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Energy and Telecommunications Interim Committee

63rd Montana Legislature

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April 24, 2014

TO: Energy and Telecommunications Interim Committee (ETIC) members
FR: ETIC staff
RE: Discussion concerning DGGS and Judith Gap Costs

At the March 21 ETIC meeting members discussed the potential impacts Montana's Renewable Portfolio Standard (RPS) has had on Montana customers. There was much discussion and some disagreement on the costs that should be attributed to the Dave Gates Generating Station (DGGS) and how much operating capacity is needed for wind integration. The Montana Public Service Commission and the Federal Energy Regulatory Commission (FERC) are involved in aspects of regulation at the facility and in determining the cost allocation.

Following the March meeting, Senator Olson requested additional information on the issue. In addition, Senator Olson requested information on the average price of renewable energy resources brought online following adoption of Montana's RPS requirement. He also requested associated costs for those facilities.

Information concerning the DGGS discussion was provided by Jeff Fox with Renewable Northwest and John Fitzpatrick with NorthWestern Energy. FERC also decided the DGGS docket on April 17. Mr. Fox provided a copy of the order for the ETIC members. NorthWestern Energy also provided information concerning the costs of renewable resources added to their portfolio after adoption of Montana's RPS.

The information provided is attached for the full ETIC's review. If you have questions, please let me know.

Sonja Nowakowski

Cl0124 4114slxc.

MONTANA LEGISLATIVE SERVICES DIVISION STAFF: SUSAN BYORTH FOX, EXECUTIVE DIRECTOR • DAVID D. BOHYER, DIRECTOR, OFFICE OF RESEARCH AND POLICY ANALYSIS • TODD EVERTS, DIRECTOR, LEGAL SERVICES OFFICE • DALE GOW, CIO, OFFICE OF LEGISLATIVE INFORMATION TECHNOLOGY • JOE KOLMAN, DIRECTOR, LEGISLATIVE ENVIRONMENTAL POLICY OFFICE

Nowakowski, Sonja

From: Alan Olson <aolson@Sanjel.com>
Sent: Thursday, April 10, 2014 4:07 PM
To: Nowakowski, Sonja
Subject: Additional information request

Sonja,

With the discussion on the RPS and Judith Gap at the last few committee meetings, I would like some additional information when you have time.

Whereas Judith Gap is often touted as the lowest cost segment of NWE's portfolio at +/- $38.00 and was brought into the portfolio before the RPS I am thinking that price should not be considered as an effect of the RPS. Therefore I would like to know the average price of the renewable energy segment of NWE's portfolio for the projects brought on line after the adoption of the RPS requirement along with the associated costs. I think this would more accurately reflect impacts of the RPS.

Hope that doesn't add much of a burden. If I've confused you with my rambling request give me a call.

Thanks,
Alan

NorthWestern Energy
Delivering a Bright Future

April 16, 2014

Ms. Sonja Nowakowski, Research Analyst
Legislative Services Division
PO Box 201706
Helena, MT 59620-1706

Dear Ms. Nowakowski:

I am writing in response to your e-mail of April 11, 2014, in which you forwarded two questions from Senator Olson for response from NorthWestern.

Senator Olson Question #1
What is the cost of renewable energy if Judith Gap is removed from the calculation because the Judith Gap contract was signed before the RPS was enacted?

NWE Response
In 2013, the total cost (direct and indirect expenses)[1] of resources to comply with the RPS was $54,412,113 for the production of 790,318 MWH of power at an average cost of $68.66/MWH. Judith Gap makes up 64.3% of the total 2013 RPS production and 57.7% of the total expenses. The total per MWH cost for Judith Gap power was $61.88 in 2013.

If Judith Gap is removed from the total calculation because the contract was signed before the RPS was enacted, then the total cost of power from the remaining RPS eligible resources[2] is $22,992,623 at a cost of $80.76/MWH.

RPS resources are not used on NorthWestern's system to offset coal generation but rather to offset market purchases. In 2013, the average market price of power on the Mid-C was $32.53/MWH, making non-Judith Gap, RPS eligible power $48.23/MWH, or 148.3% more expensive than market.

Senator Olson Question #2
Please respond to Geoff Fox's testimony that only 30% of the David Gates Generating Station (DGGS) should be allocated to wind. (Mr. Fox has since submitted information to the Commission which alleges that FERC has made such a determination.)

NWE Response
NorthWestern views Mr. Fox's testimony as inaccurate.

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[1] Direct expenses are the invoiced charges from the vendor for electricity. Indirect expenses include the fixed and variable costs for regulation services from DGGS; market purchase of balancing services; WREGIS/WECC assessments; property tax, electricity/ energy license tax, and local impact fees for the Judith Gap project; and other minor fees.

[2] Gordon Butte Wind, Flint Creek Hydro, Lower South Fork Hydro, Musselshell Wind, Musselshell Wind II, Turnbull Hydro, and Spion Kop Wind.

NorthWestern is regulated by both FERC and the Montana PSC. FERC regulates wholesale assets and services such as transmission service provided on behalf of others. The Montana PSC regulates assets used for retail services.

The defined operating capacity of the DGGS is 105 MW of which 60 MW has been allocated towards transmission and retail customers and up to 45 MW for wind integration associated with NorthWestern's retail generation portfolio. The Montana PSC has jurisdiction over the latter issue, and has approved this allocation.

The issue before FERC in Dockets ER10-1138 and ER12-316 (consolidated) is how the 60 MW dedicated for transmission and retail customers should be allocated. The intervenors in these dockets, including the Large Customer Group and the Central Montana Power Cooperative joined the case to get out of having to pay for their share of the cost of the back-up generator at DGGS. Their action is simply an effort to shift costs to another party.

FERC's actions in these dockets are far from settled. Any decision FERC makes is subject to appeal.

The 45 MW component of DGGS dedicated for wind integration was never before FERC. And, while FERC can certainly opine on any issue, it has no legal authority to specify what part of DGGS costs shall be allocated to wind integration. The matter has been settled by the Montana PSC.

Very truly yours,

John S. Fitzpatrick
Executive Director
Governmental Affairs

Nowakowski, Sonja

From: Jeff L.Fox <jeff@rnp.org>
Sent: Monday, April 14, 2014 10:20 AM
To: Nowakowski, Sonja
Subject: Re: FERC documents
Attachments: PSC cost allocation order for DGGS.pdf; FERC ALJ on DGGS for ETIC.doc

Hi Sonja,

My apologies to the committee and Senator Olson for not following up sooner.

The PSC approved the Dave Gates Generating Station (DGGS) with 45MW dedicated to wind integration out of 105MW of useful capacity. See attached order from the Public Service Commission on the DGGS cost allocation, on page 23 under "Cost Allocation." After further consideration I believe that for the purposes of the RPS Customer Impacts report, the attached order is the right lens for the Committee's work. Note that the 45MW of 105MW of useful capacity leads to the "about 40%" (of presumably fixed and variable costs) of DGGS is attributable to addressing wind energy's variability that Bob Decker testified to, not the 50% that NorthWestern testified to.

However, also attached is the FERC documentation I referenced. I have highlighted the sections I consider relevant (mostly on pages 51-59). In the FERC decision document the Montana Consumer Counsel, the Montana Large Customer Group, and the Central Montana Electric Power Cooperative all contend that the correct useful capacity at DGGS is the nameplate rating of 150MW and their arguments are summarized. In the attached document the FERC Administrative Law Judge agreed with the aforementioned entities that 150MW is the correct amount of useful capacity at DGGS. We all await to see if the FERC Commissioners agrees with the Administrative Law Judge.

If the FERC Commissioners agree with the Administrative Law Judge it will likely have implications for retail load customers of NorthWestern and by extension wind integration costs. We will cross that bridge if we come to it.

Please feel free to send this response to all committee members that you think may be interested.

Thank you,

My email address has changed to Jeff@RenewableNW.org Please update your address book.

Jeff L. Fox
Montana Policy Manager
Renewable Northwest
615 South Black Ave., Bozeman, MT 59715
406-599-2916 cell
503-223-4544 Portland office
www.rnp.org

Stay up-to-date on our advocacy work and renewable energy news.
Follow Renewable Northwest Project on ***Facebook****,* ***Twitter*** *and* ***LinkedIn****.*

On Apr 11, 2014, at 8:57 AM, Nowakowski, Sonja <snowakowski@mt.gov> wrote:

Hi Jeff,
Senator Olson requested that you provide the FERC documents that show the justification for 30 percent of the Dave Gates Generating Station being dedicated to wind. You mentioned the documents during your testimony at the March 21 meeting.
Thanks,
Sonja

Sonja Nowakowski
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UNITED STATES OF AMERICA 140 FERC ¶ 63,023
FEDERAL ENERGY REGULATORY COMMISSION

NorthWestern Corporation — Docket Nos. ER10-1138-001, ER12-316-000 (Consolidated)

INITIAL DECISION

(Issued September 21, 2012)

APPEARANCES

Gordon A. Coffee, *Esq.*, *Raymond B. Wuslich, Esq.*, *Pat Corcoran*, *Esq.*, *M. Andrew McLain*, *Esq.*, and *Katherine L. Konieczny, Esq.*, on behalf of NorthWestern Energy.

Steven W. Snarr, *Esq.*, *Thorvald Nelson, Esq.*, and *Michelle King*, *Esq.* on behalf of Montana Large Customer Group.

Laura Chipkin, *Esq.* on behalf of Basin Electric.

John P. Coyle, *Esq., Ashley M. Bond, Esq.,* and *Robert A. Nelson, Esq.* on behalf of the Montana Consumer Counsel.

Kathleen L. Mazure, Esq. and *Natalie M. Karas, Esq.* on behalf of Central Montana Electric Power Cooperative.

Todd E. Miller, Esq. and *Ethan Falatko*, *Esq.* on behalf of Bonneville Power Administration.

Dennis Lopach, Esq. on behalf of the Montana Public Service Commission.

Tracey L. Bradley, *Esq.* on behalf of Powerex Corporation.

James W. Bixby, Esq., *Renee Terry*, *Esq.*, and *John Kroeger, Esq.* on behalf of the Federal Energy Regulatory Commission.

JUDITH A. DOWD, Presiding Administrative Law Judge.

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BACKGROUND AND PROCEDURAL HISTORY

1. NorthWestern Corporation (NorthWestern, NWE, or the Company) owns and operates electric and natural gas transmission and distribution facilities primarily in Montana and South Dakota.[1] However, NorthWestern's filing seeking tariff sheet revisions that is the subject matter of this case, only impacts its Montana Open Access Transmission Tariff (OATT). NorthWestern's electric transmission system in Montana covers a vast amount of space, consisting of more than 7,000 miles of transmission lines and terminal facilities, covering an area of 107,600 square miles and providing service to approximately 322,000 customers.[2]

2. In 2002 NorthWestern acquired its electric operations from Montana Power Company (MPC) as part of Montana's electric deregulation and restructuring process.[3] MPC had already sold substantially all of its electric generation facilities prior to its sale to NorthWestern.[4]

3. In 2007, third parties became unable or unwilling to provide Schedule 3 service, Regulation and Frequency Response Service[5] to NorthWestern because of shortages of generation capacity, transmission constraints, and increases in demand attributable to the need of other balancing authorities to integrate variable energy resources.[6] In August 2008, NorthWestern sought and received approval from the Montana Public Service Commission (MPSC) to construct a facility now called the Dave Gates Generating Station (DGGS).[7]

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[1] NorthWestern maintains separate OATTs for operations in each state because its Montana and South Dakota transmission facilities are neither physically connected, nor located in the same electric reliability region.

[2] *NorthWestern Corp.*, 133 FERC ¶ 61,046, at P 2 (2010) (October 15 Hearing Order).

[3] Ex. NWE-19 at 5.

[4] *Id.*

[5] Consistent with the record in this proceeding, this decision refers to Schedule 3 Regulation and Frequency Response Service as "Schedule 3 service," "Regulation capacity," or "Regulation service."

[6] Ex. NWE-1 at 6-8.

[7] DGGS was originally named the Mill Creek Generating Station.

4. On April 29, 2010, in Docket No. ER10-1138-000, NorthWestern filed revised tariff sheets to its Schedule 3, Regulation and Frequency Response Service with the Federal Energy Regulatory Commission (the Commission or FERC). NorthWestern proposed to revise Schedule 3 of its OATT to recover the fixed and variable revenue requirement for DGGS through a monthly demand rate and monthly energy rate.[8] On May 19, 2010, the Montana Public Service Commission (MPSC) intervened in this docket. Montana Large Customer Group (LCG), Central Montana Electric Power Cooperative, Inc. (Central Montana or CMT), and Montana Consumer Counsel (MCC) also intervened and filed protests.[9]

5. On October 15, 2010, the Commission issued an order accepting and suspending NorthWestern's Revised Schedule 3, as well as establishing hearing and settlement judge procedures.[10] The Commission found that "NorthWestern's Revised Schedule 3 has not been shown to be just and reasonable and raises issues of material fact that warrant hearing procedures."[11] Specifically, the Commission noted that the issues at hearing should include, but are not limited to the following:

> [T]he proposed [DGGS] annual revenue requirement and associated return on common equity, the allocation of [DGGS]'s fixed and variable costs, the propriety of charging an energy rate to Regulation service customers, the propriety of using a $7.00 market differential in the derivation of the energy value, the level of Regulation service purchase obligations for customers, inclusion of third party regulation purchases in the proposed demand rate, and lack of ceiling rates for Regulation service.[12]

The Commission also found that aspects of NorthWestern's proposed formula for Regulation service do not appear to be consistent with certain

[8] October 15 Hearing Order at P 1.

[9] *Id.* at P 13.

[10] *Id.* at P 23.

[11] *Id.* at P 21.

[12] *Id.*

Commission precedents.[13] The Commission directed that a "public hearing shall be held as expeditiously as possible concerning NorthWestern's proposed tariff revisions."[14]

6. DGGS was placed into service in January 2011, and consists of three natural gas-fired turbine generators with a maximum capacity of 50 MW each.[15] However, a year later on January 31, 2012, a vibration was detected and all three generating units were promptly taken offline due to the significant equipment damage to each of the units.[16] On February 1, 2012, NorthWestern contacted Powerex Corporation (Powerex) to request the immediate provision of Regulation service.[17] On February 3, 2012, the Commission granted Powerex's emergency request for a limited waiver of its market-based rate tariff.[18] At the time of the hearing, Pratt Whitney, the generating units' manufacturer, was performing a root cause analysis to determine the reason for the malfunction.[19]

7. On June 10, 2011, following unsuccessful settlement proceedings, the Chief Administrative Law Judge established hearing procedures, and appointed the undersigned as Presiding Judge.[20] To comply with the Commission's above-quoted order directing an expedited hearing, the Chief Judge originally set the

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[13] *Id.* at P 23 (citing *Kentucky Utilities Co.*, 85 FERC ¶ 61,274, at 62,108-09 (1998) (*Kentucky Utilities*); *Allegheny Power Service Corp.*, 85 FERC ¶ 61,275, at 62,120-21 (1998) (*Allegheny Power*)).

[14] *Id.* at ordering para. (C).

[15] *NorthWestern Corp.*, 137 FERC ¶ 61,248 at P 3 (December 30 Hearing Order).

[16] Tr. 295-97 (Rhoads).

[17] *Powerex Corp.*, 138 FERC ¶ 61,136, P 5 (2012).

[18] *Id.* at P 6.

[19] Tr. 296 (Rhoads). At the time of the hearing, NorthWestern still relied on third-party contracts to provide Schedule 3 service.

[20] *NorthWestern Corp.*, Order of Chief Judge Terminating Settlement Judge Procedures, Designating Presiding Administrative Law Judge, and Establishing Expedited Hearing Procedures (June 10, 2011).

hearing on a Track I procedural schedule. On June 21, 2011, upon the parties' request, the Chief Judge granted a motion for Track II designation.[21]

8. On November 1, 2011 NorthWestern filed additional revisions to Schedule 3 with the Commission in Docket No. ER12-316-000. In its December 30 Order the Commission rejected NorthWestern's proposed changes insofar as they would have allowed NorthWestern to levy additional charges upon customers that elect to self-supply Schedule 3 service. The Commission set the other proposed revisions for hearing procedures, such as whether NorthWestern can set the regulation requirements for self-supplying customers and the transfer of Operation and Maintenance (O&M) costs from a monthly energy rate to a monthly demand rate.[22]

9. The Commission noted that consolidation of proceedings is appropriate where there are common questions of law or fact and consolidation will result in greater administrative efficiency. The Commission found that the issues in Docket No. ER12-316-000 are closely intertwined with those in Docket No. ER10-1138-000, and therefore, consolidated the two dockets for purposes of hearing and decision.[23]

10. On January 30, 2012, NorthWestern submitted its proposed compliance filing in response to the Commission's December 30 Order disallowing additional charges for self-supplying customers under Schedule 3.

11. On July 12, 2012, the Commission issued its Order Denying Rehearing of its December 30 Order.[24] The Commission reaffirmed its finding in the December 30 Order that NorthWestern could not impose any additional fees for self-supplying customers under Schedule 3 because such fees are anticompetitive.

12. The issues in consolidated Docket Nos. ER12-316-000 and ER10-1138-001 were heard on June 11 to June 14, 2012. Initial Briefs were filed on July 23, 2012 and Reply Briefs were filed August 6, 2012.

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[21] *NorthWestern Corp.*, Order of Chief Judge Granting Motion for Track II Designation and Waiving Period for Answers (June 21, 2011).

[22] December 30 Order at P 33. Powerex and Bonneville Power Administration (BPA) filed timely motions to intervene. *Id.* at P 15.

[23] *Id.* at P 34.

[24] *NorthWestern Corp.*, 140 FERC ¶ 61,020 (July 12, 2012).

ISSUES

13. On May 25, 2012, the parties and participants filed a Joint Statement of Issues and Summary of Positions (Joint Statement). I will, as far as practicable, discuss the issues raised in these consolidated cases in the order in which they were set out in the Joint Statement.

14. The omission from this Initial Decision of any argument or portion of the record raised by the participants in their briefs does not mean that it has not been considered. All such arguments have been evaluated and found to either lack merit or significance to the extent that their inclusion would only tend to lengthen this Initial Decision without altering its substance or effect.

Issue No. 1: Is NorthWestern's proposed annual fixed cost revenue requirement and associated return on common equity for DGGS just and reasonable?

15. On November 14, 2011 NorthWestern and Commission Trial Staff (Staff) entered into a Joint Stipulation regarding the revenue requirement and deprecation rates for DGGS.[25] The Joint Stipulation provides, in pertinent part, that the Total Fixed Cost Revenue Requirement of DGGS "prior to the allocation to Schedule 3 Regulation and Frequency Response Service shall be $38,161,353."[26] The Joint Stipulation further provides that the Fixed Cost Revenue Requirement specified therein is a "black box" revenue requirement and does not reflect any identification or attribution of costs or adjustment for any particular component of the Total Fixed Cost Revenue Requirement."[27] The Joint Stipulation also lists the depreciation rates for DGGS and contains a request that the undersigned incorporate the stipulated fixed cost revenue amount in this Initial Decision.[28]

A. Positions of the Parties

16. No party or participant opposed the Joint Stipulation. MCC commented that it does not object to the Stipulation which is a "black box" settlement between Staff and NorthWestern and, as such, "should not interfere with the use of other, not inconsistent, methodologies and assumptions to determine the DGGS revenue

[25] Ex. S-14.

[26] *Id.* at P 1.

[27] *Id.* at P 2.

[28] *Id.* at PP 3-4.

requirement associated with any Montana jurisdictional services provided by that facility."[29]

B. Decision

17. Since no party has objected to the Stipulation between NorthWestern and Staff and the Stipulation appears to be a just and reasonable resolution of the issues addressed therein, I hereby adopt the Fixed Cost Revenue Requirement and deprecation rates for DGGS contained in the Joint Stipulation.

Issue No. 2: Is NorthWestern's proposed allocation of the DGGS fixed cost revenue requirement just and reasonable?

18. NorthWestern's proposed allocation of the DGGS fixed cost revenue requirement is divided into two subparts, which examine NorthWestern's proposed numerator (2a) and denominator (2b). NorthWestern proposes a numerator of 60 MW and a denominator of 105 MW.

Issue No. 2 (a): Is NorthWestern's proposed allocation based on a numerator of 60 MW just and reasonable?

A. Positions of the Parties

1. NorthWestern

19. On July 23, 2012, NorthWestern filed its Initial Post-Hearing Brief contending that 60 MW is the appropriate amount of Regulation capacity used by its traditional load.[30] NorthWestern proposes to allocate 60/105ths of the revenue requirement of DGGS to its Schedule 3 and bundled retail customers for Schedule 3 Regulation and Frequency Response Service, and 45/105ths solely to its retail supply customers to reflect the regulation demands of wind generation.[31] These allocations are based on a 12 coincident peak (CP) load.[32]

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[29] MCC Initial Br. at 14.

[30] NWE Initial Br. at 6.

[31] *Id.* at 11.

[32] For 2011, the respective share of 12 CP load would be divided between Schedule 3 customers for 21 MW (60/105), and retail customers for 39 MW (45/105). NWE Initial Br. at 11; Tr. 452:18-453:10 (Wilson).

20. As part of its electric operations in Montana, NorthWestern operates a balancing authority area, meaning that NorthWestern matches electrical loads with generation to meet operating criteria and provide reliable service in accordance with North American Electric Reliability Corporation (NERC) and Western Electric Coordinating Council (WECC) reliability requirements.[33] One of the services which NorthWestern provides to its customers is Schedule 3 service.

21. Regulation service is an ancillary service that was first anticipated by the Commission in Order No. 888.[34] In its *pro forma* OATT, the Commission defines ancillary services as "[t]hose services that are necessary to support the transmission of capacity and energy from resources to loads while maintaining reliable operation of the Transmission Provider's Transmission System in accordance with Good Utility Practice."[35]

22. More specifically, Regulation service is the necessary ancillary service that provides the moment-to-moment balancing of resources and load within a balancing authority to maintain interconnection frequency, and is used to conform with NERC Control Performance Standards (CPS).[36] The Commission recently explained Regulation service as the "injection or withdrawal of real power by facilities capable of responding appropriately to a transmission system's frequency deviations or interchange power imbalance."[37] Both frequency deviations and interchange power imbalances are measured by the Area Control Error (ACE).[38] It

[33] Ex. NWE-19 at 5-6.

[34] *Promoting Wholesale competition Through Open Access Non-Discriminatory transmission services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, Order No. 888, FERC Stats. & Regs.¶ 31,036 (1996) (Order No. 888) *order on reh'g*, Order No. 888-A, 81 FERC ¶ 61,248 (1997), *order on reh'g* Order No. 888-B, 81 FERC ¶ 61, 248 (1997), *ordr on reh'g.* Order No. 888-C, 82 FERC ¶ 61,046 (1988), *aff'd. in relevant part sub nom. Transmission Access Policy Study Group v. FERC,* 225 F.3d 667 (D.C. Cir. 2000), *aff'd sub nom., New York v. FERC,* 535 U.S. 1 (2002). *See also* Ex. LCG-2 at 6.

[35] Ex. LCG-2 at 6.

[36] Ex. S-7 at 7; LCG-2 at 6-7.

[37] *Frequency Regulation Compensation in the Organized Wholesale Power Markets*, 134 FERC ¶ 61,124, at P 4 (Feb. 17, 2011), 76 Fed. Reg. 11177 (Mar. 1, 2011).

[38] As NorthWestern witness Michael Cashell explains, under Order No. 888, balancing authorities must provide Regulation service for transmission customers. As a

(continued…)

is a balancing authority's responsibility to use Regulation service to "prevent these adverse consequences by rapidly correcting deviations in the transmission system's frequency to bring it within the acceptable range."[39]

23. NorthWestern justifies a 60 MW of Regulation service on three grounds: (1) historically, NorthWestern has secured 60 MW of regulating resources through contracts with third parties;[40] (2) two studies, performed by Dr. Richard Tabors and GENIVAR respectively, found that NorthWestern requires between 59 and 68 MW of Regulation capacity to comply with CPS 2;[41] and (3) FERC enforces a policy that allows public utilities to fully recover costs incurred to comply with CPS 2.[42]

a. <u>Historical Basis</u>

24. NorthWestern argues that 60 MW numerator for traditional load reflects past and expected future regulation demands associated with that load. NorthWestern justifies this numerator based on a 2007 Commission order presumably accepting 60 MW as just and reasonable.[43] NorthWestern notes that the Montana Public Service Commission (MPSC) recently found all three numbers (60 MW as the numerator for wholesale, 45 MW as the numerator for bundled retail, and 105 MW as the denominator for both) just and reasonable in a parallel state commission case.[44]

25. In addition to prior regulatory commission orders, NorthWestern next points to the monthly reports it is required to provide on its CPS compliance.[45] As set forth in NERC

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part of this service, balancing authorities have two main goals: they must offset (1) within-the-hour variations between (a) scheduled load and actual load, and (b) scheduled generation and actual generation; and (2) within-the-hour fluctuations in actual load and generation. A balancing authority's failure to fulfill either of these two tasks creates ACE. Ex. NWE-22 at 7.

[39] *Id.*

[40] NWE Initial Br. at 12.

[41] *Id.* at 12-13.

[42] *Id.* at 2-3, 6-9. *See also* NERC Reliability Standard BAL-001 – Real Power Balancing Control Performance.

[43] *NorthWestern Corp.*, 121 FERC ¶ 61,204 at P 15 (2007).

[44] *See* Ex. MCC-4.

[45] NWE Initial Br. at 12; *see also* Ex. NWE-65 at 19-20.

Reliability Standard BAL-001, CPS is a mandate that if violated due to the inaccurate procurement of capacity, a public utility transmission provider will incur monetary fines.[46] These monthly CPS 2[47] compliance reports are used to determine the proper numerator in this case, due to a lack of NorthWestern's actual hour-ahead schedules.[48] Based on these reports, as well as the operational experience of contracting with third-parties for Regulation service, NorthWestern states that 60 MW of regulating resources are required.[49]

26. In 2006, NorthWestern added wind generation to its system, and initially secured an additional 15 MW of Regulation service to comply with CPS 2.[50] Despite acquiring 75 MW (60 MW plus the additional 15 MW), NorthWestern failed CPS 2 for four straight months in 2006 as it adjusted to this new variable energy resource (VER).[51] As more wind generation was added, in 2009 NorthWestern purchased as much as 91 MW of Regulation capacity.[52]

b. NorthWestern's Studies

27. NorthWestern submitted two studies in support of a 60 MW numerator, the first by NorthWestern Witness Dr. Richard Tabors (Dr. Tabors' Study),[53] and the second entitled the NorthWestern Energy Montana Wind Integration Study (GENIVAR study).[54] Both studies utilize historical data from NorthWestern's balancing authority area to calculate its regulating capacity need.

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[46] NWE Initial Br. at 2-3; *see also* CMT Initial Br. at 9-11.

[47] Under the NERC requirements for CPS 1 and CPS 2, CPS 2 is more stringent. Therefore if NorthWestern meets CPS 2 requirements it will likely also have met CPS 1 requirements. Ex. NWE-19 at 14.

[48] *Id.* at 8; Tr. 813:21-24 (Tabors).

[49] Ex. CMT-4 through Ex. CMT-7; Ex. NWE-32.

[50] NWE Initial Br. at 12.

[51] *Id.*; Tr. 704:23-705:3 (Ballard).

[52] NWE Initial Br. at 12; Ex. NWE-1 at 7.

[53] Ex. NWE-19.

[54] Ex. NWE-33.

i. Dr. Tabors' Study

28. On December 22, 2011, NorthWestern submitted its Rebuttal Testimony that included a study by Dr. Tabors analyzing NorthWestern's Regulation service needs.[55] Using a six-step methodology, Dr. Tabors determined NorthWestern's required regulating capacity to comply with CPS 2:

- First, Dr. Tabors used the 2009 one-minute ACE data as a baseline for his analysis.[56]
- Second, he subtracted on a minute-by-minute basis an estimate of the wind forecast uncertainty.[57]
- Third, Dr. Tabors subtracted the amount of regulation that was actually procured from third party suppliers by NorthWestern on a minute-by-minute basis.[58]
- Fourth, he averaged the one minute data into ten minute blocks.[59]
- Fifth, he aggregated the ten minute blocks into calendar months to identify the maximum variation both up and down that is required.[60]
- Finally, Dr. Tabors subtracted L_{10}[61] values from both the up and down variability to arrive at regulation up and regulation down quantities.[62]

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[55] Ex. NWE-19.

[56] *Id.* at 11.

[57] *Id.* The wind forecast uncertainty consists of the difference between an estimated value for the hourly wind schedule and the known wind output. *Id.*

[58] *Id.* at 13.

[59] *Id.* at 14.

[60] *Id.*

[61] L_{10} is a statistically derived value derived from NERC standards that reflects the maximum 10 minute deviation from ACE that is allowable. It is not necessary to perfectly drive ACE to zero, but rather ACE should be within the L_{10} value from zero. *Id.* See also Ex. LCG-3 consisting of NERC Standard BAL-001 ("Each Balancing Authority shall operate such that its average ACE for at least 90% of clock-ten-minute periods (6

(continued…)

29. Also, Dr. Tabors corrected an error in his analysis discovered by Staff Witness James Ballard. Initially, Dr. Tabors incorrectly associated a positive open loop ACE value with a need for regulation up capacity, as well as a negative open loop ACE value with a need for regulation down capacity.[63]

30. Using this methodology, Dr. Tabors analyzed NorthWestern's total capacity requirements for a range of CPS 2 compliance targets. NorthWestern noted that the Commission has endorsed the use of a CPS 2 compliance target as the basis for measuring the amount of regulating capacity needed for a balancing authority, such as NorthWestern.[64] Ranging from the minimum CPS 2 compliance level of 90% up to 98%, Dr. Tabors posits that NorthWestern would need between 52 MW and 101 MW of Regulation capacity.[65] Specifically, Dr. Tabors concluded that at a 92% CPS 2 compliance level NorthWestern would require 59 MW of Regulation.[66] For a CPS 2 compliance level of 94%, Dr. Tabors explained that NorthWestern would require 67 MW of Regulation capacity.[67] To meet a 95% CPS 2 compliance level, Dr. Tabors contends that NorthWestern requires 73 MW of Regulation capacity.[68]

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non-overlapping periods per hour) during a calendar month is within a specific limit, referred to as L_{10}").

[62] Ex. NWE-19 at 14.

[63] Ex. NWE-19 (corrected May 4, 2012); *see also* LCG Initial Br. at 13-14. Because NorthWestern conceded and corrected this error, the ramifications of the error will not be discussed at length herein.

[64] NWE Initial Br. at 13 (*citing Westar Energy Inc.*, 130 FERC ¶ 61,215 at P 6, n. 12 and n.14 (2010) (*Westar*)).

[65] Ex. NWE-19 at 16 (Table 2).

[66] *Id.* at 15.

[67] *Id.* It is noted that although Dr. Tabors states 67 MW is necessary for a CPS 2 compliance level of 94% in his text, Table 2 states 68 MW is necessary for a CPS 2 compliance level of 94%. *Id.* at 15-16 (Table 2).

[68] *Id.* at 16.

ii. GENIVAR Study

31. On December 22, 2011, NorthWestern introduced in its rebuttal testimony a second study performed by GENIVAR.[69] The GENIVAR study tracked NorthWestern's historical needs and Dr. Tabors' conclusions, and had multiple objectives, *inter alia* included determining the range of Regulation capacity required to maintain electric system performance criteria for various wind development scenarios.[70] GENIVAR's calculation used historical one-minute instantaneous data to project NorthWestern's possible future Regulation capacity need both with and without wind power projects. Using a Dispatch Simulator Model, the study determined that for NorthWestern to meet a 92% compliance level it would require 59 MW of regulation and for a 94% compliance level NorthWestern would require 69 MW of regulation.[71] Due to the perceived risk of allowing access to GENVIAR's proprietary software, the underlying methodology used for this study was not released to other parties for verification.[72]

iii. Summary of NorthWestern Studies

32. Without providing a specific CPS 2 compliance level, NorthWestern argues that 60 MW of regulating capacity is needed to comply with CPS 2.[73] Below is a summary of the findings of the Tabors and GENIVAR studies, as well as NorthWestern's stated position:

[69] This study is entitled the "NorthWestern Energy Montana Wind Integration Study" and was prepared by GENIVAR Consultants Limited Partnership. Ex. NWE-33.

[70] *Id.* at 14.

[71] *Id.* at *v*.

[72] LCG Initial Br. at 9-10.

[73] *Id.* at 5-6.

	Tabors #1	Tabors #2	Tabors #3	GENIVAR #1	GENIVAR #2	NWE
CPS 2 Compliance Target:	92%	94%	95%	92%	94%	Not Provided
Proposed Regulation Capacity Allocation:	59 MW	67 MW[74]	73 MW	59 MW	69 MW	60 MW

c. **Recovery of Compliance Costs**

33. NorthWestern also argues that FERC enforces a policy that allows public utilities to fully recover costs prudently incurred to comply with NERC Reliability Standards, such as the applicable CPS 2 standards in this case.[75] NorthWestern points out that LCG and Staff have not quantified the revenues available to close the gap between their estimates and NorthWestern's revenue requirement.[76]

d. **NorthWestern Rebuttal**

i. **Burden of Proof**

34. NorthWestern argues that because the Company has not changed the requested Regulation service amount in its Schedule 3 rate it does not bear the burden of proof to show that 60 MW is just and reasonable in this proceeding.[77]

[74] *See supra* note 67.

[75] *Id.* at 2-3, 6-9 (citing Policy Statement on Matters Related to Bulk Power System Reliability, 107 FERC ¶ 61,052 at P 27 (2004)).

[76] *Id.* at 6.

[77] NWE Initial Br. at 11 (citing *Public Service Comm'n of New York v. FERC*, 642 F.2d 1335, 1345 (D.C. Cir. 1980)).

ii. Regulation Down

35. NorthWestern seeks to rebut other parties' claims that regulation down should be excluded from the numerator. First, NorthWestern argues that Staff and LCG's reliance on the Commission's 1998 *Kentucky Utilities* decision is misplaced since it has been overruled by two recent Commission orders.[78] Specifically, NorthWestern concludes Order No. 755 authorizes an entity to be compensated for the total capacity up and down that it contributes towards Regulation service.[79] For example, the Commission explained in Order No. 755-A that "a resource must be measured [and compensated accordingly] based on the absolute amount of regulation up and regulation down it provides in response to the system operator's dispatch signal."[80]

36. NorthWestern next relies on Order No. 764, which was adopted to remove barriers to the integration of VERs, and to create guidelines for a new ancillary service under Schedule 10.[81] Specifically, the Commission found in Order No. 764 that due to the difficulties of incorporating variable energy resources, generating units "are often dispatched in the middle of their operating range to allow the generator to provide regulation-up as well as regulation-down and as a result forego other opportunities. Not to allow compensation would create a barrier to the provision of services by frustrating the recovery of legitimate costs."[82] NorthWestern concludes that it too incurs such costs as a result of not getting compensation for regulation down. NorthWestern concedes that Order No. 764 addresses Schedule 10, not Schedule 3, but argues that the Commission did not indicate that compensation for regulation down is only limited to Schedule 10.[83]

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[78] *Id.* at 15.

[79] *Id.* (citing *Frequency Regulation Compensation in the Organized Wholesale Power Markets*, Order No. 755, FERC Stats. & Regs. ¶ 31,324 at P 133 (2011), *reh'g denied*, Order No. 755-A, 138 FERC ¶ 61,123 (2012)).

[80] Order No. 755-A, 138 FERC ¶ 61,123 at P 14 (2012).

[81] Order No. 764, FERC Stats. & Regs. ¶ 31,331 (2012).

[82] *Id.* (quoting Order No. 764, FERC Stats. & Regs. ¶ 31,331 at P 316).

