January 1, 2021. In particular, SPP expects that all wind-powered NDVERs, unless qualified for an exemption, will convert by October 15, 2022; only 815 MWs of wind-powered NDVERs will convert between January 2, 2021, and October 15, 2022; and all NDVERs that are not wind powered (approximately 30 MWs), unless qualified for an exemption, will convert by January 1, 2027.[24]

19. In its Deficiency Response Comments, Invenergy states that it continues to object to the timetable SPP proposes to allow for the transition. Invenergy states that there are

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[21] *Id.* at 8.

[22] SPP Answer at 6-7.

[23] *Id.* at 7-8.

[24] Deficiency Response at 9.

currently 5.4 GW of wind NDVERs in SPP's footprint which will have to convert to DVER status, and it is unreasonable and discriminatory to require the 4.3 GW of wind NDVERs with the oldest technology to convert by an earlier deadline while allowing the 815 MW of remaining wind NDVERs with the newest technology to convert under an extended deadline.[25]

4. Commission Determination

20. We find that SPP's proposed DVER conversion timeline is just and reasonable. We disagree with Invenergy's assertion that the proposed deadline for DVER conversion of the latter of January 1, 2021 or the 10-year anniversary of a resource's original commercial operation date is unreasonably long or gives undue preference to newer wind facilities. As SPP explains, its proposal represents a compromise reached as a result of an extensive stakeholder process. SPP's proposed conversion timeline represents a balance among many stakeholder interests, including the need to give existing NDVERs a reasonable amount of time to complete conversions and the reliability and market efficiency concerns. Although Invenergy contends that certain NDVERs may be capable of completing conversions prior to SPP's proposed deadline, Invenergy does not demonstrate that all NDVERs are capable of converting via an expedited schedule, or that SPP is capable of identifying the individual NDVERs that may be capable of completing early conversions. We agree with SPP that the proposed DVER conversion timeline is just and reasonable, and reject Invenergy's proposal for the Commission to direct SPP to impose an earlier conversion deadline.

C. Exemptions from DVER Conversion

1. Comments

21. Joint Commenters state that the proposed changes are discriminatory because they do not recognize that wind facilities with older technology do not have the same capability as newer wind facilities to communicate and be dispatched. They maintain that these older resources should be exempt from SPP's proposed DVER conversion requirement, consistent with the grandfathering clause exempting from being dispatchable those resources that began commercial operations before April 1, 2005 in Midcontinent Independent System Operator, Inc. (MISO).[26] Joint Commenters argue that such an exemption would address the fact that, like run-of-the-river hydroelectric facilities, older wind facilities are incapable of following dispatch instructions, and

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[25] Invenergy Answer at 3.

[26] Joint Commenters Comments at 4 (citing *Midwest Indep. Transmission Sys. Operator, Inc.*, 134 FERC ¶ 61,141, at PP 19, 77 (2011)).

conversions for older wind facilities would be onerous.[27] They estimate that exempting wind facilities with commercial operation dates prior to April 1, 2005, would apply to less than 2,000 MWs and would not detract from the overall benefits of SPP's proposal. Joint Commenters conclude that this exemption would ensure that SPP's requirements are applied in a consistent, just and reasonable, and non-discriminatory way. In addition, Joint Commenters note that many older wind facilities with commercial operation dates prior to April 1, 2005, are being repowered with newer technology that will give them the capability to be dispatched, and facilities that re-power should be required to comply with SPP's proposal.[28]

2. <u>Answers</u>

22. SPP states that, by the time of the proposed implementation date, the resources for which Joint Commenters request an exemption will be at least 16 years old, and may have repowered or installed software making them capable of dispatch without SPP's knowledge. It contends that a commercial operation date alone is not an indicator of whether a VER is dispatchable and cannot be reasonably used as a bright-line test. SPP argues that, given the operational and reliability issues that NDVERs create, it would not be reasonable to grant an exclusive, and potentially unduly discriminatory, exemption for such a large portion of these resources in perpetuity.[29]

23. SPP also argues that it is not appropriate to compare Joint Commenters' requested exemption for older wind facilities with the proposed exemption for certain run-of-the-river hydroelectric facilities. SPP explains that the exemption for certain run-of-the-river hydroelectric facilities is very limited in scope and applies only to plants that are incapable of following SPP's dispatch instructions. SPP notes that a limited number of these plants are not dispatchable based on requirements imposed by the U.S. Army Corps of Engineers, and there are not any software, equipment, or control upgrades that would permit these resources to be dispatchable in the SPP market.[30]

24. In response to SPP, Joint Commenters state that they are not proposing to create a loophole to allow dispatchable resources that repower prior to the implementation date of SPP's proposal to be exempt from the DVER registration requirement. Joint Commenters clarify that they support requiring wind facilities with commercial operation

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[27] *Id.* at 5.

[28] *Id.*

[29] SPP Answer at 10.

