Service Date: October 28, 2013

DEPARTMENT OF PUBLIC SERVICE REGULATION
BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MONTANA

IN THE MATTER OF NorthWestern Energy's 2011-2012 Electricity Supply Tracker	)))	REGULATORY DIVISION DOCKET NO. D2012.5.49 ORDER NO. 7219h

FINAL ORDER

APPEARANCES

FOR THE APPLICANT:

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FOR THE INTERVENORS:

Montana Consumer Counsel
Monica Tranel, 30 W. 14th St., Suite 204, Helena, Montana 59601, and Mary Wright, 111 N. Last Chance Gulch, Suite 1B, Helena, Montana 59601 (June 14, 2013, only)

Human Resource Council District XI and Natural Resources Defense Council
Charles Magraw, 501 8th Avenue, Helena, Montana 59601

Before:
W.A. GALLAGHER, Chairman
BOB LAKE, Vice Chairman
KIRK BUSHMAN, Commissioner
TRAVIS KAVULLA, Commissioner
ROGER KOOPMAN, Commissioner

Staff:
Jason Brown, Staff Attorney
Scott Fabel, Rate Analyst
Will Rosquist, Chief, Economics & Rate Design Bureau
Neil Templeton, Rate Analyst
Kate Whitney, Administrator, Regulatory Division

PROCEDURAL HISTORY

1. On June 1, 2012, NorthWestern Energy (NorthWestern or NWE) filed its annual *Application for Approval of Electricity Supply Cost Account Balance and Projected Electric Supply Cost* (Application) with the Montana Public Service Commission (Commission or PSC). In the filing, NorthWestern requested a change in electricity supply rates to reflect: (1) Amortization of a net under-collection of $8,502,457 in the Electricity Supply Deferred Costs Account Balance (Deferred Account Balance) for the 12 months ending June 30, 2012 (2011-2012 tracking period); and (2) projected load, supply, and related electric costs for the 12-months ending June 30, 2013 (2012-2013 tracking period). NorthWestern requested that the Commission grant an interim rate adjustment effective July 1, 2012.

2. The Commission issued a *Notice of Application and Intervention Deadline* on June 15, and granted intervention to the Montana Consumer Counsel (MCC) and to the Human Resource Council District XI and the Natural Resources Defense Council (HRC/NRDC or HRC) on July 11, 2012.

3. The Commission issued *Interim Order 7219* on June 26, 2012, and *Interim Order 7219a* (superseding *Interim Order 7219*) on July 17, 2012.

4. On July 27, 2012, the Commission issued *Procedural Order 7219b*, which it suspended on October 1 to allow time for the completion of discovery.

5. On November 16, 2012, the Commission directed NorthWestern to file supplemental testimony regarding the comprehensive demand-side management (DSM) program evaluation performed by SBW Consulting, Inc. (SBW), and the efficient scheduling and dispatching of electricity supply resources.

6. On November 21, 2012, the Commission issued *Modified Procedural Order 7219e*, setting a deadline of March 22, 2013, for intervenors' testimony.

7. On January 18, 2013, NorthWestern filed the *Supplemental Testimony of William M. Thomas, Dr. Marjorie R. McRae, Faith DeBolt and Michael H. Baker*. On February 1, 2013, NorthWestern filed the *Supplemental Testimony of Casey E. Johnston and Kevin J. Markovich*.

8. On March 22, 2013, MCC filed the *Direct Testimony of Jaime Stamatson, George L. Donkin and Dr. John W. Wilson*, and HRC/NRDC filed the *Direct Testimony of Dr. Thomas M. Power*. NorthWestern filed *Rebuttal Testimony* on May 3, 2013.

9. On May 21, 2013, the Commission issued a *Notice of Public Hearing*, and it conducted a public hearing June 11 through 14, 2013. *See* Hrg. Transcr. (Tr.).

10. On July 25, 2013, NorthWestern filed its *Post-Hearing Brief*. The MCC and HRC/NRDC filed post-hearing briefs on August 14, and NorthWestern filed a *Reply Brief* on August 28, 2013.

FINDINGS OF FACT

Application

11. NorthWestern's prior period Deferred Account Balance from the 2010-2011 tracking period was an under-collection of $4,605,171 for market-based electricity supply costs, an over-collection of ($2,574,686) for Colstrip Unit 4 (CU4) variable costs and credits, and an under-collection of $1,476,330 for Dave Gates Generation Station (DGGS) variable costs and credits. Ex. NWE-13 p. 9; Ex. NWE-14 p. 3; Ex. NWE-15 p. 3. The Deferred Account Balance for the 2011-2012 tracking period was an under-collection of $6,891,257 for market-based electricity supply costs, an over-collection of ($419,284) for CU4 variable costs and credits, and an over-collection of ($1,637,561) for DGGS variable costs and credits. Ex. NWE-13 p. 10; Ex. NWE-14 p. 4; Ex. NWE-15 p. 4. NorthWestern proposed to set the DGGS variable rate at zero and carry forward the DGGS Deferred Account Balance into the 2012-2013 true-up period. Ex. NWE-15 p. 4. The net of the Deferred Account Balances not including the DGGS Deferred Account Balance was an under-collection of $8,502,457 as of June 30, 2012. Ex. NWE-13 p. 12. NorthWestern proposed to amortize this net under-collection balance in rates effective during the 2012-2013 tracking period.

12. During the 2012-2013 tracking period, the overall electricity supply rate (i.e., the electric supply rate and deferred supply rate) was designed to collect (or rebate) market-based electricity supply costs totaling $228,850,106; the CU4 fixed cost of service totaling $75,408,426; the CU4 variable cost of service totaling $24,925,255; the DGGS fixed cost of service totaling $28,395,511; the DGGS fixed rebate revenue totaling ($7,076,400); and the DGGS variable cost of service totaling $7,503,384; for a total of $358,006,282. Ex. NWE-13 p. 14.

13. The Application included a projected cost of $10,441,871 for DSM programs and labor during the 2012-2013 tracking period. Ex. NWE-19 p. 27. Pursuant to Commission

direction in Order 7154b in Docket D2011.5.38, NorthWestern included forecasted DSM lost transmission and distribution revenues.

I. Additional Regulation Costs

Background

14. DGGS started commercial operation on January 1, 2011. Ex. NWE-2 p. 6. Its sole purpose has been to meet NorthWestern's need as a transmission owner to provide Regulation and Frequency Response Service (regulation service) in its balancing authority (BA). *Id.* DGGS consists of three FT-8 SwiftPac® units manufactured by Pratt & Whitney Power Systems, Inc. (PWPS); each unit has two engines, two power turbines (turbines) and one generator. *Id*. at p. 7.

15. Damage found in the Unit 2B turbine and subsequent indications that similar trouble was occurring in other DGGS turbines caused a forced outage of the entire plant from January 31, 2012, through May 1, 2012. *Id*. at p. 9; Ex. NWE-4 p. 5. Starting February 3, 2012, NorthWestern replaced DGGS regulation service with contracts with Powerex Corp. for 70 megawatts (MW)[1] of regulating reserve capacity and with Avista Corp. for 15 MW. Ex. NWE-4 p. 6. As DGGS was returned to service in stages over three months, the amount of regulation service provided by Powerex during that period was reduced incrementally to 50 MW on March 1, 24 MW on April 1, and 10 MW on April 15. *Id*. at p. 7. NorthWestern stopped all purchases of regulation service from third parties on May 1, 2012. *Id*.

16. The purchase order between PWPS and NorthWestern included a one-year warranty on the plant's major equipment, including the turbines. Tr. p. 183. Prior to DGGS starting commercial operation, NorthWestern purchased a one-year extension to the original PWPS warranty for $395,000, which extended the warranty through December 31, 2012. Ex. NWE-2 p. 16. The warranty required PWPS to "repair, replace, or make good" the damaged turbines at PWPS' cost, including removal, installation and shipping costs, and to complete the repairs promptly. Data Response (DR) PSC-008(a); DR MCC-070. However, Section 22.0 of the purchase order did not cover "consequential damages," such as the cost of replacement regulation service. DR MCC-068(a).

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[1] NorthWestern witness Cashell originally testified that NWE contracted with Powerex for 76 MW of regulation service in February 2012, Ex. NWE-4 p. 7, but he corrected the amount to 70 MW at hearing, Tr. p. 319.

17. In response to the outage, "PWPS took extraordinary measures to get DGGS back in service" by providing replacement and reconditioned turbines, conducting a root cause analysis of the outage, and designing a remedy that NorthWestern expects will resolve the mechanical and operational problems that caused the outage:

> First, it provided replacement power turbines from its pool of lease turbines so that DGGS could get back into service as quickly as possible. In fact, PWPS delivered two of the leased power turbines from Santiago, Chile. PWPS did this all at its own cost. Second, it picked up the NWE turbines from Anaconda, repaired them in Connecticut, and returned them for installation at DGGS. PWPS did this at its cost, not NWE's. Third, it devoted a team of engineers to identifying the mechanical problem and designing a remedy. This was all at PWPS's cost, not NWE's.

Ex. NWE-2 pp. 10-12.

18. The publicly available information concerning the causes of the outage includes a May 24, 2013 PWPS report that included a *Summary of Root Cause Investigation Findings*:

> Engineering Findings from Baseline Testing and Model Analysis
> - Over-temperature of #7 bearing support Outer Diameter (OD)
>   - Baseline testing confirmed gas path ingestion
>   - Thermal analysis model validated the over-temperature
>   - Over temperature resulted in reduction of material properties
> - Excessive displacement and contact of inlet static structure
>   - Baseline testing confirmed excessive displacement
>   - Model observed deflections with thermal responses matched to test data
>   - Higher motion resulted in higher stress on the affected parts
> - Operational mission
>   - Baseline testing evaluated ramp rates above 4MW/min have similar thermal effect
>   - Investigation indicated hardware failures are cycle related
>   - Model suggested the sub-cycles are only minor contributor
>   - Reduction of operational cycle can increase part life

DR PSC-101(e), Attachment p. 2.