[83] *Id.* at 21, n.15.

iii. Diversity Benefits

37. NorthWestern opposes Schedule 3 customers receiving any diversity benefits.[84] Instead, NorthWestern argues that its retail load exclusively bears the costs of wind generation, and therefore its retail customers alone should receive any diversity benefit from wind generation.[85] NorthWestern contends that if diversity benefits are divided between retail and Schedule 3 customers, it would potentially give the Schedule 3 customers an undeserved windfall.[86]

iv. Schedules 4 and 9

38. NorthWestern next seeks to rebut Staff's argument that energy imbalance service, which is a capacity service, does not belong in Schedule 3. NorthWestern explains that in Order No. 890, the Commission recognized that typically the demand costs of providing imbalance service are covered under Schedule 3, and allowed a transmission provider to levy a separate demand charge under Schedule 4, provided the utility did not receive a double recovery.[87]

39. NorthWestern argues that it is required to provide capacity to cover all within-the-hour deviations between generation and load, and since Schedules 4 and 9 do not have capacity components, NorthWestern must recover such costs through Schedule 3.[88] NorthWestern contends that capacity associated with correcting divergences between

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[84] The Commission previously described diversity benefits as follows: "Diversity describes the effect of offsetting deviations between different customers. For example, a fluctuation decreasing one customer's value and a fluctuation increasing another customer's value would be a diversity benefit, as the two deviations would offset each other." *Westar*, 130 FERC ¶ 61,215 at 4, n.9.

[85] NWE Initial Br. at 22.

[86] NWE Reply Br. at 16-17

[87] NWE Initial Br. at 18 (citing *Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 690, *order on reh'g*, Order No. 890-A, FERC Stats. & Regs. ¶ 31,261 (2007), *order on reh'g*, Order No. 890-B, 123 FERC ¶ 61,299 (2008), *order on reh'g*, Order No. 890-C, 126 FERC ¶ 61,228, *clarifying order*, Order No. 890-D, 129 FERC ¶ 61,126 (2009) (Order 890)); *see also* Tr. 775:3-11 (Ballard).

[88] NWE Reply Br. at 10.

generation and load is usually recovered through Schedule 3, while energy costs associated with hourly imbalances are charged through Schedules 4 or 9.[89]

2. LCG

a. LCG's Initial Calculation

40. LCG, with the support of its own study by LCG Witness James R. Dauphinais, argued that a numerator of 19 MW is appropriate with a CPS 2 compliance target of 95%. Mr. Dauphinais initially performed the following seven steps to determine NorthWestern's Regulation service requirement:

- First, for each one-minute interval, he subtracted the non-wind balancing authority generation amount from the balancing authority load amount to get a net balancing authority load amount.
- Second, he converted these one-minute instantaneous values to 10-minute average values.
- Third, he dropped the 1st and 6th 10-minute intervals for each hour to eliminate ramping periods between hourly schedule amounts.
- Fourth, for each hour, he calculated from the remaining 10-minute interval data the difference between the maximum 10-minute balancing authority net load amount for that hour and the minimum 10-minute balancing authority net load amount for that hour to get an hourly gross Regulation service capacity amount for that hour.
- Fifth, for each month, he then sorted, from highest to lowest, the hourly gross Regulation service capacity amounts.
- Sixth, he determined for each month the gross hourly Regulation service capacity amount that would be necessary to cover 90% of the hours for that month.
- Lastly, he subtracted NorthWestern's L_{10} value of approximately 24 MW from the monthly 90th percentile gross Regulation service capacity amounts.[90]

From this initial methodology, Mr. Dauphinais determined that NorthWestern's Regulation capacity requirement should be 41 MW.

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[89] *Id.* at 11.

[90] Ex. LCG-2 at 13; *see also* CMT Initial Br. at 18-19.

b. Two Corrections to LCG's Initial Calculation

41. Based on two corrections, Mr. Dauphinais lowered his initial calculation from 41 MW to 19 MW.

42. First, Mr. Dauphinais agreed with Staff Witness James Ballard's corrections showing that Dr. Tabors incorrectly associated a positive open loop ACE value with a need for regulation up capacity, as well as a negative open loop ACE value with a need for regulation down capacity. This correction caused Mr. Dauphinais to lower the non-wind integration regulation up capacity need from 41 MW to 32 MW.[91] As noted above, NorthWestern conceded and corrected this error.[92]

43. Second, BPA Witness McManus points out that Dr. Tabors incorrectly assigned all the diversity benefits to wind integration capacity need, which would necessarily result in an overstatement of the Schedule 3 rate. Instead, Mr. McManus advocates for an approach that allocates the benefit provided by diversity to NorthWestern's Schedule 3 customers.[93] Mr. Dauphinais agreed with Mr. McManus' approach because it is more in line with cost causation principles.[94] Mr. Dauphinais recalculated NorthWestern's Regulation capacity requirement with this correction in mind, and found that 39 MW of Regulation capacity is needed, allocated on a 34/35 basis.[95] This correction caused Mr. Dauphinais to revise his calculation of NorthWestern's total non-wind integration regulation up capacity to 19 MW to achieve a 95 % compliance rate with CPS 2.[96]

c. LCG's Critiques of NorthWestern's Methodology

44. LCG first argues that NorthWestern's multiple attempts to justify its 60 MW numerator are flawed. In its first attempt, NorthWestern used only historical data from its third-party contracts,[97] which LCG found wholly insufficient to prove NorthWestern's

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[91] Ex. LCG-13 at 7-8; *see also* CMT Initial Br. at 19.

[92] Ex. NWE-19 (corrected May 4, 2012); *see also* LCG Initial Br. at 13-14.

[93] BPA Initial Br. at 20-21.

[94] Ex. LCG-13 at 13; *see also* CMT Initial Br. at 19.

[95] Ex. LCG-13 at 15; *see also* CMT Initial Br. at 20.

[96] Ex. LCG-13 at 15; *see also* CMT Initial Br. at 19-20.

[97] LCG points out that this historical data dates from a period prior to the integration of the 135 MW Judith Gap wind project.

future Schedule 3 requirements for DGGS.[98] In its second attempt, NorthWestern produced the GENIVAR study, however GENVIAR's proprietary software strips the results of any probative value because the results lack a transparent and verifiable methodology.[99] In its third attempt, NorthWestern relied on the testimony of Dr. Tabors, who introduced the analysis described above, relying on historical one-minute instantaneous data. LCG agrees that Dr. Tabors' testimony provides a good starting point to calculate NorthWestern's regulation requirement, but in its final form, Dr. Tabors' study contains significant errors that LCG argues must be corrected.

45. LCG offers the following three critiques of Dr. Tabors' study: First, LCG argues that Dr. Tabors failed to eliminate regulation down capacity from the calculation of NorthWestern's non-wind integration capacity need, in accordance with FERC precedent. Second, LCG contends that Dr. Tabors failed to apply regulation limits to one-minute open loop ACE values. Finally, LCG argues that Dr. Tabors erred by allocating the entire amount of diversity benefits between wind schedule deviations and non-wind schedule deviations to NorthWestern's wind integration Regulation capacity need, when a cost causation approach would produce more appropriate results.[100]

46. LCG believes that left uncorrected, these errors overstate the capacity NorthWestern needs for Schedule 3 service, as well as conflict with both FERC precedent and cost causation principles. After correcting Dr. Tabors' study with respect to these perceived errors, Mr. Dauphinais, using a CPS 2 compliance target of 95%, reached his final recommendation of 19MW as the numerator. LCG recommends the undersigned adopt a number somewhere in the range recommended by Staff and LCG – 3.96 MWs to 19 MWs, respectively.[101]

i. <u>Regulation Down</u>

47. LCG argues that Commission precedent and policy require the removal of regulation down from NorthWestern's Schedule 3 rate. LCG explains that traditionally, the need for Regulation service is determined by an analysis of the Company's historical hourly FERC Form 714 load data.[102] LCG cites *Kentucky Utilities Co.* and *Allegheny*

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[98] LCG Initial Br. at 9-10.

[99] *Id.*

[100] LCG Initial Br. at 9-10.

[101] *Id.*

[102] LCG Initial Br. at 12; Ex. LCG-2 at 11-12.

Power Service Corp. as the foundation for this doctrine.[103] LCG explains that the Commission's policy of excluding regulation down as set forth in these cases was subsequently affirmed in later cases, such as *Consumers Energy Company* and *Otter Tail Power Company*.[104] LCG argues that the Commission's policy of removing regulation down in this case is directly applicable to NorthWestern.[105]

ii. <u>One-Minute Open Loop ACE Values</u>

48. LCG next contends, as originally noted by BPA Witness Bart McManus, that Dr. Tabors fails to apply regulation limits to one-minute open loop ACE values.[106] LCG argues that simulating minute-by-minute system response is more reliable than using the average of one-minute open loop ACE to 10-minute increments.[107] To reach a more accurate result for the Regulation capacity needed for compliance with CPS 2 standards, LCG argues that one must use the minute-by-minute application of regulation up (MW), regulation down (MW) and regulation ramp rate limits (MW per minute).[108]

iii. <u>Diversity Benefits</u>

49. The last critique made by LCG, and also noted by BPA Witness McManus, is that NorthWestern must allocate the diversity benefits of wind and non-wind deviations on a cost causation basis to both non-wind integration and wind integration regulation needs, rather than on an incremental basis to wind integration alone.[109] LCG believes their approach honors cost causation principles contained in prior FERC precedent.

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[103] *Kentucky Utilities*, 85 FERC at 61,108-09; *Allegheny Power*, 85 FERC ¶ 61,275.

[104] *See Consumers Energy Co.*, 86 FERC ¶ 63,004, 65,043 (1999); *aff'd on exceptions*, 98 FERC ¶ 61,333, 62,410 (2002); *see also Otter Tail Power Co.*, 99 FERC ¶ 61,019, 61,095 (2002).

[105] LCG Initial Br. at 13-15.

[106] *Id.* at 16.

[107] Ex. LCG-13 at 9-12.

[108] LCG Initial Br. at 16; Ex.LCG-13 at 10-13; Ex.LCG-15. LCG notes that this adjustment actually raises the amount of capacity needed for Schedule 3 service and, therefore, would increase the costs to LCG. LCG Initial Br. at 16

[109] LCG Initial Br. at 17.

3. MCC

50. MCC contends that NorthWestern's proposed allocation of 60 MW is too low, and instead the numerator should be set at 76 MW. MCC states that although Dr. Tabors' study somewhat correlates with NorthWestern's proposed 60 MW numerator, MCC does not support his methodology since he made the mistake of eliminating the forecast uncertainty due to wind resources as a source of regulation demand.[110] MCC instead advocates for a more comprehensive cost causation study to determine the allocation of costs associated with NorthWestern's Regulation demand. MCC believes that 76 MW of Regulating capacity, the same amount NorthWestern recently purchased from Powerex to replace the power loss caused by the DGGS outage that began on January 31, 2012,[111] would be a better "starting point" for a numerator in this case.[112] In its Reply Brief, MCC contends that *Kentucky Utilities Co.* and *Allegheny Power Service Corp.*[113] should only apply when there is a lack of data and therefore they are not relevant to this case where there is no comparable lack of data.[114]

4. BPA

51. BPA believes a numerator of 43 MW is appropriate in this case based on the testimony of BPA Witness McManus.[115] BPA supports its analysis by arguing the following: (1) NorthWestern may recover costs associated with regulation down, (2) the *Westar*[116] methodology should be used to calculate the numerator; (3) Schedule 3 should be used to recover energy imbalance capacity; and (4) diversity benefits must be included in the methodology.

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[110] MCC Initial Br. at 17 (citing Ex. NWE-19 at 11).

[111] *See* Tr. 294:19-301:8 (Rhoads); *see also Powerex Corp.*, 138 FERC ¶ 61,136 at PP 5-7, 16-17.

[112] MCC Initial Br. at 19-20.

[113] *Kentucky Utilities*, 85 FERC ¶ 61,274; *Allegheny Power*, 85 FERC ¶ 61,275.

[114] MCC Reply Br. at 6.

[115] BPA Initial Br. at 6, 8.

[116] *Westar*, 130 FERC ¶ 61,215 (2010).

a. <u>Regulation Down</u>

52. BPA argues that it is appropriate for NorthWestern to recover its costs for regulation down as a part of Schedule 3. Mr. McManus testified that if regulation down is disallowed it will prevent NorthWestern from fully recovering the costs for the capacity it must provide for its Schedule 3 customers.[117] BPA argues that reliance on *Kentucky Utilities Co.* and *Allegheny Power Service Corp.*[118] to exclude regulation down is misplaced since the actual detailed historical data was provided in this case, and in any case, BPA argues that these cited cases have been overruled by subsequent Commission orders.[119]

53. First, in Order No. 755, BPA argues that the Commission recognized that generators should be compensated "based on performance, as measured by the amount of MWh up and down movement the resource provides."[120] Second, in Order No. 764, the Commission stated that "transmission providers that choose to propose a rate schedule for generator Regulation service may include costs for generator Regulation service in certain circumstances. Such resources are often dispatched in the middle of their operating range to allow the generator to provide regulation-up as well as regulation-down and as a result forego other opportunities."[121]

b. <u>Westar Methodology</u>

54. BPA notes that using CPS 2 compliance is not the best methodology for determining the Regulation capacity needed by a balancing authority, and instead NorthWestern should use actual one minute data that includes all of the following: load, load forecast, variable generation output, variable generation forecast, dispatchable generation output and dispatchable generation forecast.[122] However, BPA explains that NorthWestern did not provide this information and therefore supports the use of the

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[117] *Id.* at 6; *see also* Ex. BPA-003 at 14.

[118] *Kentucky Utilities*, 85 FERC ¶ 61,274; *Allegheny Power*, 85 FERC ¶ 61,275.

[119] BPA Initial Br. at 6-7, 11; BPA Reply Br. at 2-3.

[120] *See Frequency Regulation Compensation in the Organized Wholesale Power Markets*, Order No. 755, FERC Stats. & Regs. ¶ 31,324 at P 78 (2011), *reh'g denied*, Order No. 755-A, 138 FERC ¶ 61,123 (2012).

[121] *See* Order No. 764, 139 FERC ¶ 61,246 at P 316.

[122] *Id.* at 8; *see also* Ex. BPA-003 at 3-5.

CPS 2 methodology provided for in *Westar*.[123] According to the Commission's decision in *Westar*, the numerator should be based on no less than 95% CPS 2 compliance.

c. Recovery of Capacity in Schedule 3

55. BPA believes NorthWestern should be able to collect the cost of capacity needed to cover variations within the hour between generation and load.[124] BPA argues that Staff's understanding that such charges belong in Schedules 4 and 9 is misguided and contravene Commission precedent.[125] BPA relies primarily on Order No. 890, which states that "[w]e believe that the other demand costs of providing imbalance service are already being provided under Schedule 3, 5, and 6 charges."[126] BPA argues that under this Commission precedent, NorthWestern should be able to recover capacity costs under Schedule 3.[127]

d. Diversity Benefits

56. BPA criticizes both the Dr. Tabors and GENIVAR studies because they fail to account for the diversity benefits associated with using the same capacity resource to serve both load and generation.[128] Relying upon Order No. 764, but conceding that the Commission did not directly address rate making issues under Schedule 3, BPA explains that "[w]hen the transactions of two customers result in diversity benefits, it is incorrect to say that one customer is benefiting the other but not vice versa. Instead, the diversity benefits result from both transactions and sharing of these benefits among the customers is reasonable."[129] From this premise, BPA argues that the Commission's view should logically extend to Schedule 3 service since Order No. 764 dealt with the same capacity based services used for balancing actual performance against scheduled performance within the hour.[130] BPA argues that Order No. 764 further supports the inclusion of

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[123] BPA Initial Br. at 10 (citing *Westar*, 130 FERC ¶ 61,215, fn 14).

[124] *Id.* at 14-16.

[125] *Id.*

[126] Order No. 890 at P 690.

[127] BPA Initial Br. at 18.

[128] *Id.* at 20.

[129] Order No. 764, 139 FERC ¶ 61,246 at P 319.

[130] BPA Initial Br. at 20-21.

diversity benefits since the Commission held that, when developing a rate for Regulation service,

> [a] public utility transmission provider must demonstrate that the overall quantity of regulating reserve it requires of its transmission customers accounts for diversity benefits among all resources and loads, and the allocation to individual customers (or customer classes) of their proportionate share is based on the operational characteristics of such customers (or customer classes).[131]

BPA explains that North Western must allocate these diversity benefits back to its Schedule 3 customers, and if the Company does not, it would result in an overstatement of NorthWestern's proposed rate.[132]

5. <u>Central Montana</u>

57. Central Montana argues that NorthWestern's proposed numerator of 60 MW is not just and reasonable, and instead the undersigned should adopt LCG's proposal of 19 MW for a CPS 2 compliance target of 95%.

a. <u>Critiques of NorthWestern's Proposed 60 MW Numerator</u>

58. Central Montana disputes the 60 MW numerator on a number of grounds. First, Central Montana argues that 7 MW of the 60 MW numerator is used as a baseload resource for its bundled retail customers, and therefore should not be allocated to Schedule 3 customers.[133]

59. Second, Central Montana argues that NorthWestern, as the party with control over the relevant information, has the burden to bring it forward or suffer "an adverse inference from failure to do so."[134] Central Montana, quoting NorthWestern Witness Dr. Tabors, explains that if NorthWestern made available its actual hour-ahead schedules reflecting the difference between scheduled and actual load it "would have allowed for

[131] Order 764, 139 FERC ¶ 61,246 at P 320.

[132] BPA Initial Br. at 20-21.

[133] CMT Initial Br. at 13. *See also* Ex. LCG-12 at 78; Tr. at 181:6-14 (Cashell).

[134] *Alabama Power Co. v. FPC*, 511 F.2d 383, 391, n.14 (D.C. Cir. 1974); CMT Initial Br. at 14.

the hour-ahead forecast and schedule uncertainty to be quantified separately from load and generation fluctuation."[135]

60. Third, Central Montana argues that the GENIVAR study is neither transparent nor verifiable, and therefore should be given little weight.[136] As discussed above, GENVIAR's proprietary software stripped the results of transparent and verifiable data.[137]

6. MPSC

61. The MPSC supports NorthWestern's proposed 60 MW numerator. The MPSC factually distinguishes *Kentucky Utilities Co.*,[138] stating that unlike the company in that case, NorthWestern lacks a fleet of generators that would enable it to reduce output to match load, and costs for providing regulation down are as necessary as regulation up.[139] Accordingly, the MPSC explains that regulation down is a necessary part of NorthWestern's Regulation service cost, and thus should be recovered in Schedule 3.[140]

62. The MPSC further argues that diversity benefits, although used in Dr. Tabors' study, are not properly before the Commission since they were not a part of NorthWestern's original filing, and therefore are outside the scope of this proceeding.[141] The MPSC argues on the grounds of cost causation, that diversity benefits flow to the retail customers who alone bear this cost, as opposed to Schedule 3 customers.[142] Therefore, diversity benefits should not be applied in ascertaining NorthWestern's appropriate numerator.

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[135] CMT Initial Br. at 14; Ex. NWE-19 at 8; Tr. 813 (Tabors).

[136] *Id.* at 15.

[137] *See e.g.* LCG Initial Br. at 9-10.

[138] *Kentucky Utilities*, 85 FERC ¶ 61,274.

[139] MPSC Initial Br. at 3-4.

[140] MPSC Initial Br. at 2-3.

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

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

7. Powerex

63. Powerex explains its limited interest as ensuring that balancing authorities follow Good Utility Practice and take action to minimize the intervals in which they find themselves with insufficient Regulation capacity.[143] Stemming from this interest, Powerex argues that Staff's proposal is too low, in that it is substantially less than 60 MW and only allows NorthWestern the bare minimum of 90% for CPS 2 compliance.[144] Next, Powerex argues that since generators incur costs for regulation down service, NorthWestern should recover these costs.[145] Finally, Powerex, like others, argues that *Kentucky Utilities Co.* and *Allegheny Power Service Corp*.[146] are not applicable to this case.[147]

8. Staff

64. Staff contends that NorthWestern's proposed allocation based on a numerator of 60 MW is not just and reasonable since it does not reflect the actual amount of capacity NorthWestern needs to provide Schedule 3 Service. Staff proposes, as calculated by Staff Witness James Ballard, a numerator of 3.96 MW and a CPS 2 compliance of 90% based on an absolute-average measurement.[148]

a. Staff's Proposed Methodology

65. In calculating the numerator Staff Witness Ballard argues that four steps, in addition to those taken by Dr. Tabors, are needed to determine NorthWestern's Schedule 3 requirements:

- First, Staff argues that diversity benefits derived from NorthWestern's wind generation portfolio must be added to its total system Regulation capacity.

[143] Powerex Initial Br. at 12.

[144] *Id.* at 8-15.

[145] *Id.* at 15-17.

[146] *Kentucky Utilities*, 85 FERC ¶ 61,274; *Allegheny Power*, 85 FERC ¶ 61,275.

[147] Powerex Initial Br. at 18-19.

[148] Staff Initial Br. at 9, 17.

- Second, NorthWestern's Regulation capacity demand must be calculated using an absolute average of all variations, rather than separate measures of up and down variations.

- Third, the capacity attributable to regulation down service must be removed.

- Fourth, the portions of the resulting capacity attributable to the provision of Schedule 4 – Energy Imbalance Service and Schedule 9 – Generator Imbalance Service must be removed.[149]

b. Critiques of NorthWestern's methodology

66. Staff first offers a general critique of Dr. Tabors' study, noting that Dr. Tabors performed his analysis in October and November 2011,[150] over 18 months after NorthWestern initially filed for a Schedule 3 rate which used 60 MW as the numerator. Staff alleges that, traditionally, a utility seeking new rates will conduct the necessary studies *before* submitting those studies in its initial testimony.[151] Staff argues the process used by NorthWestern in this case puts the cart before the horse, and because of this, Dr. Tabors' study should be viewed with heightened scrutiny since it was conducted to support a numerator already filed by NorthWestern.[152]

c. Diversity Benefits

67. Staff views Dr. Tabors' first error as failing to include the effect that wind generation has on the amount of capacity NorthWestern needs to comply with CPS 2, and therefore how much capacity demand is attributable to Schedule 3 service.[153] Staff Witness Ballard concedes that this wind generation operates exclusively for the benefit of retail customers and that a majority of NorthWestern's combined retail and wholesale Energy Imbalance Service is provided to correct scheduling errors on NorthWestern's retail system (including wind forecast error).[154] However, these errors have the effect of

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[149] *Id.* at 6.

[150] Ex. NWE-1 (dated April 29, 2010).

[151] Staff Initial Br. at 11.

[152] *Id.* at 11-12.

[153] *Id.* at 12; *see also* NWE-19 at 11.

[154] Staff Initial Br. at 13; Ex. S-20 at 36-37.

either offsetting or exacerbating deviations between generation and load, and therefore affect NorthWestern's CPS 2 compliance.[155] In other words, if there is excess generation on the retail side, and a shortfall on the wholesale side, the retail side will offset the wholesale shortfall. To meet CPS 2 compliance, Staff argues that Dr. Tabors' analysis must take into account retail wind generation forecast error.[156]

d. <u>Absolute Average</u>

68. Staff argues that Dr. Tabors should have measured the absolute values of both upward and downward variations, thereby providing a margin of error for NorthWestern to comply with CPS 2.[157]

69. First, Staff contends that using an absolute-value based average of up and down demand values would be larger than the actual regulation up demand, thereby providing a cushion above the minimum amount of capacity necessary to maintain moment-to-moment system balance.[158] Second, Staff's use of an absolute average for all drivers of ACE (both up and down) on NorthWestern's system as potential drivers of the need for regulation up ensures NorthWestern is compensated for any regulation up service it may need to provide.[159] With these two "cushioning factors," Staff argues that Mr. Ballard's use of a 90% CPS 2 compliance target is appropriate since it provides a margin for error while still measuring the actual amount of Regulation capacity NorthWestern uses to provide Schedule 3 service.[160] Staff also argues that *Kentucky Utilities Co.* and *Allegheny Power Service Corp.* support the use of averages.[161]

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[155] Staff Initial Br. at 13 (citing Tr. 588:20-22 (LCG witness Dauphinais testifies that "[t]o the extent there's sufficient diversity that the net imbalance on the system is no worse than it would be, [wind generation] can provide a benefit").

[156] *Id.* at 14; *see also* Tr. 588:17-25 (Dauphinais).

[157] *Id.* at 14-15.

[158] Staff Initial Br. at 17 (citing Ex. S-20 at 15).

[159] *Id.* at 17 (citing Ex. S-20 at 14).

[160] *Id.* (citing Ex. S-20 at 16).

[161] *Kentucky Utilities Co.*, 85 FERC at 62,108 ("That 70 MW was computed as the average of the hourly load changes on KU's system for each hour of the year"); *Allegheny Power Service Corp.*, 85 FERC at 62,120 ("APS averaged the load changes during each hour for the 1994 test year and proposed to charge for reserves").

e. Regulation Down

70. Staff, like others, argues that the regulation down component must be removed from Dr. Tabors' analysis because the Commission recognized in *Kentucky Utilities Co.* and *Allegheny Power Service Corp.* that a balancing authority is required to remove regulation down.[162] Staff further explains that the Commission realized that a utility such as NorthWestern must operate its regulation resources at a set point above their minimum in order to be prepared to ramp down to adjust for hourly positive scheduling errors, however, the utility can nonetheless use the additional energy generated to maintain the set point for non-regulation purposes, such as off-system sales.[163] Staff emphasizes that regulation down stands in contrast to regulation up service, which requires that a utility bring additional generation online above its set point.[164]

f. Schedules 3, 4, and 9

71. Staff explains that the purpose of this proceeding is only to set a Schedule 3 rate for NorthWestern, and therefore, ancillary services that are classified under other rate schedules should be excluded from these proceedings. Staff argues that Dr. Tabors inappropriately includes the provision of non-Schedule 3 services in his study, *i.e.* Schedules 4 and 9.[165] Staff criticizes Dr. Tabor's assumption that NorthWestern complies with CPS 2 solely by providing Schedule 3 service to its customers. Staff explains that Dr. Tabors admitted on cross-examination that his study includes both (1) "capacity used to provide service which makes up the difference between the scheduled and actual delivery of energy to load located within NorthWestern's control area," and (2) "capacity used to make up for the difference between the output of generators located in NorthWestern's control area and the delivery schedule from those generators to load."[166]

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[162] Staff Initial Br. at 15.

[163] *See* Tr. 154:20-155:3 (NorthWestern witness Cashell explaining that extra megawatts get "absorbed into the system"); Tr. 635:1-14 (Staff witness Patterson explaining that extra megawatts can be used to make "an off-system sale" and such extra generation would then not be "exclusively used for Regulation service.")

[164] Staff Initial Br. at 16.

[165] *Id.* at 18-20.

[166] Tr. 362:6-23 (Tabors).

As such, Staff states that such costs should properly be classified as Energy Imbalance Service[167] and Generator Imbalance Service.[168]

72. Staff seeks to defend the Commission's definitional validity by separating these other ancillary services from Schedule 3 service. Staff argues that it is important to separate these other ancillary services and costs from Schedule 3 costs, and if upheld on this point, it would establish a precedent that would allow Schedule 3 capacity alone to be used to comply with CPS 2.[169] Staff explains that it is critical that Schedule 3 customers only pay for capacity that is used to provide Schedule 3 service.[170] In his analysis, Staff Witness Ballard separated these other costs from NorthWestern's Schedule 3 service.[171]

g. <u>Critiques of LCG's methodology</u>

73. Staff critiques LCG Witness Mr. Dauphinais' methodology on two grounds: First, LCG does not use absolute averages, and instead measures NorthWestern's regulation up and regulation down separately.[172] Second, Staff faults LCG for including Schedules 4 and 9 in NorthWestern's Schedule 3 costs. Staff specifies that Mr. Dauphinais' measurement includes "capacity which is used to provide a service which makes up for the difference between the scheduled and the actual delivery of energy to load located within NorthWestern's control area over the course of an hour," as well as "capacity used to make up for the difference between the output of generators located in NorthWestern's control area and the delivery schedule from those generators to load."[173] Staff explains that these are the exact definitions of Schedule 4 and Schedule 9 service, and argues that the costs of providing these services should not be allocated to Schedule 3 customers.[174]

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[167] Staff Initial Br. at 18 (citing *Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890-B, 123 FERC ¶ 61,299 at 63,075 (2008)).

[168] Staff Initial Br. at 18 (citing *Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890-B, 123 FERC ¶ 61,299 at 63,077 (2008)).

[169] Staff Initial Br. at 20.

[170] *Id.*

[171] *Id.* (citing Ex. S-20 at 30-32).

[172] *Id.* at 27-28.

[173] Tr. 591:14-592:6 (Dauphinais).

[174] Staff Initial Br. at 28.

74. Other than these two criticisms, Staff believes LCG's analysis is accurate and further confirms Staff Witness Ballard's methodology.[175]

B. Decision

75. As discussed in more depth below, I find LCG's proposed methodology and numerator of 19 MW are just and reasonable and are well-supported by the record in this case. I find the following: (1) NorthWestern has the burden of proof in this case, and did not carry its burden of showing that 60 MW is a just and reasonable numerator, (2) regulation down must be excluded from Dr. Tabors' study, (3) diversity benefits must be shared by wholesale and retail customers based on cost causation principles, (4) NorthWestern may include energy imbalance service in its Schedule 3 rate, and (5) the use of absolute averages is not mandated for calculating the numerator.

1. Burden of Proof

76. As a preliminary matter, NorthWestern disputes that it has the burden of proof since its Section 205 filing "represent[s] no departure from the status quo," and was approved in a previous proceeding.[176] This proposal and NorthWestern's reliance on *Public Service Commission of New York v. FERC*, 642 F.2d 1335, 1345 (D.C. Cir. 1980) is factually and legally misguided as applied to this case.[177]

77. First, as a matter of fact, NorthWestern represents that its proposed rate is not a "departure from the status quo," but this is inaccurate. NorthWestern has not previously allocated the costs of the newly-constructed DGGS to any customers, nor has it allocated any of its Schedule 3 costs based on a numerator of 60 MW in any proceedings before the Commission. Rather, NorthWestern previously passed through the costs of its third-party Schedule 3 contracts to its Schedule 3 customers using a numerator of 60 MW.[178]

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[175] *Id.* at 29.

[176] NWE Initial Br. at 11 (citing *Public Service Comm'n of New York v. FERC*, 642 F.2d 1335, 1345 (D.C. Cir. 1980)). NorthWestern alleges that a 60 MW of Regulation capacity was approved for the Company in *NorthWestern Corp.*, 121 FERC ¶ 61,204 at P 15 (2007).

[177] *See* Staff Reply Br. at 9-10.

[178] Ex. NWE-1 at 8.

78. Secondly, as a matter of law, since NorthWestern is the utility filing for revised rates under Section 205 of the Federal Power Act (FPA),[179] NorthWestern clearly bears the burden of proof to show its proposed rate is just and reasonable.[180] Moreover, NorthWestern cites to the portion of the opinion that discusses the burden of proof under Section 5 of the Natural Gas Act, which governs Commission-initiated challenges to rates.[181] However, this section is analogous to Section 206 of the FPA, not Section 205.[182] Therefore, the Court of Appeals' holding that a utility does not bear the burden on issues that "represent no departure from the status quo" generally applies only to complaints and Commission initiated filings, such as those brought under FPA Section 206, not utility-initiated Section 205 filings where the company is seeking to institute an initial rate for service provided by the utility itself, or in other words a previously non-existent rate altogether.

79. Finally, as a matter of fairness, NorthWestern has taken for itself the customary rights of the party with the burden of proof, such as the right to file rebuttal testimony.[183] NorthWestern may not take the procedural advantages of the party with the burden of proof and yet claim that it does not bear the ultimate burden.[184]

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[179] 16 U.S.C. 824d (2006).

[180] 18 C.F.R § 35.13(e)(3)(iii) (2012) ("Any utility that files a rate increase shall be prepared to go forward at a hearing on reasonable notice on the data submitted under this section, to sustain the burden of proof under the Federal Power Act of establishing that the rate increase is just and reasonable and not unduly discriminatory or preferential or otherwise unlawful within the meaning of the Act.").

[181] In that proceeding, a utility filed to change its return on equity under Section 4 of the Natural Gas Act (NGA), while the Commission challenged the utility's zonal cost allocation methodology under Section 5. *Public Service Comm'n of New York v. FERC*, 642 F.2d at 1340. The Court of Appeals found that the Commission bore the burden of proof with respect to the allocation methodology challenged under NGA Section 5. *Id*. at 1345.

[182] *See, e.g.*, *Southwest Power Pool, Inc.*, 137 FERC ¶ 61,075 at n. 88 (2011) (finding that FPA Section 205 is analogous to NGA Section 4, while FPA Section 206 is analogous to NGA Section 5).

[183] *NorthWestern Corp.*, "Order Adopting Procedural Schedule," Docket No. ER10-1138-001 (Jun. 26, 2011).

[184] *See BP Pipelines (Alaska), Inc.*, "Order on Burden of Proof" at P 12, Docket No. IS09-348-004 (May 1, 2012) ("It is also not credible that the State and A/T believed that they would have the right to go last if they do not have the ultimate burden of proof…").

80. For these reasons, NorthWestern clearly bears the burden of proof with respect to all aspects of its proposed rate.

2. **<u>NorthWestern's Evidence</u>**

81. NorthWestern has failed to meet its burden of proof with respect to supporting its proposed numerator of 60 MW. NorthWestern submitted studies by Dr. Tabors and GENIVAR to support this numerator.

82. The methodology used in NorthWestern's GENIVAR study was not provided to the other parties in this proceeding for proprietary reasons, and therefore the parties were unable to independently verify its findings, or challenge the procedures or assumptions used in the study.[185] Because the GENIVAR study is based solely on an undisclosed methodology, the validity of which cannot be independently assessed, it will be accorded no weight in this case.[186]

83. I find that Dr. Tabors' methodology is a reliable starting point for a just and reasonable rate, however, Dr. Tabors' study requires three modifications: the effect of capacity associated with regulation down must be removed, diversity benefits must be reflected, and a CPS 2 compliance target of 95% is appropriate to calculate a just and reasonable Schedule 3 rate for NorthWestern. Accordingly, with these modifications, as set forth in LCG Witness Dauphinais' analysis, I find that LCG's proposed numerator of 19 MW is within the range of a just and reasonable rate.

3. **<u>Regulation Down</u>**

84. NorthWestern, BPA, and other supporting parties, argue that regulation down must be included in NorthWestern's Schedule 3 rate on two grounds: (1) *Kentucky Utilities Co.* and *Allegheny Power Service Corp.* do not factually apply in this case, and (2) these cases have been implicitly overruled by more recent Commission Orders.[187]

85. BPA, among others, argues that reliance on these two cases is misplaced since "actual detailed historical data" was provided in this case, and that these cases only apply

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[185] Ex. LCG-2 at 11. *See also* LCG Initial Br. at 9-10; Staff Reply Br. at 15-16.

[186] Dr. Tabors did not rely on the GENIVAR study in any way. Tr. 361:1-3 (Tabors).

[187] NWE Reply Br. at 11; BPA Initial Br. at 6-7, 11; BPA Reply Br. at 2-3.

when historical data is not available.[188] As a preliminary matter, the use of the phrase "detailed" to describe NorthWestern's evidentiary record is not the most accurate description. As Central Montana points out, NorthWestern, as the party with control over the relevant information, has the burden to bring it forward.[189] Many of the expert witnesses, including NorthWestern's own witness, Dr. Tabors, agreed that if NorthWestern had produced its actual hour-ahead schedules, showing the difference between scheduled and actual load, it would have resulted in a more accurate analysis.[190] NorthWestern explains that it regularly discards this data since "it is not needed once the hour passes."[191]

86. Although the amount of data provided by NorthWestern is not ideal, Dr. Tabors' study clearly utilizes more data than the companies provided to the Commission in *Kentucky Utilities Co.* and *Allegheny Power Service Corp.* In the Hearing Order, the Commission discussed the applicability of these two cases:

> Notably, in *Kentucky Utilities Co.* and *Allegheny Power Service Corp.*, the Commission concluded that, in the absence of *any* data supporting a transmission provider's regulation requirement, the most accurate way to determine the regulation obligation applicable to transmission customers was by calculating the average of [all] hourly load variations on the transmission provider's system.[192]

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[188] BPA Initial Br. at 11-12; BPA Reply Br. at 2-3.

[189] *Alabama Power Co. v. FPC*, 511 F.2d 383, 391, n.14 (D.C. Cir. 1974); CMT Initial Br. at 14.

[190] Ex. NWE-19 at 8; Tr. 813:21-815:9 (Tabors). Staff witness Ballard was puzzled over the lack of data, stating that there is "no reason why [NorthWestern] wouldn't be able to retain the data on an hour-ahead basis and provide that as support for [its] energy imbalance demand." Tr. 710:20-25 (Ballard). I am likewise confused at NorthWestern's failure to retain this data due to its obvious benefit for providing a more accurate assessment of NorthWestern's operations. This information clearly would have been useful in determining factors for capacity cost allocation of DGGS associated with Schedule 3.