[30] *Id.* at 11.

dates prior to April 1, 2005 that either have already repowered or will repower in the future to register as DVERs.[31]

3. Deficiency Response

25. SPP states that it does not have information as to whether older wind facilities will repower or whether such repowering would render the resources dispatchable. SPP states that it will cost more to convert older units than newer units, but it does not have information as to how the conversion costs for older and new units might compare. SPP states that the situations for the various resources are often unique and conversion costs are not standardized.[32]

26. With regard to the proposed exemption for run-of-the-river hydroelectric facilities, SPP notes that all run-of-the-river hydroelectric facilities are not exempt from the requirement to convert to DVERs; rather, only those that are incapable of following dispatch instructions would be exempt.[33] SPP states that its stakeholders indicated that some run-of-the-river hydroelectric facilities are capable of becoming dispatchable, but SPP lacks any consistent means to ascertain this ability. However, SPP states that, if a run-of-the-river hydro VER is capable of becoming dispatchable, it should do so and re-register as a DVER. SPP states that the ability for a particular run-of-the-river facility to become dispatchable is primarily driven by operating restrictions placed on plant operators by the U.S. Army Corps of Engineers. In addition, SPP states that the discrepancy in its proposed Tariff language between the exemption for QFs and the exemption for run-of-river-hydroelectric was due to a “scrivener’s error.” SPP states that it will add Tariff language to clarify that run-of-the-river hydroelectric facilities that are incapable of following dispatch instructions are excluded from the DVER registration and conversion requirements, if so ordered by the Commission.[34]

4. Commission Determination

27. We disagree with Joint Commenters’ argument that SPP should exempt wind facilities with commercial operation dates before April 1, 2005, that have not repowered from the DVER registration and conversion requirements. While some of these older facilities may not currently be dispatchable, they are not similarly situated to the subset of run-of-the-river hydroelectric facilities that SPP proposes to exempt. We find that SPP’s

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[31] Joint Commenters Answer at 3.

[32] Deficiency Response at 9-10.

[33] *Id.* at 6.

[34] *Id.* at 4.

proposed exemption for run-of-the-river hydroelectric facilities that are incapable of following dispatch instructions is reasonable because the U.S. Army Corps of Engineers has the final say about software, equipment, and control upgrades on these facilities. Wind facilities with commercial operation dates prior to April 1, 2005 do not have similar restrictions on their ability to become dispatchable and, therefore, are not similarly situated to run-of-the-river hydroelectric facilities that are incapable of following dispatch instructions. With respect to Joint Commenters' reliance on precedent in MISO to support an exemption for certain older units, we find that the Commission's determination in that proceeding does not require the same outcome here. Although MISO's stakeholder process resulted in the addition of a grandfather clause, we note that ISO New England Inc. proposed, and the Commission accepted, a requirement for all non-dispatchable resources to purchase equipment to become dispatchable.[35] Regional transmission organizations and independent system operators may arrive at different solutions depending on the circumstances of their regions, as SPP has here, and we find a grandfathering clause unnecessary for SPP's proposal to be just and reasonable. In addition, we agree with SPP's proposal to correct its "scriveners' error" and clarify in the Tariff that, like QFs, run-of-the-river hydroelectric facilities that are incapable of being dispatchable are exempt from both the DVER registration and conversion requirements. Therefore, in the compliance filing ordered below, we direct SPP to revise Section 2.2(10) of Attachment AE in the Tariff accordingly.

D. DVER Conversion Requirement and Responsibility

1. Comments

28. Joint Commenters argue that SPP's proposed Tariff language is ambiguous with regard to which NDVERs are required to convert to DVERs, and that SPP should clarify that all NDVERs capable of following dispatch instructions would need to comply with the proposed rules that require operation as DVERs, including units that do not have GIAs with SPP. Joint Commenters claim that many NDVERs do not have GIAs with SPP and should be required to comply with the proposed DVER conversion requirement.[36]

29. Joint Commenters state that in its filing SPP states that "the relevant Market Participant is responsible for updating a generator's registration status" but Section 2.2(10) of the Tariff states that the generation interconnection customer must convert to a DVER. Joint Commenters maintain that, rather than making generation interconnection customers responsible for DVER conversion, SPP should clarify that the market participant is responsible for making this change in registration to a DVER. Joint

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[35] *See ISO New England Inc.*, 157 FERC ¶ 61,189, at PP 4, 24 (2016).

[36] Joint Commenters Comments at 5-6.