19. Additional information regarding the causes of the outage was submitted on a confidential basis pursuant to protective orders, or provided at the confidential portion of the hearing through cross-examination of witness Rhoads. Tr. pp. 58-154; DR PSC-006(d), Attachment 1; *see* Order 7219f ¶ 23 (Feb. 12, 2013) (protecting this information as trade secret).

20. PWPS planned to install hardware modifications on all the DGGS turbines to remedy issues that contributed to the outage, and to test the turbine modifications on site with one turbine in the summer of 2013; if the testing proves successful, the modifications will be made to all of the remaining turbines by the end of 2013. Ex. NWE-2 p. 18. The evidence describing the "[turbine] inlet module hardware modifications" was submitted on a confidential basis. DR PSC-106(a), Attachment p. 2; Tr. pp. 83-88. Besides the planned hardware modifications, PWPS modified control software at DGGS following the outage to limit the ramp rate of the units to 15 MW per minute. DR PSC-106(b).

21. Although the software modifications will limit ramp rates to 15 MW per minute, Rhoads testified that the modifications that have been and will be made as a result of the outage will not limit the ability of DGGS to meet federally-required transmission reliability standards. *Id.*; NWE Reply Br. p. 13; Tr. pp. 158-159.

22. The sum of ongoing DGGS fixed costs, variable costs, and replacement contract costs exceeded the sum of DGGS fixed costs and variable DGGS costs that would have been incurred if there had been no outage. Ex. MCC-1a p. 8; DR MCC-059, Attachment p. 1. NorthWestern witness Cashell calculated the net cost that NorthWestern proposed to be included in retail customers' rates to be $1,419,172.[2] Ex. NWE-5 p. 7; DR MCC-59, Attachment p. 1. The parties do not dispute that this is the correct amount. Other than replacement regulation costs, NorthWestern is not seeking recovery of any other outage-related costs in this docket. NWE Post-Hrg. Br. p. 12.

<u>Summary of Parties' Positions</u>

23. NorthWestern requested full recovery from ratepayers of the costs it incurred for replacement regulation service during the three-month outage, including the $1.4 million in incremental replacement regulation costs. NorthWestern argued that it prudently managed the risk of an outage as evidenced by its selection of a reputable equipment vendor in PWPS, its purchase of a one-year extension to the PWPS warranty in 2010, its incorporation of design features that contributed to the plant's reliability such as the spare third unit and the blanking plate, and its adherence to PWPS' instructions for operating the plant. Ex. NWE-2 pp. 16-17;

[2] This amount is 80% of the total net outage cost; 20% of the cost is assigned to customers subject to Federal Energy Regulatory Commission (FERC) jurisdiction. Tr. pp. 340-341.

Tr. p. 157. NorthWestern further argued that it mitigated the cost impact of the outage by: (1) Obtaining the extended warranty from PWPS; (2) purchasing regulation service from third parties at the same prices offered in its 2011 solicitation for regulation service (required by the Commission); (3) structuring those purchases to allow NorthWestern to incrementally reduce the amount purchased as DGGS came back online in stages; and (4) acting swiftly to get DGGS back into service. DR MCC-062; Tr. pp. 306, 337; Ex. NWE-4 pp. 6, 7.

24. MCC recommended the Commission disallow the $1,419,172 in incremental replacement costs attributable to the outage. Ex. MCC-1a p. 9. MCC argued that NorthWestern's failure to evaluate the availability, price and terms of outage insurance prior to commencement of DGGS' commercial operation in January 2011 was imprudent. Tr. p. 575; MCC Br. pp. 3, 9. According to MCC, obtaining a quote for replacement insurance was especially important due to the warranty's exclusion of consequential damages and the fact that DGGS is "an uncommon plant that is a *pioneer in the field*, and by definition atypical" MCC Br. pp. 9-11; Tr. p. 605. MCC contended that replacement power insurance is widely available and that it would have been less costly for DGGS than for a baseload plant because DGGS provides regulation service only. Tr. pp. 576, 581, 588-589. According to MCC:

> NWE did not know the actual cost of replacement power; nor did it know what replacement insurance would cost, because it didn't even obtain a quote for such insurance. It had no facts to base a risk assessment on; and made no such risk analysis. Such failure is not prudent, and should not be paid for by the ratepayers of Montana.

MCC Br. p. 13.

25. NorthWestern disputed MCC's contention that the utility acted imprudently by failing to evaluate the price and availability of outage insurance prior to DGGS starting commercial operation. According to NorthWestern, based upon its experience with and ownership of other plants, it has never purchased replacement power insurance, but instead has relied on the market for replacement power when needed. DR MCC-067(b). NorthWestern contended it is common knowledge in the power industry that outage insurance is not cost effective and does not guarantee coverage. Tr. p. 274; Ex. NWE-2 p. 20; NWE Post-Hrg. Br. p. 17. NorthWestern provided an October 17, 2012 internal memo from its insurance manager that estimated the annual premium for such insurance to be $1 million, and noted that such a policy would not provide coverage until the 61st day of an outage. DR PSC-008(c),

Attachment 8. NorthWestern estimated that if it had purchased outage insurance for $1 million annually, the cost to ratepayers of the premium costs would have exceeded the cost of replacement regulation service during the outage. Tr. p. 224.

26. NorthWestern contended ratepayers have actually benefited from the outage because, in exchange for releasing PWPS from all outage-related claims, NorthWestern obtained a contract modification that secured the following benefits from PWPS: (1) An extension of the turbine warranty for two years after installation of the last of the six modified turbines at DGGS (expected to occur by the end of 2013); (2) coverage of costs for any additional modifications to the turbines that PWPS determines are needed as a result of the outage during the warranty period; and (3) coverage of costs for materials and labor to incorporate new turbine hardware that PWPS develops related to the outage, regardless of whether the warranty extension has expired. NWE Reply Br. p. 20; DR PSC-100.

27. MCC argued that requiring ratepayers to pay the full DGGS plant costs plus the incremental costs of replacement power during the outage would be unreasonable. Ex. MCC-1a pp. 9-10; MCC Br. pp. 3-4. MCC also claimed that ratepayers are now getting less from DGGS than what they paid for because, in response to the outage, PWPS reduced the ramp rate to a maximum of 15 MW per minute from the previous 30 MW or more per minute that MCC said was one of the plant's initial design criteria. Tr. pp. 51, 54; MCC Br. p. 8.

28. NorthWestern challenged MCC's contention that the control software change to limit DGGS' ramp rate to 15 MW per minute has reduced the value of the plant to ratepayers. NWE Reply Br. p. 13. NorthWestern said MCC was mistaken because the ramp rate specified in the original purchase order was a minimum of 15 MW per minute per engine. Tr. pp. 68-69. Because each unit has two engines, the aggregate ramp rate for each unit is 30 MW per minute. *Id.* at p. 69.

Commission Decision

29. As the owner and operator of DGGS, NorthWestern was in a better position to prevent the outage and the costs of the outage than its customers, who have already paid $6,742,625 for the fixed cost of DGGS during the outage, including NorthWestern's usual rate of return, plus $1,527,714 for variable costs that were never actually incurred, but that NorthWestern *would have* incurred had there been no outage. DR PSC-014(a), Attachment 6.

To require customers to pay an additional $1.4 million would relieve NorthWestern from bearing any costs whatsoever for an outage that it was in the best position to prevent, and would not be a fair or equitable outcome.

30. NorthWestern, as the owner and operator of DGGS (and seller of electricity supply service), and PWPS, as the manufacturer of the components that failed, acted in concert in contributing to the outage and the costs of the outage. For example, NorthWestern

> asked and Pratt & Whitney obliged, that we have a control system expert on site for a period of three months following commercial operation of the plant, who could be there in the operating room witnessing how the plant was operating. So Pratt & Whitney not only knew prior to commercial operation how the plant was responding, but they were also present for a three-month period following commercial operation to see the moment-to-moment operation of the plant to ensure that we were operating within the parameters of the specifications.

Tr. pp. 212.

31. To-date, PWPS has borne far more of the total cost of the outage than NorthWestern, perhaps more than $10 million. *Id*. at p. 238; *supra* ¶ 17. NorthWestern has avoided more than $10 million in repair costs (due partly to an extended warranty paid for by its customers), and collected almost $8.3 million in DGGS costs from its customers during the outage.

32. NorthWestern's customers cannot recover the incremental replacement costs of the outage from PWPS, whose warranty specifically "excluded consequential damages" and has only intervened in this proceeding "for the limited purpose of applying for a Protective Order." Ex. NWE-2 p. 14; PWPS Mot. to Intervene p. 1 (Aug. 23, 2012).

33. The Commission accepts MCC's argument that NorthWestern's failure to evaluate the availability, price and terms of outage insurance prior to commencement of DGGS' commercial operation in January 2011 was imprudent. Given the warranty's exclusion of consequential damages and the uniqueness of DGGS, NorthWestern should have identified the risk of incurring replacement costs in the event of an outage. *See* Tr. p. 211 ("the very unique way in which the power plant is controlled is really. . . different than most other power plants. . . . So early on we knew that the plant was going to have a very unique control application"). Its failure to identify risk ensured that incremental costs of replacement service would be incurred in the event of an outage.

34. The Commission finds that replacement insurance was available. DR PSC-008(c), Attachment 8. Although it may not have been cost-effective to procure replacement insurance – and may not be cost-effective to do so in the future – the failure to evaluate the availability, price and terms of outage insurance guaranteed that any incremental replacement costs would be unavoidable in the event of an outage. As a result, NorthWestern has not met its burden of showing that these costs were prudently incurred.