[191] Ex. NWE-22 at 22.

[192] Hearing Order at P 23 (citations omitted) (emphasis added).

87. As recognized in this sentence, the Commission has set forth a specific methodology when there is an absence of *any* data to support the regulation requirement. Staff Witness An Jou Jo Hsiung employed this methodology, which required calculating the average hourly load deviations from 2006 to 2010 using data from FERC Form 714, then dividing those deviations by two (referred to herein as the "inter-hour Load Following methodology").[193] However, Staff did not adopt the inter-hour Load Following methodology or its result in this case because NorthWestern provided enough data to reach a more accurate result than if there wasn't any data available.[194] In this sense, BPA is correct in arguing that the facts of this case are different from those in *Kentucky Utilities Co.* and *Allegheny Power Service Corp.*, however, this merely precludes the otherwise necessary use of the inter-hour Load Following methodology.

88. The fact that the inter-hour Load Following methodology is not applicable to this case, does not mean every principle set forth in *Kentucky Utilities Co.* and *Allegheny Power Service Corp.* should be categorically disregarded. Staff and LCG argue that these cases direct a balancing authority to remove regulation down from its Schedule 3 rate.[195] Specifically, the Commission found in *Allegheny Power Service Corp.* that a balancing authority "would only need to have, on average, adequate generation capacity to cover the portion of the hour when a customer's load is above the amount of generating capacity it has block scheduled. This amount of capacity is sufficient to provide load following through the entire hour."[196] Further, the Commission found in *Kentucky*

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[193] Ex. S-5 at 6. *Allegheny Power Service Corp.*, 85 FERC at 62,120. Staff elucidates the term "load following" used in these cases by explaining that consistent with the original Order No. 888 NOPR, the *Kentucky* and *Allegheny* orders refer to Schedule 3 Regulation and Frequency Response service as "load following." *Id*. at 61,218 ("Throughout this proceeding, the parties used the term 'load following.' In Order No. 888, the Commission adopted the term 'Regulation and Frequency Response' for this ancillary service. Because the term 'load following' has been used extensively in the record, we will continue to use it herein").

[194] Ex. S-7 at 25-26. It is worth noting that the results reached using the inter-hour Load Following methodology, between 16.0-16.7 MW, are close to the result reached by LCG witness Dauphinais of 19 MW. *See* S-5 at 2 ("I calculated that NorthWestern's regulation demands are 16.7 MW in 2006, 16.6 MW in 2007, 16.6 MW in 2008, 16.3 MW in 2009, and 16.0 MW in 2010.").

[195] Staff Initial Br. at 15.

[196] *Allegheny Power Service Corp.*, 85 FERC at 62,120.

Utilities Co. that a utility's Regulation capacity requirement could be derived "by simply dividing the average of the hourly load changes during the year by two."[197]

89. The Commission's policy that a utility must divide the average of the hourly load changes by two (i.e. to exclude regulation down) was subsequently affirmed in later cases. For example, in *Consumers Energy Company* the Administrative Law Judge explained that "the load variation must be divided by 2, as the amount of generation a customer scheduling its load is providing exceeds energy for a portion of the hour. Thus, the regulating margin must be provided only when the customer's load is in excess of the average for the hour."[198] Similarly, in *Otter Tail Power Company*, the Commission ruled, "[S]ince a company would only be required to provide, on average, adequate generating capacity to cover the portion of the hour when a customer's load is above the amount of generating capacity it has block scheduled, then the company is required to divide the regulation obligation figure that it has derived by two."[199]

90. The Commission's policy to exclude regulation down reflects the fact that, although a utility like NorthWestern must operate its regulating resources at a point above NorthWestern's minimum (i.e. a set point) in order to be prepared to ramp down in case demand drops (i.e. positive scheduling errors), NorthWestern can utilize the energy used to maintain the set point for non-regulation purposes.[200] NorthWestern did not provide any evidence showing why it would be unable to use this energy for non-regulation purposes, such as off-system sales. Indeed, NorthWestern, Staff, and LCG, among others, are in agreement that these extra megawatts are absorbed into NorthWestern's system and have value, and therefore have the potential to be used for off-system sales.[201]

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[197] *Kentucky Utilities*, 85 FERC at 62,109.

[198] *Consumers Energy Co.*, 86 FERC ¶ 63,004, 65,043 (1999); *aff'd on exceptions*, 98 FERC ¶ 61,333, 62,410 (2002).

[199] *Otter Tail Power Co.*, 99 FERC ¶ 61,019, 61,095 (2002).

[200] Staff Initial Br. at 16.

[201] *See* Tr. 154:20-155:3 (NWE witness Cashell explaining that extra megawatts get "absorbed into the system"); Ex. LCG-19 (In response to a LCG Data Request, NorthWestern explained that additional energy "will be absorbed into the system as the regulation occurs and thus has value"); Tr. 179:16-29 (LCG witness Dauphinais explaining that extra megawatts are "absorbed in the system to keep the system in balance, and value is created"); Tr. 635:1-14 (Staff witness Patterson explaining that extra megawatts can be used to make "an off-system sale" and such extra generation

(continued…)

91. While BPA is correct that the inter-hour Load Following methodology as set forth in *Kentucky Utilities Co.* and *Allegheny Power Service Corp*. is not factually on all fours with this case, the Commission's policy to exclude regulation down is still applicable here. Accordingly, NorthWestern has not carried its burden of proof to factually distinguish itself in a way that would demonstrate why the undersigned should depart from this Commission precedent. Therefore, under *Kentucky Utilities Co.* and *Allegheny Power Service Corp*. NorthWestern is directed to exclude regulation down from its Schedule 3 rate.

92. Second, BPA and NorthWestern argue that even if the policies established in *Kentucky Utilities Co.* and *Allegheny Power Service Corp*. are applicable to this case, these precedents have been overruled by two subsequent Commission orders.

a. <u>Order No. 755</u>

93. NorthWestern, among others, cites Order No. 755 for the proposition that NorthWestern should receive compensation for regulation down. In Order No. 755 the Commission recognized that generators should be compensated "based on performance, as measured by the amount of MWh up and down movement the resource provides."[202] Specifically, NorthWestern concludes that based on this sentence, Order No. 755 authorizes it to be compensated for the total capacity up and down that it contributes towards Regulation service.[203] NorthWestern next cites Order No. 755-A for this same proposition: "[A] resource must be measured [and compensated accordingly] based on the absolute amount of regulation up and regulation down it provides in response to the system operator's dispatch signal."[204]

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would then not be "exclusively used for Regulation service"). Additionally, Staff points out that if a utility needed to provide regulation down service in this instance, "the Automatic Generation Control associated with the utility's generation would signal the generation to momentarily ramp down without affecting the average hourly set point value, allowing excess system energy to provide whichever service had been provided from set point energy." Staff Initial Br. at 16, n.39.

[202] Order No. 755, FERC Stats. & Regs. ¶ 31,324 at P 78.

[203] *See* NWE Initial Br. at 15-16; Powerex Initial Br. at 15-17; MPSC Initial Br. at 3; BPA Initial Br. at 3.

[204] Order No. 755-A, 138 FERC ¶ 61,123 at P 14; NWE Initial Br. at 16.

94. Staff, among others, concedes that Order No. 755 allows a utility to receive compensation for regulation down in certain circumstances.[205] However, Staff explains that Order No. 755 does not apply to NorthWestern. Instead, Order No. 755 applies to "organized wholesale electric markets" operated by Independent System Operators (ISOs) and Regional Transmission Organizations (RTOs), of which NorthWestern is not a member.[206] Staff argues that if the Commission had intended this order to apply to non-market participants such as NorthWestern, the Commission would not have recently issued a Notice of Proposed Rulemaking on Schedule 3 compensation for non-market participants.[207] Central Montana also explains that the Commission has previously recognized that NorthWestern's situation should not be compared to that of an organized ancillary services market.[208]

95. LCG further demonstrates that NorthWestern's argument is flawed because the compensation mechanism and incentives, as contemplated in Order No. 755, cannot logically apply to NorthWestern's proposed rate.[209] LCG explains the term "compensation" referred to in Order No. 755 is actually a "performance payment" that is based on a market-based price, as opposed to an administratively determined price that NorthWestern seeks in this case.[210]

96. I agree with Staff, LCG, and Central Montana that Order No. 755 does not permit NorthWestern to include regulation down in its Schedule 3 rate. As stated above, Order No. 755 applies to organized markets, of which NorthWestern is not a member. Moreover, the compensation NorthWestern seeks in this proceeding differs substantially from the performance payments set forth in Order No. 755. If the Commission intended

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[205] Staff Reply Br. at 12.

[206] CMT Reply Br. at 10-11 (citing Order No. 755 at P 1).

[207] *Notice of Proposed Rulemaking, Third-Party Provision of Ancillary Service*, 139 FERC ¶ 61,245 (2012).

[208] *Id.* (citing *NorthWestern Corp.*, 140 FERC ¶ 61,020 at P 22 (2012) ("[T]he *MISO* language cited by NorthWestern was inextricably tied to the complexities of designing a functional Ancillary Services Market, and those facts have little relevance to the case at hand.").

[209] LCG Reply Br. at 7-10.

[210] Order No. 755-A, 138 FERC ¶ 61,123 at P 5; Order No. 755, 76 F.R. ¶ 67,260 at P 133; *see also Frequency Regulation Compensation in the Organized Wholesale Power Markets*, Notice of Proposed Rulemaking, 134 FERC ¶ 61,124 at P 34 (2011) (Order No. 755 NOPR).

performance payments that apply to non-market participants such as NorthWestern, it would have done so explicitly in Order No. 755. NorthWestern does not persuasively demonstrate why Order No. 755 should apply in this case. Accordingly, I find that Order No. 755 does not allow NorthWestern to receive compensation for regulation down in this case and does not render moot the holdings in *Kentucky Utilities Co.* and *Allegheny Power Service Corp*.

b. <u>Order No. 764</u>

97. In Order No. 764, NorthWestern explains that the Commission sought to remove barriers to the integration of VER, as well as to create guidelines for Schedule 10.[211] Although Order No. 764 did not directly address Schedule 3, NorthWestern nonetheless argues that the Commission's discussion of cost recovery for regulation down should also apply to NorthWestern's Schedule 3 service.[212] As noted above, Order No. 764 does not specifically address Schedule 3, however, NorthWestern argues that the Commission's discussion of cost recovery for regulation down should apply to the Company's Schedule 3 service.[213] Specifically, the Commission found that due to the difficulties of incorporating variable energy resources, generating units "are often dispatched in the middle of their operating range to allow the generator to provide regulation-up as well as regulation-down and as a result forego other opportunities. Not to allow compensation would create a barrier to the provision of services by frustrating the recovery of legitimate costs."[214]

98. NorthWestern argues that it has had to forego other opportunities, and therefore has incurred a loss of compensation for the legitimate costs of regulation down.[215] NorthWestern concedes that Order No. 764 addresses Schedule 10, not Schedule 3, but argues that the Commission did not indicate that compensation for regulation down is only limited to Schedule 10.[216]

99. LCG argues that Order No. 764 applies to Schedule 10 services, not Schedule 3. LCG examines the context of the above-quoted language, by emphasizing that the

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[211] Order No. 764, 139 FERC ¶ 61,246 at P 316.

[212] NWE Initial Br. at 21.

[213] NWE Initial Br. at 21.

[214] *Id.* (quoting Order No. 764, 139 FERC ¶ 61,246 at P 316).

[215] *Id.* at 21-22.

[216] *Id.* at 21, n.15.

Commission stated that opportunity costs may only be included in "certain circumstances."[217] The Commission explains these circumstances:

> [T]hose public utility transmission providers that choose to propose a rate schedule for generator Regulation service may include opportunity costs for generator Regulation service in *certain circumstances*. Such resources are often dispatched in the middle of their operating range to allow the generator to provide regulation-up as well as regulation-down and as a result forego other opportunities. Not to allow compensation would create a barrier to the provision of services by frustrating the recovery of legitimate costs.[218]

The Commission further explained:

> [G]enerator regulation rates should be fully compensatory, and may legitimately reflect a utility's full opportunity cost. . . . [T]here may also be lost opportunity costs associated with reserving unloaded generation capacity during peak market conditions.[219]

LCG argues that the compensation at issue in Order No. 764 does not extend to providers simply for regulation down, but instead, such compensation is provided to induce the provider to forgo the opportunity to make energy sales from the portion of their generating capacity that in a given hour is providing regulation up.[220]

100. I agree with LCG that Order 764 does not supercede the Commission's policy of excluding regulation down from a utility's Schedule 3 rate. First, Order No. 764 was issued on June 22, 2012, a date subsequent to the conclusion of the hearing in this case. However, no party or participant argued the effect of Order No. 764 on this case by way of a motion to reopen the record herein after Order No. 764 was issued.[221] Second, as

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[217] LCG Reply Br. at 12 (quoting Order No. 764, 139 FERC ¶ 61,246 at P 316) (emphasis added).

[218] *Id.* at P 316.

[219] Order No. 764, 139 FERC ¶ 61,246 at P 284.

[220] LCG Reply Br. at 13.

[221] LCG Witness Dauphinais generally discussed the applicability of opportunity costs to NorthWestern at the hearing. Tr. 605-07 (Dauphinais).

NorthWestern itself notes in a footnote, it is not precluded from making the appropriate filing in the future to recover its opportunity costs through Schedule 10.[222]

101. Finally, NorthWestern has not introduced any evidence into the record regarding opportunity costs. Indeed, I find opportunity costs to be a difficult proposition for NorthWestern to argue given the utility's claim that DGGS was exclusively built and fully used only for Regulation services for its retail and Schedule 3 customers.[223] If that were the case, there could be no other opportunity to forego and hence no opportunity costs to reflect in its Schedule 3 rate. The Company cannot have its cake, i.e. claim it must recover the full cost for DGGS under Regulation Schedule 3 service rates because it was solely built for that purpose – and eat it too, i.e. claiming it is forgoing opportunities for other services thereby permitting the Schedule 3 rates to be increased due to the supposed opportunity costs NorthWestern must forgo. Through NorthWestern's own testimony, it is clear that the Company believes these other services that could result in opportunity costs do not exist. NorthWestern's argument for opportunity costs is internally inconsistent and therefore, disregarded.

102. At bottom, NorthWestern has not carried its burden factually or legally to show that it should receive compensation for regulation down through Schedule 3 service rates. I find that the Commission's policy to exclude regulation down from Schedule 3 service, announced in *Kentucky Utilities Co.* and *Allegheny Power Service Corp*., and upheld through fifteen years of case law, applies to NorthWestern in this case.

4. Diversity Benefits

103. NorthWestern opposes Schedule 3 customers receiving any diversity benefits. NorthWestern and the MPSC argue that since its retail load exclusively bears the costs of wind generation, its retail customers alone should receive any diversity benefits to prevent its Schedule 3 customers from receiving an undeserved windfall.[224]

104. BPA and Staff, among others, argue that Dr. Tabors should have included the effect wind generation has on the amount of capacity NorthWestern needs to comply with

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[222] NWE Initial Br. at 19, n.12.

[223] *See* Ex. NWE-15 at 6 (NWE Witness Merchant emphasizes "without reservation that DGGS will solely be used to provide Regulation Service) (original emphasis); *see also* Ex. NWE-22 at 4 (NWE Witness Cashell explains that "DGGS was built specifically for the purpose of providing regulating reserves to NorthWestern's Schedule 3 and bundled retail customers.").

[224] NWE Initial Br. at 16-17, 22; MPSC Initial Br. at 6-7.

CPS 2, and therefore how much capacity demand is attributable to Schedule 3 service.[225] Staff concedes that this wind generation operates exclusively for the benefit of retail customers, however, Staff argues that wind generation errors either offset or exacerbate deviations between generation and load, and therefore impact NorthWestern's CPS 2 compliance.[226] Put simply, if there is excess generation on the retail side, and a shortfall on the wholesale side, the retail side will offset the wholesale shortfall, and vice versa. Indeed the Commission in *Westar* recognized that in such moments, the deviation of load and wind can cancel each other out, and therefore, both retail and Schedule 3 customers share these benefits:

> [w]hen the transactions of two customers results in diversity benefits, it is incorrect to say that one customer is benefiting from the other but not vice versa. Instead the diversity benefits result from both transactions and sharing of these benefits among the customers is reasonable.[227]

The Commission further explained that "such sharing of diversity benefits is consistent with traditional ratemaking practices of allocating fixed costs where exact precision in cost allocation is not always possible."[228]

105. I find that NorthWestern has not carried its burden of proving that diversity benefits should be allocated solely to its retail load. NorthWestern did not submit any evidence that shows with "exact precision" how the benefits of its wind generation are actually allocated when deviations occur or how such benefits should apply to retail customers alone. The mutual benefits that accrue from the presence of both load and wind must be shared between wind and non-wind, and, as a result, NorthWestern needs less overall generation capacity, thereby lowering costs for all customers. Accordingly, I find that NorthWestern's diversity benefits must be allocated between its retail and Schedule 3 customers.

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[225] Staff Initial Br. at 12; *see also* NWE-19 at 11 (Dr. Tabors' analysis removes "wind forecast uncertainty – the difference between a calculated (estimated) value for the hourly wind schedule and the known wind output" from NorthWestern's 2009 ACE data.).

[226] Staff Initial Br. at 13 (citing Tr. 588:20-22 (LCG witness Dauphinais testifies that "[t]o the extent there's sufficient diversity that the net imbalance on the system is no worse than it would be, [wind generation] can provide a benefit").

[227] BPA Initial Br. at 20 (quoting *Westar*, 130 FERC ¶ 61,215 at P 37).

[228] *Westar*, 130 FERC ¶ 61,215 at 38.

5. **95% CPS 2 Compliance**

106. Although NorthWestern does not adopt a specific CPS 2 compliance target, NorthWestern Witness Tabors produced multiple calculations based on a range from the minimum CPS 2 compliance level of 90% up to 98%.[229] Staff argues that their CPS 2 compliance target of 90% is sufficient since, as an absolute-value based average of up and down demand values, it would provide a cushion above the minimum amount of capacity necessary to maintain moment-to-moment system balance.[230] BPA, LCG, and Central Montana argue that a CPS 2 compliance target of 95% provides the right margin of error for NorthWestern to successfully comply with CPS 2. BPA notes that in *Westar*, the Commission approved the use of a CPS 2 standard that was calculated to meet CPS 2 95% of the time to determine the balancing authority's reserve requirements.[231]

107. I agree that, based on the Commission's acceptance of a CPS 2 compliance target of 95 % in *Westar*, NorthWestern's numerator is reasonably based on a 95% CPS 2 compliance target, as set forth by LCG Witness Dauphinais, to allow it an adequate margin of error.

6. **Absolute Average**

108. Staff is the sole party to advocate for the use of an absolute average, while the other parties separately measure regulation up capacity and regulation down capacity.[232] Staff argues that an absolute average helps to avoid confusing regulation up and regulation down (as Dr. Tabors initially did, but later corrected), as well as provides for a margin of error for compliance with CPS 2 since it treats both up and down variations as possible drivers of ACE.[233] Staff also argues that an absolute value methodology is required by the Commission's orders in *Kentucky Utilities Co.* and *Allegheny Power Service Corp.* because they both use an absolute-value based average calculation of load variation.[234]

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[229] Ex. NWE-19 at 15-16.

[230] Staff Initial Br. at 17 (citing Ex. S-20 at 15).

[231] BPA Initial Br. at 8-9 (citing *Westar*, 130 FERC ¶ 61,215, fn 14).

[232] Staff Initial Br. at 14-15.

[233] *Id.* (citing Ex. S-20 at 14).

[234] *Id.* (citing *Kentucky Utilities*, 85 FERC ¶ 61,274; *Allegheny Power*, 85 FERC ¶ 61,275).

109. I find that Staff's use of absolute averages to calculate NorthWestern's Regulation capacity needed to comply with CPS 2 requirements would provide a sufficient margin of error and would also help avoid confusion. However, the use of an absolute average is not mandated by Commission precedent. Similar to the discussion above concerning whether *Kentucky Utilities Co.* and *Allegheny Power Service Corp.* factually apply in this case, the Commission mandated that the inter-hour Load Following methodology should be used in the absence of any data, and this methodology clearly uses the average hourly load deviations from FERC Form 714. In this case, NorthWestern has provided enough data so that the inter-hour Load Following methodology is not necessary. I find that the choice of Dr. Tabors and Mr. Dauphinais to separately measure regulation up capacity and regulation down capacity results in a just and reasonable process in designing a Schedule 3 rate.

7. <u>Schedules 3, 4, and 9</u>

110. Staff is the sole party to disagree with the inclusion of the costs of capacity for energy imbalances in Schedule 3, and instead, argues that these costs should be properly classified within Schedules 4 and 9.[235] Staff argues that Schedule 3 Service is only for the balancing of moment-to-moment and instantaneous variations between generation and load within the course of an hour.[236] Whereas, the hourly balancing of scheduled generation with actual load, and actual generation with scheduled generation, reflects the provision of service under OATT Schedules 4 and 9, respectively.[237]

111. At hearing, Dr. Tabors admitted that his study includes both (1) "capacity used to provide service which makes up the difference between the scheduled and actual delivery of energy to load located within NorthWestern's control area," and (2) "capacity used to make up for the difference between the output of generators located in NorthWestern's control area and the delivery schedule from those generators to load."[238] As such, Staff contends that such costs should be properly classified as Energy Imbalance Service[239] and Generator Imbalance Service, respectively.[240]

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[235] *Id.*

[236] *Id.* at 18 (citing *Kentucky Utilities.*, 85 FERC at 62,108).

[237] *Id.*

[238] Tr. 362:6-23 (Tabors).

[239] "Energy Imbalance Service is provided when a difference occurs between the scheduled and the actual delivery of energy to a load located within a Control Area over a single hour." Staff Initial Br. at 18 (citing *Preventing Undue Discrimination and*

(continued…)

112. Staff argues that if these services were classified under Schedule 3, the Commission's definitional validity would be at risk since NorthWestern would be allowed to comply with CPS 2 solely through Schedule 3 service.[241] To rebut NorthWestern's argument that these charges are separated only when there is a risk of double recovery, Staff argues that NorthWestern did not provide any specific filing or data, such as hour-ahead scheduling data, to ensure double recovery is not a possibility.[242] In his analysis, Staff Witness Ballard separates these imbalance capacity costs from NorthWestern's Schedule 3 service.[243]

113. NorthWestern seeks to rebut Staff's position by arguing that in Order No. 890, the Commission agreed that a transmission provider may seek permission to levy a separate demand charge under Schedule 4, provided the utility did not receive a double recovery:

> If the transmission provider elects to have separate demand charges to recover the cost of holding additional regulation reserves for meeting imbalances, the Commission stated that the transmission provider should file a rate schedule and demonstrate that these charges do not allow for double recovery of such costs. With regard to the realtime regulation burden imposed by merchant generation, the Commission stated that transmission providers could propose, on a case-by-case basis, separate regulation charges for generation resources selling out of the control area. The Commission concluded that *the other demand costs of providing*

Preference in Transmission Service, Order No. 890-B, 123 FERC ¶ 61,299 at 63,075 (2008)).

[240] "Generator Imbalance Service is provided when a difference occurs between the output of a generator located in the Transmission Provider's Control Area and a delivery schedule from that generator to…another Control Area or…a load within the Transmission Provider's Control Area over a single hour." Staff Initial Br. at 18 (citing Order No. 890-B, 123 FERC ¶ 61,299 at 63,077).

[241] *Id.* at 19.

[242] Staff Initial Br. at 20.

[243] *Id.* (citing Ex. S-20 at 30-32).

> *imbalance service are already provided under Schedule 3*, 5, and 6 charges.[244]

NorthWestern explains that typically the demand costs of providing imbalance service are covered under Schedule 3. Since these demand costs can also be placed in Schedule 4, the Commission sought to prohibit the double recovery of capacity services under Schedules 3 *and* 4.[245]

114. NorthWestern further argues that as a balancing authority it is required to provide capacity to cover all within-the-hour deviations between generation and load, and since Schedules 4 and 9 do not have capacity components, the capacity associated with correcting divergences between generation and load is usually recovered through Schedule 3.[246] Whereas the energy costs associated with hourly imbalances are charged through Schedules 4 or 9.[247]

115. NorthWestern contends that since transmission providers can charge Schedule 3 customers for the capacity needed to cover energy imbalances, they have felt little need to seek permission to do so separately through Schedule 4.[248] Indeed at hearing, Staff Witness Ballard conceded that NorthWestern would be the first utility to his knowledge to file and gain Commission approval for a demand charge under Schedule 4.[249] BPA adds that Schedule 3 is the only schedule in the *pro forma* OATT that addresses the capacity needed by a balancing authority to meet the within-hour variations of load.[250]

116. Central Montana and MCC agree with NorthWestern that it has limited opportunities for collection under its OATT,[251] and both parties argue that in a future

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[244] NWE Initial Br. at 18 (citing Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 690 (emphasis added)).

[245] *Id.*; *see also* Tr. 775:3-11 (Ballard).

[246] NWE Reply Br. at 10.

[247] *Id.* at 11.

[248] NWE Initial Br. at 19.

[249] Tr. 775:3-11 (Ballard).

[250] BPA Initial Br. at 13-18; Ex. BPA-003 at 6.

[251] NorthWestern Proposed Finding of Fact 25 (citing Ex. NWE-35 at 3-5); CMT Reply Br. at 9.

filing NorthWestern should probably adopt an additional ancillary service schedule to its OATT to modify its handling of energy imbalance so that it can capture the costs of operating those resources appropriately.[252] However, Central Montana believes that Schedule 3 customers should not be penalized for NorthWestern's failure to properly structure its OATT.[253] In *Entergy Services, Inc.*, the Commission found that utilities have discretion as to the rate filings they make, and therefore the utility, not the customers, must bear the risk of filing an inadequate rate.[254]

117. I find that NorthWestern is entitled to be compensated through Schedule 3 for all capacity associated with energy imbalance services, i.e. the capacity necessary to cover the difference between scheduled generation and actual load. In Order 890, the Commission clearly recognized that the "demand costs of providing imbalance service are already provided under Schedule 3, 5, and 6 charges."[255] NorthWestern seeks to recover its demand costs for energy imbalance service under Schedule 3, which as BPA explains above clearly allows for the recovery of capacity costs. Although the ideal amount of data has not been produced in this case, I find by a preponderance of the evidence that currently there is not a risk of double collection for NorthWestern to receive compensation for capacity associated with energy imbalance service under Schedule 3.[256]

118. Indeed, the Commission's concern regarding the potential double collection of Schedule 3 capacity costs does not exist in the context of this case. The cited language from Order 890 represents the inverse of the situation at hand. The Commission in Order 890 emphasized that it would scrutinize a filing by an electric utility where it was seeking to implement a capacity charge in the historically "energy only" Schedule 4 rate. Ostensibly, this is because the Imbalance related capacity costs were already being provided or collected within Schedule 3 rates.[257]

119. It is telling that LCG, a coalition comprised of seven large industrial customers who receive Schedule 3 service from NorthWestern and who will ultimately be

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[252] MCC Reply Br. at 12; CMT Reply Br. at 9.

[253] CMT Reply Br. at 9-10.

[254] *Id.* (citing *Entergy Services, Inc.*, 109 FERC ¶ 61,095 at P 24 (2004)).

[255] Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 690.

[256] This ruling is strictly based on the record in this proceeding as applied to NorthWestern's proposed rate.

[257] *See* Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 690.

responsible for these costs, did not contest this issue.[258] As Central Montana explains, Staff's overly rigid interpretation would actually penalize NorthWestern's customers who rely on the provision of this service.[259] I conclude Central Montana's comment should not be overlooked in a just and reasonable determination for NorthWestern's Schedule 3 rate. Consequently, I find Staff's forcefully rigid adherence to a regulatory ideal, for regulation's sake, is not in the best interest of NorthWestern and its Schedule 3 customers under these circumstances. I find little purpose served in requiring NorthWestern to comply with Staff's proposal.

120. Indeed, Staff does not dispute that NorthWestern's Schedule 3 customers receive a benefit from imbalance capacity, and a burden related to this benefit is imposed on NorthWestern. Allowing NorthWestern's customers to pay for a service from which they draw a benefit, and allowing NorthWestern to charge these same customers for the burden this service imposes, reflects the basic cost causation principles that underlie the Commission's work. The seminal recitation of these principles was provided by the Seventh Circuit Court of Appeals in *Illinois Commerce Commission v. FERC*, wherein it stated:

> [A]ll approved rates [must] reflect to some degree the costs actually caused by the customer who must pay them. Not surprisingly, we evaluate compliance with this unremarkable principle by comparing the costs assessed against a party to the burdens imposed or benefits drawn by that party.[260]

121. At bottom, Staff agrees that compensation is owed for this service and that customers will benefit from it, but argues that NorthWestern simply held out the wrong bucket for collection in its filing. I find that Staff's interpretation is not adequately supported by Commission precedent. To the contrary, the Commission in Order 890 clearly explained that capacity associated with energy imbalance service can be provided through Schedule 3.[261] Accordingly, NorthWestern may be compensated through Schedule 3 for capacity costs associated with energy imbalance service.

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[258] Ex. LCG-2 at 4.

[259] CMT Reply Br. at 9-10.

[260] *Ill. Commerce Comm'n v. FERC*, 576 F.3d 470, 476 (7th Cir. 2009) (internal citations and quotations omitted) (emphasis added).

[261] Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 690.

Issue No. 2 (b): Is NorthWestern's proposed allocation based on a denominator of 105 just and reasonable?

A. Positions of the Parties

1. NorthWestern

122. The Company contends that 105 MW is the maximum sustained amount of firm Regulation service that NorthWestern can reliably provide from DGGS. There are three 50 MW units at DGGS that are available to provide Regulation service. NorthWestern states that it cannot provide reliable firm Regulation service necessary to satisfy NERC Reliability Standards unless it keeps one of its three units in reserve as an operational spare.

123. NorthWestern denies that the 150 MW denominator supported by LCG and Staff is appropriate. NorthWestern argues that any increase of the denominator would create a rate mismatch, resulting in NorthWestern being unable to recover its revenue requirement. The 105 MW denominator supported by NorthWestern represents the expected total regulating reserves needed to serve traditional load and wind generation. The 60 and 45 figures which make up the numerator reflect the relative contributions of each of the two uses—traditional load and wind generation--to the 105 MW of total regulating reserves. The numerator and the denominator match, consistent with traditional ratemaking principles.[262]

124. NorthWestern further argues that there is no legitimate reason for using a denominator greater than 105 MW. According to NorthWestern, the rationale for Staff and LCG supporting a denominator of 150 MW is that: (1) only a small portion of DGGS is "used and useful" for Regulation service; (2) the nameplate ratings for all three DGGS units is 150 MW; and (3) NorthWestern can use the portion of DGGS allegedly not used for Regulation service to supply other services. NorthWestern seeks to rebut Staff's and LCG's positions in support of 150 MW by arguing that the testimony showed that all three DGGS generators are dedicated to providing firm Regulation service.[263] NorthWestern concludes that therefore there is no surplus DGGS capacity that can be sold for other purposes on a firm basis. NorthWestern alleges that even though one of DGGS' three

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[262] In support of its position NorthWestern cites *Midwest Indep. Transmission Sys. Operator, Inc.*, 125 FERC ¶ 61,156 at P 30 (2008).

[263] NWE Initial Br. at 25; Ex. NWE-20 at 3-4; Ex. NWE-21 at 3.

generators serves primarily as a reserve unit, NorthWestern is still entitled to recover the costs of that unit from the Schedule 3 customers. [264]

125. NorthWestern also argues that the 150 MW supported by Staff and LCG is erroneous because DGGS cannot even achieve a consistent output of 150 MW. DGGS was not designed to operate at maximum output, it was designed to have the units operate from a set point, with the ability quickly to ramp up or down from that set point to offset ACE.[265]

126. If 150 MW is adopted as the denominator on the theory that NorthWestern will make firm sales of other services from DGGS, NorthWestern would not be able to recoup the revenue requirement for DGGS because those sales would be opportunistic only. NorthWestern would be left in the position of subsidizing its regulation customers for millions of dollars every year. NorthWestern contends that if it becomes able to generate revenue for DGGS in the future by providing other services, it has committed to credit such revenues to the Regulation customers, consistent with Commission policy on opportunity sales.

127. NorthWestern argues in its Reply Brief that using the nameplate capacity for the denominator would cause an inconsistency, since the numerator would be based on one concept (regulating reserves) and the denominator on another (generator nameplate rating). This would deprive NorthWestern of the ability to recover the DGGS revenue requirement from the Schedule 3 customers for whom DGGS was built.

128. NorthWestern further argues that it would not fully recover its cost of service under the approach advocated by LCG and Staff unless three conditions were met: (1) it had surplus capacity from DGGS; (2) it was able to sell such capacity; and (3) the sales revenues equaled the DGGS costs allocated to those sales. LCG's own witness acknowledged that these three conditions may never be satisfied.[266]

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[264] NWE Initial Br. at 26; citing *Louisiana Public Service Comm'n v. FERC*, 174 F. 3d 218, 228-29 (D.C. Cir. 1999) (affirming FERC's finding that reserve generating units are "used and useful" even when not it service); *Illinois Cities v. FERC*, 670 F. 2d 187, 200-201, n.59 (D.C. Cir. 1981 (sustaining inclusion of 30.2% excess capacity in rate base in the absence of any showing of managerial imprudence).

[265] NWE Initial Br. at 28; Tr. 304:7-9 (Rhoads); 528:8-19 (Dauphinais).

[266] NWE Reply Br. at 22; Tr. 507-1:4 (Dauphinais).

129. NorthWestern addresses LCG's argument that the Company's crediting proposal does not give NorthWestern an incentive to fully utilize any surplus capacity.[267] NorthWestern counters that the MPSC has approved the crediting approach.[268] NorthWestern points out that since retail customers pay 80% of the DGGS revenue requirement, the MPSC can reasonably be expected to insure that NorthWestern markets any surplus capacity, if and when it is available.

2. LCG

130. LCG believes that NorthWestern's proposed denominator of 105 MW (60 MW plus 45 MW) is erroneous. The denominator should reflect the full nameplate capacity of DGGS units which is 150MW. LCG Witness Dauphinais, supported by Staff Witness Patterson, contend that OATT customers are not, nor should they be, responsible for guaranteeing NorthWestern's recovery of the entirety of its investment in DGGS. LCG contends that by using 150 MW as the denominator and using a per MW value for developing the revenue requirement, Schedule 3 customers will pay a rate based on "the fairly traceable costs of actually providing Regulation service to them, no more or less."[269]

131. LCG argues that under NorthWestern's crediting approach, Regulation service customers would underwrite the DGGS investment, whether or not it is used and useful to them, and would only see their costs go down if there were additional revenues generated by sales at wholesale that were then credited back.[270] The Commission did not authorize the construction of DGGS as a generation source dedicated to providing Regulation service.[271] LCG quotes Staff Witness Patterson on this point:

> While NorthWestern is at liberty to choose to operate DGGS at less than its full capacity, there is no reason why NorthWestern's customers should pay for services obtained from DGGS under any rate structure other than that which

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[267] NWE Reply Br. at 23; LCG Initial Br. at 19.

[268] NWE Reply Br. at 23; Ex. NWE-27.

[269] LCG Initial Br. at 18; Ex.S-1 at 11; Ex. LCG-10 at 38.

[270] LCG Initial Br. at 18-19.

[271] *See NorthWestern Corp.*, 121 FERC ¶ 61,204 (2007).

> assumes DGGS can provide the capacity for which it is rated, i.e., 150 MW.[272]

132. LCG Witness Dauphinais and Staff witnesses testified that the value of DGGS to NorthWestern is not limited to 105 MW, but extends to the full nameplate capacity of 150 MW because, in addition to providing Regulation service, the DGGS units can be deployed to provide a number of other services, including the following:[273]

> Meeting planning reserve margin requirements, providing Reactive Supply and Voltage Control from Generation Sources or Other Sources Service (if equipped with Automatic Voltage Regulation), and black-starting the Company's transmission system in the event of system blackout, providing electric energy to offset curtailment during generator deficiencies or system emergencies, and providing electric energy to serve bundled retail customers or to support spot market off-system economically-favorable energy sales, or providing Spinning Reserve Service or Supplemental Reserve Service.[274]

LCG contends that whether or not these services are needed today or in the future, the ability of DGGS to provide services with intrinsic value to NorthWestern and to its customers should be factored into the allocation of fixed costs.[275]

133. LCG maintains that

> Transmission Providers typically use a pool of generating units in excess of their total Regulation service capacity need to reliably meet NERC CPS requirements, but this does not increase a Transmission Provider's total capacity need for serving its native load customers. Transmission Providers need only ensure that a certain portion of their total generation capacity is capable of being ramped under AGC

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[272] LCG Initial Br. at 19; Ex. S-1 at 10-11.