Commenters state that SPP should be required to clarify that only the market participant is required to make this change in registration and Joint Commenters propose associated Tariff language. Joint Commenters contend that because this is a requirement for participation in the market, the responsibility for DVER conversion should fall to the market participant.[37]

2. <u>Answers</u>

30. SPP argues that the proposed language is not ambiguous as to which resources are required to become dispatchable. SPP states that all VERs in the Integrated Marketplace must be registered as DVER, with only two limited exceptions. SPP states that "the requirement to be dispatchable is not preconditioned on SPP having a [GIA] with the Resource."[38] SPP also contends that the relevant market participant would continue to be responsible for updating a generator's registration status, and none of the changes proposed in the filing alter the market participant's responsibility for registration functions.[39]

31. Xcel states that Joint Commenters' recommendation to place responsibility for conversion on the market participant, rather than the generation interconnection customer, is legally impractical unless the market participant and the generation interconnection customer are the same entity. Xcel explains that the generation interconnection customer has the sole right to operate, maintain, and upgrade its VER facilities, and the market participant does not have the ability to make changes to the generation interconnection customer's physical equipment.[40] Xcel maintains that SPP needs to specify the party responsible for converting a resource from NDVER to DVER status in order to enforce its Tariff.[41] Xcel also argues that the Tariff changes regarding DVER conversion proposed by Joint Commenters should be rejected because Joint Commenters lack filing rights under section 205 of the FPA.[42]

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[37] *Id.* at 7.

[38] SPP Answer at 11-12.

[39] *Id.*

[40] Xcel Answer at 4.

[41] *Id.* at 5.

[42] *Id.* at 6.

32. In their response, Joint Commenters agree with SPP's clarification that, with only two limited exceptions, all VERs must register as DVERs, regardless of GIA status, and urge the Commission to require SPP to clarify this in its Tariff via a compliance filing.[43] With regard to responsibility for DVER conversion, Joint Commenters state that they are not arguing that the market participant should be responsible for DVER conversion or bear the cost of any improvements necessary to operate under the new rules. Instead, they maintain that the costs and responsibilities of conversion to a DVER, including technology and communication modifications necessary for the new registration, should be determined by the parties to the relevant contracts or those with rights to the generation. They contend that SPP should not interfere with contracts between parties that determine which party is responsible for conversion or the associated costs.[44]

3. Deficiency Response

33. SPP explains that NDVERs that do not have a GIA with SPP will still be required to register as DVERs, as all VERs that do not fall into one of the two limited exemptions must be dispatchable in order to participate in the Integrated Marketplace.[45] SPP states that to make this requirement clear, SPP would, if ordered so on compliance, include Tariff language to explicitly state that the conversion requirement applies to both generation interconnection customers as well as "[r]esources registered in the Integrated Marketplace for which SPP does not have an executed Generator Interconnection Agreement."[46]

34. SPP explains that, after discussion with stakeholders, it was determined that the generation interconnection customer is the better party to bear responsibility for ensuring that conversion of a resource from NDVER to DVER is undertaken because, unless the market participant and the generation interconnection customer are the same entity, the market participant may not have the contractual rights to ensure that any necessary physical upgrades or modifications are completed.[47]

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[43] Joint Commenters Answer at 4-5.

[44] *Id.* at 5-7.

[45] Deficiency Response at 5, 8.

[46] *Id.* at 8.

[47] *Id.* at 4.

4. Commission Determination

35. We find that it is reasonable for SPP to specify in its Tariff that the generation interconnection customer bears responsibility for DVER conversion. We agree that the generation interconnection customer is the party best suited for the responsibility of conversion because unless the market participant and the generation interconnection customer are the same entity, the market participant may not have the contractual rights to ensure that necessary physical upgrades or modifications are completed. Furthermore, the generation interconnection customer is responsible for operating its facilities in compliance with all applicable requirements under the SPP GIA.[48] Under these circumstances, we find it is reasonable to specify that the generation interconnection customer is the party responsible for conversion.

36. Finally, with regard to the treatment of NDVERs without GIAs with SPP, we find SPP's proposal to require all VERs to register as DVERs in order to participate in the Integrated Marketplace, with the two limited exceptions discussed above, to be just and reasonable. To clarify this requirement, we agree with SPP's proposal that it should include Tariff language to provide that the DVER conversion requirement applies to both generation interconnection customers and "[r]esources registered in the Integrated Marketplace for which SPP does not have an executed Generator Interconnection Agreement." We find that this clarification should address Joint Commenters' concerns that SPP's proposed language is ambiguous. Accordingly, in the compliance filing ordered below, we direct SPP to submit revisions to reflect this language in its Tariff.

The Commission orders:

(A) SPP's proposed Tariff revisions are hereby accepted, subject to condition, effective January 16, 2019, as discussed in the body of this order.

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[48] *Id.* at 5 (quoting SPP, OATT, Att. V, Appendix 6 Generation Interconnection Agreement, § 9.4 – Interconnection Customer Obligations (10.1.0)).

(B) SPP is hereby directed to submit a compliance filing within 30 days of the date of this order, as discussed in the body of this order.

By the Commission.

(S E A L)

Kimberly D. Bose,
Secretary.

Document Content(s)