35. In addition to failing to adequately identify the risk of incurring replacement costs, NorthWestern did not appear to exhibit the level of situational awareness that the Commission would expect from a utility managing a one-of-a-kind power plant, which NorthWestern touted as a first-of-its-kind that "has the potential to be a model facility for the supply of regulation." Ex. MCC-13 p. 25. Specifically, NorthWestern was aware that: (1) "[T]he units need[ed] to change load rapidly" as measured in "MW change per minute," and that a single engine in operation could "ramp up or down at a rate of at least 15 MW per minute"; (2) "the ability to respond to demand within seconds" was critical to the operational mission of DGGS; and (3) the units could experience unique "thermal stresses," and that going "from a cold start to a very high temperature" can cause "a lot of distress within rotating equipment." *Id*. at pp. 5-9, 16; DR PSC-006(c), Attachment 47, p. 225; Tr. p. 91. The outage specifically involved ramp rates "much greater" than anticipated, excessive temperatures and cycle-related hardware failures. NWE Reply Br. pp. 12-13, DR PSC-101(e), Attachment p. 2.

36. Nonetheless, NorthWestern failed to retain "ramp rate data for each minute of operation." DR PSC-105(a); Tr. p. 102. Using software that allowed the ramp rate of each unit at DGGS to exceed 30 MW per minute without taking any steps to monitor the actual ramp rate makes it impossible for NorthWestern to prove and for the Commission to determine prudence. Likewise, cycling individual units frequently may not have been the most reasonable way to dispatch DGGS. Tr. p. 100.

37. NorthWestern carries the burden of proving that it its costs were prudently incurred, and was in the unique position of being able to monitor, record, and tender evidence that it exhibited the situational awareness and reasonable operation that the Commission would expect from a utility managing a one-of-a-kind power plant. *Infra* ¶ 102.

38. To require customers to pay an additional $1.4 million would relieve NorthWestern from bearing any cost responsibility whatsoever for an outage that it was in the

best position to prevent (or prove unpreventable), and would not be a fair or equitable outcome. Had DGGS been operational, consumers would have paid for certain variable costs of operating the plant if they were prudently incurred. In light of the limited disallowance sought by MCC, the unique design of DGGS, and the fact that the full outage lasted less than three months, the Commission has only considered the *incremental* costs resulting from the outage in this case.

39. NorthWestern has failed to prove that the incremental regulation costs that it incurred during the DGGS outage were prudently incurred. *Supra* ¶¶ 29-38. To allow NorthWestern to recover an additional $1,419,427 for incremental regulation costs would not result in just and reasonable rates for consumers.

II. True-Up of Lost Revenues

Background

40. In December 2011, NorthWestern retained SBW to conduct a comprehensive evaluation of its DSM programs for tracking periods 2006-2007 through 2010-2011. The Commission directed NorthWestern to supplement its Application in this Docket with testimony regarding the results of SBW's evaluation. *See* Not. of Commn. Action (NCA) pp. 1-2 (Nov. 15, 2012). On January 18, 2013, NorthWestern filed SBW's *Impact and Process Evaluation of NorthWestern's 2007-2011 DSM Programs* (SBW Report) as an attachment to the *Supplemental Testimony of Michael H. Baker*, the project manager of SBW's evaluation. *See* Ex. NWE-17, Attachment MHB-1a.

41. The purpose of the SBW Report was to measure and verify electricity savings achieved by NorthWestern's energy efficiency programs from July 2006 through June 2011 in order to evaluate the cost effectiveness of individual programs and true up lost revenue calculations.

42. SBW concluded that NorthWestern's actual electric program savings – from both electricity supply DSM programs and Universal System Benefits (USB) programs – were 87 percent of its reported savings, resulting in a Net Savings Adjustment rate of 0.87. SBW Report p. iii. Of the 309,336 megawatt-hours (MWh) of total energy savings that NorthWestern reported over the evaluated period, SBW verified 270,564 MWh. *Id*. Verified savings are also referred to as realized savings.

43. NorthWestern used SBW's estimate of realized savings to true up its lost revenue estimates. Ex. NWE-20, Attachment WMT-5. HRC/NRDC supported NorthWestern's recovery of lost revenues and continued use of the lost revenue adjustment mechanism. HRC/NRDC Br. pp. 2-3; Ex. HRC-1 p. 19. MCC expressed general concerns regarding lost revenue recovery, particularly for USB program savings. MCC Reply Br. p. 4.

44. NorthWestern requested final approval of lost revenues associated with its transmission charges, distribution charges, and capital charges for CU4 and DGGS for the 2006-2007 through 2010-2011 tracking periods, and interim approval of lost revenues for 2012-2013 tracking period. Ex. NWE-19 pp. 3, 31-32. In this Docket, NorthWestern also requested approval of the DSM program costs for the 2011-2012 tracking period. *See* Ex. NWE-10 p. 15. NWE witness Thomas revised NorthWestern's initial lost revenue estimate to reflect the realized savings in the SBW Report. Ex. NWE-20 pp. 2, 4-7. He also revised NorthWestern's lost revenue estimate to remove savings from conservation investments in NorthWestern's own facilities, and to correct errors identified by MCC witness Stamatson. After these adjustments, revised lost revenues totaled $18,086,023, resulting in an over collection of $225,703. Ex. NWE-21 pp. 10-11. NorthWestern agreed that the over collection of lost revenues should be rebated to consumers with interest. DR PSC-066.

45. NorthWestern contended that prior Commission orders require NorthWestern to aggressively pursue DSM and establish a precedent for allowing full recovery of lost revenues attributable to savings verified by an independent third party; it also asserted that no party has advocated or provided reasoned explanation for a departure from that precedent. NWE Br. pp. 35-39.

46. After careful consideration of the SBW Report's analysis of NorthWestern's reported energy efficiency program energy savings, as well as other evidence on this subject, the Commission finds four adjustments are necessary to ensure that NorthWestern only recovers lost revenues that were actually incurred as a result of its programs, and that the rates through which it collects lost revenues are just and reasonable. The four adjustments are discussed below.

<u>Free Ridership and Spillover</u>

47. In the terminology of DSM verification, "free ridership" refers to reported energy savings likely to have occurred without a utility's program, and "spillover" refers to additional

savings induced but not subsidized by a utility program. SBW Report p. 859. Lost revenue adjustments must account for free ridership and spillover effects to ensure that a utility's revenue recovery includes only those energy savings attributable to its DSM programs. NorthWestern specifically solicited bids for an evaluation, measurement, and verification of its DSM program savings that would assess free ridership and spillover effects. DR PSC-043(a), Attachment p. 10. A similar effort was undertaken in the previous study conducted by Nexant, Inc. *Infra* ¶ 54.

48. McRae testified regarding SBW's analysis of free ridership and spillover effects. Ex. NWE-16 pp. 4-5. Through surveys of program participants and nonparticipants, SBW estimated free ridership and spillover effects for several electric DSM and USB programs. In its draft report, SBW presented its findings for free ridership and spillover in a table for each program. *See* DR PSC-051(b) (Draft SBW Report pp. 56, 108-109, 143-144, 187, 224, 258, 298, 331, 361-362, 405-406, 440-441, 489, 538-539, 577-578, 604-605, 631, 652, 683-684, 719, 768 (Oct. 15, 2012)). Estimated net realized savings for all electric programs, after accounting for free ridership and spillover, was 79 percent of reported savings. DR PSC-033, Table 645.

49. SBW ultimately concluded that its free ridership estimates for NorthWestern's programs were comparable to free ridership estimates found by other energy efficiency program evaluators for other program administrators. SBW Report pp. 860-864. McRae testified that SBW followed national common and best practices to estimate free ridership and spillover. Tr. p. 646.

50. However, the SBW Report's final net realized savings estimates did not incorporate SBW's estimated free ridership and spillover rates. Instead, it ignored the conclusion of its October Draft Report and assumed that spillover completely offsets free ridership. In technical terms, SBW adopted a net-to-gross (NTG) adjustment equal to 1.0. SBW Report p. 881. This approach produced an average Net Savings Adjustment rate of 87 percent of total reported savings, rather than 79 percent. *Id*. at p. 822. To adjust realized savings for SBW's free ridership and spillover estimates would require an NTG adjustment of 0.91 (resulting from the division of 0.79 by 0.87).[3] DR PSC-033.

51. SBW conducted its own surveys, but it was later critical of biases that allegedly undermine their validity. These biases, according to SBW, include asymmetric perceptions of

[3] This number may change because program-specific realized savings will change due to the adjustments ordered below.

gains versus losses, attribution errors, cognitive dissonance, and the inability to accurately report events and predict participants' behavior. SBW Report pp. 864-870. SBW also identified three specific challenges associated with estimating spillover, including difficulty identifying unincented efficiency actions, estimating baseline energy usage, and showing a causal relation to an efficiency program. *Id*. at pp. 870-874 (quoting Haeri & Khawaja, *The Trouble with Freeriders*, Pub. Utils. Fortnightly, p. 39 (Mar. 2012)).

52. McRae described one difficulty in separating free ridership from spillover in a transforming market as follows:

> So then when you ask someone, would you have done this in the absence of NorthWestern? They go, well, yeah, sure, because now I'm aware. Now it's in the store. Now the salesman or the contractor can tell me its benefits. They support it. They can come back and maintain it. Yeah, of course they would have done it. But all of that is what has been put in place over ten years in Montana.

Tr. pp. 652-653. HRC/NRDC witness Power concurred that free ridership and spillover are difficult to measure, and that their interaction prevents valid and accurate measures of each one. Ex. HRC-1 pp. 27-31.

53. McRae testified that it is reasonable to specify a null hypothesis that the NTG equals 1.0:

> If you take 1.0 as the null hypothesis that these effects are offsetting, then, I think the burden is – especially if you're going to be in a lost-revenue calculation or something like that, I think the burden of proof is to say, no, these aren't offsetting. These savings would have happened anyway.