[273] LCG Initial Br. at 22; Ex. LCG-10 at 37; Ex. S-1 at 10.

[274] LCG Initial Br. at 22; Ex. LCG-2 at 17-18; Ex. NWE-22 at 14; Ex. NWE-21 at 3-4.

[275] LCG Initial Br. at 22.

> (Automatic Generation Control). Schedule 3 Regulation service capacity rates generally only reflect the total generation capacity needed to meet total Regulation service capacity need.[276]

134. In its Reply Brief, LCG points out that NorthWestern has taken inconsistent positions. According to LCG, NorthWestern claims "DGGS was not intended to have all three units operating all the time."[277] At the same time, NorthWestern contends that "all three DGGS generators are used and useful, as they are all dedicated to providing firm Regulation service."[278] LCG argues that NorthWestern cannot have it both ways; either the generators are used and useful or they are not. To the extent the generators are not used and useful in providing Regulation service there is no basis for assigning cost responsibility to Schedule 3 Regulation service customers.

3. MCC

135. MCC contends that NorthWestern's proposed allocation based on a denominator of 105 MW is not just and reasonable. MCC alleges that NorthWestern's argument that it needs an operating spare is a "convenient rationalization."[279] In MCC's view, NorthWestern's 105 MW proposal is grounded on its position that 60 MW is the traditional load Regulation requirement and 45 MW is an estimate of future regulation demand attributable to wind generation.

136. MCC reasons from the starting point that DGGS has an altitude adjusted value of 150 MW and that each of the generators must operate at a minimum load of 3.5 MW in order to provide Regulation service.[280] MCC proposes that it is therefore appropriate to subtract a total of 10.5 MW (3.5 MW for each of the three units) from the denominator to account for the fact that the DGGS units have a minimum operating capability which cannot be used to provide Schedule 3 Service. MCC recommends that the denominator should be 139.5 MW, based on

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[276] LCG Initial Br. at 24-25; Ex. LCG -10 at 38-44.

[277] LCG Reply Br. at 16, quoting from NWE Initial Br. at 7.

[278] *Id.*; NWE Initial Br. at 25.

[279] MCC Initial Br. at 23.

[280] MCC Initial Br. at 24-25; Tr. 288:24-291:5 (Rhoads).

the altitude adjusted nameplate capacity of the DGGS minus the minimum load limitation on each of the three DGGS units.[281]

4. BPA

137. In its prehearing filings BPA supported the position of NorthWestern that the denominator should be 105 MW. Based on testimony from NorthWestern Witness Cashell at the hearing, BPA altered its position and now supports a higher figure for the denominator.[282] BPA quotes from Witness Cashell's testimony that DGGS has an estimated baseload component of "about 7 megawatts with two units operating…".[283] In light of this testimony BPA concludes that the 105 MW denominator proposed by NorthWestern does not include the 3.5 MW baseload component for each generator. Therefore, BPA amends it recommendation to add the 7MW for the baseload component for two generators. BPA supports a denominator of 112 MW rather than the 105 MW proposed by NorthWestern.[284]

5. Central Montana

138. Central Montana argues that NorthWestern has failed to establish any grounds for using less than the nameplate capacity of the DGGS units (150 MW) as the denominator. Central Montana cites the evidence of Staff Witness Patterson who testified that "the nameplate capacity or some slight variation of that has been used since [Order No.] 888 in developing ancillary service charges."[285] Central Montana further relies on *Westar Energy, Inc.,* a case in which "[t]he Commission's acceptance of Westar's proposal [was]…conditioned on Westar revising its calculation to use name place capacity in the derivation of the portfolio-wide regulation requirement percentages when it submits its compliance filing."[286]

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[281] MCC Initial Br. at 24.

[282] BPA Initial Br. at 22-23.

[283] BPA Initial Br. at 23; Tr. at 199-200 (Cashell).

[284] BPA Initial Br. at 23-24.

[285] CMT Initial Br. at 21; Tr. 654:4-7 (Patterson).

[286] *Westar*, 130 FERC ¶ 61,215 at P 40, *order on reh'g.,* 92 FERC ¶ 61,070 (2000).

139. In its Reply Brief, Central Montana takes issue with MCC's contention that the DGGS nameplate capacity (150 MW) should be reduced by the amount needed for minimum operation capability which is 7 MW with two units operating and 10.5 MW with three units operating. According to Central Montana, NorthWestern Witness Cashell admitted at the hearing the 7MW offsets the capacity needs for NorthWestern's retail customers that they would otherwise be required to acquire. Contrary to MCC, Central Montana would assign the cost of the 7 MW or 10.5 MW to retail customers.[287]

140. Central Montana disputes NorthWestern's claim that it may recover the costs of all three DGGS units even if one acts primarily as an operational spare. Central Montana argues that if the capacity of the DGGS is not being used to serve Schedule 3 customers, NorthWestern may not recover those costs from Schedule 3 customers. Central Montana suggests that if NorthWestern's logic is adopted there is no end to the costs the Company could recover, such as installing one or more additional operational spares.[288]

6. <u>Staff</u>

141. Staff contends that NorthWestern's proposed denominator of 105 MW is unjust and unreasonable because it is not an accurate reflection of the total amount of the capacity of DGGS from which NorthWestern can provide service. Staff alleges that NorthWestern is relying upon some nebulous concept of "firmness" to support its claim of only 105 MW as the denominator. Staff argues that (1) there is no basis for the concept of "firmness" in Commission precedent or utility practice or any NERC reliability standard; (2) DGGS has consistently provided 150 MW for use by NorthWestern since it began operations without any negative consequences; and (3) NorthWestern's own witnesses use the term "firmness" in several different and contradictory ways.

142. According to Staff, the Commission has endorsed the calculation of Schedule 3 capacity obligations using generator name plate capacity and that nameplate capacity (or some very slight variation thereof) is the sole method by which ancillary service charges are designed.[289] Staff argues that NorthWestern

[287] CMT Reply Br. at 17-18.

[288] CMT Reply Br. at 18; *NEPCO Mun. Rate Comm.v. FERC*, 668 F.2d 1327, 1333 (D.C. Cir. 1981) ("[R]ate payers should bear only legitimate costs of providing service to them.").

[289] Staff Initial Br. at 35; Tr. 654:4-7 (Patterson).

has not demonstrated that the 105 MW figure they support is somehow more firm than the 150 MW nameplate capacity. Upon cross examination, the NorthWestern witness who testified on this subject was unable to identify a single Commission order or NERC standard that specified what percentage of a nameplate capacity is considered firm.[290]

143. Staff suggests that the number 105 does have one attribute that may have attracted NorthWestern: 105 MW is equal to the 60 MW of wholesale regulation for which the Company has filed plus the 45 MW of retail wind energy that they have already set aside. Thus, the 105 MW figure "permits NorthWestern to recover all remaining unallocated DGGS costs from Schedule 3 customers, rather than only those costs attributable to the provision of Schedule 3 Service."[291]

144. Staff contends that since DGGS can produce 150 MW that amount should be the denominator. NorthWestern's assertion that it must retain one of the three units of DGGS as an "operational spare" in order to reliably provide Schedule 3 Service at all times is without foundation. NorthWestern fails to cite any requirement in CPS 2 or any reliability standard or operational guideline which requires "operational spares" for the provision of Schedule 3 Service. The Commission has uniformly approved the allocation of ancillary services costs based on the nameplate capacity of the facilities involved.

145. Staff cites tests by an independent consulting firm, Vantage Energy Consulting, retained by the Montana Public Service Commission to asses DGGS. Vantage found that the DGGS turbines actually *exceeded* their nameplate capacity, producing slightly greater than 150 MW total for the three units.[292] Staff further alleges that DGGS had 140 MW (or more) of available capacity from which to provide service during every month of 2011.[293]

146. Staff addresses NorthWestern's contention that only two units could be used to provide Regulation service because the third unit must be held as an "operational spare" to insure that Regulation service can be provided on a continuous basis.[294] Staff asserts that on cross examination several NorthWestern

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[290] Staff Initial Br. at 36; Tr. 312-313 (Rhoads).

[291] Staff Initial Br. at 36; Tr. 655:10-16 (Patterson).

[292] Staff Initial Br. at 37; Tr. 335:9-12 (Rhoads); Ex. S-34 at 13.

[293] Staff Initial Br. at 38; Tr. 335-336:13-3 (Rhoads); Ex. S-29 at 3.

[294] Staff Initial Br. at 39; Ex. NWE-20 at 5-6; Ex. NWE-22 at 8.

witnesses conceded that even the 105 MW they consider "firm" cannot be achieved without operating all three units.[295] Staff argues that once NorthWestern uses a unit to provide service, the Company has that unit's full capacity available at its disposal. "NorthWestern may choose to use one of DGGS' units sparingly, but that that does not mean that NorthWestern only has some fraction of that unit's capacity available. Rather, the issue is black and white; if the unit is on, NorthWestern has 50 MW of capacity at its disposal, and it is off, NorthWestern has 0 MW of capacity."[296]

147. In its Reply Brief, Staff responds to NorthWestern's criticism of the use of the nameplate capacity of the turbines. NorthWestern alleges that the use of the nameplate capacity would result in a denominator that is greater that the numerator, leaving some costs of DGGS not allocated to Schedule 3 customers. Staff responds that the purpose of this proceeding is not to allocate all costs of DGGS to Schedule 3 customers. Staff maintains that the denominator must reflect the actual capacity of the DGGS from which NorthWestern can provide service. Failure to do so would result in an allocation of costs to Schedule 3 customers in excess of the amount that is used and useful to them. Staff concludes that the fact that DGGS provides capacity in excess of what NorthWestern requires to provide Schedule 3 service "is the single most important fact in this proceeding."[297] If DGGS has excess capacity NorthWestern has "another product to sell besides regulation."[298]

B. <u>Decision</u>

148. I find that NorthWestern has not met its burden of showing that a denominator of 105 MW is just and reasonable. One of NorthWestern's principal contentions is that it cannot provide "firm" Regulation service without keeping one of its three DGGS generators as an operational spare. NorthWestern's argument is undercut by the evidence provided by Vantage Energy Consulting

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[295] Staff Initial Br. at 39; Tr. 337:8-11 (Rhoads); Tr. 238:6-10 (Cashell).

[296] Staff Initial Br. at 39.

[297] Staff Reply Br. at 19.

[298] *Id.*; Tr. 416:15-23 (Merchant). Staff also notes that NorthWestern currently has on file a Market-Based Rate tariff that permits it to sell any service into many organized markets and to any third party. Staff comments that because the Company has market-based rates the Company may charge whatever level it deems necessary to recover the remaining portion of the DGGS revenue requirement. Ex. S-26.

which was retained by the MPSC to assess DGGS. The Vantage studies show that at the time of the study, February 28, 2011, DGGS turbines exceeded their nameplate capacity.[299] Staff also produced a FERC Form 1 showing that the DGGS had 140 MW or more available capacity to provide service during every month of 2011.[300] None of this evidence of DGGS capabilities beyond 105 MW was controverted by NorthWestern. Furthermore, the Vantage Consulting report was prepared at the request of the MPSC which, according to NorthWestern, supports its 105 MW denominator position.[301]

149. NorthWestern cites no legal support for using less than the nameplate capacity of 150 MW. [302] Staff Witness Patterson testified that nameplate capacity has consistently been used in developing ancillary service charges since Order 888 was issued.[303] While Staff cited no case law to support its position, no party challenged the veracity of Witness Patterson's testimony and I find that she is a credible expert witness. Central Montana cites *Westar Energy, Inc.* which does offer support for the use of the nameplate capacity.[304]

150. In finding that the denominator should reflect the nameplate capacity of 150 MW I rely primarily upon the case presented by Staff, and in particular, Witness Patterson's testimony regarding nameplate capacity used in designing electric service rates, and Staff's evidence demonstrating the ability of DGGS to perform at, above, or near the 150 MW level. NorthWestern's presentation has another serious flaw in that the Company relies upon a capacity figure for rate

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[299] Ex. S-34 at 13.

[300] Ex. S-29 at 3.

[301] I note that although MPSC did not address the denominator issue in their post-hearing briefs, NorthWestern states that MPSC supports its 105 MW denominator position. NWE Reply Br. at 18 ("Although NorthWestern's 105 MW denominator is supported by the MPSC…").

[302] NorthWestern does cite *Midwest Indep. Transmission Sys. Operator, Inc.*, (*MISO*), 125 FERC ¶ 61,156, P 30 (2008) ("finding no mismatch when the components in the numerator matched the definition of the summed components in the denominator"). NWE Initial Br. at 24. As argued by LCG, the *MISO* case is distinguishable on its facts. LCG Initial Br. at 19.

[303] Tr. 654:4-7 (Patterson).

[304] *Westar Energy, Inc.*, 130 FERC ¶ 61,215 at P 40.

design that inflates the amount of costs attributable to Rate Schedule 3 Regulation Service by using the now discredited 60 MW capacity level. Indeed, NorthWestern's 105 MW divisor figure is based primarily on the 60 MW Regulation capacity argument discussed above in Issue 2 (a) which I rejected as being without merit for rate design for NorthWestern's Schedule 3 service. Consequently, there is no rationale for supporting any approach which uses or includes the 60 MW level for any rate calculation here.

151. Further, I specifically make no finding with respect to LCG's argument that the mere capability of providing additional services from the DGGS generators provides intrinsic value to NorthWestern and to its customers that should be factored into the allocation of fixed costs. That proposal is best left for another day, if and when, those additional services are being considered by these parties or the Commission.

<u>Issue No. 3: Is NorthWestern's proposed imposition of an energy rate charge just and reasonable?</u>

A. <u>Positions of the Parties</u>

1. <u>NorthWestern</u>

152. The Company offers three major arguments in favor of its proposal to impose an energy rate charge upon Schedule 3 customers.[305] NorthWestern contends that (1) fuel is consumed in providing Regulation service under Schedule 3; (2) such costs are properly assessed to Schedule 3 customers; and (3) recovery from OATT customers under Schedule 4 as proposed by Staff and other parties, would depart from cost causation principles and result in subsidization of Schedule 3 customers.

153. NorthWestern relies, in part, on the testimony of its witness, Steven Merchant. Witness Merchant testified that "typical" FERC cases where energy costs were recovered under Schedule 4 present very different facts from the instant case. According to the NorthWestern witness, the utilities in the cases relied upon by Staff and LCG involved fleets of generators making it nearly impossible to

[305] NorthWestern's proposed Monthly Energy Rate calculation is developed by multiplying the plant's total variable costs (reduced by an energy value credit) by the Company's proposed allocation ratio of 60/105. The reduced value would then be divided by the rolling 12 CP billing determinants for transmission customers taking Regulation service. Ex. NWE-1 at 20-21.

identify which generator was used to provide regulation or other services.[306] Mr. Merchant points out that under those circumstances, the Commission uses Schedule 4 to calculate a proxy incremental cost using the last 10 MW dispatched in the hour. NorthWestern states that in this case there is no difficulty in identifying the unit providing Regulation service, since it can only come from DGGS.

154. NorthWestern argues that the Commission has not prohibited charging energy costs under Schedule 3, and moreover, the Commission has approved ancillary services rates with charges for both capacity and energy. In support of this argument NorthWestern cites several cases, including *Southern California Edison Co.* (*SCE*).[307]

155. NorthWestern contends that Schedule 4 customers only pay an energy charge when their *average* load over the course of an hour exceeds their *average* generation over that same time.[308] Even when there is no net energy consumed by Schedule 4 customers over the course of an hour, NorthWestern is still burning fuel to generate the set point for which DGGS provides regulation up and down service. NorthWestern contends that it has no practical means of recovering these fuel costs other than under Schedule 3.[309] According to NorthWestern, denying it recovery is at odds with the Commission's Order 764.[310]

156. NorthWestern also argues that shifting to Schedule 4 would lead the Schedule 4 customers to subsidize the Schedule 3 customers. NorthWestern contends that customers who take Schedule 4 service are not the same customers who take Schedule 3, for example, BPA.[311]

157. NorthWestern further contends that it could not recover its past energy costs from the years 2011-2012 under Schedule 4. As written, NorthWestern's

[306] NWE Initial Br. at 34; Ex. NWE-15 at 18.

[307] *Southern California Edison Co., et al.,* 86 FERC ¶ 63, 014 at 65,146-47 (1999), *aff'd in part and rev'd in part, Southern California Edison Co.,* 92 FERC ¶ 61,070 (2000); *Allegheny Power System, Inc,* 80 FERC ¶ 61,143 at 61,540 (1997).

[308] NWE Initial Br. at 34; Ex. NWE-22 at 43; Ex. NWE-18.

[309] NWE Initial Br. at 34; Ex. NWE-22 at 42; Tr. 273:19-25 (Cashell).

[310] NWE Initial Br. at 34; Order No. 764, 139 FERC 61,246 at P 316.

[311] NWE Initial Br. at 34-35; NWE-22 at 43; Tr. 147:19-148:7 (Cashell).

Schedule 4 does not allow DGGS energy costs to be passed to Schedule 4 customers; it only allows recoupment of charges leveled by a separate third party provider of imbalance service.[312] NorthWestern rejects Staff's and LCG's suggestion that NorthWestern should make the appropriate Section 205 filing to modify its OATT Schedule 4.[313] NorthWestern believes it would "get only prospective relief, leaving it on the hook for past energy costs".[314]

158. In NorthWestern's Reply Brief, the Company contends that its effort to recover the fuel costs of operating DGGS through Schedule 3 is supported by MCC and BPA.[315] NorthWestern reiterates that it's Schedule 4 does not permit the DGGS fuel costs to be charged under that schedule and that the Commission has approved the inclusion of fuel costs in Schedule 3, again relying on the *SCE* case cited above.[316] NorthWestern again quotes the following language from Order 764 "resources are often dispatched in the middle of their operating range to allow the generator to provide regulation-up as well as regulation-down and as a result forego other opportunities. Not to allow compensation would create a barrier to the provision of services by frustrating the recovery of legitimate costs." [317]

159. Finally, NorthWestern discusses MCC's suggestion that NorthWestern should explore amending its Schedule 4 and adding a Schedule 9 when NorthWestern makes its Order No. 764 compliance filing.[318] NorthWestern responds that it already has a Schedule 9. NorthWestern offers, however, to evaluate the idea of amending Schedule 4 after its makes its compliance filing under Order No. 764.[319] NorthWestern adds that in making that evaluation it will need to take into account the fact that BPA, one of its largest Schedule 4 customers, does not take Schedule 3 service from NorthWestern. NorthWestern

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[312] NWE Initial Br. at 35; NWE-18.

[313] NWE Initial Br. at 35; Ex. S-1 at 15.

[314] NWE Initial Br. at 35; Ex. S-1 at 15.

[315] NWE Reply Br. at 23.

[316] Ex. NWE-15 at 50:2-51:4; Ex. NWE-18; Tr. 144:14-25 (Cashell).

[317] NWE Reply Br. at 24 (quoting Order No. 764, 139 FERC ¶ 61,246 at P 316).

[318] NWE Reply Br. at 24; MCC Initial Br. at 25-26.

[319] NWE Reply Br. at 24.

claims it is not sure how it can modify Schedule 4 to recover some of the DGGS fuel costs without having BPA subsidize Schedule 3 customers.[320]

2. LCG

160. LCG states that it opposes NorthWestern's proposed imposition of an energy rate charge through Schedule 3 rates since that approach is contrary to cost causation principles.[321] LCG agrees with Staff Witness Patterson that NorthWestern's claim is inconsistent with Commission policy and ratemaking practices. LCG asserts that energy costs associated with Regulation capacity have been recovered under Schedule 4 since its inception.[322]

161. LCG argues that Schedule 3 customers as a group do not cause the energy costs to be incurred. As a capacity service, Regulation service rates should reflect only the fixed capacity costs of service.[323] Regulation service is intended to be, and historically has been, energy neutral to the system.[324] Schedule 4 allocates the costs associated with energy imbalances to the respective transmission customers that cause them. "NorthWestern's proposed Schedule 3 energy rate would blanket all unbundled transmission customers with the responsibility for DGGS energy-related costs, regardless of an individual customer's net imbalance position." [325] LCG Witness Dauphinais and Staff Witness Patterson agree that DGGS variable energy costs (including fuel costs) are more appropriately recovered through NorthWestern's Schedule 4 energy imbalance service for OATT customers and its state-jurisdictional bundled retail rate tracker for fuel costs.[326]

162. In its Reply Brief LCG quotes from Order 764 with respect to the relationship between Schedule 3 and Schedule 4 as follows:

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[320] NWE Reply Br. at 24.

[321] LCG Initial Br. at 29; Ex. LCG-1; Ex. S-13.

[322] LCG Initial Br. at 30; Ex. S-13 at 15.

[323] LCG Initial Br. at 30; Ex. LCG-1 at 18.

[324] LCG Initial Br. at 30; Ex. LCG-1 at 17-19.

[325] LCG Initial Br. at 30; Ex. LCG-7 at 34-39.

[326] LCG Initial Br. at 31; Ex. LCG-7 at 36; Ex. S-13 at 14.

> Regulation service and energy imbalance service while different in function, are complementary services through which public utility transmission providers maintain their systems' balance and recover both the capacity (Regulation service) and energy (energy imbalance service) costs of doing so from transmission customers serving load on their systems.[327]

163. In its Reply Brief, LCG also responds to NorthWestern's reliance on the *SCE* case.[328] LCG argues that *SCE* must be read in the context in which it arose since the Commission was responding at the time to the "skyrocketing" prices in ancillary services market in California during the summer of 1998.[329] LCG contends that because of these extraordinary market conditions the Commission granted market based rate authority to all entities providing ancillary services in California, including SCE.[330] Although SCE adopted a market based rate it also had cost-based bid caps which were at issue for some period. LCG contends that it was with respect to the discrete bid caps that the Commission permitted the recovery of an energy charge on an interim basis with the knowledge that these rates were already scheduled to be revised to a market based rate.[331]

164. LCG seeks to rebut NorthWestern's assertion that fuel costs are incurred in generating a set point, that these costs benefit Schedule 3 customers, and that Schedule 4 does not encompass the energy costs associated with the generation of a set point. LCG rejects this argument as a red herring since LCG and Staff have explained that energy generated below the set point is absorbed into the NorthWestern system for the benefit of NorthWestern's retail customers. LCG asserts that retail customers and not FERC jurisdictional customers, should pay for both the capacity costs and the energy costs below the set point.

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[327] LCG Reply Br. at 23; Order No. 764 at P 237.

[328] LCG Reply Br. at 23; *Southern California Edison Co., et al.,* 86 FERC ¶ 63,014 at 65,146-47 (1999) *aff'd in part and rev'd in part, Southern California Edison Co*., 92 FERC ¶ 61,070 (2000).

[329] LCG Reply Br. at 23; *SCE* at 65,147.

[330] *Id.*

[331] LCG Reply Br. at 23-24.

3. MCC

165. MCC supports NorthWestern's efforts to recover its fuel and variable operation and maintenance costs through NorthWestern's Schedule 3 rates for Regulation and Frequency Response service. MCC adds the caveat that "the specifics of NorthWestern's proposed treatment of these costs requires modifications."[332] MCC quotes the same excerpt from Order No. 764 that is quoted above by NorthWestern.[333] MCC suggests that NorthWestern's proposed energy charge reflects an "enormous opportunity cost imposed by its choice to supply Regulation and Frequency Response ancillary service through a generating facility specifically dedicated to that purpose."[334]

166. Alternatively, MCC suggests that rather than imposing an Energy Rate Charge under Schedule 3, energy charges could be allocated to energy imbalances under Schedule 4. MCC acknowledges that Schedule 4 would have to be amended in light of the fact that its current language speaks only to the pass-through of cost incurred from third-party provision of imbalance service. MCC also suggests that NorthWestern add a Schedule 9 to its OATT.[335]

167. MCC expresses its concern that if fuel costs are recovered under Schedule 4 or 9 it could result in shifting costs to retail loads "without regard to whether NorthWestern's Montana retail loads actually benefit from any of the energy that DGGS is required to produce in order to provide Regulation and Frequency Response Service."[336] MCC asserts that the purpose for constructing DGGS, as accepted by the MPSC, was the provision of Regulation and Frequency Response Service and not for energy support for retail loads.[337]

4. Central Montana

168. Central Montana maintains that NorthWestern's proposal to recover energy costs through Schedule 3 is inconsistent with Commission precedent,

[332] MCC Initial Br. at 24; Ex. MCC-1 at 25:9-27:9.

[333] NWE Reply Br. at 24.

[334] MCC Initial Br. at 25.

[335] MCC Initial Br. at 25.

[336] MCC Reply Br. at 10-11.

[337] MCC Reply Br. at 11; Ex. NWE-4 at ¶ 219.

NorthWestern's current and past practices, and virtually every other transmission provider's Schedule 3 rates, and therefore should be rejected.[338] Central Montana notes that in Order 764, the Commission defined Schedule 3 service as the "capacity reserve necessary for the continuous balancing of resources (generation and interchange) with load to maintain a scheduled interconnection frequency of 60 cycles per second (60 Hz)."[339]

169. Central Montana argues that the principal case upon which NorthWestern relies in support of its Schedule 3 argument, the *SCE* case discussed above, is distinguishable, as demonstrated by LCG.[340] Central Montana points out that among the distinctions between the cases, SCE was operating in an ancillary services auction with market-based rates. Central Montana comments that NorthWestern's proposal to recover energy costs through Schedule 3 in a non-RTO setting is so novel that there is very little Commission precedent on point. Central Montana adds that NorthWestern has ample discretion as to the rate filings it makes and is free to restructure its OATT and seek to recover energy costs through other means.[341]

170. Central Montana adds that NorthWestern's business practices support limiting Schedule 3 to capacity costs. NorthWestern's current self-supply agreement with BPA is energy neutral.[342] Furthermore all of NorthWestern's previous third-party contracts for Regulation service were energy neutral.

171. Central Montana makes the point that NorthWestern is not comparable to an ISO or RTO, and argues that generators located in an RTO market are compensated differently from generators located in bilateral markets.[343]

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[338] CMT Initial Br. at 25.

[339] *Id.* (quoting Order No. 764, 139 FERC ¶ 61,246 at P 235).

[340] CMT Initial Br. at 26-27; *Westar Energy, Inc.*, 130 FERC ¶ 61,215 at P 40 (2010), *order on reh'g*, 137 FERC ¶ 61, 142 (2011).

[341] Central Montana cites *Entergy Services, Inc.*, 109 FERC ¶ 61,095 at P 24 (2004).

[342] Ex. LCG-1 at P 8.

[343] CMT Reply Br. at 21; Tr. 605:24-606:7 (Dauphinais).

5. <u>BPA</u>

172. BPA asserts that arguments on this issue are misdirected because the issue has been misstated. BPA suggests that the issue is whether NorthWestern's proposal to include in the Schedule 3 rate the variable cost of fuel is just and reasonable? According to BPA, NorthWestern is not proposing an energy rate charge, which has been opposed by Staff, LCG, and Central Montana on the ground that Schedule 3 encompasses capacity charges only.[344] BPA supports what it describes as NorthWestern's fuel charge proposal.

173. BPA protests that it is a self-supplier of Schedule 3 services, but it does pay NorthWestern's Schedule 4 rate.[345] BPA states that it receives no benefit from NorthWestern's operation of DGGS. Accordingly, BPA contends that it should not be required to pay a portion of the fuel cost for the operation of DGGS. When BPA self-supplies Schedule 3 services it is already incurring its own fuel costs. BPA concludes that the proposal to include NorthWestern's fuel costs in Schedule 4 would result in charging BPA and any other self-suppliers for DGGS fuel costs that do not provide any benefit to them.[346]

6. <u>Staff</u>

174. Staff maintains that NorthWestern errs in seeking to recover the fuel costs associated with DGGS through a Monthly Energy Charge under Schedule 3.[347] As a preliminary matter, Staff points out that NorthWestern removed the variable O&M costs from its original proposed Monthly Energy Charge rate formula in acknowledgement that these cost were properly classified as demand related and should be collected through Schedule 3.[348] Staff also notes that NorthWestern continued to include the component VOM/12 in its proposed Monthly Energy Rate and recommends that NorthWestern delete it from the formula.[349]

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[344] BPA Initial Br. at 24; Tr. 139:1-17 (Cashell).

[345] BPA Initial Br. at 25; Tr. 148:2-7 (Cashell).

[346] BPA's Reply Brief generally reiterated the same arguments in its Initial Brief.

[347] Staff Initial Br. at 40; Ex. NWE-1 at 20.

[348] Staff Initial Br. at 42; Ex. S-1at 15, Ex. S-38 at 3, Ex. NWE-34 at 7.

[349] Staff Initial Br. at 42; Ex. S-37 at 7.

175. Staff contends that Schedule 3 Service is a capacity service and not an energy service.[350] Staff explains that Schedule 3 Service is provided on a moment-to-moment basis. Balancing Areas allocate a fixed amount of capacity whose output can be controlled on an automated basis. Schedule 3 Service, due to the fact that it involves absorbing as well as providing generation to balance load, should theoretically result in no net provision of energy. Staff suggests that to the extent NorthWestern is providing more energy than it is absorbing with respect to delivery of energy to load, it should recover the cost of the overage through Schedule 4, Energy Imbalance Service.[351] Staff relies on the testimony of Staff Witness Patterson who stated that since the Commission issued Order No. 888, capacity costs have been recovered under Schedule 3, Regulation and Frequency Response Service, while the costs associated with the complementary energy have been recovered under Schedule 4, Energy Imbalance Service.[352]

176. Staff Witness Patterson also recommends that if NorthWestern's OATT Schedule 4 does not currently provide for the recovery of Energy Imbalance costs, NorthWestern should make the appropriate Section 205 filing seeking to modify Schedule 4.[353] Staff argues that NorthWestern Witness Cashell acknowledged that if the Commission were to find that these costs could be recovered from Schedule 4 customers, NorthWestern's Schedule 4 would have to be modified, perhaps substantially, to recover these costs.[354] Finally, Staff argues that Schedule 4 rates are designed in part to promote good scheduling practices and if a Schedule 4 customer can reduce its energy imbalances, such a customer could potentially reduce its Schedule 4 charges.[355]

177. In its Reply Brief, Staff addresses NorthWestern's argument that the Commission has never "prohibited charging energy costs under Schedule 3." [356] Staff points out that having established the regulatory paradigm that capacity costs should be recovered under Schedule 3 and the costs associated with the

[350] Staff Initial Br. at 43; Ex. S-1 at 14, Ex. S-37 at 14, Tr. 666:1-6 (Patterson).

[351] Staff Initial Br. at 43; Ex. S-1 at 14-15.

[352] Staff Initial Br. at 44; Ex. S-37 at 14.

[353] Staff Initial Br. at 44; Ex. S-1 at 14-15.

[354] Staff Initial Br. at 45; Tr. 144:14-23 (Cashell).

[355] Staff Initial Br. at 45; Tr. 148-149 (Cashell).

[356] Staff Reply Br. at 21; NWE Initial Br. at 33.

complementary energy should be recovered under Schedule 4, there was no need for the Commission to expressly prohibit filing under Schedule 3 to collect energy costs.

178. Also in its Reply Brief, Staff distinguishes the *SCE* case along the same lines as LCG and Central Montana. Staff also distinguishes *Allegheny Power System, Inc.*, the other case NorthWestern relies upon concerning the energy charge issue.[357] Staff states that in *Allegheny* the Commission found that the utility could recover in its Spinning Reserve Service the rates for the cost of fuel used to keep the generators spinning. Staff distinguished this case because the charge for Spinning Reserve Service refers to an hourly capacity rate and not an energy rate as proposed by NorthWestern in this proceeding.

179. Staff responds to MCC's argument that in light of Order 764, fuel costs may be compensable as an opportunity cost under Schedule 3. Staff makes the point that Order 764 concerns Schedule 10 and not Schedule 3. Moreover, it is speculative whether NorthWestern could recover opportunity costs, especially since that issue was never raised in this proceeding or through a motion to reopen the record following the issuance of Order 764.

180. Finally, Staff addresses the argument made by NorthWestern and BPA that recovering the energy costs through Schedule 4 would lead to Schedule 4 customers subsidizing Schedule 3 customers. Staff contends that the fact NorthWestern may require its transmission customers to self-supply Schedule 4 imbalance energy does not justify recovering the costs associated with the energy produced from Schedule 3 Regulation capacity from Schedule 3 customers. Schedule 3 customers already self-supply imbalance energy. Requiring them to pay for energy costs under Schedule 3 is effectively requiring them to pay twice for the imbalance energy.[358]

B. <u>Decision</u>

181. I agree with LCG, Central Montana, and Staff that NorthWestern's Schedule 3 Regulation and Frequency Response service is a capacity service and not an energy service. No party has contradicted Staff's assertion that, in general, the fuel costs associated with the provision of Regulation service have been recovered through Schedule 4 since Order No. 888 first issued. While

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[357] Staff Reply Br. at 22; *Allegheny Power System, Inc.*, 80 FERC ¶ 61,143, 61,540 (1997).

[358] Staff Reply Br. at 26.

NorthWestern cites two cases, *SCE* and *Allegheny Power System, Inc., et al.*, that assertedly allow recovery under Schedule 3, both cases are easily distinguishable on their facts as shown by Staff, LCG, and Central Montana.[359]

182. Staff contends that Schedule 3 Service is energy neutral since it is absorbing and well as providing generation to balance load. Staff suggests that if NorthWestern is providing more energy than it is absorbing it should recover the cost of the overage under Schedule 4 Energy Imbalance Service. NorthWestern rejects the idea of recovering its energy related costs through Schedule 4. NorthWestern contends that its Schedule 4 as written is limited to recoupment of charges leveled by a separate third party provider of imbalance service. There seems to be general agreement among the parties that NorthWestern would need to make a Section 205 filing to revise its present Schedule 4 in order to allow for collection of Regulation service related energy costs under Schedule 4. However, neither NorthWestern nor any allied party has contended that NorthWestern is somehow foreclosed from filing under Section 205 to make the necessary revisions to its Schedule 4.

183. NorthWestern raises a number of objections to the idea of recovering its fuel costs under Schedule 4. None of the Company's objections are persuasive because NorthWestern has admittedly never attempted to revise its Schedule 4 to allow it to recover these expenses. Moreover, in its Reply Brief NorthWestern concedes that it will evaluate the idea of revising its Schedule 4 when it makes its Order No. 764 compliance filing.

184. I note that NorthWestern and MCC quoted certain language from Order 764 which assertedly supports the Company's contention that an energy charge can be collected through Schedule 3. The language they cited is as follows: "[R]esources are often dispatched in the middle of their operating range to allow the generator to provide regulation-up as well as regulation-down and as a result forego other opportunities. Not to allow compensation would create a barrier to the provision of services by frustrating the recovery of legitimate costs." As Staff has cogently stated, Order 764 relates to Schedule 10 and not Schedule 3 which is the subject matter of this case. Moreover, the quoted language concerns opportunity costs which were not brought to light or litigated at the hearing by NorthWestern or any other party. NorthWestern did not seek to present any evidence whatsoever demonstrating opportunity costs foregone through providing regulation up or down, even after the issuance of Order 764, through a motion to reopen the record. Indeed, as mentioned above, I find opportunity costs to be a difficult proposition for NorthWestern to argue given the utility's contradictory

[359] Staff Reply Br. at 22-24; LCG Reply Br. at 23; CMT Reply Br. at 20-21, n.16.

claim that DGGS was exclusively built and fully used only for Regulation services for its retail and Schedule 3 customers.[360] As found above, NorthWestern's argument for opportunity costs is internally inconsistent and therefore, disregarded.

185. NorthWestern is apparently correct that the Commission has never expressly prohibited the collection of related energy costs under Schedule 3, so it is up to the Commission to make an exception for NorthWestern in this case. If that were to become the Commission's decision, I recommend NorthWestern, at a minimum, needs to change the energy cost formula to conform to the above findings with respect to the amount of Regulation service customers must purchase.[361] Absent such a holding by the Commission, I find that NorthWestern may not collect energy costs under Schedule 3.

Issue No. 4: Is NorthWestern's proposal to use a $7.00 market differential in the derivation of the energy value just and reasonable?

A. Positions of the Parties

186. As shown above, I have found that NorthWestern has failed to meet its burden of showing that it should be permitted to impose an energy rate charge for Schedule 3 Service. In light of that finding I see little merit in a lengthy discussion of whether NorthWestern should be allowed to subtract a $7.00 market differential from the energy value credit it proposes for its customers to offset DGGS fuel costs. NorthWestern's proposed $7.00 market differential allegedly reflects the cost of transmission between Montana and the Mid-Columbia hub.

187. NorthWestern's market differential proposal is contested by all of the parties that commented on this issue.[362] Moreover, LCG Witness Dauphinais

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[360] *See* Ex. NWE-15 at 6 (NWE Witness Merchant emphasizes "without reservation that DGGS will solely be used to provide Regulation Service) (original emphasis); *see also* Ex. NWE-22 at 4 (NWE Witness Cashell explains that "DGGS was built specifically for the purpose of providing regulating reserves to NorthWestern's Schedule 3 and bundled retail customers.").

[361] *See* Staff Initial Br. at 42. NorthWestern would also need to remove the reference to VOM/12 from its proposed Monthly Energy Rate formula.

[362] LCG Initial Br. at 31-33, LCG Reply Br. at 24-25; MCC Initial Br. at 26-27; CMT Initial Br. at 29-30, CMT Reply Br. at 23. Staff did not brief this issue because of its strong opposition to NorthWestern's proposed imposition of a fuel charge under Schedule 3.

performed an analysis of 2010 data provided by NorthWestern and found that the price to buy hourly energy from, and sell hourly energy to, NorthWestern was only $3.22 per MW lower that the Mid-C Daily Index Price. MCC cogently argues that NorthWestern errs in relying on market-based pricing that bears no relationship to costs actually being incurred on NorthWestern's system. According to MCC, "there is no differential basis in transmission cost that is being incurred to move energy generated by DGGS to NorthWestern's system. DGGS is already there."[363]

B. Decision

188. Based on the record evidence offered on this issue there is insufficient support for NorthWestern's proposed $7.00 differential. If the Commission permits NorthWestern to impose an energy charge within Schedule 3 and upon Schedule 3 customers, NorthWestern should be required to produce more persuasive evidence to support any market differential proposal it may advance.

Issue No. 5: Is NorthWestern's proposed level of Regulation service purchase obligations for customers just and reasonable?

A. Positions of the Parties

1. NorthWestern

189. In its Initial Brief, NorthWestern explains its proposal that 60/105ths of the DGGS revenue requirement for traditional, non-wind load should be divided between Schedule 3 and bundled retail customers based on their 12-CP network load in relation to NorthWestern's total CP network load. NorthWestern defends its use of 12-CP on grounds that the Commission has long accepted 12-CP as a means of allocating costs for ancillary services.[364] NorthWestern states that MCC is the only party that opposes the use of 12-CP, claiming that regulation demand does not necessarily correlate to peak load. NorthWestern contends that MCC offers no empirical data showing that its proposed demand in all hours approach is somehow preferable to 12-CP.[365]

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[363] MCC Initial Br. at 26-27.

[364] *Arizona Public Service Co.*, 12 FERC ¶ 61,419, at 61,931, *aff'd.*, 773 F.2d 1056 (9th Cir. 1985).

[365] NorthWestern's Reply Brief does not add anything to its position as set out in its Initial Brief. NWE Reply Br. at 25.

2. LCG

190. LCG points out that NorthWestern, LCG and Staff all agree that the Regulation capacity need should be divided by NorthWestern's 12-CP transmission load.[366] They also agree that MCC's approach of using demand in all hours should be rejected. LCG Witness Dauphinais explained that the generation capacity cost that NorthWestern incurs to provide Regulation service is the additional generation capacity cost it must carry above the generation capacity costs it already needs to supply its own native load customers at the time of its monthly system peak. [367] LCG cites the testimony of Staff Witness Patterson that variation in load should not be the determining factor when deciding how these costs should be allocated among customers.[368] LCG points out that since the issuance of Order No. 888, Staff Witness Patterson's experience shows that rates have typically been designed on the basis of 12-CP. LCG also relies on the testimony of its Witness Dauphinais, that with a single exception, all of the Transmission Providers surrounding NorthWestern's transmission system utilize a Regulation service charge that is based on a monthly coincident peak demand allocation method.[369] LCG notes that the MPSC has ordered NorthWestern to produce a study concerning the 12-CP versus demand in all hours issue but that it would not be completed for about 3 years.[370]

191. In its Reply Brief, LCG makes the point that there is nothing in the record in this case to support a change from the Commission's long-standing policy favoring 12-CP. LCG suggests that the data necessary to support such a change will not be available until NorthWestern completes its study ordered by the MPSC. LCG argues that there is no demonstration in the record that the MCC's hourly approach would produce results that are a better indicator. On the contrary, the record shows that the 12-CP allocation reasonably reflects the additional generation costs NorthWestern must carry above the generation capacity costs already needed to supply its native load customers at the time of its monthly system peaks.

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[366] LCG Initial Br. at 25; Ex. NWE-1, Ex. LCG-13, Ex. S-23.

[367] Ex. LCG-10 at 33.

[368] LCG Initial Br. at 28; Ex. S-23 at 8.

[369] LCG Initial Br. at 28; Ex. LCG-8.

[370] LCG Initial Br. at 28-29; Ex. MCC-4.

3. MCC

192. MCC relies upon the testimony of its witness, Dr. John Wilson, concerning the proposed 12-CP demand. Dr. Wilson contends that the allocation of Regulation service costs based on 12-CP demand is illogical and unreasonable. Dr. Wilson maintains that the use of a 12-CP cost allocation does not track, and may tend to mask, cost causation for regulation demand.[371] According to Dr. Wilson, and allegedly supported by a finding of the MPSC, a statistical analysis of data from NorthWestern shows there is no relationship between coincident peak loads of customers and demand for Regulation service.[372]

193. MCC argues that different types of loads are likely to entail substantially different Regulation requirements. According to MCC, the Commission has found it may be appropriate to develop specialized OATT treatment for transmission customers whose whole load fluctuations are highly variable and therefore stress the transmission provider's ability to maintain compliance with applicable reliability standards.[373] MCC contends that NorthWestern has neither performed the necessary analysis of potential differences in demand among customers nor provided the data to allow others to make this analysis.

194. MCC quotes extensively from findings by the MPSC that show a lack of correlation on NorthWestern's system between Coincident Peak and demand for Regulation service.[374] MCC recommends the use of transmission demand in all hours until such time as NorthWestern completes the studies directed by the MPSC in related proceedings.[375] Dr. Wilson submitted testimony that 12-CP demand is the least logical method for the allocation of NorthWestern's regulation costs, since it reflects transmission network usage in only 12 hours of the year. In contrast, Regulation service is required to support transmission usage in all 8,760 hours. Regulation is not a peak demand-related cost.

195. Dr. Wilson suggests that NorthWestern should be ordered to perform studies on its system to quantify differences between customer classes and

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[371] MCC Initial Br. at 27; Ex. MCC-1 at 6:11-15:19.

[372] MCC Initial Br. at 28; Ex. MCC- 2 at 5-7; Ex. MCC-3; Ex. MCC-4 at ¶ 91-92.

[373] MCC Initial Br. at 28; *Indianapolis Power & Light Co.*, 90 FERC ¶ 61,180, 61,584 (2000).

[374] MCC Initial Br. at 29; Ex. MCC-4 at ¶ 92.

[375] MCC Initial Br. at 30; Ex. MCC-4 at ¶ 94.

between large industrial customers to establish responsibility for regulation requirements. Until such time those studies are completed and evaluated, Dr. Wilson recommends that NorthWestern's network Regulation costs that are not attributable to variable retail energy resources be allocated between Montana retail and FERC jurisdictional customers requiring Regulation service in proportion to the sum of their transmission demands each hour.

196. In MCC's Reply Brief it argues that NorthWestern, Staff, LCG, and Central Montana are all wrong to criticize MCC Witness John Wilson for recommending an interim allocation of DGGS costs based on a Schedule 3 customer's demand in all hours.[376] According to MCC these parties ignore Dr. Wilson's and MPSC's empirical demonstration that there is no correlation between demand for Regulation service and peak load.[377] MCC reiterates that demand in all hours should be used until such time as the studies ordered by the MPSC have been completed and evaluated.[378]

4. MPSC

197. MPSC states that it approved the use of the 12-CP load ratio method pending further study which should determine "the relative contributions of the two classes to "the within-hour load fluctuations that drive Regulation capacity needs."[379] MPSC apparently agrees with the testimony of MCC Witness Dr. John Wilson to the effect that 12-CP is an historical allocator that bears little relationship to the demands on NorthWestern's system which caused it to construct DGGS to provide Regulation service. MPSC criticized Staff for following the traditional 12-CP method simply because it is the historic practice.[380] MPSC alleges that Staff and LCG have "hung their hats on this outmoded precedent rather than an alternative allocation based on intra-hour load patterns."[381]

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[376] NWE Initial Br. at 36; Staff Initial Br. at 8, 44-46; LCG Initial Br. 26-29; CMT Initial Br. at 31-31.

[377] MCC Reply Br. at 11; Ex. MCC-3, Ex. MCC-4 at ¶¶ 88-92.

[378] MCC Reply Br. at 12; Ex. MCC-4 at ¶ 94.

[379] MPSC Initial Br. at 9; *In re Application for Approval to Construct and Operate DGGS*, D2008.8.95, Ord. 6943e at 32 (MPSC Mar. 21, 2012).

[380] In support of its allegations, MPSC cites Ex. S-13 at 21.

[381] MPSC Initial Br. at 10.

198. In its Reply Brief MPSC argues that parties supporting the 12-CP methodology have ignored the fact that ancillary services have taken on a wholly different complexion in the relatively new environment in which VERS substantially complicate system operations.[382] MPSC states that "neither the peak nor the shoulder hour *ever* was the hour with the highest level of load variation in a period of nearly three years and suggests that no party has rebutted this evidence."[383] MPSC concludes that it has ordered NorthWestern to undertake a study to explore alternative allocation methodologies.[384] MPSC agrees with MCC that this issue should be reconsidered after the NorthWestern study has been completed and evaluated.

5. Central Montana

199. Central Montana asserts that the Regulation capacity need should be divided by NorthWestern's 12-CP transmission system load. Central Montana disagrees with the approach advocated by MCC which is based on energy consumption. Central Montana criticizes MCC's reliance on an Oak Ridge/ DOE Study.[385] Central Montana argues that MCC Witness Wilson admitted at the hearing that the Oak Ridge/DOE study looks generally at wholesale-industrial versus residential loads and does not reflect the specific load on the NorthWestern system."[386] Central Montana maintains that the fact that the study upon which MCC Witness Wilson relied is not reflective of conditions on NorthWestern's system undermines its value. Further, Central Montana points out that Dr. Wilson has not performed any analysis of NorthWestern's system, and therefore, his testimony should be given no weight. Central Montana notes that despite MPSC's position in this case, it has held "there is also no evidence that MCC's proposal to allocate DGGS costs based on load in all hours would be an improvement over a 12-CP load ratio share method, since the provision of Regulation service is obviously greater in certain hours."[387]

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[382] MPSC Reply Br. at 11; Tr. 458 (Wilson).

[383] MPSC Reply Br. at 12 (original emphasis); Ex. MCC-4 at 26-27.

[384] MPSC Reply Br. at 12; MCC-4 at 28-29.

[385] CMT Initial Br. at 32; Ex. MCC-1 at 12, n.5.

[386] CMT Initial Br. at 32; Tr. 455:16-19 (Wilson).

[387] CMT Initial Br. at 32; Ex. MCC-4 at 27 (NorthWestern Energy, Docket No. D2008.8.95, Order No. 6943e at P 92 (March 21, 2012)). Central Montana did not

(continued…)

6. Staff

200. Staff agrees with NorthWestern's method of determining the level of a customer's purchase obligation by dividing NorthWestern's Schedule 3 Regulation service demand by its total 12-CP Balancing Area load.[388] Nevertheless, Staff maintains that NorthWestern's proposed purchase obligation is not just and reasonable because it is calculated on a 60/105 allocation factor which is not appropriate, as Staff contends that NorthWestern's customers' purchase obligation should be calculated by dividing NorthWestern's 3.96MW of Schedule 3 Regulation service demand by NorthWestern's 1443.734 MW 12-CP Balancing Area load for 2009. This equates to 0.27 % of a customer's 12-CP where its Point of Delivery is located within the NorthWestern Balancing Area.[389]

201. Staff maintains that the Coincident Peak method is an effective way for NorthWestern to predict the amount of resource and demand balancing it will need to provide on a minute-to-minute basis. Staff quotes the Commission as stating "peak demand has a broad impact in planning the transmission system" as "the reliability of the system will be most severely tested at the time of the peak."[390] Staff asserts that the coincident peak is the "Commission's preferred method of demand charge calculation under Schedule 3, absent a showing of sufficient evidence that another method would be more appropriate."[391]

202. Staff contends that MCC Witness Dr. Wilson's argument that the demand charge for Regulation service should not be allocated to customers using the 12-CP methodology is unpersuasive, because the alternative method he recommends has not been shown to be more accurate than 12-CP. Thus, Dr. Wilson maintains that 12-CP does not accurately allocate costs according to a customer's reserve capacity use.[392] However, he provides no evidence that his all-hours allocation

address this issue any further in its Reply Brief because it addressed it fully in its Initial Brief. CMT Reply Br. at 24.

[388] Staff Initial Br. at 46; Ex. S-20 at 3-4.

[389] Staff Initial Br. at 46.

[390] *Kentucky Utilities Co.*, Order No. 116-A, 15 FERC ¶ 61,222 at 61505 (1981).

[391] Staff Initial Br. at 47; Ex. S-37 at 21. In further support of its position Staff cites *Lockhart Power Co.*, 4 FERC ¶ 61,337 at 61807 (1978); *Golden Spread Elec. Coop v. Southwestern Pub. Serv. Co.*, 123 FERC ¶ 61,047 at P 66 (2008).

[392] Staff Initial Br. at 48; Ex. MCC-1 at 13.

does so either. Staff argues that a customer's Schedule 3 service must be provided in all hours but that dos not imply that a customer's Schedule 3 usage is correlated to that customer's load during all hours, any more than at peak hours. Staff argues that while load level may be largely uncorrelated to load variation; the use of 12-CP as a load measurement in ancillary service pricing at least has the benefit of being in harmony with the load measurement used to allocate generation and transmission pricing. Furthermore, 12-CP has been applied consistently by the Commission to Schedule 3 rates. Staff concludes that it is unaware of any Schedule 3 rate on file with the Commission that does not employ a Coincident Peak methodology. Staff points out that MPSC has approved NorthWestern's proposed use of the 12-CP method in related proceedings before it.[393]

203. Staff reiterates in its Reply Brief that MCC has failed to produce any compelling evidence that load in all hours has any greater correlation to regulation demand then 12-CP load. Staff concludes that in these circumstances the 12-CP methodology, which has long been accepted by the Commission, should be adopted in this case.[394]

B. Decision

204. All parties except MCC and the MPSC agree that the customers' Regulation Capacity need should be divided by NorthWestern's 12-CP transmission load to determine the appropriate allocation of Regulation service purchase obligations. MCC alone supported its position with testimony from an expert witness, Dr. Wilson, who contended that it is erroneous to use 12-CP in determining the appropriate allocation. MCC Witness Dr. Wilson argues that 12- CP is not a proper way to measure allocation because 12-CP looks only at 12 hours of each year and Regulation service is needed 24 hours per day every day of the year. Dr. Wilson supports the use of demand in all hours. However Dr. Wilson fails to demonstrate that his approach is in any way superior to the 12-CP methodology. Dr. Wilson's testimony was not based on a study of NorthWestern's system. MPSC supports MCC Witness Dr. Wilson's view that the 12-CP approach is inappropriate. Nevertheless, the MPSC accepted NorthWestern's use of 12-CP when the issue was raised in related proceedings before it. Moreover, in MPSC Order No. 6943e the Montana commission acknowledged that there is "no evidence that

[393] Staff Initial Br. at 48; Ex. S-38 at 8-9.

[394] Staff Reply Br. at 27; *Kentucky Utilities Co.*, Order No. 116-A, 15 FERC ¶ 61,222 at 61,505 (1981).

MCC's proposal to allocate DGGS costs based on loads in all hours would be an improvement over a 12-CP load ratio share method…".[395]

205. MCC Witness Dr. Wilson suggests that NorthWestern should be ordered to produce a study that would take into account the variability of the loads of all of the customers. While a study conducted by NorthWestern may be helpful in evaluating the question of 12-CP as opposed to demand in all hours, no study has been completed or even undertaken at this time. Although the MPSC has ordered such a study, estimates show that it will not be completed for at least three years.[396]

206. MCC does not cite any case in which a method other than 12-CP was used the Commission. I agree with NorthWestern, LCG, Central Montana, and Staff that the appropriate measure is 12-CP.

Issue No. 6: Is inclusion of third-party regulation purchases in the proposed demand rate just and reasonable?

A. Positions of the Parties

1. NorthWestern

207. The Company states that its Schedule 3 includes a provision for the pass-through of actual costs (with markup) incurred in obtaining Regulation service from third parties. NorthWestern concedes that the proposed tariff language would allow it to contract with third parties "if the need arose."[397] The Company states that it expected to limit use of this provision to situations where it could secure Regulation service from third parties at a price below the variable costs of operating DGGS.

208. NorthWestern alleges that in late January 2012 a need for third-party supply arose because all three DGGS turbines had to be replaced by the manufacturer.[398] The Company entered into contracts with Powerex and Avista for

[395] Ex. MCC-4 at 27.

[396] LCG Initial Br. at 28-29; Tr. 448-451 (Wilson); Ex. LCG-20 at 2; Ex. MCC-4.

[397] NorthWestern Initial Br. at 37.

[398] *Id.*; Tr. 90-91 (Cashell).

short-term regulating resources.[399] NorthWestern now intends to pass the costs of those contracts through to its wholesale and retail customers under its tariff.

209. NorthWestern acknowledges that it has committed to file long-term contracts under Section 205 but it contends that in the January 2012 situation, the contracts were short-term.[400] In any event, NorthWestern contends that seeking after-the-fact approval of the contracts would be pointless, since relief under Section 205 is generally prospective only.[401] Since NorthWestern has already incurred the costs under the Powerex and Avista contracts, NorthWestern argues that it could not recoup them under a new Section 205 filing. NorthWestern contends that the Commission has recognized that customers should bear these emergency expenses since "incurrence of these types of costs benefits its customers by allowing it to resume full service as quickly as possible following a catastrophic event."[402]

210. NorthWestern argues that it makes no sense for it to file short-tem contracts under Section 205. NorthWestern points out that its Avista and Powerex contracts were already on file with the Commission, albeit for another purpose. NorthWestern claims that all parties had the opportunity to undertake discovery on the causes of the outage and to explore those causes at the hearing. NorthWestern contends that Section 205 does not operate retroactively without a Commission finding of exceptional circumstance. NorthWestern suggests that if Central Montana and LCG want to challenge the prudency of the contracts with Powerex and Avista, they should file a Section 206 action.

211. NorthWestern notes that MCC has proposed that Schedule 3 tariff language should be amended to allow the pass-through of third party contract costs only in the event of a DGGS outage or where the third party contracts are less than the variable costs of operating DGGS.[403] NorthWestern acknowledges that this

[399] NorthWestern cites Ex. NWE-42, NWE-43, and NWE-44 which are the contracts entered into with Powerex and Avista.

[400] NorthWestern Initial Br. at 37; Ex. NWE-42; Ex. NWE-43; Ex. NWE-44.

[401] In support of its contention NorthWestern cites *Tenaska Power Services Co. v. Midwest Independent Transmission Sys. Operator, Inc.*, 107 FERC ¶ 61,308, at P 22 (2004).

[402] *Sea Robin Pipeline Co., LLC,* 137 FERC ¶ 61,201 at P 49 (2011).

[403] NWE Reply Br. at 27; MCC Initial Br. at 32.

suggestion is reasonable and that the Company is amenable to inserting language to that effect in Schedule 3. NorthWestern is concerned, however, that the modification suggested by MCC should not impede NorthWestern's right to recover the costs of the Powerex and Avista contracts it entered into when the generators malfunctioned in January 2012.

212. NorthWestern also contends that if it needs to contract with third parties because it has insufficient capacity for some reason, the cost of securing Regulation service from third parties is properly included in Section 3, since NorthWestern has a duty to attempt to secure supplemental regulating reserves under Order No. 764.[404]

2. LCG

213. LCG challenges the Component "C" of NorthWestern's Regulation service monthly demand rate. LCG maintains that if the Commission accepts the position of LCG and Staff that no variable costs should be included in Schedule 3 then no third party costs should be allowed in Schedule 3. At a minimum, NorthWestern should not be permitted to recover replacement Regulation service costs associated with the extended outage of the DGGS in January 2012, unless it first formally seeks and receives Commission authority to do so.[405] LCG contends that the intention behind Component "C" was to allow NorthWestern to recover the costs of third party Regulation service contracts it enters into when such contracts have a lower cost than operating the DGGS.[406] NorthWestern should not be permitted to expand the scope of costs to be recovered through Component "C" to include Regulation service costs incurred in connection with the extended DGGS outage that began in January, 2012. LCG asserts that in not seeking Commission approval to recover DGGS outage costs through a filing, NorthWestern denied the Commission and OATT customers the opportunity to review the prudency of NorthWestern's actions in response to the outage. It also prevents customers from insuring that any available proceeds from vendor warranties or NorthWestern's insurers are appropriately applied against NorthWestern's additional Regulation service costs.[407] LCG Witness Dauphinais acknowledges that OATT customers or

[404] Order No. 764 at P 270.

[405] LCG Initial Br. at 33; 16 U.S.C. § 824d.

[406] LCG Initial Br. at 28-30; NorthWestern Corporation, Revisions to Schedule 3, Regulation and Frequency Response Service, of NorthWestern's Open Access Transmission Tariff, Docket No. ER10-1138 (April 29, 2010); Ex. NWE-1 at 18-20.

[407] Ex. LCG-10 at 45-50.

the Commission could file a complaint to obtain information about the outage, but he argues that such a procedure unfairly shifts the burden of proof to the parties initiating the complaint, when NorthWestern controls the relevant information.[408]

214. In its Reply Brief, LCG proposes that it would not object to the following sequence of procedures to govern NorthWestern's efforts to recover its third party contract costs stemming from the January 2012 outage: (1) NorthWestern should be required to document on OASIS the total amount of the third-party costs; (2) following the conclusion of this case the Company should be allowed to retain rather than refund immediately, an amount equal to those documented costs to the extent the rates approved by the Commission are less that the rates proposed by NorthWestern; (3) the Company should then be required to make a Section 205 filing to demonstrate the costs were prudently incurred and reasonable; and (4) the Company may retain, rather than refund, that money permanently to the extent approved by the Commission in that filing.[409]

3. MCC

215. MCC contends there are only two circumstances under which the inclusion of third-party regulation purchases in NorthWestern's proposed demand rate should be deemed just and reasonable. The first circumstance is that DGGS is unavailable due to an outage or other equipment failure. MCC agrees that at such times, NorthWestern has no choice but to purchase third-party services in order to supply the regulation requirements of its Balancing Authority.[410] The other circumstance is if it is less costly to use third party services than to run the DGGS.[411] MCC maintains that NorthWestern's proposal to include the cost of purchases from third parties is not just and reasonable unless it adds MCC's proposed restrictions to the Schedule 3 language.[412]

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[408] LCG Initial Br. at 5-36; Ex. LCG-10 at 45-50; Ex. LCG-11.

[409] LCG Reply Br. at 27.

[410] MCC Initial Br. at 30-31; *Powerex Corp.*, 138 FERC ¶ 61,136 at PP 5-7, 16-17 (2012).

[411] See, Montana PSC Order No. 6943a (May 20, 2009), Docket No. 2008.8.95 at ¶230, EX. NWE-4 at ¶ 230.

[412] MCC Initial Br. at 31-32. MCC adds nothing further on this issue in its Reply Brief.

4. Central Montana

216. Central Montana contends that NorthWestern should be allowed to pass through third party purchases only if so doing lowers the overall rate for Regulation service. According to Central Montana, NorthWestern initially proposed that it would only procure third party Regulation, and pass those costs on to ratepayers if it is more cost-effective than dispatching DGGS.[413]

217. Central Montana counters NorthWestern's argument that it should have raised this issue at the hearing by pointing out that that Pratt & Whitney, the manufacturer of the turbines that failed, have not yet finished their analysis of the root cause of the problem.[414] Central Montana adds that any claim of imprudence is also premature because NorthWestern has yet to quantify the capital costs it expects to incur in order to fully return the DGGS to Service.[415]

218. Central Montana contends that in the *Sea Robin* case upon which NorthWestern relies, the Commission did not authorize a mere pass through of costs due to hurricane damage, but rather set for hearing the issue of the reasonableness of those costs.[416] Central Montana argues that NorthWestern should be restricted to a pass through of third party purchase costs only if doing so lowers the overall rate for Regulation service.[417]

219. In its Reply Brief Central Montana quotes a number of excerpts from the hearing transcript in this case suggesting that there was insufficient analysis done of the cause of the outage to raise a cognizable prudency claim at that time.[418] In response to NorthWestern's claim that it would be able to obtain only prospective relief under Section 205, Central Montana asserts that the Commission has made it

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[413] Central Montana cites NorthWestern Transmittal Letter in ER10-1138 at 2-3 (April 2010) in support of its contention.

[414] CMT Initial Br. at 34; Tr. 296: 6-16 (Rhoads) (explaining that Pratt & Whitney is in the process of performing a root cause analysis, but has no answer yet).

[415] CMT Initial Br. at 34-35; Ex. CMT-8 at 1.

[416] *Sea Robin Pipeline Co., LLC,* 137 FERC ¶ 61,201 at P 8.

[417] CMT Initial Br. at 36; Ex. NWE-1 at 19:18-19.

[418] CMT Reply Br. at 25; Tr. 296:6-15 (Rhoads); Tr. 296:15-16 (Rhoads); Tr. 300:25-301:8 (Rhoads); Tr. at 95:15-18 (Cashell); Ex. CMT-8 at 1.

clear that if costs passed through a formula rate are unjust and unreasonable, the Commission may order retroactive relief.[419]

5. Staff

220. Staff contends that the inclusion of a variable that would flow the costs of third party Regulation capacity purchases through to NorthWestern's Schedule 3 customers is not just and reasonable and should be removed from NorthWestern's proposed Schedule 3. Staff argues that if NorthWestern were to obtain Regulation capacity under a third party contract, NorthWestern's proposed Schedule 3 rate would allow NorthWestern to simultaneously recover both the full costs of the service obtained through the contracts and the fixed cost portion of DGGS, even if DGGS was no longer used to provide Schedule 3 service.[420] Staff suggests that NorthWestern should seek reimbursement for the charges for any third party Regulation contract though a new Section 205 filing with the Commission to insure the NorthWestern's customers are only charged for the cost of the resources actually used to provide Schedule 3 Service.[421]

221. In its Reply Brief, Staff suggests that NorthWestern's focus on third party contracts entered into because of the outage masks the serious flaws in NorthWestern's proposed rate structure. Staff emphasizes that under the Company's proposed Schedule 3, NorthWestern could flow through *any* cost of *any* third party contract even though there is no emergency, without giving its customers the right to challenge the contract.[422]

222. Finally, Staff contends that NorthWestern errs in arguing that Section 205 relief is prospective only. Staff avers that Section 205 rate filings are routinely accepted by the Commission subject to refund.[423]

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[419] CMT Reply Br. at 26; *PJM Interconnection, LLC*, 110 FERC ¶ 61,053, at P 120, n.105 (2005), *order on reh'g and compliance*, 114 FERC ¶ 61,302 (2006).

[420] Staff Initial Br. at 50; Ex. S-1 at 12.

[421] Staff Initial Br. at 50; Ex. S-1 at 14.

[422] Staff Reply Br. at 27-28 (emphasis in original).

[423] Staff Reply Br. at 28; *Empire Dist. Elec. Co.,* 140 FERC ¶ 61,087, at P1 (2012).

B. Decision

223. The issues before me in this proceeding are limited to the justness and reasonableness of NorthWestern's proposed revisions to Schedule 3 of its tariff. [424] With respect to its third party costs, NorthWestern proposes to include a C component in the Monthly Demand Rate where "C= Transmission Provider's total cost of procuring Regulation service during the second month preceding the month, if any, for Transmission Customers from third party suppliers."[425] The tariff also provides that "[t]o the extent Transmission Provider procures product to supply this [Regulation and Frequency Response] service it will pass through the actual costs of providing this service as described through component 'C' in the formula above."[426] Even NorthWestern recognizes that this unlimited language cannot be allowed to stand and has accepted as reasonable MCC's proposed limitations. As shown above, MCC proposes that Schedule 3 should allow the pass through of third party contract costs only in the event of a DGGS outage or where the third party contracts are less that the variable costs of operating DGGS.

224. No party objects to a revision of the NorthWestern Schedule 3 language intended to allow a pass through of third party contracts that are less than the variable costs of operating DGGS. The more controversial proposal is to allow a pass through of third party contract costs in the event of a DGGS outage. As illustrated by this case, DGGS customers want to examine the propriety of third party contracts entered into because of an outage. As far as the outage that occurred in January 2012 is concerned, I agree with LCG, Central Montana, and Staff that NorthWestern should file under Section 205 to seek to pass through the costs of the January outage when the necessary studies are completed and the cause(s) and total costs of the outage are established.

225. I find that the proposed revisions to Schedule 3 quoted above by NorthWestern are not just and reasonable and that third party contract costs should be passed through only if the costs are lower than the variable costs of operating DGGS. Furthermore, NorthWestern must file under Section 205 of the FPA for Commission review any time there is a third party contract and or expenses associated with Schedule 3 Service that NorthWestern seeks to pass through to its

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[424] *See* October 15 Hearing Order at ordering para. (C); December 30 Hearing Order at ordering para. (D).

[425] *NorthWestern Corp.*, Docket No. ER12-316-000 and ER10-1138-001 Compliance Filing (January 30, 2012).

[426] *Id.*

wholesale customers. Under such review and forum, NorthWestern and its customers can analyze the ramification of the contracts; likewise the Commission can take appropriate action as necessary to ensure protection of all parties with the overall public interest.

Issue No. 7: Is the lack of proposed ceiling rates for Regulation service just and reasonable?

A. Positions of the Parties

1. NorthWestern

226. NorthWestern opposes what it describes as the position of Staff and LCG to substitute a set rate in place of NorthWestern's formula rate. NorthWestern contends that a formula rate does provide a price cap as it is based on the recovery of a defined set of costs.[427] NorthWestern argues that the formula rate does not provide it with an opportunity to earn any profit beyond the rate of return allowed in the revenue requirement.[428] NorthWestern further contends that the Commission has approved Schedule 3 rates having formulas similar to the one NorthWestern proposes here.[429]

227. For the most part, NorthWestern reiterates the above arguments in its Reply Brief.[430] NorthWestern adds that LCG, Central Montana, and Staff continue to insist on a ceiling rate without acknowledging that NorthWestern's formula rate acts as a ceiling.[431]

2. Central Montana

228. Central Montana insists that NorthWestern's formula rates are not ceiling rates. Central Montana argues that in its October 15, 2010 order the Commission set for hearing, *inter alia*, the "lack of ceiling rates for Regulation service."[432]

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[427] NWE Initial Br. at 39; Ex. NWE-15 at 51-53.

[428] *Id.* at 52.

[429] NWE Initial Br. at 39; *U.S. Department of Energy –Western Area Power Administration, (Central Valley Project)*, 137 FERC ¶ 62,201 (2011).

[430] NWE Reply Br. at 28.

[431] NWE Reply Br. at 28.

[432] CMT Initial Br. at 37; October 15 Hearing Order at P 21.

According to Central Montana, NorthWestern's inclusion of the DGGS replacement contract costs in its Schedule 3 rates demonstrates that the formula is not fixed and predictable and does not protect customers against the exercise of unfettered discretion by NorthWestern in choosing what costs to charge customers. Central Montana quotes the Commission's Order No. 888 in support of its position as follows:

> In the absence of a demonstration that the seller does not have market power in such services, rates for ancillary services should be cost-based and established as price caps from which transmission providers may offer a discount to reflect cost variations or to match rates available from any third party. If a rate discount is offered to the transmission owner itself or an affiliate of the transmission owner, the same discounted rate must be offered to non-affiliates, as well. In addition, discounts offered to non-affiliates must be on a basis that is not unduly discriminatory. All discounts must be posted on the transmission provider's OASIS.[433]

Central Montana requests that NorthWestern be required to label its monthly, weekly, daily and hourly Schedule 3 rates as ceiling rates.[434]

3. Staff

229. Staff argues that NorthWestern should be directed to label its Schedule 3 Service rates as ceiling rates, as required by the Commission for all ancillary service rates. Contrary to NorthWestern, Staff explains that this issue is not about whether the Company will recover more than the costs of DGGS.[435] Staff maintains that even a formula rate must be labeled as a ceiling rate so that it potentially could be discounted. Staff quotes from Witness Patterson's testimony that "[i]f NorthWestern's formulaic proposal is ultimately approved by the Commission in some form; it simply means that each annual recalculation will produce new ceiling rates applicable for that particular rate year."[436] In Staff's view, NorthWestern has offered no reason why the Commission's requirement

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[433] Order No. 888, FERC Stats. & Regs.¶ 31,036, 31,720-21.

[434] CMT Initial Br. at 38.

[435] Staff Initial Br. at 51; Ex. NWE-15 at 51-52.

[436] Staff Initial Br. at 51.

that rates for ancillary services be established as rate caps should not be applied in this case.

230. Staff adds in its Reply Brief that this issue is one of labels, not of substance. Staff clarifies that contrary to NorthWestern, Staff does not propose changing the Company's formula rate to a fixed rate.[437] If a formula rate is approved it merely must be labeled as a ceiling rate to satisfy Staff's concerns. Each annual recalculation will produce new ceiling rates applicable for the particular rate year.[438]

B. Decision

231. I agree with Staff that there is no reason why the Commission policy establishing rate caps for ancillary services should not be applied in this case. Even if NorthWestern is ultimately approved for formula rates, Staff points out that "[e]ven a formula rate must be labeled a ceiling rate so that it could, potentially, be discounted." [439] NorthWestern's proposed Schedule 3 should be amended to provide that the rates for Regulation services – whether they are fixed rates or formula rates – are rate caps, and as such are discountable.

Issue No. 8: Are NorthWestern's proposed regulation requirements for self-supplying customers just and reasonable?

A. Positions of the Parties

1. NorthWestern

232. NorthWestern alleges that its amended Schedule 3 filed on November 1, 2011, provides instructions on how each potential self-supplying customer should calculate the amount of regulation needed for self-supply. Amended Schedule 3 further provides that all remaining technical and operational details regarding self-supply arrangements will be laid out in customer specific service agreements, network operating agreements, or NorthWestern's business practices.[440]

[437] Staff Reply Br. at 28; NWE Initial Br. at 29.

[438] Staff Reply Br. at 28-29; Ex. S-37 at 12.

[439] Staff Initial Br. at 51.

[440] NWE Initial Br. at 40.

233. NorthWestern notes that several parties object to the Company's proposal on two grounds. They contest the use of 60 MW as the total Regulation service requirement and they recommend changing the formula so that it is based on the previous 12 months of data rather than the projected load.[441] NorthWestern argues that because customers considering self-supply would analyze options for future service, it makes sense that this formula should be based on anticipated future needs.

234. NorthWestern opposes the suggestion made by LCG and Central Montana that Schedule 3 should be revised to reflect a notice period of 180 days for initiation as well as for termination of a self-supply arrangement.[442] NorthWestern cites the following language from Order 764 in support of its position:

> The Commission notes that public utility transmission providers already are obligated to post on their public websites all rules, standards, and practices, to the extent they exist, that relate to transmission service. The provision of ancillary services is necessary to accomplish transmission service and, therefore, we conclude this posting obligation applies equally to ancillary services. Public utility transmission providers must post any rules, standards, and practices regarding self-supply requirements pursuant to their obligation to allow self-supply of ancillary services.[443]

235. NorthWestern states that it will post on its OASIS the notice period for customers leaving NorthWestern to self-supply and the conditions, including the notice period, that will apply to customers seeking to become Schedule 3 customers. NorthWestern also agrees to post the technical requirements, such as telemetering, that self-supplying customers will need to meet in the time period set by the Commission in Order No. 764, or any subsequent Commission orders.[444]

236. In its Reply Brief NorthWestern contends that in Order 764, the Commission declined to require utilities to spell out in their tariffs what they view

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[441] NWE Initial Br. at 40.