Tr. p. 668. She also stated that "in the absence of any other information, you just assume that one is positive and one is a negative; they're offsetting." *Id*. at p. 671. McRae did not see any justification for rejecting the null hypothesis or saying "it's anything other than 1.0," and if "for argument's sake it's 0.9, well, then for argument's sake why don't we say it's 1.1?" *Id*. at p. 669.

54. The only other comprehensive verification of NorthWestern's energy efficiency program savings occurred in Docket D2007.5.46. In that case, and contrary to what SBW proposes here to do, Nexant did adjust realized savings for the effects of free ridership and spillover in estimating net savings for several important programs. *See* Order 6836c pp. 22-23 (June 3, 2008). McRae testified that she was on the Nexant team that performed the impact evaluation, and that free ridership and spillover were reported in the net impacts. Tr. pp. 647-648.

55. Although free ridership and spillover may be difficult to estimate, the remedy is not to discard the only empirical data that attempts to ascertain those values. In this case, SBW initially used the best practices prevalent today (which are similar to practices used previously) to adjust realized savings based on the only empirical evidence of the distinct effects of free ridership and spillover.

56. The Commission is also not persuaded that an NTG of 1.0 is a legitimate "null hypothesis." McRae's argument that free ridership and spillover are perfectly offsetting is not persuasive. Offsetting does not imply perfectly offsetting, and NorthWestern has not demonstrated that an NTG of 1.0 is more reasonable as a null hypothesis than an NTG of 0.9 or any other fixed relation of the effects of free ridership and spillover. Because SBW did not test the null hypothesis proposed by McRae, it cannot be supported.

57. Regarding lost revenues, the Commission's task is to approve an accurate level of savings and associated lost revenues. The Commission does not accept that free ridership always exceeds spillover or vice versa. To accept SBW's approach would require two speculative findings: First, that assuming some fixed relation between free ridership and spillover would produce a more accurate and reliable calculation of lost revenues than using free ridership and spillover figures derived from surveys of NorthWestern's customers, and second, that a fixed NTG of 1.0 would be a more accurate and reliable assumption than 0.9 or any other fixed NTG that could be assumed. The Commission rejects this approach and approves an NTG based on the free ridership and spillover figures that SBW obtained using nationally accepted empirical methods.

58. Finally, the Commission is not persuaded by SBW's claim that program participants identified by survey methods as free-riders may have been influenced by years or decades of utility sponsored energy efficiency programs and should therefore be counted as spillover. The only spillover relevant to SBW's calculations is spillover attributable to program activity from July 2006 through December 2011. The Commission is not persuaded that spillover effects exceed free ridership effects; SBW's own empirical estimates of free ridership and spillover indicate otherwise. DR PSC-033. Although SBW contends that many evaluators believe that well designed and implemented programs commonly produce – after many years – spillover effects that exceed free ridership effects, this is not relevant to the estimation of free ridership and spillover in this case. Again, the only relevant spillover is the spillover associated

with programs in the period under review. Furthermore, the Commission has based its approval of lost revenues in previous orders primarily on a real throughput disincentive. *See* Ord. 6574e, Docket D2004.6.90, pp. 46-47 (Dec. 14, 2005); Ord. 6836c p. 60. In this case, the Commission disregards spillover from actions taken in periods prior to July 2006 as not relevant to any throughput disincentive related to actions taken in the current study period.

59. NorthWestern has not met its burden of showing that lost revenues attributable to an assumed NTG of 1.0 were actually incurred. The Commission is not persuaded that it is reasonable to assume spillover completely offsets free ridership when verifying NorthWestern's realized energy efficiency savings. Specifically, the record does not show that an NTG ratio of 1.0 is preferable to an adjustment based on SBW's empirical research. The Commission directs NorthWestern to true up its lost revenue calculations using realized savings that incorporate the free ridership and spillover figures provided in response to Data Request PSC-033.

Burn Hours of Compact Fluorescent Lights

60. To estimate average hours of use (burn hours) for incented residential compact fluorescent lights (CFLs), SBW sampled participants in NorthWestern's owner-install and direct-install programs. SBW metered sampled participants' CFLs between May and August 2012. SBW then scaled up the average burn hours for each lamp by 16.5 percent to account for seasonal variation based on results from a 2010 California study and a 2004-2005 New England study. SBW aggregated the adjusted metered results across households and programs to derive an estimate of 2.02 burn hours per CFL per day. SBW Report pp. 780-800. Baker testified to the level of care taken in the metering study:

> I would say in my experience of evaluations, comparable evaluations, to have the luxury of metering 220 fixtures, which we did for this study, was unusual. So I would say there's a degree of care being exercised in the study that goes beyond many.

Tr. p. 722.

61. Partly based on a 1996 Tacoma Public Utilities study, SBW hypothesized that consumers behave rationally and install CFLs in their highest-use lamps first and lesser-used lamps later. SBW Report p. 566. SBW supported this hypothesis with a simple linear regression of burn hours on date of study using burn hour estimates from eight studies conducted around the country over the period 1996 through 2012. SBW treated the date of each study as a proxy for

the date of installation. SBW used its own 2012 estimate of 2.02 burn hours per CFL per day as one observation in the analysis. Because the linear regression results indicated declining burn hours over time, SBW "used professional judgment to estimate that residential CFL operating hours in NWE territory were most likely greater in the earlier program years than the value we found in 2012." *Id*. at pp. 566-567.

62. By treating the date of study as a proxy for the date of installation, the linear regression model produced misleading results; the Commission is not persuaded that it established a statistically valid estimate of the relation between expected average burn hours and the date of installation for at least three reasons.

63. First, the record does not show that all of the CFLs sampled in 2012 were all acquired and installed in 2012. Since SBW may have metered CFLs installed in earlier years, the Commission cannot conclude that its metering results represent an adequate proxy for CFLs installed in 2012.[4] Furthermore, because the record does not include the other lighting studies, the Commission cannot determine whether the burn hour estimates from those studies represent lamps installed on the date of study, or even whether those studies fairly represent usage profiles in NorthWestern's service territory. The Commission approves of the use of other studies for the limited purpose of adjusting SBW's own summer metering results for annual use (albeit with some skepticism) because the 2012 Montana-based study would be intrinsically flawed if no adjustment were made to acknowledge seasonal differences in lighting use. However, including results from non-Montana studies as observations in the linear regression unacceptably dilutes the results of the only study conducted in NorthWestern's service territory. In this particular case, SBW made virtually no effort to demonstrate the relevance of the seven observations from other studies to CFL usage in NorthWestern's system.

64. Second, the Commission is skeptical that the regression on only eight observations forms an adequate sample in this case, particularly when the observations were drawn from studies that might vary greatly in sampling methods and other factors.

65. Third, the Commission is not convinced that SBW took adequate precaution to check that its linear model did not omit relevant variables. Although Baker testified that variables such as latitude can significantly affect burn hours, Tr. p. 722, SBW did not test models

[4] In fact, SBW notes that it randomly selected CFLs to meter from all CFLs found in a sampled residence, not just program CFLs. SBW Report p. 780; *see also* DR PSC-058e.

that included other variables; it should have known that ignoring important variables like latitude could produce biased results. The Commission concludes that SBW did not establish the relevance or validity of its linear regression model, and rejects the regression results that are largely based on seven out-of-state studies. Instead, the Commission accepts SBW's 2012 estimate of 2.02 burn hours per day based on service territory-specific data (adjusted for annual use) as the best estimate of burn hours for CFLs installed throughout the study period.

66. The Commission directs NorthWestern to recalculate lost revenues after adjusting SBW's estimated savings (from the E+ Residential Lighting, NEEA Initiatives, and E+ New Homes programs) to reflect 2.02 burn hours per CFL per day in all years.

Storage of Compact Fluorescent Lights

67. On-site inspections of E+ Residential Lighting program participants revealed that 8.6 percent of program CFLs were in storage rather than in actual use. SBW Report pp. 572-573. SBW chose not to adjust realized savings for these stored bulbs "[b]ecause the storage rate was low and the stored bulbs were likely to be installed in the near future. . . ." *Id*.

68. For purposes of estimating lost revenue, the Commission finds that realized savings should be adjusted to account for CFLs that SBW found in storage. The purpose of SBW's Report was to determine energy savings from July 2006 through December 2011. Clearly, lamps that are installed in drawers and closets rather than fixtures are not producing energy savings. The Commission is not persuaded by the claim that stored lamps should be considered installed because they are likely to be installed in the near future. SBW's own study indicates that consumers want a supply of extra bulbs in storage, which suggests that there are always bulbs in storage and that this inventory has a negative impact on realized savings. *Id*. at p. 596. Because SBW did not provide evidence to support a rate at which lamps would move from storage to fixtures, the Commission cannot conclude that stored lamps were installed and producing electricity savings within the study period. The Commission directs NorthWestern to adjust all residential CFL savings estimates, except those associated with the direct install program, to reflect an 8.6 percent storage rate for residential CFLs.

Department of Environmental Quality Appliance Program

69. Thomas testified that NorthWestern's participation in the Department of

Environmental Quality (DEQ) appliance program was limited to program promotion. Tr. p. 848. The DEQ funded program incentives using federal stimulus money. According to Thomas, NorthWestern included all realized savings from the program in its lost revenue calculation because "[i]f we participate in a program, there is a – not to be flip – but there is a notion that if we touch it, we claim it, that we work by." *Id*. at p. 847. He admitted that it would be logical to assume that NorthWestern's efforts were not needed to persuade customers to acquire the incentives. *Id*. at pp. 848-849.

70. The Commission does not find it reasonable to provide NorthWestern lost revenue recovery for all DEQ appliance program savings when NorthWestern's participation was not primarily responsible for producing those savings. The Commission directs NorthWestern to adjust realized savings from the DEQ appliance program by a factor equal to the ratio of NorthWestern's program costs to the total resource costs of the DEQ Appliance Program.

Table 461

71. File review and site visit adjustments for three delivery methods (i.e., owner-install, direct-install, and upstream buy-down) of the residential CFL program are shown in Table 461. SBW Report pp. 574-575. Cross examination of Baker and DeBolt at hearing failed to clarify the derivation of the final adjustment rate of 0.78. *Id*. at pp. 734-735, 762. The Commission directs NorthWestern to include work papers in its compliance filing showing the final savings rate for the E+ Residential Lighting program after making the adjustments required by this Final Order to reported savings for the three delivery methods described above. *Id.* at pp. 570-575.

Conclusion

72. In certain instances, NorthWestern did not meet its burden of demonstrating through an independent, third-party program evaluation that its reported energy efficiency program savings from July 2006 through December 2011 were actually realized. *Supra* ¶¶ 46-70. To the extent that the estimates of realized savings relied on unsupported, unproven, or unreasonable assumptions regarding free ridership and spillover, CFL burn hours, CFL storage

rates, and the DEQ appliance program, NorthWestern did not meet its burden of verifying actual energy savings.

73. Because the Commission is not persuaded that NorthWestern actually realized all of the savings calculated by SBW, it directs NorthWestern to make the adjustments to those savings as described above for purposes of determining its final authorized lost revenues. Allowing NorthWestern to recover lost revenues for savings that were not shown to have been realized (or were shown to have been realized based on flawed assumptions) would result in unjust and unreasonable rates.

74. The Commission finds that reducing the realized savings in the SBW Report based on the concerns described above (regarding assumptions about free ridership and spillover, CFL burn hours, CFL storage rates, and the DEQ appliance program) produces a reasonable estimate of realized savings for purposes of determining NorthWestern's final authorized lost revenues for the 2006-2007 through 2010-2011 tracking periods. Because SBW also examined the savings realized during the last six months of 2011, the Commission also approves the lost revenues actually incurred (i.e., subject to the adjustments described above) from July through December 2011 on a final basis.

75. Once modified to reflect the adjustments described in this Order, the lost revenues incurred during the first six months of 2012 are approved on an interim basis.

76. All estimates or projections of lost revenues incurred after the 2011-2012 tracking period shall be modified to reflect the adjustments to realized savings made in the Order.

77. Based on the adjustments made in this Order, NorthWestern must submit a compliance filing within 30 days of its service date to true-up lost revenues. This compliance filing must include: (1) The calculation of total realized savings after incorporating the adjustments ordered above; (2) the total amount of lost revenues to be rebated, plus interest at 10.25 percent, *infra* ¶ 108; and (3) the derivation of new rates designed to credit the total rebate amount to ratepayers over a period of no more than one year.

III. Lost Revenue Adjustment Policy

78. The Commission recognizes that prior orders have established a precedent of full recovery of lost revenues associated with verified savings. *See* Ord. 6574e pp. 46-48; Ord. 6836c pp. 59-60. Nevertheless, the Commission hereby provides notice to NorthWestern

that it is skeptical of the *status quo* regarding lost revenue recovery. The Commission is troubled by the magnitude and complexity of the SBW Report, and by the administrative cost associated with overseeing the process of determining realized savings. The Commission recognizes that NorthWestern's expectation of lost revenue recovery is embedded in its cost estimates in this case, as well as in Docket D2013.5.33. However, as of the service date of this Order, NorthWestern bears the burden of demonstrating why any request for incremental lost revenues resulting from the acquisition of additional USB or DSM savings is reasonable and in the public interest. The Commission observes that the policy of allowing lost revenue recovery for USB programs appears particularly questionable given that such programs are required by law.

79. Regarding lost revenues associated with electric supply DSM program savings, the Commission observes that frequent rate cases will largely mitigate the impact of lost revenues due to energy efficiency programs on NorthWestern's usage-dependent recovery of capital asset costs. Ex. HRC-1 p. 25; Tr. pp. 872-875 (confirming NorthWestern's 2012 annual report refers to "annual or biennial rate cases.").

IV. Off-System Fixed-Price Hedges

Background

80. NorthWestern's off-system fixed price transactions involve contracts to buy and sell power delivered to the Mid-Columbia (Mid-C) trading hub. Typically, NorthWestern purchases power delivered to Mid-C at a fixed price while simultaneously selling the same quantity delivered to Mid-C at the Mid-C index price, and purchasing the same quantity delivered on-system. The on-system power is generally priced at a discount to the Mid-C index due to the basis differential between the Montana market and Mid-C, which is largely attributable to the cost of wheeling power to Mid-C (discount to index).[5] Tr. pp. 451-453. The quantities bought and sold at Mid-C net to zero, so NorthWestern is left with on-system power purchased at the fixed price less the discount to index. *Id*.

81. NorthWestern uses fixed price hedges to insulate part of its portfolio from unexpected increases in the market price of electricity. It hedges the portfolio in several different ways. It acquires rate-based assets such as Colstrip Unit 4, it enters fixed price contracts for on-

[5] This basis differential between Montana and Mid-C exists because the power generated on NorthWestern's system generally exceeds load, and a large portion of that power is transmitted to the west to serve loads in other states (e.g. Colstrip power).

system power such as the 7-year PPL contract and certain QF contracts, and it enters fixed price contracts for off-system power such as the ten-year Citigroup contract. In the 2011-2012 tracking period, NorthWestern hedged 75 percent of its total delivered energy using on-system hedges, and roughly 10 percent more using off-system fixed-price purchases. *Id*. at pp. 456-462.

Summary of Parties' Positions

82. MCC recommended that the Commission order NorthWestern to terminate its off-system fixed price electric hedges. Ex. MCC-2 p. 18. MCC witness Donkin provided a table showing a "Projected Net Off-System Hedging Loss" of $14.9 million in the 2012-2013 tracking period. *Id*. at Ex. GLD-1. NorthWestern witness Markovich confirmed at hearing that actual and projected losses from NorthWestern's off-system hedges from July 2011 through June 2014 amount to $47 million, less the discount to index. Tr. pp. 442-443, 453.

83. NorthWestern argued, however, that a hedging analysis should examine prices over a longer period than three years, and that MCC failed to recognize the value of hedging. *Id*. at pp. 455, 509-510; NWE Reply Br. pp. 20-22. NorthWestern contended that the $47 million represents the value of insurance to mitigate the potential impact of rising prices. According to Markovich, the value of insurance is the protection provided, and that value is received regardless of whether a damage claim is filed: "An insurance policy is intended to mitigate very adverse outcomes, and the same holds true with hedging." Ex. NWE-9 p. 6; Tr. pp. 522-523. NorthWestern asserted that the off-system fixed price transactions are prudent because they reduce exposure to price volatility, and that the Commission's resource planning rules require mitigating risks associated with the uncertainty of wholesale markets. NWE Post-Hrg. Br. pp. 27-29 (citing Admin. R. Mont. 38.5.8219 (2013)). NorthWestern pointed out that the risk of price volatility is asymmetrical because the price floor is close to zero but the ceiling is theoretically infinite. *Id*. at pp. 29-30; Tr. pp. 480-481, 506-507.

84. MCC claimed that NorthWestern's off-system electric supply hedges are similar to its natural gas "swaps" that have produced losses of at least $80.9 million. Ex. MCC-2 pp. 14, 18; *see Stip. & Settle. Agreement of NWE & MCC*, Dockets D2009.5.63 & D2010.5.49 (Oct. 29, 2010). NorthWestern disagreed, noting that unlike electricity, natural gas may be stored, and its off-system electric hedges require immediate scheduling and delivery. Tr. pp. 460-461, 465.

85. MCC also contended that because NorthWestern passes through all hedging gains and losses, and engages in these transactions solely to achieve price stability, NorthWestern is more likely to lose money than counterparties that put their own money at risk. Ex. MCC-2 pp. 15-18. Markovich acknowledged at hearing that NorthWestern's counterparties are more sophisticated than NorthWestern in market knowledge, risk valuation, and technical modeling. Tr. p. 473. Donkin testified that this disparity is likely to produce ongoing losses from NorthWestern's off-system fixed price hedges. *Id*. at pp. 541-542.

86. Markovich testified that the Mid-C hub is a liquid market with many participants and transparent pricing, but NorthWestern's on-system market is dominated by one electricity supplier. He testified that if NorthWestern was not allowed to hedge at Mid-C, its fixed prices would be set by one dominant supplier in the Montana market (i.e., PPL). Tr. pp. 451, 462-463. Markovich acknowledged that NorthWestern is a dominant buyer in the Montana market, but maintained that having access to another liquid market allows NorthWestern to avoid monopoly price pressure from PPL. *Id*. at pp. 520-521, 524-525.

87. NorthWestern argued that if it replaced its off-system fixed price electric supply transactions with market priced transactions, 25 percent of its portfolio would be exposed to market prices, which would be too risky. It pointed out that the Commission has previously found a 25 to 30 percent spot-market exposure to be "higher than is optimal," and "prefer[ed] that NWE move aggressively to less reliance on the short-term spot market." NWE Post-Hrg. Br. pp. 33-34 (citing Ord. 6682d, Docket D2005.5.88, ¶ 60 (July 12, 2006)). Markovich testified that energy markets are volatile, and that hedging provides discipline, structure and focus, and protects customers from extremely high prices such as occurred with California energy prices in 2000. Tr. p. 519, 522-523.

<u>Commission Discussion</u>

88. The Commission is disquieted by the hedging losses, but will not direct NorthWestern to discontinue its off-system fixed priced hedging transactions at this time. NorthWestern explained its hedging strategy clearly in its 2011 Electricity Supply Resource Procurement Plan (2011 Plan) and will do so again in its 2013 Electricity Supply Resource Procurement Plan. *See* 2011 Plan, Vol. 1, Appendix 1, pp. 194-198 (Dec. 15, 2011).