[442] NWE Initial Br. at 41.

[443] NWE Initial Br. at 41; Order No. 764, 139 FERC 61,246 at P 273.

[444] NWE Initial Br. at 42.

as "alternative comparable arrangements" for self-supply.[445] NorthWestern argues that the Commission held in Order 764 that utilities should post such requirements and conditions on their OASIS.[446] NorthWestern asserts that it will comply with Order No. 764 and will post on its OASIS all technical requirements, including the notice period, for self-supplying customers. NorthWestern notes that it will require that any departing or returning customer must give at least 180 days notice. NorthWestern adds that service to returning customers will also be conditioned on "the availability of regulation reserves."[447]

2. LCG

237. LCG contends that NorthWestern's proposed changes to its OATT have not been shown to be consistent with, or superior to those in the compliance tariff as required by Order 888.[448] LCG alleges that the proposed tariff lacks sufficient detail that would enable a customer to intelligently analyze and evaluate the option for third-party service.[449] LCG cites, for example, NorthWestern's failure to clearly prescribe the amount of notice required to initiate or terminate Schedule 3 Service.[450] LCG suggests the following language be included in the tariff revisions:

> Any Schedule 3 network customer shall have the right, with 180 days notice for initiation and 180 days notice for termination, to self-provide its regulation obligation. The customer's regulation obligation shall be deemed equal to the total NorthWestern Balancing Authority Area (NWBAA) percentage requirement for Regulation capacity times the customer's average 12-CP load for the most recent calendar year. The Regulation Service can either be provided by a third party dispatchable generation source interconnected with the NWBAA (or otherwise deliverable to the NWBAA with the appropriate transmission service) or a load within the

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[445] NWE Reply Br. at 28; Order No. 764, 139 FERC 61,246 at P 273.

[446] Order No. 764, 139 FERC 61,246 at P 273.

[447] NorthWestern Reply Br. at 29.

[448] LCG Initial Br. at 37; Order No. 888, 61 F.R. at 21,619.

[449] NWE Initial Br. at 38; Ex. LCG-7.

[450] LCG Initial Br. at 38; Order No. 888, 61 F.R. at 21,619.

> NWBAA capable of providing a positive or negative demand response within the prescribed limits, or some combination of the two means which sum to the total regulation requirement of the customer.[451]

238. LCG argues in its Reply Brief that NorthWestern seems to assume that an OASIS posting puts it in compliance with Order No. 764. LCG argues that the requirements of Order No. 764 do not modify or supplant any requirements stemming from Order No. 888. LCG makes the point that NorthWestern attempts to blur the line between what is applicable to Schedule 10 (Order No. 764) which is not at issue here and Schedule 3 which is directly at issue in this case. LCG contends that posting on OASIS does not cure the problem that NorthWestern's tariff lacks sufficient detail to enable a customer to intelligently analyze and evaluate the option for third party service.[452] LCG argues that the tariff as written does not even state "the amount of each ancillary service that the customer must purchase, self-supply, or otherwise procure."[453]

3. MCC

239. MCC offers two proposals on the self-supply requirements issue. MCC suggests that NorthWestern should be required to specify obligations associated with the self-supply of Schedule 3 ancillary services, "based on a specific evaluation of the regulation burdens that individual large industrial customers place on the requirements of NorthWestern's Balancing Authority Area for Schedule 3 service."[454] MCC adds that the proposed evaluation should await completion and evaluation of the studies NorthWestern has been directed to perform by the Montana Commission and could be taken up when NorthWestern submits its Order 764 compliance filing.

240. MCC's second proposal is that NorthWestern's Schedule 3 should explicitly provide for adjustment of carrying cost burdens when a self-supplying customer resumes taking Schedule 3 service from the Company.[455] MCC believes that this is not the equivalent of a "stand-by charge" which has been rejected by

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[451] LCG Initial Br. at 39-40; Ex. LCG-1 at 11-12.

[452] LCG Reply Br. at 36-41; Ex.LCG-7.

[453] LCG Reply Br. at 28.

[454] MCC Initial Br. at 33.

[455] MCC Initial Br. at 33; Ex. MCC-1 at 20:1-25:6.

the Commission. MCC Witness Dr. Wilson explains in his testimony that his proposal does not involve imposing ongoing charges on a self-supplying customer when the customer is engaged in self-supply.[456] MCC states that the purpose of the adjustment is to insure that those customers (primarily retail customers) who are not able to exercise the right to self-supply are not unreasonably burdened by the exercise of that right by others.[457]

4. Central Montana

241. Central Montana urges that NorthWestern's OATT should include an express right to self-supply and provide for a notice period of 180 days to leave or return, as suggested by LCG.[458] Central Montana argues that a 180 day notice period for customers would be just and reasonable since they would only be able to switch to self-supply once per year.[459] Furthermore, this 180-day period is consistent with the notification period in NorthWestern's self-supply agreement with BPA.[460]

242. Central Montana disputes NorthWestern's proposal to use projected loads in calculating a self-supplying customer's regulation need. Central Montana contends that this proposal will only lead to disputes as to whether NorthWestern's load projections are accurate. Central Montana contends that actual network load data should be used. Central Montana relies, in part, on language in the Commission's December 30 order in this case:

> The pricing of ancillary services should include the amount of each ancillary service that the transmission customer must purchase, self-supply, or otherwise procure and <u>must be readily determinable from the transmission provider's tariff</u>

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[456] MCC Initial BR. at 33; Ex MCC-1 at 20:1-25:6.

[457] MCC adds nothing further on this issue in its Reply Brief. In LCG's Reply Brief it opposes MCC's suggestion of a carrying charge adjustment for returning customers on the ground that MCC's proposal is anti-competitive. LCG Reply Br. at 28; *NorthWestern Corp.*, 140 FERC ¶ 61,020 (July 2, 2012). LCG argues that the only reason for charging a customer who seeks to return is to influence the customer not to leave in the first place.

[458] CMT Initial Br. at 40; Ex. LCG-16 at 29.

[459] CMT Initial Br. at 40.

[460] CMT Initial Br. at 41; Ex. LCG-7 at 29- 30.

> and comparable to obligations to which the transmission provider itself is subject.[461]

243. Central Montana supports the inclusion of LCG's proposed language quoted above, in NorthWestern's tariff.[462] Central Montana contends in its Reply Brief that NorthWestern has in the past exhibited antipathy toward self-supplying customers, citing *NorthWestern Corp.,* 137 FERC ¶ 61,248 at P 28 (2011) , in which NorthWestern sought to charge customers for Schedule 3 service even if they fully self-supplied on a long-term basis.

244. Central Montana suggests that a reasonable deadline should be incorporated in the tariff to avoid significant transactional costs and to eliminate needless future litigation. Central Montana supports a 180 day exit/reentry period. Central Montana notes that Order No. 764 concerns the question of what must be posted on OASIS. Order 764 does not preclude incorporating deadlines or other requirements into the tariff itself. The Commission has previously recognized the importance of including customer safeguards in the transmission providers' OATT.[463]

5. Staff

245. Staff takes issue with NorthWestern's November 1, 2011 proposed tariff sheets on the ground that NorthWestern uses projected 12-CP load rather than data from the previous 12 months, to determine the amount of Regulation service needed for self-supply. Staff also opposes, as discussed above, NorthWestern's use of 60 MW as the amount of Regulation service needed, instead arguing that 3.96 MW of Regulation service is required.[464] Staff recommends that

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[461] CMT Initial Br. at 42; December 30 Hearing Order at P 29 (emphasis added).

[462] LCG Initial Br. at 39-40, Ex. LCG-1 at 11-12; Central Montana joins LCG in opposing the imposition of costs on customers returning to NorthWestern after a period of self-service, as proposed by MCC and its Witness Dr. Wilson.

[463] In support of its position, Central Montana cites *Idaho Power Co.*, 115 FERC 61,281 at P29 (2006). Central Montana opposes MCC's suggestion that a carrying cost be charged to customers that seek to return to Schedule 3 service from NorthWestern after a period of self-supply. Central Montana equates this proposed charge with stranded costs and argues that any such charge would be anti-competitive. CMT Reply Br. at 29-30.

[464] Staff Initial Br. at 52; Ex. S-37 at 7.

NorthWestern specify the customer's purchase obligation based on the use of the prior 12 months of CP load data, consistent with NorthWestern's rate development.[465]

246. In its Reply Brief, Staff seeks to rebut NorthWestern's contention that any customer contemplating self-supply would analyze options for future service, making it logical that the formula to determine a customer's self-supply obligation would be directed toward future needs.[466] Staff asserts that, contrary to NorthWestern, a customer contemplating whether to self-supply will look at the percentage obligation relative to its transmission service in making its decision. Staff argues that the purchase obligation implicit in Schedule 3 rates is based on historical loads. Staff asserts that NorthWestern has provided no explanation why transmission customers who choose to self-supply should be treated differently from those who do not. Staff maintains that the purchase obligation of a self-supplying customer should be determined based on the previous 12 months of data.

B. <u>Decision</u>

247. The proposed tariff sheets filed by NorthWestern on November 1, 2011 have not been shown to be just and reasonable with respect to the provisions concerning self-supplying customers. The tariff sheets provide, in pertinent part, that the amount of Regulation service required by NorthWestern for Schedule 3 customers is 60 MW. As shown above, I have found that NorthWestern failed to meet its burden of showing that 60 MW is the appropriate Regulation service requirement. I have recommended that 19 MW is the amount needed. Accordingly, NorthWestern must revise its tariff to conform to that amount.

248. Staff, and Central Montana specifically object to NorthWestern's tariff language that a customer that self-supplies must secure Regulation and Frequency Response in "an amount equal to its projected 12-CP load for the next 12 months…"[467] Staff and Central Montana contend that this tariff provision must be revised to use the prior 12 months of CP load data. Central Montana supports the use of the previous 12 months of data on the ground that using projected 12-CP

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[465] Ex. S-13 at 9.

[466] Staff Reply Br. at 29; NWE Initial Br. at 41.

[467] NorthWestern's revisions to Schedule 3 filed November 1, 2011. I note that NorthWestern's January 2012 proposed revisions to Schedule 3 repeat the same language.

data as proposed by NorthWestern will lead to disputes about the accuracy of the projected data. Central Montana also argues that using the past 12 months' data is more in keeping with the Commission's finding in its December 30 Order that the amount of ancillary services a self-supplying customer is required to provide "must be readily determinable from the transmission provider's tariff…". [468] NorthWestern opposes this change because, in the Company's view, customers considering self-supply will analyze options for future service and would look to future projections. I find that Central Montana's argument persuasive that using future projected data will only lead to disputes about the accuracy of the data. I conclude that NorthWestern must revise its proposed Schedule 3 rate to reflect the use of the prior 12 months of CP load data.

249. Central Montana and LCG propose that Schedule 3 provisions concerning self-supply should include a 180 day notice period for initiation or termination of a self-supply agreement. Although NorthWestern opposed the 180 day proposal initially, the Company stated in its Reply Brief that it intends to require that any departing or returning customer must give at least 180 days notice.[469] While Central Montana and LCG support a notice period of 180 days, they may still object to NorthWestern's proposed language since it allows the Company to require a substantially longer notice period than 180 days if it so chooses.[470] I find that NorthWestern must revise its proposed Schedule 3 to reflect a notice period of 180 days.

250. Finally, the Company continues to maintain that information about the notice period (and other information about the self-supply option) could be posted on OASIS without any corresponding modification to its tariff. I agree with LCG that the essential information for prospective self-supplying customers must be included in the Company's tariff, regardless of what it chooses to post on its OASIS.

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[468] December 30 Hearing Order at P 29.

[469] NWE Initial Br. at 41, NWE Reply Br. at 28-29.

[470] *See* CMT Reply Br. at 28. "[T]here is nothing to prevent NorthWestern from proposing …roadblocks in the future. For instance, if NorthWestern were to impose a three year notice requirement for self-supply exit and reentry, the only redress for the customer would be to seek relief from the Commission. Tr. at 130-132 (Cashell).

FINDINGS AND CONCLUSIONS

251. It is found and concluded that NorthWestern and Staff' stipulation of the Company's annual fixed cost revenue requirement for DGGS is just and reasonable.

252. It is found and concluded that NorthWestern's proposed allocation of the DGGS fixed cost revenue requirement is not just and reasonable. Specifically, NorthWestern's proposed allocation based on a numerator of 60 is not just reasonable, instead LCG's proposed numerator of 19 MW is found to be just and reasonable because:

a. NorthWestern has the burden of proof in this case, and did not carry its burden to show that 60 MW is a just and reasonable numerator,

b. Regulation down must be excluded from the measure of Schedule 3 capacity,

c. Diversity benefits must be shared between retail and wholesale customers,

d. NorthWestern may include energy imbalance service in its Schedule 3 rate, and

e. The use of absolute averages is not mandated for calculating the numerator.

253. It is found and concluded that NorthWestern's proposed allocation based on a denominator of 105 is also not just and reasonable; instead, the nameplate capacity of DGGS, 150 MW, is found to be just and reasonable.

254. It is found and concluded that NorthWestern's proposed imposition of an energy rate charge in Schedule 3 is not just and reasonable.

255. It is found and concluded that NorthWestern's proposal to use a $7.00 market differential in the derivation of the energy value has not been shown on this record to be just and reasonable.

256. It is found and concluded that NorthWestern's proposed level of Regulation service purchase obligations for customers is not just and reasonable.

257. It is found and concluded that the inclusion of third-party regulation purchases in NorthWestern's proposed demand rate is not just and reasonable unless the proposed purchases are more cost effective than dispatching the DGGS.

258. It is found and concluded that the lack of proposed ceiling rates for Regulation service is not just and reasonable. NorthWestern must label its approved rate as a ceiling rate.

259. It is found and concluded that NorthWestern's proposed regulation requirements for self-supplying customers are not just and reasonable.

ORDER

260. IT IS ORDERED, subject to review by the Commission on exception or on its own motion, as provided by the Rules of Practice and Procedure, that within thirty (30) days of issuance of the final order of the Commission in this proceeding, NorthWestern shall file revised compliance filings in accordance with the findings and conclusions of this Initial Decision, as adopted or modified by the Commission.

SO ORDERED.

Judith A. Dowd
Presiding Administrative Law Judge

Service Date: March 21, 2012

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

IN THE MATTER OF the Application of NorthWestern Energy for Approval to Construct and Operate the Dave Gates Generating Station to Supply Regulation Service for NorthWestern Energy's Montana Electric Operations and Montana Transmission Control Area	)))))	REGULATORY DIVISION DOCKET NO. D2008.8.95 ORDER NO. 6943e

ORDER ON COMPLIANCE FILING

APPEARANCES

For the Applicant:

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For the Intervenors:

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Natural Resources Defense Council
Charles E. Magraw, 501 8th Avenue, Helena, Montana 59601

Before:

TRAVIS KAVULLA, Chairman
GAIL GUTSCHE, Vice Chair
W.A. GALLAGHER, Commissioner
BRAD MOLNAR, Commissioner
JOHN VINCENT, Commissioner

Commission Staff:

Leroy Beeby, Utility Rate Analyst
Eric Eck, Chief, Revenue Requirements Bureau
Scott Fabel, Utility Rate Analyst
James C. Paine, Staff Attorney
Will Rosquist, Chief, Economics & Rate Design Bureau
Kate Whitney, Administrator, Regulatory Division

BACKGROUND AND PROCEDURAL HISTORY

1. On August 25, 2008, NorthWestern Energy (NWE) filed with the Public Service Commission (Commission) an application for pre-approval to construct the Mill Creek Generating Station, now the Dave Gates Generating Station (DGGS), at an estimated cost of $206,132,000. At the February 2009 hearing, NWE reduced its cost estimate for DGGS to $201,819,778.

2. The Montana Consumer Counsel (MCC), the Large Customer Group (LCG), Renewable Northwest Project and Natural Resources Defense Council (RNP/NRDC), Colstrip Energy Limited Partnership, and Shell Energy North America LP were granted intervention in the proceeding. MCC, LCG and NRDC were active intervenors in the Compliance Filing phase of the proceeding.

3. On May 19, 2009, the Commission issued Order No. 6943a authorizing NWE to construct DGGS. The Commission found prudent the $81,112,000 turbine generator cost. The Commission directed NWE to submit a Compliance Filing within 90 days after DGGS commenced commercial operation to serve as the basis for a final cost review of DGGS and for establishment of DGGS's revenue requirement. The Commission deferred a decision on cost allocation issues until the Compliance Filing stage of the proceeding.

4. On October 8, 2010, NWE filed an Application for Interim Rates requesting that the Commission approve an interim increase in electric revenues in the amount of $45,282,419 to be effective January 1, 2011, the date DGGS was expected to be commercially operational. On October 19, 2010, NWE updated its interim request to reflect a lower actual cost of debt for DGGS.

5. On November 17, 2010, the Commission issued Interim Order 6943b, which authorized NWE to increase rates on an interim basis by $44,935,134.

6. DGGS commenced commercial operation on January 1, 2011. On March 31, 2011, NWE submitted its required Compliance Filing. On the same date, NWE also filed a Motion to Revise Interim Rates to reflect the revenue requirement information included in the Compliance Filing, including the use of 51.875% accelerated bonus tax depreciation for 2011.

7. On April 20, 2011, the Commission issued a Second Interim Order, Order No. 6943c, which approved a revised interim revenue requirement of $37,825,239, effective in rates on an interim basis beginning May 1, 2011.

8. On June 3, 2011, the Commission issued Procedural Order No. 6943d.

9. On October 19, 2011, the Commission issued a Notice of Public Hearing.

10. The hearing was held November 9 and 10, 2011, in Helena, Montana. NWE, MCC, NRDC and LCG filed post-hearing briefs.

SUMMARY OF PREFILED TESTIMONY

Revenue Requirements

NWE compliance direct testimony

William T. Rhoads

1. William Rhoads, NWE's general manager of generation, described the construction of DGGS and the roles of the various project team members. He reported that DGGS was completed on time, under budget, and is operating as planned.

2. Rhoads testified that, through the end of February 2011, the total capital cost for DGGS was $182,503,288, but that there were approximately $2.2 million of remaining capital costs that would be finalized during the processing of this case, as well as an as-yet unknown amount of NWE/NewMech contingency cost savings. (NewMech was NWE's Engineer, Procure and Construct contractor.) Rhoads said the DGGS total capital cost of $184.7 million is $17.1 million below the original estimate of $201.8 million. Rhoads explained each of the cost categories as well as the total project cost.

3. According to Rhoads, the total projected O&M costs for DGGS are approximately $6.8 million per year.

4. Rhoads said that Vantage Consulting, the PSC's consultant, requested NWE develop formalized in-service test criteria to assure the Commission that the plant met all of the contractual guarantees related to performance and emissions. Rhoads asserted the results of the tests performed in accordance with the test criteria were that the turbine generators met and often times exceeded the performance and emission guaranteed levels, the balance of plant performed with no limitations, and the plant successfully provided regulation service as designed for January and February 2011.

Eugene Scott

5. The Shaw Power Group was NWE's Owner's Engineer for the DGGS project. Eugene Scott, Shaw's construction site representative at DGGS, provided information on his participation in the project on behalf of Shaw, including reviewing pay applications and change

orders, ensuring quality assurance specifications were met, and monitoring adherence to the project schedule.

Michael J. Barnes

6. Michael Barnes, NWE's manager of Montana Production Operations, described the DGGS fuel procurement plan. According to Barnes, DGGS has unique operational demands because the amount of electricity required for moment-to-moment regulation on the transmission system must continually be adjusted up or down. Therefore, the amount of fuel needed varies from day to day. Barnes said NWE estimated the annual fuel need by examining the amount of regulation needed historically, then translating that into the amount of fuel needed each day. NWE provided this information to prospective suppliers to help them prepare bids. Barnes said future fuel procurement activities will have the benefit of actual historic DGGS fuel consumption data, which will be provided to suppliers to assist them to predict the expected range of daily values and total volume requirements.

7. Barnes discussed the volatility of natural gas and electric markets in the region and its effect on DGGS's net fuel costs (actual fuel costs minus energy revenue credits). He noted the price of electricity on the Mid-Columbia (Mid-C) index is tied to the price of natural gas that is used to fuel gas plants. He said DGGS's energy revenue credit is based on the volatile Mid-C index, which is a factor that must be considered when NWE plans to acquire stably priced natural gas for the plant. Barnes stated that NWE addressed the volatility in the Mid-C index and the desire for stable net fuel costs by taking advantage of the fact that, while both gas and electricity prices are volatile, they generally move together. By buying index-based natural gas, Barnes said NWE is able to reduce the volatility by following the price of electricity over time. According to Barnes, the alternative method would be to purchase gas on a fixed-price basis, but he contended that fixed-price purchasing results in greater volatility in the net fuel cost because the energy revenue credit would continue to vary with the Mid-C index.

8. Barnes testified that DGGS subscribes to interruptible gas transmission service because firm gas transmission service is unavailable and NWE will use diesel as an alternative fuel source for the facility in the event natural gas service is interrupted. Barnes said NWE determined it did not want to have to store large quantities of diesel and included in its diesel procurement plan a process that emphasizes the supplier's ability to intermittently, but reliably,

deliver large quantities of diesel on short notice in the cold-weather situations when interruptions are most likely.

9. Barnes explained there is no on-system natural gas storage available for use at DGGS. Had it been available, the strategy for natural gas procurement would have allowed for consideration of different procurement options, such as using storage as a tool to meet peak demand and to mitigate market price fluctuations. Instead, NWE's expects to seek suppliers with on-system storage, assuming their prices to NWE will reflect their use of the benefits of on-system storage.

10. Barnes said that NWE contracted with Jefferson Energy Trading (Jetco) for DGGS's natural gas needs in 2011. According to Barnes, NWE sought bids from four potential bidders and two suppliers responded. Barnes said the procurement process followed NWE's fuel procurement plan, which called for NWE to select the supplier who could provide the full volume required by DGGS on a daily basis for 2011 at the best Alberta-Nova Inventory Transfer (AB-NIT, also known as AECO C) index-based price. Bidders were required to manage any imbalance between daily scheduled and actual usage.

11. Barnes said NWE contracted with Northwest Petroleum Co. for 2011 diesel supply to DGGS on an as-requested basis for up to 70,000 gallons per day with 24 hours notice. Pricing is index-based on the Oil Price Indicator Service Diesel Rack Price for this area. According to Barnes, bid packages were sent to four potential bidders and Northwest Petroleum was the only supplier to respond.

Wayne M. Hitt

12. Wayne M. Hitt, NWE's director of corporate taxes, supervised the preparation of the income and property tax items included in the development of the DGGS net revenue requirement that NWE presented in witness Patrick Corcoran's testimony.

13. Hitt said income taxes included in this filing have been calculated utilizing the partial flow-through method that the Commission has approved in prior dockets.

14. Hitt explained the computation of the 50% bonus tax depreciation for 2011 for which DGGS is qualified for under a 2010 federal law. According to Hitt, bonus tax depreciation is simply a more accelerated tax depreciation method than standard accelerated tax depreciation and it only applies to the first year of depreciation. All subsequent years are computed using the standard accelerated tax depreciation rates. Hitt said the tax benefits of the

accelerated bonus tax depreciation will result in a reduction in DGGS's 2011 total fixed cost revenue requirement of approximately $6 million. Because the bonus tax depreciation only applies to 2011, the fixed cost revenue requirement in 2012 is $5 million higher than in 2011. Customers will continue to benefit from accelerated bonus tax depreciation beyond 2011 as the federal deferred tax benefits related to bonus tax depreciation are subject to normalization requirements that will reduce rate base in future years.

15. Regarding the deferred income taxes in Corcoran's exhibits, Hitt explained the accelerated tax depreciation deferral and the net operating loss (NOL) deferral and noted the related adjustments to rate base.

16. Hitt described how NWE computed the current income tax items that are shown in Corcoran's exhibits. He said actual 2010 property taxes were used to arrive at appraised value for DGGS. Estimated mill levies were used to calculate the updated property tax expense and NWE will update these in its rebuttal testimony to reflect known changes.

17. Hitt mentioned that the Energy Producers License Tax is included in Corcoran's exhibits in the Other Taxes category.

Patrick R. Corcoran

18. Patrick Corcoran, NWE's vice president of government and regulatory affairs, presented the proposed DGGS revenue requirement, the majority of which reflected actual costs, but which also included a few outstanding estimated plant costs and estimated O&M expenses. (Ex. NWE-10, (PRC-01CF).)

19. Corcoran stated that the asset value of DGGS used in the revenue requirement computation was $184,702,288 (construction cost of $173,256,081 plus $11,446,207 AFUDC). The plant was depreciated straight line over 30 years. The other plant assets were depreciated according to NWE's current utility depreciation study. The project costs that did not meet NWE's capitalization policy (small tools, office supplies and other items having a useful life less than a year) were proposed to be included in rate base and amortized over a 3-year period.

20. Corcoran went on to explain NWE's adjustments, including the effects of bonus tax depreciation on deferred income taxes (which was discussed at length by NWE witness Hitt).

21. Corcoran stated that the overall rate of return (ROR) of 8.16% was authorized by PSC Order No. 6943a in this docket, and the total revenue requirement before cost and credit adjustments is $58,050,857. After the adjustments the net revenue requirement is $41,853,190.

22. Corcoran said NWE expects the PSC-approved interim rates to be in effect for most of 2011 and that, once the PSC sets final rates for DGGS, NWE can compute any refund due retail customers resulting from the difference in revenues billed under the interim rates during the interim period, and the revenues that would have resulted during that same time period, as if the final rates, adjusted to reflect a first-year bonus tax depreciation of 51.875%, had been in effect. NWE proposed to include any fuel cost and revenue credit tracking differences during the interim rate period as part of any interim rate true-up.

23. Corcoran proposed that electric supply service rates should be adjusted in conjunction with the most practical monthly supply tracker filing following the issuance of the final order in this proceeding. He proposed using calendar year 2011 weather-normalized loads to determine fixed cost rates, which would be consistent with NWE's use of the forecasted loads to develop the DGGS interim rates. The most current forecast loads would be used for the DGGS variable costs at that time. Corcoran provided illustrative rates for DGGS.

24. Corcoran suggested that future changes in DGGS' fixed cost of service and/or transmission service cost allocations should be considered in general rate cases, while fuel costs, revenue credits and carbon offset costs should be considered in the annual electricity supply tracker filing.

NWE compliance rebuttal testimony

Patrick R. Corcoran

25. Exhibit_(PRC-01CFR) in Corcoran's rebuttal testimony updates several revenue requirement components. Plant cost was reduced by about $2.16 million to $182,537,625. However, he noted that this figure is still not the final construction cost because a number of outstanding items are yet to be completed. Corcoran proposed tracking the outstanding construction costs items until NWE's next general rate filing, at which time material differences would be trued up.

26. Other items in the revenue requirement calculation that were updated include: the authorized return based on the updated 13-month average rate base; O&M expenses based on eight months of actual and four months of estimated costs; and depreciation and property and other taxes based on the updated plant value. His updated revenue requirement for the second year of operation, before cost and credit adjustments, is $53,927,810. Cost and credit

adjustments represent costs allocated to Transmission Service and revenue credits from energy produced by DGGS. NWE treats these adjustments as reductions to total DGGS costs that reduce retail customers' revenue responsibility. The updated net revenue requirement, including fuel expenses and less cost and credit adjustments, is $38,554,753.

27. Corcoran provided illustrative retail rates using the $38,554,753 net second year revenue requirement. Below is a reproduction of a table he provided in his testimony (page 13) that compares the cost of service impact to typical residential customer bills from the initial interim rates that were effective January 1, 2011, the revised interim rates that were effective May 1, 2011, and the updated net revenue requirement.

	DGGS Net Revenue Requirement	Total Electricity Supply Rate as of 4/1/11	Residential Electricity Supply Rate	Typical Residential Customer Bill	Percent change
Interim Rates 01/01/11	$44,935,134	$0.06140	$0.062129	$80.09	
Revised Interim Rates 05/01/11	$37,825,239	$0.06017	$0.060887	$79.16	-1.16%
Final Rates	$38,554,753	$0.06017	$0.061011	$79.25	0.001%

28. Corcoran stated that NWE does not propose to update rates until the Commission issues a final revenue requirement order. Based on the final order, NWE would calculate the over-collection amount for the interim period and propose a refund to customers over a yet-to-be-determined time period.

<u>Cost Allocation</u>

NWE compliance direct testimony

Michael R. Cashell

29. NWE's chief transmission officer Michael Cashell testified that the following considerations shaped NWE's cost allocation proposal: 1) the current allocation method; 2) the amount of regulation needed; 3) the past practice of allocating regulation costs; 4) the customers (retail and wholesale) who cause the need, and; 5) the regulation reserve capacity DGGS is capable of providing on a reliable basis.

30. Cashell explained that NWE designed DGGS so that regulation service requirements are supplied primarily by two of the plant's three generating units. The third

generator acts as an operational spare, but can be used with the other two to meet peak regulation service needs. He testified that each of the three generators has a nominal capacity of 50 MW. With two generators always on, the plant produces 7 aMW (3.5 aMW per unit) of minimum "turn-down" energy that NWE proposes to include in its retail supply portfolio. Under optimal conditions, two units can produce about 93 MW of regulation capability.

31. Cashell stated that, historically, NWE's 60 MW regulation need was allocated between retail and wholesale customers based on their relative need for regulation service when the need for that service is at its peak. He contended that approach is reasonable because a balancing authority must be able to provide regulation service under peak conditions. He said the relative needs of retail and wholesale customers are measured as their respective shares of 12-month rolling coincidental peak (CP) load. He also asserted that this allocation method is consistent with Schedule 3, Regulation and Frequency Control, of NWE's FERC-jurisdictional Open Access Transmission Tariff (OATT), and is the method that NWE has used in its electricity supply tracker filings since 2002. He added that the method is also consistent with the cost-causer pays principle. He said DGGS's regulation capability, and the associated cost, above the 60 MW historically needed for loads would be directly assigned to retail customers because the need for that capability arises from variable energy resources (VERs, e.g., wind) currently serving retail customers or anticipated to serve retail customers in the future.

32. Cashell testified that 105 MW is a reasonable estimate of NWE's near-term regulation need and matches what DGGS is capable of producing on a sustained, reliable basis, given the engineering and expected operational characteristics of the plant. He concluded, therefore, that 105 MW should be the denominator for purposes of allocating the costs between NWE's retail and wholesale customers. He noted that NWE also proposed using 105 MW as the denominator in its DGGS filing with FERC (Docket No. ER-10-1138) and in its pre-approval application in this docket. Cashell asserted that it is crucial for cost allocation factors to be applied consistently in its two regulatory jurisdictions for NWE to fully recover DGGS costs.

33. The table below shows the result of NWE's proposed DGGS allocation method. Eighty percent of DGGS cost is allocated to retail customers and 20 percent to wholesale customers.

Allocation of Regulation Costs		
	Capacity (MW)	Allocation %
Traditional/Historic Regulation Requirements	60	
Wholesale Customers Load Ratio Share (35%)	21	20%
Retail Supply Customers Residual Share (65%)	39	
Retail Supply Customers Wind Integration (lower end)	45	
Total Retail Customers Regulation Needs	84	80%
Total Regulation Needs	105	

34. Cashell stated the Commission and FERC have consistently used and authorized a load ratio share allocation, based on coincident peak loads by class, for many years to allocate regulation costs between retail and wholesale customers. Accordingly, NWE proposed the same method in this case.

35. Responding to MCC witness John Wilson's suggestion that it may be more appropriate to allocate the 60 MW of traditional regulation needs based on the relative energy use by retail and wholesale customers, rather than on coincident peak demand, Cashell contended that if Wilson's cost allocation methodology were adopted in Montana, NWE would under-recover over $12.2 million of its annual net operating income for DGGS. Given that the total annual net operating income for DGGS is estimated to be about $14 million, Cashell stated that Wilson's approach would wipe out over 85 percent of the net operating income for DGGS and have a significant financial impact on NWE.

36. According to Cashell, allocating DGGS costs based on average energy use would grossly understate the amount of regulating resource and associated costs needed to serve NWE's retail customers. He said that just as the transmission system must be built to withstand the peak amount of power that will flow on it, DGGS was built to provide the peak amount of regulation necessary to serve its customers, based upon each customer class's peak use. He added that, public policy notwithstanding, wholesale customers are not, in fact, using power from the VERs that NWE was required to acquire for its retail loads.

37. Cashell testified that if DGGS provides any additional services or serves additional customers, NWE will propose changes to the allocation and revenue credits to account for those additional services or customers. He added that while the future is uncertain with regard to VER integration, NWE designed DGGS with operational flexibility in mind.

MCC compliance direct testimony

Dr. John W. Wilson

38. Dr. John Wilson, an economic consultant, contended that NWE's allocation method failed to reasonably allocate regulation costs to major users of its transmission network, and that this is evidenced by the fact that retail customers, to whom NWE proposed to allocate 80 percent of regulation costs, were responsible for only about 40 percent of the energy transmitted on the network.

39. According to Wilson, NWE proposed to allocate 60 MW of "traditional" regulation service between PSC and FERC jurisdictional customers based on a 65/35 12-CP load ratio share (39 MW to PSC-jurisdictional customers, 21 MW to FERC-jurisdictional customers) and to directly assign an additional 45 MW to PSC-jurisdictional customers. In the end, NWE would attribute 84 MW of transmission regulation (80%) to PSC retail loads and 21 MW (20%) to FERC loads (wholesale, cooperative and choice customers). He contrasted this allocation to NWE's most recent annual report to the PSC which showed NWE's network received 17,984,717 MWh of electricity for transmission in 2010, of which 6,018,605 MWh (33.5%, including line losses) were delivered to retail (non-choice) customers.

40. Wilson pointed to a published Oak Ridge/DOE study showing that on a system with a total load of about 2,000 MW, non-industrial load had a 65.7 percent energy share, but accounted for only 7.2 percent of the system's regulation requirements. Conversely, industrial customers, accounting for 34 percent of system energy, were responsible for 92.8 percent of regulation requirements.[1]

41. Wilson asserted that different types of loads require different regulation requirements. He said coincident peak demand is not a logical method for allocating regulation costs because it reflects transmission network usage in only 12 hours of the year, whereas regulation service is required to support transmission usage in all 8,760 hours. He added that this is especially the case with DGGS. He contended that a large portion of DGGS costs, which NWE allocated on the basis of 12-CP demand, is for natural gas consumed at all times during the year. He said allocating these costs on the basis of peak demand is illogical and would result in an allocation that does not reflect cost responsibility.

[1] See Brendan Kirby and Eric Hirst, "Customer-Specific Metrics for the Regulation and Load Following Ancillary Services" prepared for the Office of Energy Efficiency and Renewable Energy, U.S. Department of Energy by Oak Ridge National Laboratory, ORNL/CON-474, January, 2000.

42. According to Wilson, because industrial loads likely bear greater responsibility for regulation costs than non-industrial loads (see the Oak Ridge/DOE study referenced above) and since regulation requirements likely differ among industrial customers, the Commission should order NWE to perform studies that quantify differences between customer classes and between large industrial customers regarding responsibility for regulation requirements. Until those studies are completed and evaluated, he recommended allocating regulation costs between non-choice (retail), and other (FERC-jurisdictional) customers requiring regulation in proportion to electricity transmission MWh. As an interim measure (again until studies quantifying responsibility for regulation requirements are completed), he proposed exempting through-wheeling loads from any responsibility for regulation service costs. He said this allocation approach would likely overcharge PSC-jurisdictional retail customers since industrial loads are probably more than proportionally responsible for NWE's transmission system regulation service requirements.

43. Wilson's recommended allocation percentages for PSC- and FERC-jurisdictional transmission system users requiring regulation service are:

Transmission Users	MWH	Percentage
Non-choice (PSC)	6,018,605	47.55%
FERC Jurisdictional	6,637,745[2]	52.45%

44. Wilson testified that choice customers seek to minimize their own cost allocation by avoiding regulation costs associated with wind-generated power, even though they enjoy the environmental benefits of that power, and, in fact, are consuming it. He asserted that being a choice customer does not, as an economic or equity matter, entitle one to avoid the sharing of integrated transmission network costs that enable the delivery of clean energy throughout the network.

45. Wilson concluded that DGGS costs should be allocated on the basis of transmission system use in all hours, not just peak hours. He asserted that, regardless of whether transmission costs continue to be allocated as they have been historically, an independent allocation of regulation costs is now necessary. He said it would make no more sense to allocate NWE's transmission regulation costs on the basis of peak demand because transmission lines are

[2] Excludes through area wheeling.

allocated that way than it would to allocate generation fuel costs on the basis of peak demand because generating plant costs are allocated that way.

LCG compliance direct testimony

James R. Dauphinais

46. James Dauphinais, a regulatory consultant, addressed the allocation of DGGS costs between NWE's bundled retail electric customers and OATT customers.

47. Dauphinais emphasized that, for OATT ratemaking purposes, FERC will independently decide on the allocation of DGGS costs regardless of how the PSC allocates costs for bundled retail customers. He also said FERC's cost allocation to OATT customers may differ significantly from what NWE proposed. He noted that Dr. Alan Rosenberg discussed NWE's cost recovery risk in testimony on behalf of LCG earlier this proceeding (see Direct Testimony of Dr. Rosenberg (originally Ms. Iverson) at 5-6). Dauphinais asserted that NWE understood this risk when it made its decision to construct DGGS rather than to continue to purchase regulation service from third-party suppliers on an as-needed basis.

48. Dauphinais contended that DGGS is able to provide more than just regulation service to NWE's retail customers, such as reactive supply and voltage control to the extent the plant is equipped with automatic voltage regulation equipment, and the ability to restart NWE's transmission system if a system blackout occurs to the extent the DGGS units can be started without offsite electric power. He testified that DGGS excess capacity can be used to provide electric energy to retail customers to avoid involuntary curtailment during system emergencies, to either serve retail customers or to support economic off-system energy sales on their behalf, and/or to provide spinning reserve service or supplemental reserve service for retail or OATT customers who do not self-provide or acquire these two ancillary services from third-party suppliers. Dauphinais asserted it would be unreasonable to allocate the entire capacity of DGGS to the provision of regulation service.

49. Dauphinais expressed doubt that DGGS's primary role will continue to be the provision of regulation service in the future. He said vertically integrated utilities typically use all of their dispatchable generation that can operate under AGC to economically provide for regulation service, that the trend toward consolidation of NERC balancing authorities results in more efficient use of existing regulation capacity, and that a possible FERC decision to move to

intra-hour scheduling would likely reduce regulation capacity needs. According to Dauphinais, although NWE uses DGGS to meet all of its regulation capacity needs, it does so by dispatching the plant out of economic merit order. He said that as NWE acquires or constructs intermediate and baseload generation, it will be able to use those resources to provide regulation service in a manner that is more economical. He argued that these factors should act over time to transform the operation of the DGGS from continuous operation for purposes of providing regulation service to the limited operation of a peaking generation facility, and said these factors further support the idea that the entire capacity of DGGS should not be allocated to regulation service.

50. Dauphinais noted that in FERC Docket No. ER10-1138-000, FERC found that NWE's proposed OATT rate for regulation service may not be just and reasonable. FERC has scheduled a hearing on NWE's proposed OATT rate for regulation service and the cost allocation proposal that underlies that rate. He said that when he filed his testimony, the FERC proceeding was still in an early stage, but he expects the following issues to be raised in it:

- Whether the 60 MW estimate of the regulation capacity needed for load is too high;
- Whether the estimated 45 MW amount of regulation capacity needed to integrate wind power purchases for bundled retail customers is too low;
- Whether the entire capacity of DGGS (150 MW nominal) should be allocated to regulation service or only the portion of that capacity that is equal to the total estimated regulation capacity need for NWE (i.e., the sum of the estimated regulation capacity need for load and the estimated regulation capacity need for wind integration for bundled retail customers);
- Whether NWE should be allowed to recover any DGGS fuel costs in its OATT regulation service rate; and
- To the extent NWE is allowed to recover DGGS fuel costs in its OATT regulation service rate, whether NWE's estimates of the DGGS generation level necessary to provide regulation service and the credit that should be provided back to OATT regulation service customers are reasonable.

51. Dauphinais recommended that the Commission expressly retain its right to reconsider and/or adjust any DGGS cost allocation to bundled retail customers that may be determined in this proceeding once FERC issues a final order in Docket No. ER10-1138-000. He said that in making this recommendation he is not suggesting that NWE should be allowed to automatically adjust its proposed cost allocation to bundled retail electric customers based on the

outcome of the FERC proceeding; rather, he acknowledged the Commission's authority to adjust the allocation following FERC's resolution of the OATT customer allocation issue.

NWE compliance rebuttal testimony

Michael R. Cashell

52. Cashell testified that, in prior orders approving NWE's third-party regulation service contracts, FERC specifically approved a 12-CP-based allocation approach, and that allocation approach has been the basis for costs that were subsequently approved by the PSC. He noted that regulation costs associated with VERs (e.g., wind) serving retail supply customers have always been directly assigned. He asserted that FERC prefers the 12-CP approach and has a long history of applying it. He said NWE's allocation approach in this case is based on that consistent historical regulatory treatment and the sound policy reasons supporting the approach. He argued 12-CP is a reasonable basis for allocating DGGS costs because the plant must be available based on peak needs for regulation service.

53. Cashell rejected Wilson's assertion that in the past regulation costs were small and were combined with other transmission network costs for administrative reasons. Cashell countered that the relative amount of regulation costs should not matter and that costs should be allocated according to sound ratemaking principles. He also rejected an allocation of regulation costs based on energy use, asserting that regulation is a demand service, despite the fact that energy is produced as a by-product. He contended that because regulation is an ancillary service to transmission, FERC has long held that it is properly allocated on the basis of demand.

54. Cashell contended that the Oak Ridge/DOE study Wilson cited is a single study about load and regulation variation between different classes of industrial customers and has nothing to do with allocating regulation costs between retail and wholesale customers. He maintained that the 12-CP approach captures the load characteristics of each and every customer and the additional studies Wilson recommended are not necessary.

55. Cashell acknowledged that energy is produced during the regulation process. He stated that NWE's allocation approach reflects the energy's value through revenue credits and that the proper way to allocate the revenue credits between retail and wholesale customers is with the 12-CP approach because the energy is produced by the regulation process.

56. Cashell asserted that there is no basis for Wilson's contention that wholesale customers should bear some responsibility for integrating VERs into the retail supply portfolio. He said VER output specifically serves retail customers so those customers should bear the integration costs. He noted that historically these costs have been directly assigned to retail customers.

57. Cashell asserted that, contrary to Dauphinais's testimony, it is unlikely that in this case FERC will deviate from the approach it previously used to set NWE's Schedule 3 OATT rates based on third-party contracts. However, he said that if FERC does adopt a different allocation method, NWE and its customers face significant financial risk.

58. Regarding Dauphinais's assertion that DGGS can be used to provide other services besides regulation so the PSC should not allocate all the plant's costs to regulation service, Cashell countered that DGGS was built solely to provide regulation service given an illiquid market for such services. He stated that the plant cannot simultaneously provide regulation services and the other services Dauphinais discussed. More specifically, Cashell asserted:

- DGGS cannot be used to meet a planning reserve margin, and even if it could, that is not a service that is specifically purchased by customers or identified by FERC in the OATT;

- Reactive Support and Voltage Control, Schedule 2 in NWE's OATT, is set at a rate of $0 because NWE does not pay generators for the service. There are no customers to charge and DGGS is located in an area where reactive support and voltage control are not needed;

- Although DGGS can be used for system restoration, that is not a service specifically purchased by customers;

- DGGS cannot be used to provide energy for retail customers. The energy produced in the regulation process is a by-product and its value is accounted for in the allocation approach NWE proposed;

- DGGS cannot provide spinning and supplemental reserves. NERC/WECC reliability criteria require NWE to maintain spinning and supplemental reserves in addition to regulating reserves. Even if DGGS could provide spinning and supplemental reserves, NWE has no customers that purchase these reserves.

59. Cashell disagreed with Dauphinais that NWE dispatches DGGS out of economic merit. According to Cashell, there is no economic merit for DGGS because it is a regulating

resource that exists to serve the reliability needs of the system, not the energy needs of customers. He noted that NWE does not have multiple resources capable of providing regulation service that it can dispatch on economic grounds. He said NWE continues to pursue market products that may be cost-effective compared to dispatching DGGS.

60. Finally, Cashell stated that FERC's finding that NWE's proposed OATT Schedule 3 rate may not be just and reasonable is typical when the agency sets a matter for hearing to further examine a utility's proposals.

Gary L. Goble

61. Gary Goble, a NWE consultant with the firm Management Applications Consulting, Inc., rebutted Wilson's testimony regarding the allocation of DGGS costs between retail and wholesale customers. Goble explained that demand-related costs vary with the rate of power use, while energy costs vary according to cumulative use of a facility over time, regardless of the rate of use. He likened demand to a car's speed at a point in time and energy to the distance traveled in some time period. He contended that because demand is related to the rate of output of a plant, the fixed costs of that plant depend on the size of the plant and are generally allocated on the basis of demand rather than energy.

62. Goble linked customers' coincident peak demand – the combined demand of customers at the time of the system's maximum demand – to the total amount of transmission system capacity NWE needs to serve its customers. He said the linkage between coincident peak demand and capacity requirements justifies using coincident peak demand to allocate costs. He asserted that NWE's 12-CP allocation approach reasonably reflects those transmission loads that caused NWE to build DGGS for regulation service.

63. While acknowledging that a number of factors drive regulation requirements, including the size of moment-to-moment load fluctuations, changes in the direction of those fluctuations, and generation response rates, he disputed Wilson's testimony that coincident peak demands are not the cause of regulation costs. He countered that a 12-CP allocation method is fair and reasonable, is used by much of the utility industry, and accurately reflects the manner in which regulation costs are incurred. He pointed to references in NARUC's Electric Cost Allocation Manual and FERC's Electric Rates Handbook that support the use of coincident peak demand allocators. He also asserted that Wilson's proposed energy allocation is not an accepted industry approach and is not mentioned in either NARUC's or FERC's manual. Furthermore,

according to Goble, a number of balancing authorities, including the Western Area Power Administration, the Electric Reliability Council of Texas, and the Midwest Independent System Operator, use some form of load share ratio to allocate regulation costs.

64. Goble discounted the likelihood that the additional studies Wilson recommended would yield information useful for allocating regulation costs and asserted that any allocation factors that might emerge from such studies would not meet the often-referenced Bonbright standards of simplicity, certainty, convenience of payment, economy in collection, understandability, public acceptance, and feasibility. He contended that the massive amounts of customer usage data needed to implement Wilson's approach are not available today and would be subject to extensive disagreement and litigation if used to allocate costs.

Stephen M. Merchant

65. NWE's consultant Stephen Merchant addressed Wilson's and Dauphinais's respective cost allocation proposals. He asserted that the normal regulatory cost allocation process seeks to specify how a utility can recover an authorized revenue requirement. He contended that, in contrast, although neither MCC nor LCG contested NWE's compliance revenue requirement for DGGS, both parties recommend cost allocation approaches that would make it impossible for NWE to recover that revenue requirement.

66. Merchant testified that Wilson's kwh-based allocation method would require NWE to withdraw and/or revise its current FERC application and convince FERC that a kwh-based allocation is preferable to a 12 CP load-based allocation. Should that effort fail, Merchant asserted NWE would not recover its DGGS revenue requirement because of the inconsistent allocation approaches applied by the state and federal regulators. He said the chances of FERC accepting a kwh-based allocation method are "slim to none," noting that, to his knowledge, FERC has not considered or authorized anything other than capacity-based allocations since it adopted Order 888 15 years ago.

67. According to Merchant, FERC has consistently applied capacity-based cost allocation methods for ancillary services. He said FERC could view Wilson's suggested kwh-based allocation as an attack on fundamental premises underlying the OATT and associated rate-making policies. He asserted that Wilson's proposal would change long-standing and settled FERC practices and would require a very high level of logical and empirical support. He said Wilson's proposal does not meet that standard.

68. Merchant testified that Wilson's proposal is incomplete because it does not specify the rate design by which allocated costs would be collected from customers. Merchant advocated using a 12 CP load-ratio share cost allocation method, stating that Goble's compliance rebuttal testimony accurately described the rationale for this method.

69. In response to Dauphinais's cost allocation proposals, Merchant disagreed that DGGS costs are attributable to anything other than regulation service. He testified that DGGS was constructed solely to provide all of the regulation service requirements in NWE's balancing area and, therefore, regulation service is the sole cost driver. He said that it would not be appropriate to allocate DGGS costs based unknown, speculative services that the plant might be able to provide at some point in the future.

70. Merchant contended that regulators should allocate costs and set rates in a way that applies the rates to predictable billing determinants and gives the utility an opportunity to recover the authorized revenue requirement. He said Dauphinais's proposal to allocate a portion of DGGS costs to Schedule 2 (Reactive Supply) in the OATT would violate this principle because NWE does not have a rate in its OATT for Reactive Supply and, therefore, has no way to bill for these costs. He also noted that all generating resources that serve loads in NWE's balancing area are required to provide reactive power according to protocols specified in their interconnection agreements with NWE. He asserted that if NWE were to establish a Schedule 2 rate, the result would be an unpredictable re-allocation of such costs among NWE's retail and wholesale customers that could increase costs for customers if other generators also unbundled reactive supply costs. Merchant stated that NWE's current Schedule 2 rate of zero effectively bars other generation owners in the balancing area from developing and charging reactive power costs through NWE's OATT.

__Carbon Offset Projects__

NWE compliance direct testimony

John Fitzpatrick

71. John Fitzpatrick, NWE's executive director of governmental affairs, described NWE's efforts to implement the proposed carbon offset plan for DGGS.

72. Fitzpatrick said that in March 2010 NWE mailed an RFP for carbon offset projects to the 41 counties in its service territory, and a notice of the RFP's availability was

published in the Montana League of Cities and Towns' newsletter. According to Fitzpatrick, NWE viewed this first round of applications as a pilot test intended to not only start the carbon offset program, but also to identify its flaws so that it could be improved in the future. NWE received 23 applications from 13 different entities. The requests for funding ranged from a low of $11,500 to a high of $637,500 and totaled $2,621,650.

73. A three-member advisory committee, comprised of Fitzpatrick and one representative each from Commission staff and the Montana Environmental Information Center, reviewed the applications and recommended a short list of five projects totaling $557,045 to NWE's Senior Management team. Of those, NWE recommended PSC approval of the following three carbon offset projects that total $257,045: (1) Anaconda-Deer Lodge County street lights retrofit; (2) Montana Land Reliance acquisition of conservation easement in Jefferson and Silver Bow counties; and (3) Trout Unlimited reforestation of lands damaged by historic mining practices.

74. Fitzpatrick said these projects meet the statutory definition at § 69-8-103(5), MCA, of "cost effective carbon offset," which defines the term as actions "which collectively do not increase the cost of electricity produced annually on a per megawatt hour basis by more than 2.5%." According to Fitzpatrick, the 2.5% statutory limitation applied to the proposed $41,853,190 DGGS net revenue requirement results in a carbon offset cap of $1,046,330. The three recommended projects increase the revenue requirement by 0.6%, well below the 2.5% cap.

DISCUSSION, ANALYSIS AND FINDINGS OF FACT

Revenue Requirements

75. In the pre-approval phase of this case, the Commission determined that NWE's acquisition of DGGS as a regulation resource was in the public interest. (Order No. 6943a, ¶ 257.) The Commission found that the known cost of $81,112,000 for the DGGS turbine generators was prudently incurred (*Id.*, ¶ 263), but directed NWE to submit a Compliance Filing after DGGS commenced commercial operation to serve as the basis for a final cost review of DGGS and for establishment of DGGS's revenue requirement. (*Id.*, ¶¶ 264-265.)

76. In the Compliance Filing, NWE reported that through the end of February 2011, the total capital costs for DGGS were $182,503,288. (Ex. NWE-1, p. 17.) At the time of filing, NWE had yet to finalize approximately $2.2 million of remaining capital costs for DGGS, but

indicated that would occur during the processing of the filing. NWE estimated the total DGGS capital cost to be $184,702, 288. (Ex. NWE-10, p. 4.) In rebuttal testimony, as more actual costs became known, NWE reduced the total DGGS capital cost to $182,537,625. (Ex. NWE-11, p. 3.)

77. No party to the proceeding contested the final capital cost, the fuel cost or the O&M expenses associated with the plant. Accordingly, the prudence of these DGGS-related costs incurred by NWE is not at issue.

78. NWE has in place a first-year interim revenue requirement of $37,825,239. This is the result of the Second Interim Order, in which the Commission approved a decrease from the original interim granting of $44,935,134. (Second Interim Order No. 6943c, ¶ 10, and Interim Order 6943b, ¶ 12.) NWE witness Corcoran's updated analysis of the second-year revenue requirement in his compliance rebuttal testimony was $38,554,753. (Ex. NWE-11, (PRC-01CFR) , p. 1.) In NWE's Post Hearing Provide No. 1, dated December 2, 2011, NWE requested that the Commission adjust the first- and second-year revenue requirements to include and approve the DGGS actual property tax amount. The now-known actual property tax amount for DGGS was $3,735,886, which is $666,435 more than the amount provided in Corcoran's rebuttal compliance testimony. (NWE Post-Hearing Provide, Att. 1.) As a result, NWE requests that the final first-year revenue requirement be adjusted to $34,513,978 and that the final second-year revenue requirement be adjusted to $39,089,270. (NWE Br., p. 34.) The Commission approves the first- and second-year revenue requirements as adjusted to account for the actual DGGS property tax amount. Attachments 1 and 2 to this Order show the first- and second-year revenue requirements derivations as adjusted to reflect the increase in property taxes.

79. The proposed adjustment to the first-year revenue requirement results in an over-collection of revenues and necessitates a rebate to NWE customers. NWE will rebate the over-collection over a one-year period beginning with the effective date of this Order. Both the first and second interim orders required any over-collection to be rebated with 10.25% interest. (Order 6943b, Order ¶ 5, and Order 6943c, Order ¶ 5.)

80. The rate base of DGGS and the rate base used for calculation of both the first- and second-year revenue requirements is $182,537,625, which is $19,281,375 below the originally estimated construction cost of DGGS. Both NWE and its contractors managed construction

costs well and the savings in construction costs will provide ratepayer benefits over the life of the project.

81. NWE proposed to track the final actual cost for outstanding items identified by Corcoran in his rebuttal testimony (NWE Ex. 11, at (PRC-3), (PRC-4)) and to identify at the time of NWE's next general rate filing any differences in the final actual cost of these items compared to the levels included in the final revenue requirements in this docket. There is an estimated $673,000 remaining work to be accomplished, and two construction liens totaling about $3 million that have been filed due to contractors' disputes with NewMech. The construction liens have been paid in that amount to NewMech, and any reduction as a result of the negotiation of the liens will result in a reduction in rate base for DGGS. The Commission approves the rate base amount of $182,537,625, except for and including any adjustments as a result of the outstanding items noted above.

82. NWE proposed the use of calendar year 2011 normalized loads to determine the DGGS fixed costs. (Ex. NWE-10, p. 16.) The use of those normalized loads was not contested and is approved by the Commission as reasonable and prudent.

Amount of Regulating Reserve Required in NWE Balancing Authority

83. As described above, Cashell's DGGS cost allocation proposal assumes that NWE currently needs, and DGGS provides, 105 MW of total regulating reserve capacity, and that NWE's "traditional" loads and resources (i.e., prior to significant wind generation capacity) required 60 MW of regulating reserves. In the pre-approval phase of this case NWE proposed, and the Commission approved, acquisition of DGGS to meet current and anticipated within-hour regulation service needs (Order 6943a, ¶¶ 32, 63-70, 104-108, 219.). That Order deemed "reasonable" the then-current need for 91 MW of regulating reserves (Order 6943a, ¶¶ 32, 219) and found "reasonable" also "NWE's projection that it will need 115 MW of regulation service by 2015" (Order 6943a, ¶ 219). NWE testified to a range between 105-135 MW by 2015, and this estimate was contingent on the acquisition of meeting the renewable portfolio standard by 2015, which would require "an additional 194 MW of renewable resources...which includes 68 MWs of CREPs [community renewable energy projects] and 50 MW of QF [qualifying facility] projects" (Order 6943a, ¶¶ 107-108). Therefore, the Commission's decision here regarding allocation of DGGS costs between Commission-jurisdictional retail customers and FERC-

jurisdictional wholesale customers does not revisit the regulating reserve requirements for traditional loads and resources or total current regulating reserve requirements, although it is contingent on the usefulness of the project to the planned acquisition of intermittent generating resources as laid out in the testimony of John Hines in the original DGGS hearing. That is, NWE's 60 MW traditional regulation capacity requirement and, contingent on the need for wind integration, 105 MW total regulation capability are approved values pursuant to Order 6943a. The Commission finds counterintuitive the proposition that NWE would have habitually purchased an excess of regulation service for such a long period of time from third-party providers for its traditional regulation needs. GENIVAR's June 1, 2011 *NorthWestern Energy Montana Wind Integration Study*, which was added to evidence in the compliance phase of this Docket, further supports the Commission's prior determination that 60 MW is an accurate measure of NWE's traditional regulation capacity requirement.

84. Regulation service requirements are altered depending on the time interval in which a utility schedules its load and supply; by the markets it has opportunity to and does participate in; and by refined scheduling techniques irrespective of the scheduling interval (Tr., pp. 310-315). Nothing in this Order should prevent NWE from participating in systems or adopting methods that more efficiently dispatch or predict the load and generation on NWE's system; indeed, the Commission encourages such efficiencies. NWE should notify the Commission when its need for regulating reserves changes as a result of participating in such a system or adopting such a method.

Cost Allocation

85. The 45 MW difference between NWE's 60 MW traditional regulation capacity requirement and DGGS's 105 MW total regulation capability accommodates existing and future wind generation capacity intended to serve Commission-jurisdictional retail customers. Therefore, direct assignment to these customers of that proportional share of DGGS's fixed and variable costs associated with integrating wind is approved. In its Answer Brief, MCC appeared to abandon its position that the Commission should allocate a portion of the 45 MW wind generation-related regulating reserve requirement to wholesale customers, contending that the net effect of its allocation approach would be to allocate 70% of DGGS costs to retail customers and 30% to wholesale customers. (MCC Answer Br., p. 2.) MCC calculated the 70% retail

customer share by allocating the 60 MW traditional regulation capacity requirement using loads in all hours and assigning the 45 MW wind generation-related regulation capacity requirement to retail customers. (*Id.*) To the extent residual regulation capability available at DGGS is used to provide other services, or to provide regulating reserve capacity for wind resources not serving NWE's retail customers, NWE proposed to credit the resulting revenue against DGGS costs in future rate proceedings. The Commission finds this approach reasonable and approves it.

86. NWE proposed to allocate its 60 MW traditional regulation capacity requirement between Commission-jurisdictional retail customers and FERC-jurisdictional wholesale customers using the 12-CP load ratio share method. That method establishes the retail customers' share of DGGS costs by subtracting the sum of the 12-month average coincidental peak demands of individual wholesale customers from the total balancing area 12-month average coincidental peak demand. (Ex. NWE-7, pp. 11-12, Ex. NWE-8, p. 8.) The retail-wholesale jurisdictional cost allocation that results from this method is 65% retail-35% wholesale. (Ex. NWE-7, p. 14.) For Commission-jurisdictional rate-setting purposes, this allocation would remain fixed until revised by the Commission in a future rate proceeding. (Tr. pp. 126-127.)

87. NWE contended that the 12-CP load ratio share method is a long-standing method that the Commission and FERC previously approved for recovering traditional regulation services. (Ex. NWE-8, p. 9.) NWE also claimed that the 12-CP load ratio share method is cost-based because it incorporates those factors that drive the costs of regulation service and sends appropriate price signals to customers regarding their contribution to regulation service costs. (Ex. NWE-7, pp. 10, 12, DR PSC-030.) Cashell acknowledged an imperfect correlation between coincident peak loads and peak use of regulation service. (Tr. p. 199.) He testified that load and resource fluctuations cause regulation needs and that NWE experiences the greatest load fluctuations as load transitions toward or away from peaks. (Tr. pp. 137, 140-1, 156, 199-200.) For these reasons he concluded that the 12-CP method is reasonable.

88. NWE's post-hearing brief included a partial analysis of 15-minute load data it provided in response to data request RNP-018. NWE analyzed 11 days from 2006 – 2008. It asserted that the analysis confirms that load variability on its system is greatest during or near system peak times. (NWE Br., p. 17.) In its reply brief, NWE stated that an analysis of load data is appropriate because within-hour load variation is an important driver of the need for traditional regulation. (NWE Reply Br., p. 7.)

89. LCG endorsed NWE's proposal to use the 12-CP load ratio share allocation method and opposed MCC's proposal to allocate DGGS costs on the basis of demand in all hours. (LCG Br., p. 4.)

90. MCC testified that a 12-CP load ratio share allocation is illogical and unreasonable because it reflects transmission network usage in only 12 hours of the year whereas regulation service is required in all hours. (Ex. MCC-1, p. 6.) Wilson asserted that regulation is not a peak demand-related cost and that a large portion of DGGS costs consists of costs for natural gas that is consumed at all times during the year. In its answer brief, MCC contended that NWE's analysis of 15-minute load data does not support a 12-CP load ratio share allocation. MCC pointed out that the days NWE analyzed do not appear to correspond to monthly peak days. It further found that the intra-hour load changes at the time of the monthly peaks were less than the highest intra-hour changes for the day, which tended to occur hours earlier or later. (MCC Answer Br., p. 6.) MCC stated that statistical analysis of the data included in NWE's brief showed an extremely low correlation between hourly load levels and within-hour load variation. (*Id.*, p. 7.) Wilson also provided a DOE-sponsored study by Oak Ridge National Laboratory that concluded that the amount of generating capacity assigned to regulation service is a function of the short-term volatility of system load and charges for regulation should be related to the volatility of each load, not to its average demand.[3] (DR PSC-027.)

91. The Commission's own analysis of the 15-minute load data in DR RNP-018 validates MCC's concerns over allocating DGGS costs based on 12-CP load ratio shares. The Commission analyzed all 15 minute load data for the 34 month period included in DR RNP-018. The results are summarized in the table below. The maximum hourly load variation and average hourly load were calculated as specified in NWE's post-hearing brief, page 18. In general, system peak periods do not align with the periods that experience the highest within-hour load variation, which NWE asserted is an important driver of the need for traditional regulation. Nearly all of the monthly system peaks during this period occurred in the afternoon or evening hours, but most of the hours with the highest load variation are in the early morning. The within-hour load variation observed during monthly peak hours, as well as the variation in the hours before and after the peak hours, tended to be significantly less than the highest observed monthly

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[3] The 12-CP load ratio share method relates charges for regulation to average demand because the load ratios reflect average demands during the peak hour. Tr. p. 92.

load variation. Rarely did the monthly system peak day correspond to the day that experienced the highest within-hour load variation, and the system load at the time of the highest monthly within-hour load variation averaged almost 300 MW less than the monthly system peak load. Finally, statistical analysis of an entire year's data (2006) confirmed MCC's finding that there is a very low correlation between hourly load levels and within-hour load variation ($R^2 = 0.0007$).[4]

		Monthly peak	Monthly peak	Within hour load variation (MW):				Highest load variation:	
Year	Month	MW	day – time	peak hr	peak hr-1	peak hr+1	highest	load	day – time
2006	Jan	1,452	9 – 18:00	13	63	14	122	1,209	18 – 06:00
2006	Feb	1,594	16 – 19:00	13	51	51	125	1,258	14 – 06:00
2006	Mar	1,364	14 – 19:00	10	60	18	120	1,147	7 – 06:00
2006	Apr	1,292	6 – 09:00	12	20	36	134	1,175	6 – 06:00
2006	May	1,395	18 – 16:00	4	10	19	110	1,191	3 – 07:00
2006	Jun	1,523	29 – 15:00	1	11	33	98	1,147	1 – 07:00
2006	Jul	1,651	28 – 16:00	3	6	30	179	1,030	6 – 23:00
2006	Aug	1,537	7 – 16:00	2	19	37	176	1,066	15 – 06:00
2006	Sep	1,347	5 – 17:00	13	12	13	178	866	19 – 05:00
2006	Oct	1,420	30 – 18:00	5	100	14	130	1,189	17 – 06:00
2006	Nov	1,641	28 – 18:00	10	69	21	136	1,359	12 – 18:00
2006	Dec	1,601	18 – 18:00	11	83	13	139	1,368	19 – 06:00
2007	Jan	1,628	11 – 18:00	5	68	16	137	1,247	24 – 06:00
2007	Feb	1,542	1 – 19:00	10	16	29	137	1,154	26 – 23:00
2007	Mar	1,447	1 – 19:00	10	63	8	139	1,129	26 – 22:00
2007	Apr	1,324	2 – 11:00	7	5	16	144	1,185	2 – 06:00
2007	May	1,343	17 – 15:00	53	12	35	193	1,095	2 – 09:00
2007	Jun	1,578	28 – 15:00	20	15	9	179	1,361	26 – 12:00
2007	Jul	1,739	23 – 15:00	14	24	3	188	1,448	24 – 21:00
2007	Aug	1,530	2 – 16:00	9	15	25	107	1,267	14 – 22:00
2007	Sep	1,451	30 – 23:00	34	73	482	125	1,131	24 – 06:00
2007	Oct	1,310	22 – 19:00	7	58	32	134	1,086	24 – 06:00
2007	Nov	1,561	29 – 18:00	7	29	25	128	1,164	5 – 06:00
2007	Dec	1,570	10 – 18:00	17	62	14	155	1,279	26 – 06:00
2008	Jan	1,667	21 – 18:00	19	107	20	126	1,427	24 – 06:00
2008	Feb	1,514	4 – 18:00	17	84	19	137	1,315	14 – 06:00
2008	Mar	1,424	4 – 19:00	9	43	17	133	1,224	10 – 06:00
2008	Apr	1,381	1 – 08:00	14	24	28	133	1,224	8 – 06:00
2008	May	1,344	20 – 16:00	16	9	22	133	1,064	19 – 06:00
2008	Jun	1,606	30 – 15:00	20	27	16	189	1,236	11 – 09:00
2008	Jul	1,687	21 – 16:00	8	23	36	125	1,375	24 – 10:00
2008	Aug	1,672	7 – 16:00	21	24	44	111	1,544	25 – 14:00
2008	Sep	1,365	17 – 20:00	17	67	89	134	1,137	16 – 06:00
2008	Oct	1,429	9 – 19:00	24	62	17	149	1,179	20 – 06:00
Averages		1,498		13	42	38	141	1,214	

* The high load variability shown for September 30, 2007 in the hour following the peak hour reflects an apparent error in the data.

92. NWE's cost-causal justification for the 12-CP load ratio share allocation is based on the reasoning that load changes are greatest around peak periods, so the greatest need for regulation occurs around peak periods and, therefore, the average loads of retail and wholesale customers during peak periods is a reasonable basis on which to assign responsibility for regulation service costs. As the chart above shows, neither the peak nor the shoulder hour before

[4] Analysis of 2006 load data produced statistically significant results with a 95% confidence interval (t = 2.379). The ORNL paper cited by Wilson also concluded that there is a very low correlation between load and regulation/load following requirements. See footnote 1, infra.

and after the peak hour *ever* was the hour with the highest level of load variation in a period of nearly three years. The analysis directly contradicts the claims of NWE's and LCG's expert witnesses, who, in the instance of the former, spoke of "the fact that we see regulation requirements increasing as you move to a peak period" (Tr., p. 93). There seems, if anything, to be a trend of load variability, and thus regulation needs, very late at night and early in the morning. Based on the record evidence just discussed and the parties' testimony and briefing, the Commission rejects NWE's reasoning. The evidence shows that within-hour load changes are not greatest around peak periods and load levels, no matter when they occur, are a very poor indicator of within-hour load variability. This means there is also no evidence that MCC's proposal to allocate DGGS costs based on loads in all hours would be an improvement over a 12-CP load ratio share method, since the provision of regulation service is obviously greater in certain hours. Rather, what is needed, as MCC recognized, is a measure of each customer segment's contribution to the intra-hour variability that drives the need for regulation capacity. (DR LCG-80.)

93. NWE's dedication of DGGS to the provision of regulation service is unique. (Tr. p. 340, DR LCG-91.) NWE's acquisition of DGGS, with the Commission's approval, has also imposed significant costs on customers. The Commission finds that relying on allocation methods simply because they sufficed in the past or are used by other utilities that do not provide regulation service the way NWE does is not reasonable in the long term. However, in this case, the Commission approves an allocation of final DGGS revenue requirements between Commission-jurisdictional retail and FERC-jurisdictional wholesale customers based on NWE's proposed 12-CP load ratio share method on a temporary basis and on the condition that NWE undertake a study of the relative contribution of retail and wholesale customers to the within-hour load fluctuations that drive regulation capacity needs. Temporary use of the 12-CP allocation is preferable to using MCC's proposed annual average load allocation because, although record evidence does not support either method, both the Commission and FERC have approved interim rates based on the 12-CP method and maintaining that allocation at the retail level, temporarily, prevents inconsistent treatment by the two regulatory jurisdictions that could result in a near-term gap in NWE's cost recovery. With recognition that this inconsistency ought to be avoided, and while preserving the justness of NWE's rates, the Commission renews its commitment to participating in FERC proceedings, both now and in the future should an

eventual departure from 12-CP warrant a tariff alteration, so to assist in achieving parity between the regulatory jurisdictions to which NWE is subject. Furthermore, the 12-CP allocation is the established method and, although the facts of this case raise considerable doubts about the reasonableness of its continued use for NWE's regulation service costs, adopting MCC's method appears to require the Commission to assume that the results of the ORNL study apply to NWE's system when there is no evidence to support that assumption. Given the near-term possibility of impairing NWE's recovery of prudent costs incurred based on the Commission's pre-approval, the Commission prefers to allow NWE to study the matter before adopting a change in the allocation method. However, the Commission does not guarantee cost recovery denied through customer flight or FERC order.

94. NWE's assertion that it does not have, or cannot reasonably obtain, adequate data to perform a study is not persuasive. In this proceeding, the Commission's interest is primarily the jurisdictional allocation between retail and wholesale customers of the 60 MW traditional regulation capacity requirement. NWE has short time-interval data for its total balancing area load and, at a minimum, has 15-minute interval data for each of its FERC-jurisdictional wholesale customers. NWE should strive to obtain 5 minute time-interval data for wholesale customers from which it can derive aggregate retail load data for the same time-interval by subtracting wholesale load from total load. Cashell testified that this is the approach NWE now uses to obtain 12-CP load data for the retail customer segment. (Ex. NWE-7, pp. 11-12.) At this time, the Commission is not directing NWE to study the variability of each individual customer class separately. Since NWE agrees that its regulation capacity needs are caused by short-term fluctuations in loads and resources (see Tr. p. 137), it would be unreasonable if NWE did not put forth a meaningful effort to determine the relative contribution of retail and wholesale customers to those short-term load fluctuations. Moreover, beyond the mere allocation between wholesale and retail customers, NWE should contemplate in a proposed plan and timeline for its study of this topic further consideration of within-retail and within-wholesale disparities of customer demand for regulation service based on class of service and customer profile. NWE should attempt to identify substations for which load variability data is available that serve a homogeneous pool of customers or that tend toward one class of service or another, so it might be seen how customer classes differ in their need for regulation service. So, too, will it be necessary (if not before this Commission) for NWE in such a study to evaluate the need of

Montana wholesale customers for regulation service on an individuated basis. The Commission directs NWE to submit for Commission review its proposed plan and timeline for performing the required study no later than April 23, 2012.

Carbon Offset Projects

95. The Commission is directed by § 69-8-421(6)(e), MCA, to require NWE to implement cost-effective carbon offsets upon approval of electric generation facilities fueled by natural or synthetic gas and constructed after January 1, 2007. This statute applies to DGGS. The statute further provides that NWE's expenditures for carbon offsets are fully recoverable in rates.

96. NWE's 2008 Application in this docket included a proposed Carbon Offset Plan. No party objected to the plan and the Commission approved it. (Order 6943a, p. 57.)

97. Section 69-8-103(5), MCA, provides that the carbon offset actions collectively shall not increase the annual cost of producing electricity from a natural or synthetic gas facility by more than 2.5%. Fitzpatrick testified that the spending cap for carbon offsets at DGGS is $1,046,330, which was 2.5% of the facility's annual revenue requirement at the time of the Compliance Filing of $41,953,190. (Ex. NWE-5, p. 8.)