89. However, MCC's advocacy in this docket has made clear the need for a review of NorthWestern's fixed price hedging strategy. The Commission is persuaded that NorthWestern transacts with less incentive to avoid hedging losses than its hedging counterparties. The Commission will open a docket within 90 days of this Order to investigate possible mechanisms to better align the goals of rate stability and risk mitigation with the goal of providing service at the lowest-long term total cost. In the meantime, the prudence of hedging losses will continue to be a potential issue in annual electricity tracker dockets.

V. Dispatch of Basin Creek

Background

90. In 2004, the Commission granted NorthWestern approval for its request to enter into a 20-year supply contract with the natural-gas facility owned by Basin Creek Equity Partners, LLC (Basin Creek), which was to provide the following services, in order of importance: (1) Enhanced supply reliability; (2) ancillary services; (3) integration of wind resources; and (4) economically dispatchable energy and capacity. Ord. 6557c, Docket D2004.3.45, p. 13 (Sept. 7, 2004). NorthWestern asserted that Basin Creek's reciprocating engine technology would provide operating reserves and load following services. *Id*. at p. 12. In Order 6557c, the Commission directed NorthWestern to optimize the dispatch of Basin Creek, and stated that it would conduct prudence reviews of such dispatch. *Id*. at p. 27.

91. In its written comments on NorthWestern's 2011 Plan, the Commission expressed concern over whether NorthWestern was optimizing resources capable of producing multiple services. *Written Comments Identifying Concerns Regarding NWE's Compliance with ARM 38.5.8201-8229*, Docket N2011.12.96 pp. 7-8 (Sept. 28, 2012). In this proceeding, the Commission directed NorthWestern to address how efficiently it dispatches its portfolio of resources and minimizes energy imbalance charges, and specifically the feasibility and economics of dispatching Basin Creek "on an intra-hour basis to correct for deviations from scheduled load and supply." NCA p. 2.

Commission Discussion

92. NorthWestern's Energy Supply Function needs both imbalance service and regulation service from NorthWestern's Transmission Function. The role of Basin Creek in

providing these services appears to have changed over time. Tr. pp. 324-331, 387-395; DR PSC-078(d), Attachment 4; 2011 Plan p. 63. Whereas Basin Creek was once dispatched by the Transmission Function, today it is controlled entirely by the Energy Supply Function. Tr. pp. 324, 503-505; DR PSC-079(b). Basin Creek's capacity factor has fallen recently from about 20 percent in the 2007-2008 tracking period to about three percent in the 2011-2012 tracking period. Ex. NWE-10 Ex. FVB-1.

93. NorthWestern's Transmission Function could use another resource capable of within-hour adjustments. Tr. pp. 356-403. While Basin Creek may not be capable of responding to moment-to-moment fluctuations, it can cycle from zero to maximum output in nine minutes, and could cope with larger within-hour deviations from schedules (i.e., provide ancillary services). *Id*. at p. 326; Ex. NWE-8 p. 5; DR PSC-079(d). Basin Creek also has a lower heat rate than DGGS, which could result in lower operating costs. DR PSC-078(b).

94. The Commission questions whether NorthWestern is fully utilizing Basin Creek's flexible ramping capabilities, and directs NorthWestern to evaluate whether Basin Creek could serve both Energy Supply and Transmission Function needs. NorthWestern's Transmission Function should assess whether Basin Creek could cost-effectively provide transmission services, and its Energy Supply Function should assess whether Basin Creek could cost-effectively correct schedule deviations (due to supply or load) on an intra-hour basis.

95. The record does not show that NorthWestern has analyzed such questions with respect to both functions. Other utilities dispatch their generation fleets to provide both supply and transmission ancillary services despite the functional separation requirements of the Federal Energy Regulatory Commission (FERC). As NorthWestern has become more vertically integrated, the potential efficiencies of utilizing its resources for both supply and transmission functions has become more worthy of study.

96. The Commission finds that NorthWestern's biennial resource procurement plans are a reasonable place for NorthWestern to address the economic dispatch questions just discussed. To the extent NorthWestern is unable to complete a full analysis in its upcoming procurement plan, NorthWestern should outline a plan for undertaking such an analysis.

CONCLUSIONS OF LAW

Background

97. The Commission has "full power of supervision, regulation, and control" over public utilities, including NorthWestern. Mont. Code Ann. §§ 69-3-101–102 (2013).

98. NorthWestern's electricity supply rates "shall be reasonable and just, and every unjust and unreasonable charge is prohibited and declared unlawful." *Id.* at § 69-3-201.

99. The Commission "shall establish an electricity cost recovery mechanism that allows a public utility to fully recover prudently incurred electricity supply costs, subject to the provisions of 69-8-419, 69-8-420, and [C]ommission rules." *Id.* at § 69-8-210(1) (this proceeding is the mechanism that allows NorthWestern to recover "prudently incurred" electricity supply costs).

100. "Electricity supply costs" are "the actual costs incurred in providing electricity supply service," including "ancillary service costs." *Id.* at § 69-8-103 (defining "electricity supply service" in part as "the provision of electricity supply and related services through power purchase agreements").

101. The costs of the replacement regulation service purchased from third parties were "electricity supply costs" because they were "actual [ancillary service] costs incurred in providing electricity supply service through power purchase agreements." *Id.*

102. NorthWestern bears the burden of showing that its electricity supply costs were prudently incurred. *See e.g.* Admin. R. Mont. 38.5.182 ("A utility filing for an increase in rates and charges shall be prepared to . . . sustain the burden of proof of establishing that its proposed charges are just and reasonable"); 38.5.8213 (requiring modeling and analysis to meet the "burden of proof in prudence and cost recovery filings"); 38.5.8220 (discussing how a utility may "satisfy its burden of proof."); 16 U.S.C. § 824d (2013) ("At any hearing involving a rate or charge sought to be increased, the burden of proof to show that the increased rate or charge is just and reasonable shall be upon the public utility").

103. In fulfilling its duty to "manage a portfolio of electricity supply resources," NorthWestern must attempt to "identify and cost-effectively manage and mitigate risks related to its obligation to provide electricity supply service." Mont. Code Ann. § 69-8-419.

104. Nothing limits the Commission's ability to inquire into the manner in which NorthWestern has “managed, dispatched, operated, or maintained any resource. . . as part of its overall resource portfolio.” *Id*. at § 69-8-421(9).

105. The Commission may “disallow rate recovery for the costs that result from the failure of a public utility to reasonably manage, dispatch, operate, maintain, or administer electricity supply resources in a manner consistent with 69-3-201, 69-8-419, and [C]ommission rules.” *Id*.

106. DGGS is an “electricity supply resource.” *Id*. at § 69-8-103(9) (“electricity supply resource” includes utility-owned plants and “equipment used to generate electricity”).

107. “As necessary, a utility’s periodic electricity supply cost tracking filings should include the information, analyses, and documentation recommended in [procurement planning] guidelines to support its request for cost recovery related to electricity supply cost additions or changes.” Admin. R. Mont. 38.5.8226(2).

108. The Commission must order interest, “as determined by the [C]omission],” to be paid on a rebate. Mont. Code Ann. § 69-3-304. Interest associated with the rebate to customers resulting from this Order shall be computed at 10.25 percent. Ord. 7219a ¶ 36 (July 17, 2012) (citing Docket D2009.9.129).

109. The Commission has provided adequate public notice, and an opportunity to be heard to all parties to this proceeding. *Supra* ¶¶ 2-9; Mont. Code Ann. § 2-4-601.

Additional Regulation Costs

110. Because NorthWestern was “in a better position to prevent the [costs] resulting” from the outage, it “is properly liable as opposed to the innocent buyer” of its electricity supply service, who has no right to buy electricity from another supplier. *Pracht v. Rollins*, 239 Mont. 62, 66, 779 P.2d 57, 60 (1989) (“the theory behind the implied warranty [of habitability] is not to discern fault, but to place the liability on the party most able to prevent the resulting harm.”); *Avanta Fed. Credit Union v. Shupak*, 2009 MT 458, ¶ 27 (“[i]f there is a policy implicit in the UCC’s rules for the allocation of losses due to fraud, it surely is that the loss be placed on the party in the best position to prevent it.”); *Kuiper v. Goodyear Tire & Rubber Co*., 207 Mont. 37, 63, 673 P.2d 1208, 1222 (1983) (“Recognizing that the seller is in the best position to insure product safety, the law of strict liability imposes on the seller a duty to

prevent the release" of unreasonably dangerous products "into the stream of commerce."); *see also* Mont. Code Ann. § 69-8-201(2)(b) ("A [small] retail customer that . . . is currently purchasing electricity from a public utility may not choose to purchase electricity from another source after October 1, 2007."). NorthWestern's captive customers should not be responsible for costs that they were in no position to prevent or mitigate, especially where, as here, NorthWestern is recovering all of the costs (and profits) that it would have collected had there been no outage. *Supra* ¶¶ 29-31, 38.

111. "A party may be jointly liable for all damages caused by the negligence of another if both acted in concert in contributing to the claimant's damages or if one party acted as an agent of the other." Mont. Code Ann. § 27-1-703(3). Here, NorthWestern and PWPS acted in concert in contributing to the full cost of the outage, most of which was borne by PWPS. *Supra* ¶¶ 30-31. Thus, their relationship is analogous to the relationship between parties that may be held jointly liable. The apportionment of the full cost of the outage between NorthWestern and PWPS is immaterial to NorthWestern's customers, who in no way contributed to the outage and should not be held responsible for its costs. *Id.*

112. "If for any reason all or part of the contribution from a party liable for contribution cannot be obtained, each of the other parties shall contribute a proportional part of the unpaid portion of the noncontributing party's share. . . ." Mont. Code Ann. § 27-1-703(5). In this case, assuming PWPS is liable for part of the replacement costs incurred by NorthWestern, the Commission cannot obtain contribution from PWPS, which appeared in this proceeding only "for the limited purpose of applying for a Protective Order." PWPS Mot. to Intervene p. 1 (Aug. 23, 2012); *supra* ¶ 32; *see also* Mont. Code Ann. § 69-1-102 (creating the Commission "to supervise and regulate the operations of public utilities, common carriers, railroads, and other regulated industries"). As a result, NorthWestern should contribute any unpaid portion of PWPS' share of the incremental regulation costs.

113. NorthWestern's imprudence ensured that it would incur replacement costs in the event of an outage. *Supra* ¶¶ 33-34. Because the incremental regulation costs were not "prudently incurred," the Commission need not allow recovery of these costs. *Supra* ¶ 39; Mont. Code Ann. § 69-8-210(1).

114. Because cost recovery is subject to Section 69-8-419(2)(c) (requiring NorthWestern to attempt to "identify . . . risks related to its obligation to provide electricity

supply service."), *id*. at § 69-8-210(1), and NorthWestern did not attempt to identify the risk of incurring additional regulation costs in the event of an outage, *supra* ¶¶ 24, 33-34, the Commission need not allow full recovery of these costs.

115. Because the incremental regulation costs resulted from NorthWestern's failure to reasonably manage and operate DGGS, *supra* ¶¶ 35-37, the Commission may disallow these costs, Mont. Code Ann. §§ 69-8-210(1), 69-8-421(9).

True-Up of Lost Revenues

116. In 2005, the Commission found "that it is reasonable and in the public interest to implement, *on an interim basis*, NWE's proposed lost T&D revenue requirement adjustment mechanism." Ord. 6574e pp. 47, 58 (emphasis added). The Commission ordered that "the estimated lost T&D revenue amount must *be trued-up based on actual program activity* . . . following a comprehensive program evaluation and independent verification of actual savings. . . ." *Id*. (emphasis added).

117. In 2008, the Commission reiterated that "in Order 6574e it authorized NWE to recover estimated DSM-related lost revenue *on an interim basis subject to true-up* following a program evaluation and independent savings verification." Ord. 6836c, Docket D2007.5.46, p. 59 (June 3, 2008) ("True-up adjustments are not retroactive ratemaking."). In that case, the Commission found that "Nexant's evaluation satisfie[d] the DSM program evaluation and savings verification requirements in Order 6574e." *Id*.

118. Although the Commission has concluded in past orders that lost revenues that reflect "actual costs" are "electricity supply costs," *id*. at p. 62; Ord. 6574e p. 56, it will revisit and may reassess this conclusion in future proceedings, *supra* ¶¶ 78-79.

119. Lost revenues that are calculated based on savings assumptions that the Commission has rejected are not "actual costs," and therefore not "electricity supply costs." *See* Mont. Code Ann. § 69-8-103(8) (defining "electricity supply costs" in part as "the actual costs incurred" through DSM and efficiency programs).

120. Because lost revenues attributable to flawed savings assumptions are not "electricity supply costs," the Commission need not allow recovery of those lost revenues. *Id*.; *see supra* ¶¶ 46-74.

121. To allow recovery of lost revenues attributable to unreasonable savings assumptions would result in "unjust and unreasonable" electricity supply rates. *Supra* ¶¶ 46, 73; Mont. Code Ann. § 69-3-201.

ORDER

IT IS HEREBY ORDERED THAT:

122. Excluding $1,419,427 for incremental regulation costs during the DGGS outage and lost revenues that were not actually incurred, NorthWestern's request to recover electricity supply costs incurred during the 2011-2012 tracking period is APPROVED;

123. NorthWestern's request to recover $1,419,427 for incremental costs of regulation service during the DGGS outage is DENIED**;**

124. NorthWestern make a compliance filing, including work papers, within 30 days of the service date of this Order that: (1) Adjusts its reported energy efficiency savings as directed in paragraphs 46 through 74; and (2) recalculates the true-up of lost revenues actually incurred from July 2006 through December 2011;

125. NorthWestern's lost revenues incurred during the first six months of 2012 are APPROVED on an interim basis;

126. NorthWestern address the findings made in paragraphs 92 through 96 concerning the dispatch of Basin Creek in its next electric supply resource procurement plan or, to the extent NorthWestern is unable to complete the analysis in its next procurement plan, outline a plan for undertaking such an analysis; and

127. NorthWestern submit tariffs in compliance with this Order within 45 days of the service date of this Order.

DONE IN OPEN SESSION in Helena, Montana on this 17th and 22nd days of October, 2013 by a vote of 5 to 0 and 4 to 1, respectively.

BY ORDER OF THE MONTANA PUBLIC SERVICE COMMISSION

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W. A. GALLAGHER, Chairman

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BOB LAKE, Vice Chairman

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KIRK BUSHMAN, Commissioner (dissenting in part)

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TRAVIS KAVULLA, Commissioner

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ROGER KOOPMAN, Commissioner

ATTEST:

Aleisha Solem
Commission Secretary

(SEAL)

NOTE: Any interested party may request the Commission to reconsider this decision. A motion to reconsider must be filed within ten (10) days. Admin. R. Mont. 38.2.4806.

DEPARTMENT OF PUBLIC SERVICE REGULATION
BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MONTANA

IN THE MATTER OF NorthWestern Energy's 2011-2012 Electricity Supply Tracker	)))	REGULATORY DIVISION DOCKET NO. D2012.5.49

CONCURRING OPINION OF COMMISSIONER TRAVIS KAVULLA

NorthWestern Energy is a firm that aspires toward greater vertical integration, a trend that began several years ago for the company and is today accelerating. Certain other parts of the country are moving, it would seem, in the opposite direction; a natural monopoly is seen in the poles-and-wires business of transmitting energy, but competition prevails in the functions of retailing it to customers and generating it in power plants. In Montana, the Legislature has already settled (or, rather, re-settled) this debate: After a decade of so-called "deregulation," state law has done an about-face, granting NorthWestern an exclusive monopoly to serve a large set of residential customers. Mont. Code Ann. § 69-8-201. And so long as those customers are reliably captive to a monopoly on the retail end, it may make some sense, further up the vertical totem pole, for generators to stand by under the NorthWestern aegis, ready to committedly serve those customers.

Since the legal authority to own generating plants was restored to NorthWestern in 2007, the utility has gradually inched its way toward greater ownership, and greater profits, by buying a share of Colstrip Unit IV and by constructing the Dave Gates Generating Station (DGGS) and the Spion Kop Wind Farm. In the years to come, the utility will be more responsible than ever for a fleet of generators that it either owns or operates under an exclusive contract. It is important that those generators be used to their greatest efficiency.

The Need for Prudence Reviews

Even before the trend of vertical integration commenced in earnest, the utility already had some experience in operating generating units in Montana. One such plant—the Basin Creek gas-fired generating station (Basin Creek)—is at issue in this proceeding. *See* Order 7219h ¶¶ 90-96. In its Order, the Commission made good, somewhat, on its duty to evaluate whether the operations of Basin Creek are reasonable and efficient. This is a duty expected of us by law. Mont. Code Ann. § 69-8-421(9) (The Commission may "disallow rate recovery for the costs that result from the failure of a public utility to reasonably manage, operate, maintain, or administer electricity supply resources."). It is also a responsibility the Commission imposed on itself in the order that permitted NorthWestern to operate the unique plant in question in the first place. Ord. 6557c, Docket D2004.3.45, ¶ 80 (Sept. 7, 2004) ("routine prudence reviews by the Commission should encourage NWE to hone its skills, to the benefit of customers.").

Why can it not simply be assumed that a power plant will be efficiently operated by a public utility? The reason is relatively simple: NorthWestern's costs related to owning and operating a plant like Basin Creek are recovered from ratepayers no matter whether the unit operates optimally, sub-optimally, or not at all. In proceedings like this, all of the utility's costs are recovered—dollar for dollar, no more and no less than those costs—unless they were *imprudently incurred*. Mont. Code Ann. § 69-8-210(1). To exclude costs from consumer rates rarely occurs and, when it does, it is an onerous task for all involved: Witness the thousands of pages of record evidence collected, and the year-and-a-half exhausted, in reaching a decision to disallow about $1.4 million in costs related to the early 2012 outage of the DGGS, which, in the end, amounts to only about 10 percent of the total amount of profit this Commission has authorized NorthWestern to earn on its DGGS investment. Ord. 7219h ¶ 39.

Undoubtedly, employees and management at NorthWestern feel an ethical and professional commitment to efficiency, but there can be equally little doubt that there are almost no *financial* incentives that prod them toward that efficiency. There is only the distant prospect of a disallowance and, perhaps even more fanciful, an administrative rule that allows the Commission to reward the utility for "superior electricity supply service." Admin. R. Mont. 38.5.8227 (No such award has ever been given.). In this sense, NorthWestern is unlike any ordinary business when it comes to the electricity supply costs that are here at issue: It does not profit when it outperforms, it does not suffer when it underperforms. While the Commission has wisely committed to an evaluation of how certain incentives (mis-)align, that endeavor has not yet borne fruits. Order 7219h ¶ 89.

The Problem of Basin Creek

Returning, then, to Basin Creek, it is impossible to determine based on the record evidence in this proceeding whether the plant is being operated efficiently or not. What is in the record, however, is unnerving. It is clear that the facility is not being used for the purposes for which it was built. Order 7219h ¶ 92. Indeed, Basin Creek hardly seems to be used at all—recently generating only 2 aMWs of energy out of a 52 MW capacity, or a 3.8 percent capacity factor. *See* 2011 Electricity Supply Resource Procurement Plan (2011 Plan), Docket N2011.12.96, p. 55 (Dec. 15, 2011).

There are possible explanations for this. The variable cost of operating Basin Creek may exceed market prices. Or, given other changes to NorthWestern's make-up, including the construction of DGGS, it may be reasonable that Basin Creek has been repurposed. One might be tempted to give NorthWestern the benefit of the doubt were it not for the very real bureaucratic and organizational barriers to using Basin Creek for possibly more efficient purposes—namely, the so-called "functional separation" between the Transmission Function and the Energy Supply Function of the utility.

The Energy Supply Function's main duty is to procure an appropriate amount of resources, and schedule and dispatch them to serve its estimate of retail customers' demand. Ex. NWE-7 p. 3. The Transmission Function serves NorthWestern's Energy Supply Function, but transmission customers also include those industrial customers and other load-serving entities such as electric co-operatives that are not subject to the Commission's jurisdiction. The Transmission Function operates a BA, sometimes referred to as a Control Area, pursuant to its reliability obligations under the North American Electric Reliability Corporation regulations. Ex. NWE-6 p. 4.

Within an operating hour, the generators supplying energy to NorthWestern's system and loads drawing energy from this system are rarely, if ever, equal. The disparity creates a need for regulation service to provide for the continuous balancing of resources with load and for maintaining scheduled interconnection frequency at sixty cycles per second. NWE Fed. Energy Reg. Commn. Elec. Tariff Vol. 5 (FERC Tariff), Sched. 3 (Sept. 29, 2010). That regulation service is provided today by DGGS, which ramps up and down quickly to counteract this disparity and balance the system. Hrg. Transcr. (Tr.) p. 372 (June 11-14, 2013). While NorthWestern responds to moment-to-moment fluctuations by raising or lowering DGGS' output by small increments, it also requires more dramatic ramping from DGGS to cope with large swings of load and resources, including wind. DR PSC-081 (showing large ramps on an intra-hourly basis); Tr. pp. 501-502; *see also Ky. Utils. Co.*, 85 F.E.R.C. 61,274, 62,108 (1998).

Individual transmission customers of NorthWestern must pay for regulation service via its FERC Tariff. Each customer of NorthWestern's BA must also pay for imbalance service, which is based on the net total excess or deficit of energy that must be provided to or received from the customer based on whether it has under- or over-estimated its load or generation during a particular hour. FERC Tariff, Sched. 4. These services are part of a larger array of ancillary services that transmission operators are obliged to provide under their open-access transmission tariffs.

As the Commission's Order observes, the Energy Supply Function needs both imbalance service and regulation service from the Transmission Function of NorthWestern's business. Ord. 7219h ¶ 97. The Energy Supply Function must predict the average demand from retail customers' loads against the predicted output of NorthWestern-controlled generation (both that purchased from third parties and from NorthWestern-owned power plants) on an hourly basis. Tr. pp. 501-502. The inevitable difference between demand and supply in this scheduling process results not only in a net surplus or deficit in megawatt-hours of energy over the course of an hour (i.e., imbalance service) but also a need for flexible generating capacity that dispatches to meet deviations within the hour (i.e., regulation service).

Basin Creek is a resource that is able to cycle from zero to full output in nine minutes. DR PSC-079(d). When requesting approval for Basin Creek in Docket D2004.3.45, NorthWestern stated that it preferred the project's reciprocating engine technology because it would allow NorthWestern to efficiently provide operating reserves and load following, which are ancillary services that were especially needed at the time, especially for future wind resources. Ord. 6557c ¶ 29. The Order approving the asset stated that the plant would provide the following services, in order of importance: (1) Enhanced supply reliability; (2) ancillary services; (3) integration of wind resources; and (4) economically dispatchable energy and capacity. *Id*. at ¶ 33. At the time of approval, the plant appeared to be associated mostly with the Transmission Function: "Load following and capacity would be needed to maintain reliability standards and balance loads and resource within the control area if NWE acquired wind resources." *Id*. at ¶ 18. The Transmission Function operates the control area, and it is the part of NorthWestern's business subject to the obligation of maintaining reliability standards.

Basin Creek was also represented to have "regulation down" and "regulation up" capabilities, services today provided by DGGS. Tr. p. 388; DR PSC-078(d), Attachment 4. A memorandum of understanding (MOU) between NorthWestern's Energy Supply and Transmission Functions allowed transmission operators to request dispatch of Basin Creek in situations involving a significant drop in output from the Judith Gap wind farm. Tr. pp. 324-325, 331. The MOU was dissolved at some point, but exactly when and why is not shown in the record. In this proceeding, the Transmission Function's Casey Johnston testified that Basin Creek was not designed to provide regulation service. Tr. p. 387. Johnston conceded, however, that his understanding appears to be contrary to what was represented in Order 6557c. Tr. pp. 394-395.

As recently as 2011, NorthWestern represented that Basin Creek "continues to serve the purpose" of "the integration of wind resources." 2011 Plan p. 63. The integration of wind resources was one of the primary reasons why Basin Creek was acquired in the first place. Similar to the novel claim regarding regulation service, Johnston testified in this proceeding that, from the perspective of the Transmission Function, Basin Creek was not meant to integrate wind. Tr. pp. 389-390 ("the 45 MW that we have available at [DGGS] were designed to integrate wind.").

In light of what the plant was represented to do—mostly, operations supportive of the Transmission Function—it is remarkable that the Transmission Function has no access to Basin Creek whatsoever today. Order 7219h ¶ 92. The resource does not operate on an intra-hourly basis, which would be consistent with the provision of regulation, load-following, wind-integration, and other ancillary services.

The Energy Supply Function, which today exclusively controls Basin Creek, schedules only on an hourly basis. Tr. pp. 501-502. Kevin Markovich testified that once the Energy Supply Function submits its hourly schedule to the Transmission Function, it does not attempt to make it more accurate with intra-hour adjustments (e.g., dispatching Basin Creek in the middle of an hour). Tr. pp. 501-504. Only the Transmission Function has made a practice of within-hour dispatch of resources, and then only with DGGS. Tr. p. 372.

NorthWestern admitted that Basin Creek can be dispatched within an hour to correct deviations from scheduled load and supply. Ex. NWE-8 p. 5. In its testimony, NorthWestern offered two perspectives on the matter: one from the Energy Supply Function and one from the Transmission Function. Neither of them are particularly convincing.

NorthWestern also asserted that dispatching Basin Creek on a within-hour basis for energy supply purposes without real-time imbalance information could exacerbate the Energy Supply Function's imbalance. Ex. NWE-6 p. 5; Ex. NWE-8 pp. 5-6. Yet, the Energy Supply Function does have at least some awareness of its real-time imbalance, including when it monitors the output of wind facilities, major contributors to imbalance, and is generally cognizant of the changes in load during the morning and evening hours when demand is sloping upward and downward. DR PSC-081. For Energy Supply to exacerbate its overall imbalance by using Basin Creek to respond to known or predictable wind and load ramps over the course of an hour relies on an unreasonable assumption that other, unknowable contributors to its imbalance are contributing an imbalance in the opposite direction of the known deviations.

NorthWestern's Energy Supply Function witness also argued that dispatching Basin Creek to help balance the BA would require allocating some of the cost of Basin Creek to other BA customers that would benefit, and NorthWestern currently does not have a way to do that. Ex. NWE-8 p. 6. That is a much more apropos point, but a regulatory hurdle should not prevent NorthWestern from operating its flexible resources flexibly. NorthWestern should not, merely for the ease of cost recovery, escape form an obligation to operate its generators efficiently.

There is also the question of whether Basin Creek could be put into the Transmission Function's hands, to obviate the need to run DGGS. As the Commission's order notes, Basin Creek can ramp up quickly and has a lower heat rate than DGGS so it would seem possible for such a displacement to occur and be cost effective. Ord. 7219h ¶ 93

Regulation service is provided in response to an Area Control Error (ACE) signal, which is created by the difference between the scheduled and actual flows over transmission lines connecting the NorthWestern BA to neighboring BAs. An ACE value will cause regulation units equipped with automatic generator control (AGC) to be dispatched upward or downward to meet the deficit or surplus of energy on the system. Ex. NWE-6 p. 4. According to NorthWestern, its System Operations Control Center (SOCC), which manages the provision of regulation service, receives little real-time meter data for individual transmission customers within the BA, and

SOCC operators cannot accurately determine which load or generator is causing a disparity between supply and demand in real-time. *Id*. at p. 5. The SOCC manages the disparity in aggregate.

Johnston argued that regulation included only resources that have a frequency signal, responding to ACE through AGC. Tr. p. 389. Yet, NorthWestern's FERC Tariff does not place an absolute bar on non-AGC resources providing regulation, stating only that it is "predominantly" AGC-equipped resources that provide regulation service. FERC Tariff, Sched. 3. No one disputes that the dispatch of resources like Basin Creek on a longer, but still intra-hour, basis can be conducted even without AGC. For example, when the output from a wind farm decreases, the ramp might be considerable but spread over a period of time longer than seconds or minutes. Providing service to balance these longer events is included within the scope of regulation service, which for NorthWestern's BA is a service defined by an hourly time-span.

Conclusion

Utilities in the U.S. West have focused recently on the need for flexible ramping capacity. Other utilities use such generators nimbly, and draw a distinction between load-following (accounting for larger ramps during an hour) and regulation (the more minute, AGC-controlled ramps). Recent federal regulations likely will cause these distinctions to be drawn even more clearly. *See e.g. Integration of Variable Energy Resources*, FERC Ord. 764, 77 Fed. Reg. 41482 (July 13, 2012). As NorthWestern moves toward vertical integration, it is important that it ask the question of how a utility with a fleet of generators would operate Basin Creek—more flexibly, in my mind, than does NorthWestern presently.

I am supportive of the Order's guidance to NorthWestern to study the operation of Basin Creek. Ord. 7219h ¶¶ 94-96. I hope, too, the Commission will keep in mind that it is merely a hope, not a reasonable expectation, for power plants to operate highly efficiently absent a financial incentive for them to do so.

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TRAVIS KAVULLA, Commissioner (concurring)