98. NWE recommended that the Commission approve three carbon offset projects: 1) Anaconda-Deer Lodge County to retrofit street lights; 2) Montana Land Reliance to acquire a conservation easement in Jefferson and Silver Bow Counties; and 3) Trout Unlimited for the reforestation of lands damaged by historic mining practices. No party objected to the proposed projects.

99. The unit costs of carbon quantities offset by the three projects are $38.10/ton for the Anaconda-Deer Lodge County street light project, $8.96/ton for the Montana Land Reliance project, and $9.11/ton for the Trout Unlimited reforestation project. (Ex. NWE-5, JSF-03CF.) The total cost of the projects is $257,045. (Ex. NWE-5, p. 7.)

100. Fitzpatrick testified that carbon offset project selection is a difficult process and that it would be helpful if the Commission adopted rules to provide guidance. He identified three ways the process could be improved: 1) set boundaries about what types of projects could qualify as carbon offsets; 2) standardize a method for calculating carbon savings and offsets; and 3) define life cycle timeframes for carbon offset projects. (Tr., pp. 76-80.) Fitzpatrick added

that NWE anticipates that the process of reviewing, recommending, and obtaining Commission approval of carbon offset proposals will occur annually. (Tr., p. 84.)

101. Montana law states that the Commission shall require NWE to implement carbon offsets that are cost-effective. MCA 69-8-421(6)(e). The administrative rule that implements this section of law establishes a cost cap of 2.5% of the "cost of producing electricity." ARM 38.5.8202. It is unclear how that cost cap should be construed to apply to DGGS, which is a transmission facility that also generates electricity as an incidental byproduct. In any case, NWE's selection process did not place emphasis on the definition of cost-effectiveness or establish terms or units for the measurement of cost-effectiveness, and the carbon offset projects that NWE recommended to the Commission for approval were not presented or argued in a context of cost-effectiveness.

102. Due to the lingering uncertainty about what constitutes a cost-effective carbon offset, as well as the value to which the 2.5% cost cap should apply, the Commission declines to approve the carbon offset projects at this time.

103. The Commission acknowledges that NWE's Carbon Offset Plan, which was approved by the Commission in Order 6943a, contemplated an ongoing carbon offset program whose costs would be recovered in rates through an annual tracker mechanism. Upon further consideration, the Commission is uncertain that it is necessary to establish an annual or ongoing procedure to implement the statutorily required carbon offsets. It may be sufficient under the law for carbon offset projects to be selected by NWE and approved for rate recovery by the Commission just once for each generation resource that is required to acquire carbon offsets. For that reason, and because it is time to review the Plan since more than three years have elapsed since its filing, the Commission directs NWE to submit for review its Carbon Offset Plan with any proposed revisions and updates to address the issues raised by NWE in this case and to address the Commission's question about the necessity for an ongoing annual carbon offset program and tracker. NWE, the Commission and other stakeholders will be able to apply the knowledge and experience gained through the DGGS carbon offset selection process as they evaluate NWE's filing. The Commission directs NWE to file a Plan for Commission review by June 29, 2012.

CONCLUSIONS OF LAW

1. All findings of fact that are properly conclusions of law and that should be considered as such to protect the integrity of this Order are incorporated herein and adopted as such.

2. The Commission has provided adequate public notice of all proceedings, and an opportunity to be heard to all interested parties in this docket. § 69-3-104, MCA.

3. The Commission supervises, regulates, and controls public utilities pursuant to Title 69, Chapter 3, MCA. § 69-3-102, MCA.

4. NWE is a public utility subject to the jurisdiction of the Commission. § 69-3-101, MCA.

5. The Commission may approve prudently incurred costs associated with the construction of DGGS and a return on invested capital.

ORDER

1. The final first-year DGGS revenue requirement of $34,513,978 and the final second-year DGGS revenue requirement of $39,089,270 are approved.

2. NWE must refund to customers over a one-year period the difference between the current level of interim rates and the final rates approved herein, with 10.25% interest. The one-year period will begin at the earliest practical monthly electric tracker filing following the issuance of this Order.

3. The DGGS rate base amount of $182,537,625 is approved, except for and including any adjustments as a result of the outstanding items discussed in Finding of Fact ¶ 81.

4. NWE must file compliance tariffs in accordance with the provisions of this Order within 10 days of the service date.

5. NWE's proposal to track the final actual cost for the outstanding items and to identify at the time of NWE's next general rate filing any differences in the final actual cost of these items compared to the levels included in the final revenue requirements in this docket is approved. If the net difference is material, NWE must true up the costs for the time period January 2011 through the date of the order in the next general filing, with the net difference to be returned to, or collected from, customers.

6. Any future sale, transfer, etc., of NWE's interest in DGGS will require regulatory approval of the PSC. Because DGGS is a regulated asset whose purchase and construction was borne, subject to the conditions of this and prior orders, by the ratepayers of NWE, any future gains on any activity revert to the ratepayers.

7. The NWE balancing authority area requires 60 MW of traditional regulation service, used by both retail and wholesale customers, to comply with reliability standards, based on the current practices of scheduling intervals and methods. An additional 45 MW of DGGS capacity is allocated to the integration of wind and borne by retail ratepayers exclusively. This portion of regulation capacity is useful inasmuch as wind energy is online and integrated as forecast to meet the renewable portfolio standard by 2015. This order does not prevent NWE from maximizing the efficiency of DGGS by using it for other purposes.

8. The allocation of final DGGS revenue requirements between Commission-jurisdictional retail and FERC-jurisdictional wholesale customers based on NWE's proposed 12-CP load ratio share method is granted on a temporary basis and on the condition that NWE undertake a study of the relative contribution of retail and wholesale customers to the within-hour load fluctuations that drive regulation capacity needs. NWE must submit its proposed plan and timeline for performing the required study no later than April 23, 2012.

9. The Commission declines to approve the Montana Land Reliance, the Trout Unlimited, and Anaconda-Deer Lodge County carbon offset projects as proposed. The Commission directs NWE to submit its Carbon Offset Plan for review by June 29, 2012.

DONE IN OPEN SESSION this 20th day of March 2012 by a 5-0 vote.

BY ORDER OF THE MONTANA PUBLIC SERVICE COMMISSION

TRAVIS KAVULLA, Chairman

Gail Gutsche

GAIL GUTSCHE, Vice Chair

W. A. GALLAGHER, Commissioner

Brad Molnar

BRAD MOLNAR, Commissioner

JOHN VINCENT, Commissioner

ATTEST:

Aleisha Solem

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. See 38.2.4806, ARM.

ATTACHMENT 1

	A	B	C	D	E	F
1		**NorthWestern Energy**				
2		**Dave Gates Generating Station**				
3		**Docket D2008.8.95**				
4		**First Year - Revenue Requirement Analysis**				
5		**Rebuttal - Interim Calculation**				
6						
7						
8		**Description**		Year End		13-Month Ave
9		**Utility Plant in Service**				
10		Electric Generation Plant		$ 182,537,625		$ 182,537,625
11						
12		Less:				
13		Accumulated Depreciation (Book Life 30 Yrs)		5,969,257		2,984,628
14		Total Net Plant		176,568,368		179,552,997
15						
16		DGGS Project Costs		231,716		231,716
17						
18		Less: Customer Contributed Capital				
19		Deferred Income Taxes				
20		Accelerated Tax Depreciation		30,345,985		15,172,993
21		DGGS Project Costs		91,267		91,267
22		NOL Deferred Tax Asset		(30,502,324)		(15,251,162)
23		Total Customer Contributed Capital		(65,072)		13,098
24						
25		Plus: Working Capital				
26		Materials and Supplies		1,630,623		1,630,623
27		Fuels		349,914		349,914
28		Total Working Capital		1,980,537		1,980,537
29						
30		Total Year End Rate Base		$ 178,845,693		$ 181,752,152
31						
32		**Rate of Return**				8.16%
33						
34		***Authorized Return (Avg. Rate Base * Rate of Return)***				$ 14,830,976
35						
36		***Fixed Cost of Service:***				
37		Operation & Maintenance Expenses		$ 4,849,385		
38		Depreciation		5,969,257		
39		Amortization of DGGS Project Costs		154,477		
40		Property & Other Taxes		3,804,214		
41		MPSC & MCC Revenue Tax	0.53%	182,924		
42		DGGS Project Costs Deferred Income Taxes		(60,845)		
43		Deferred Income Taxes		(156,339)		
44		Current Income Taxes		-		
45		***Total Fixed Cost of Service***				$ 14,743,073
46						
47		**Total Fixed Cost Revenue Requirement**				$ 29,574,049
48						
49		**Plus:**				
50		Fuel Costs (Expense)				$ 19,302,792
51		Total DGGS Revenue Requirement				$ 48,876,841
52						
53		**Less Cost and Credit Adjustments:**				
54		Transmission Service Cost Allocations				$ 8,231,063
55		Supply and Transmission 27 MW Revenue Credits				6,131,800
56		**Net DGGS Revenue Requirement**				$ 34,513,978

ATTACHMENT 2

	A	B	C	D	E	F
1		**NorthWestern Energy**				
2		**Dave Gates Generating Station**				
3		**Docket D2008.8.95**				
4		**Second Year - Revenue Requirement Analysis**				
5		**Rebuttal Filing**				
6						
7						
8		**Description**		Year End		13-Month Ave
9		**Utility Plant in Service**				
10		Electric Generation Plant		$ 182,537,625		$ 182,537,625
11						
12		Less:				
13		Accumulated Depreciation (Book Life 30 Yrs)		11,938,514		8,953,885
14		Total Net Plant		170,599,111		173,583,740
15						
16		DGGS Project Costs		231,716		231,716
17						
18		Less: Customer Contributed Capital				
19		Deferred Income Taxes				
20		Accelerated Tax Depreciation		30,513,611		30,429,798
21		DGGS Project Costs		91,267		91,267
22		NOL Deferred Tax Asset		(24,309,102)		(27,405,713)
23		Total Customer Contributed Capital		6,295,776		3,115,352
24						
25		Plus: Working Capital				
26		Materials and Supplies		1,630,623		1,630,623
27		Fuels		349,914		349,914
28		Total Working Capital		1,980,537		1,980,537
29						
30		Total Year End Rate Base		$ 166,515,588		$ 172,680,641
31						
32		**Rate of Return**				8.16%
33						
34		***Authorized Return (Avg. Rate Base * Rate of Return)***				$ 14,090,740
35						
36		***Fixed Cost of Service:***				
37		Operation & Maintenance Expenses		$ 4,849,385		
38		Depreciation		5,969,257		
39		Amortization of DGGS Project Costs		154,477		
40		Property & Other Taxes		3,804,214		
41		MPSC & MCC Revenue Tax	0.32%	125,086		
42		DGGS Project Costs Deferred Income Taxes		(60,845)		
43		Deferred Income Taxes		6,360,849		
44		Current Income Taxes		-		
45		***Total Fixed Cost of Service***				$ 21,202,423
46						
47		**Total Fixed Cost Revenue Requirement**				$ 35,293,163
48						
49		**Plus:**				
50		Fuel Costs (Expense)				$ 19,302,792
51		Total DGGS Revenue Requirement				$ 54,595,956
52						
53		**Less Cost and Credit Adjustments:**				
54		Transmission Service Cost Allocations				$ 9,374,886
55		Supply and Transmission 27 MW Revenue Credits				6,131,800
56		**Net DGGS Revenue Requirement**				$ 39,089,270

Nowakowski, Sonja

From: Jeff L. Fox <jeff@renewablenw.org>
Sent: Thursday, April 17, 2014 1:21 PM
To: Nowakowski, Sonja
Subject: Re: FERC documents
Attachments: FERC order on DGGS.pdf

Sonja,

FERC decided the DGGS docket today. Attached is the FERC order on the Dave Gates Generating Station at Mill Creek. The order reaffirms the initial decisions of the Administrative Law Judge, including that the useful capacity at DGGS is the nameplate rating of 150MW.

Frankly, I'm not sure what this decision might foretell for DGGS costs borne by NorthWestern customers. Until further action by NorthWestern or the PSC, I believe the "about 40%" of DGGS costs are attributable to addressing wind energy's variability that Bob Decker testified to is still the correct lens for the Committee's work in assessing the consumer costs of Montana's RPS.

Please share the FERC order with all committee members that you think may be interested.

Thank you,

My email address has changed to Jeff@RenewableNW.org Please update your address book.

Jeff L. Fox
Montana Policy Manager
Renewable Northwest
615 South Black Ave., Bozeman, MT 59715
406-599-2916 cell
503-223-4544 Portland office
www.rnp.org

Stay up-to-date on our advocacy work and renewable energy news.
*Follow Renewable Northwest Project on **Facebook**, **Twitter** and **LinkedIn**.*

On Apr 14, 2014, at 10:36 AM, Nowakowski, Sonja <snowakowski@mt.gov> wrote:

Thanks Jeff.
Sonja

20140417-3015 FERC PDF (Unofficial) 04/17/2014

147 FERC ¶ 61,049
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Cheryl A. LaFleur, Acting Chairman;
Philip D. Moeller, John R. Norris,
and Tony Clark.

NorthWestern Corporation | ER10-1138-001
ER12-316-000
(Consolidated)

OPINION NO. 530

ORDER AFFIRMING INITIAL DECISION

(Issued April 17, 2014)

1. This case is before the Commission on exceptions to an Initial Decision[1] issued on September 21, 2012. The Initial Decision identified and resolved eight contested issues regarding NorthWestern Corporation's (NorthWestern) filing of revised tariff sheets for Schedule 3 service under its Open Access Transmission Tariff (OATT or Tariff). In this opinion, we summarily affirm the Initial Decision, without discussion, on seven of the issues, and affirm the remaining issue with further discussion.

I. Background and Procedural History

A. NorthWestern's System

2. NorthWestern owns and operates electric and natural gas transmission and distribution facilities primarily in Montana and South Dakota. NorthWestern's proposed tariff sheet revisions that are the subject matter of this case only impact its Montana OATT.[2] NorthWestern states that its electric transmission system in Montana consists of

[1] *NorthWestern Corp.*, 140 FERC ¶ 63,023 (2012) (Initial Decision).

[2] NorthWestern maintains separate OATTs for operations in each state because its Montana and South Dakota transmission facilities are neither physically connected, nor located in the same electric reliability region.

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more than 7,000 miles of transmission lines and terminal facilities, which covers an area of 107,600 square miles and provides service to approximately 322,000 customers.

3. According to NorthWestern, it acquired its electric operations from Montana Power Company in 2002 as part of Montana's electric deregulation and restructuring process. Montana Power Company had already sold substantially all of its electric generation facilities to other entities prior to selling its transmission and distribution systems to NorthWestern. NorthWestern operates a balancing authority area in Montana that requires NorthWestern to match electrical loads with generation to meet operating criteria and provide reliable service in accordance with North American Electric Reliability Corporation (NERC) and Western Electric Coordinating Council reliability requirements.

4. As part of its OATT, Northwestern must offer to supply its transmission customers with Regulation and Frequency Response Service pursuant to Schedule 3 when the transmission service is used to serve load within its Balancing Authority Area.[3] With no significant generation facilities of its own, NorthWestern was required to purchase regulation service from third parties. NorthWestern states that in 2007, such third party sellers became unable or unwilling to continue providing regulation services to NorthWestern because of shortages of generation capacity, transmission constraints, and increases in demand attributable to the need of other balancing authorities to integrate variable energy resources. In May 2009, NorthWestern sought and received approval from the Montana Public Service Commission (Montana Commission) to construct a facility now called the Dave Gates Generating Station (Gates Station)[4] for the specific purpose of providing regulation service on its transmission system.

5. According to NorthWestern, Gates Station, which consists of three natural gas-fired turbine generators with a maximum capacity of 50 MW each, was placed into service in January 2011.[5] One year later, on January 31, 2012, NorthWestern took all three units offline when it detected an equipment malfunction that resulted in significant damage to each of the units. On February 1, 2012, Northwestern requested Powerex Corporation (Powerex) to sell it regulation service to supply its Schedule 3 customers,

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[3] Consistent with the Initial Decision and the record in this proceeding, this order refers to Schedule 3 Regulation and Frequency Response Service as "Schedule 3 service," "regulation capacity," or "regulation service."

[4] Gates Station was originally named the Mill Creek Generating Station.

[5] *NorthWestern Corp.*, 137 FERC ¶ 61,248, at P 3 (2011) (December 30 Hearing Order).

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and Powerex agreed to do so.[6] At the time of the hearing, NorthWestern still relied on third party sources for Schedule 3 service.[7]

B. NorthWestern's Filing

6. On April 29, 2010, in Docket No. ER10-1138-000, NorthWestern filed revised tariff sheets to its OATT Schedule 3 to recover in that Schedule the fixed and variable revenue requirement for Gates Station through a monthly demand rate and monthly energy rate. The Montana Commission intervened, and the Montana Large Customer Group, Central Montana Electric Power Cooperative, Inc. (Central Montana), and Montana Consumer Counsel also intervened and filed protests.

7. On October 15, 2010, the Commission issued an order accepting and suspending NorthWestern's Revised Schedule 3, and establishing hearing and settlement judge procedures.[8] The Commission found that NorthWestern's Revised Schedule 3 had not been shown to be just and reasonable and raised issues of material fact that warranted hearing procedures.[9] Furthermore, the Commission stated that:

> The issues to be investigated at hearing include, but are not limited to, the proposed [Gates Station] annual revenue requirement and associated return on common equity, the allocation of [Gates Station] fixed and variable costs, the propriety of charging an energy rate to regulation service customers, the propriety of using the $7.00 market differential in the

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[6] Because Powerex's market-based rate tariff limits its ability to make sales of ancillary services at market-based rates to transmission providers for use in fulfilling their open access transmission tariff obligations, the Commission granted Powerex's February 2012 requests for a limited waiver of its tariff to provide NorthWestern with up to 76 MW of regulating reserve service on an interim basis. *See Powerex Corp.*, 138 FERC ¶ 61,136, at PP 1, 5 (2012).

[7] *See* Initial Decision, 140 FERC ¶ 63,023 at n.19. One of the issues before the Presiding Judge was whether NorthWestern should be allowed to flow through to Schedule 3 customers the cost of regulation purchases when the Gates Station had an outage. The Initial Decision concluded that those costs should be the subject of a separate section 205 filing. *Id*. P 225.

[8] *NorthWestern Corp.*, 133 FERC ¶ 61,046, at ordering para. (A) (2010) (October 15 Hearing Order).

[9] *Id*. P 21.

> derivation of the energy value, the level of regulation service purchase obligations for customers, inclusion of third party regulation purchases in the proposed demand rate, and lack of ceiling rates for regulation services.[10]

In addition, the Commission noted that NorthWestern's proposed formula for regulation service does not appear to be consistent with Commission precedent.[11]

8. On June 10, 2011, after unsuccessful settlement discussions, the Chief Administrative Law Judge established hearing procedures, and appointed the Presiding Judge.[12] On November 1, 2011, NorthWestern filed additional revisions to Schedule 3 in Docket No. ER12-316-000. In the December 30 Hearing Order, the Commission rejected NorthWestern's proposal to subject customers who elect to self-supply Schedule 3 service to additional charges.[13] The Commission accepted the remainder of NorthWestern's revisions, suspended them for a nominal period, to become effective on December 31, 2011, and set them for hearing procedures.[14] The Commission stated that, among other things, the hearing would address "the manner in which NorthWestern proposes to set the regulation requirements for self-supplying customers, the movement of operations and maintenance costs from the monthly energy rate to the monthly demand rate, and the manner in which NorthWestern proposes to credit certain revenues to Schedule 3 customers."[15] Finally, after noting that the issues in Docket No. ER12-316-000 are closely intertwined with those in Docket No. ER10-1138-000, the Commission consolidated the two dockets for purposes of hearing and decision.[16]

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[10] *Id*.

[11] *Id*. P 23 (citing *Kentucky Utilities Co.*, 85 FERC ¶ 61,274, at 62,108-109 (1998) (*Kentucky Utilities*); *Allegheny Power Service Corp.*, 85 FERC ¶ 61,275, at 62,120-121 (1998) (*Allegheny Power*)).

[12] *NorthWestern Corp.*, Order of Chief Judge Terminating Settlement Judge Procedures, Designating Presiding Administrative Law Judge, and Establishing Expedited Hearing Procedures (June 10, 2011).

[13] December 30 Hearing Order, 137 FERC ¶ 61,136 at P 33.

[14] *Id*.

[15] *Id*.

[16] *Id*. P 34. On January 30, 2012, NorthWestern submitted its proposed compliance filing in response to the Commission's December 30 Hearing Order

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9. On May 25, 2012, the parties and participants filed with the Presiding Judge a Joint Statement of Issues and Summary of Positions (Joint Statement). The evidentiary hearing in consolidated Docket Nos. ER12-316-000 and ER10-1138-001 was held on June 11 to June 14, 2012. Initial Briefs were filed on July 23, 2012 and Reply Briefs were filed on August 6, 2012.

C. Initial Decision, Briefs On and Opposing Exceptions, and Procedural Motions

10. On September 21, 2012, the Presiding Judge issued the Initial Decision, which, as discussed below, rejected the basis for most of NorthWestern's proposed tariff revisions. NorthWestern, Montana Consumer Counsel, Bonneville Power Administration (Bonneville), and the Montana Commission filed briefs on exceptions to the Initial Decision. Montana Large Customer Group, NorthWestern, Central Montana, and Commission Trial Staff (Trial Staff) filed briefs opposing exceptions.

11. On November 6, 2012, Edison Electric Institute (Edison Electric) filed a Motion to Intervene out-of-time and comments. On November 13, 2012, pursuant to Rule 711(c),[17] NorthWestern filed a motion for oral argument. On November 14, 2012, Montana Large Customer Group and Central Montana filed a joint motion to strike portions of NorthWestern's Brief On Exceptions. On November 21, 2012, Central Montana filed an answer in opposition to Edison Electric's Motion to Intervene out-of-time and comments. On November 29, 2012, NorthWestern filed an answer opposing Montana Large Customer Group and Central Montana's motion to strike portions of NorthWestern's Brief On Exceptions.

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disallowing additional charges for self-supplying customers under Schedule 3. On July 12, 2012, the Commission denied rehearing of its December 30 Hearing Order. *NorthWestern Corp.*, 140 FERC ¶ 61,020 (2012) (Rehearing Order). In the Rehearing Order, the Commission affirmed its finding in the December 30 Hearing Order that allowing a standby fee could potentially hinder competition by imposing costs on self-supply customers in excess of the costs of providing this service themselves. *Id*. P 24.

[17] 18 C.F.R. § 385.711(c) (2013).

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II. Discussion

A. Procedural Matters

12. We deny NorthWestern's motion for oral argument. Pursuant to Rule 711(c) of the Commission's Rules of Practice and Procedure, 18 C.F.R.§ 385.711(c) (2013), any participant filing a brief on exceptions or a brief opposing exceptions may request, by written motion, oral argument before the Commission or an individual Commissioner. In its motion for oral argument, NorthWestern asserts that this is a case of first impression; specifically, NorthWestern asserts that oral argument would aid the Commission in determining how to treat a generation resource dedicated to providing regulation and frequency response service and satisfying NERC Reliability Standards. Given that the briefs on, and opposing, exceptions clearly and comprehensively represent the positions of the parties, we are not convinced there is anything to be gained from an oral argument.

13. Pursuant to Rule 214(d) of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.214(d) (2013), the Commission denies Edison Electric's Motion to Intervene out-of-time and comments for failure to demonstrate good cause warranting late intervention. The Commission has found that parties seeking to intervene in a proceeding after issuance of a Commission determination bear a heavy burden. When late intervention is sought after the issuance of a dispositive order, the prejudice to other parties and burden upon the Commission of granting the late intervention may be substantial. Edison Electric has not met this higher burden of justifying its late intervention.[18] Edison Electric's Motion to Intervene out-of-time was filed nearly two months after the Presiding Judge issued the Initial Decision, thus depriving other parties the opportunity to test the basis of Edison Electric's positions. For these reasons, we will deny Edison Electric's Motion to Intervene out-of-time.

14. Pursuant to Rule 212 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.212 (2013), the Commission denies Montana Large Customer Group's and Central Montana's joint motion to strike portions of NorthWestern's Brief On Exceptions. Montana Large Customer Group and Central Montana seek to strike sections of NorthWestern's Brief on Exceptions that cite (1) NorthWestern's 2011 Annual Report; (2) POWER Magazine; (3) NERC Reliability Standard BAL-005-01.b; (4) NE-ISO Market Rule 1; and (5) CAISO Tariff § 30.5.2.6. We find that the sources cited by NorthWestern are either within the Commission's subject-matter expertise or are otherwise publicly available, and we find no reason to strike them.

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[18] *See, e.g., Midwest Indep. Transmission Sys. Operator, Inc.* 102 FERC ¶ 61,250, at P 7 (2003).

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B. Substantive Matters

15. For the reasons discussed herein and in the Initial Decision, we find that the Schedule 3 rates proposed by NorthWestern have not been shown to be just and reasonable, and that the rates resulting from the findings and methodology adopted in the Initial Decision are just and reasonable. Accordingly, NorthWestern must make appropriate refunds.

1. Issues Summarily Affirmed

16. The Initial Decision addressed and resolved eight issues identified by the parties in their Joint Statement. These issues were:

> Issue No. 1: Is NorthWestern's proposed annual fixed cost revenue requirement and associated return on common equity for [Gates Station] just and reasonable?
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> Issue No. 2: Is NorthWestern's proposed allocation of the [Gates Station] fixed cost revenue requirement just and reasonable?
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> Issue No. 2 (a): Is NorthWestern's proposed allocation based on a numerator of 60 MW just and reasonable?
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> Issue No. 2 (b): Is NorthWestern's proposed allocation based on a denominator of 105 just and reasonable?
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> Issue No. 3: Is NorthWestern's proposed imposition of an energy rate charge just and reasonable?
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> Issue No. 4: Is NorthWestern's proposal to use a $7.00 market differential in the derivation of the energy value just and reasonable?
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> Issue No. 5: Is NorthWestern's proposed level of regulation service purchase obligations for customers just and reasonable?
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> Issue No. 6: Is inclusion of third-party regulation purchases in the proposed demand rate just and reasonable?
>
> Issue No. 7: Is the lack of proposed ceiling rates for regulation service just and reasonable?
>
> Issue No. 8: Are NorthWestern's proposed regulation requirements for self-supplying customers just and reasonable?

17. We summarily affirm the Initial Decision on all issues for the reasons given in the Initial Decision, except for the additional discussion herein on the "regulation down" component of Issue No. 2(a). We have reviewed the briefs on and opposing exceptions and find that the Initial Decision properly decided the issues that we are summarily affirming. The arguments on exceptions have failed to convince us that the Initial Decision erred or that additional discussion is necessary.

18. Although we affirm the Initial Decision's denial of NorthWestern's request to include capacity used for regulation down to calculate its Schedule 3 rates, we do so in part for reasons in addition to those given in the Initial Decision.

2. NorthWestern's Proposed Basis for Schedule 3 Rates

19. Regulation service is "the necessary ancillary service that provides the moment-to-moment balancing of resources and load within a balancing authority to maintain interconnection frequency, and is used to conform with NERC Control Performance Standards (CPS)."[19] As the Presiding Judge noted, the Commission recently described regulation service as the "injection or withdrawal of real power by facilities capable of responding appropriately to a transmission system's frequency deviations or interchange power imbalance."[20] Frequency deviations and interchange power imbalances are both measured by the Area Control Error (ACE). It is NorthWestern's responsibility, as a balancing authority, to rapidly correct deviations in the transmission system's frequency to bring it within the acceptable range by regulating the power entering the system either up or down.[21]

20. Based on its assertion that it built the Gates Station solely to provide regulation service, NorthWestern proposed to recover 100 percent of the Gates Station revenue requirement from its wholesale and retail customers through charges for regulation service. It argued that 60 MW represented the regulation demands of its Schedule 3 and bundled retail customers, and 45 MW was required to reflect the regulation demands of wind generation.[22] Accordingly, it proposed to allocate 60/105th of the Gates Station

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[19] Initial Decision, 140 FERC ¶ 63,023 at P 22.

[20] *Id.* (quoting *Frequency Regulation Compensation in the Organized Wholesale Power Markets*, Order No. 755, FERC Stats. & Regs. ¶ 31,324, at P 4 (2011), *reh'g denied*, Order No. 755-A, 138 FERC ¶ 61,123 (2012)).

[21] *Id.*

[22] *Id*. P 19.

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revenue requirement to regulation demands of wholesale and retail transmission service, and 45/105th to retail customers for the regulation demands of the wind generation. NorthWestern proposed that the 60 MW for total transmission regulation be allocated between wholesale and bundled retail customers based on 12 coincident peak load share.[23]

21. The Initial Decision rejected NorthWestern's analysis and instead concluded that Montana Large Customer Group's proposed methodology that calculated 19 MW as the total regulation demand was just and reasonable and well-supported by the record. In addition, the Presiding Judge found that:

> (1) NorthWestern has the burden of proof in this case, and did not carry its burden of showing that 60 MW is a just and reasonable numerator, (2) regulation down must be excluded from Dr. Tabors' study, (3) diversity benefits must be shared by wholesale and retail customers based on cost causation principles, (4) NorthWestern may include energy imbalance service in its Schedule 3 rate, and (5) the use of absolute averages is not mandated for calculating the numerator.[24]

22. The Initial Decision also concluded that the 150 MW nameplate capacity of the Gates Station must be used in the denominator of the fraction to compute what proportion of the Gates Station revenue requirement would be attributed to regulation customers. There were also other distinct issues addressed in the Initial Decision.

23. NorthWestern and Montana Consumer Counsel assert on exceptions, among other things, that policy considerations warrant full Commission review of the Initial Decision.[25] Particularly, NorthWestern states that this case presents an issue of first impression—how to treat the cost recovery of a generation resource dedicated exclusively to providing regulation and frequency response service and satisfying NERC Reliability Standards. NorthWestern argues that a failure by the Commission to reverse the Initial Decision will discourage the construction of additional facilities that could provide the ancillary services required to integrate wind and solar generation. In addition, NorthWestern contends that other Commission policies that compel review and reversal of the Initial Decision include: (1) the concept that a utility be given the

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[23] *See* NorthWestern Initial Brief at 11.

[24] Initial Decision, 140 FERC ¶ 63,023 at P 75.

[25] NorthWestern Brief On Exceptions at 5-10; NorthWestern Motion for Oral Argument at 1-3; Montana Consumer Counsel Brief On Exceptions at 9-10.

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reasonable opportunity to recover the costs it prudently incurs in providing service; (2) the principle that costs be allocated to the customers on whose behalf the costs were incurred; (3) the Commission's policy of having customers pay for the standby capability associated with regulation service; and (4) the Commission's stated preference for crediting opportunity sales against a revenue requirement.[26]

24. NorthWestern's underlying premise of the case is that all of Gates Station's revenue requirement should be recovered through regulation service rates. The Initial Decision did not accept NorthWestern's premise and, instead, based its derivation of Schedule 3 rates on a traditional rate analysis of how much capacity is actually needed to support Schedule 3 service, without regard to how much of the Gates Station revenue requirement would be collected by NorthWestern. We agree with the Presiding Judge's approach; the purpose of the hearing was to determine whether NorthWestern's Schedule 3 rate was just and reasonable, not to ensure that NorthWestern collects the total revenue requirement for the Gates Station through regulation service rates.

25. Furthermore, we do not believe that Commission policies with respect to reliability and ancillary service availability will be hampered by not granting NorthWestern full cost recovery of Gates Station costs from regulation customers. Transmission providers should be able to satisfy their balancing and regulation obligations without resorting to compensation mechanisms that do not comply with applicable Commission precedent and methodology. To accept NorthWestern's argument that a generating facility dedicated to regulation service deserves full recovery of its cost of service might in fact encourage transmission providers to build generation facilities solely to provide ancillary services at cost-of-service rates without regard to the economic value of such facilities.

3. Regulation Down

a. Initial Decision

26. One of the largest deductions that was used to reduce NorthWestern's proposed 60 MW of regulation demand to 19 MW was the elimination of capacity used for regulation down. In determining that regulation down must be excluded from NorthWestern's Schedule 3 rate, the Presiding Judge first addressed NorthWestern's argument that *Kentucky Utilities* and *Allegheny Power*, which both direct a balancing authority to remove regulation down service from a Schedule 3 rate, do not apply. In *Kentucky Utilities* and *Allegheny Power*, where there was an absence of any data supporting the transmission provider's regulation requirement, the Commission established that "the

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[26] NorthWestern Brief On Exceptions at 5-10.

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most accurate way to determine the regulation obligation applicable to transmission customers was by calculating the average of [all] hourly load variations on the transmission provider's system."[27]

27. The Presiding Judge noted that unlike in those cases, here, NorthWestern had provided some data to support its regulation requirement. Nonetheless, the Presiding Judge stated that this fact alone did not mean that the principles set forth in *Kentucky Utilities* and *Allegheny Power* must be categorically disregarded. Instead, the Presiding Judge concluded that the factual distinction between *Kentucky Utilities* and *Allegheny Power*, and the present case, required only the preclusion of "the otherwise necessary use of the inter-hour Load Following methodology."

28. The Presiding Judge stated that, in *Allegheny Power*, the Commission found that "a balancing authority 'would need to have, on average, adequate generation capacity to cover the portion of the hour when a customer's load is above the amount of generating capacity it has block scheduled. The amount of capacity is sufficient to provide load following through the entire hour.'"[28] Also, the Presiding Judge stated that, in *Kentucky Utilities*, the Commission found "that a utility's Regulation capacity requirement could be derived 'by simply dividing the average of the hourly load changes during the year by two.'"[29] The Presiding Judge reasoned that the Commission's policy to exclude regulation down stems from the fact that:

> [A]lthough a utility like NorthWestern must operate its regulating resources at a point above NorthWestern's minimum (i.e., a set point) in order to be prepared to ramp down in case demand drops (i.e., positive scheduling errors), NorthWestern can utilize the energy used to maintain the set point for non-regulation purposes.[30]

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[27] Initial Decision, 140 FERC ¶ 63,023 at P 86 (quoting October 15 Hearing Order, 133 FERC ¶ 61,046 at P 23).

[28] *Id.* P 88 (quoting *Allegheny Power*, 85 FERC at 62,120).

[29] *Id*. (quoting *Kentucky Utilities*, 85 FERC at 62,109). *See also Otter Tail Power Co*., 99 FERC ¶ 61,019, 61,095 (2002); *Consumers Energy Co*., 86 FERC ¶ 63,004, 65,043 (1999), *aff'd on exceptions*, 98 FERC ¶ 61,333, at 62,410 (2002).

[30] Initial Decision, 140 FERC ¶ 63,023 at P 90 (citation omitted).

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Furthermore, the Presiding Judge observed that NorthWestern failed to present any evidence as to why it would not be able to use this energy, which would be absorbed into its system, for non-regulation purposes, such as off-system sales.[31]

29. The Presiding Judge went on to find, contrary to NorthWestern's argument, that Order Nos. 755 and 755-A do not allow NorthWestern to include regulation down in its Schedule 3 rate because those orders apply only to organized markets, of which NorthWestern is not a member. Specifically, the Presiding Judge noted that the compensation NorthWestern seeks in this proceeding is substantially different from the performance payments described in Order No. 755. The Presiding Judge also stated that, if the Commission had intended for performance payments to apply to non-market participants, then it would have explicitly indicated so in Order No. 755.[32]

30. The Presiding Judge also rejected NorthWestern's argument that Order No. 764, which addresses Schedule 10, permits NorthWestern to include regulation down in its Schedule 3 rate. As an initial matter, the Presiding Judge noted that Order No. 764 was issued on June 22, 2012, after the hearing in this case had concluded. The Presiding Judge added that no party or participant filed a motion to reopen the record in the present case after Order No. 764 was issued. Moreover, the Presiding Judge stated that NorthWestern itself acknowledged that it is not precluded from making the appropriate filing in the future to recover its opportunity costs through Schedule 10.[33] The Presiding Judge concluded that NorthWestern had not introduced any evidence into the record regarding opportunity costs. The Presiding Judge noted that it would likely be difficult for NorthWestern to argue opportunity costs given that the Gates Station was exclusively built and fully used for regulation services for its retail and Schedule 3 customers.[34]

[31] *Id*.

[32] *Id*. P 96.

[33] *Id*. P 100.

[34] *Id*. P 101.

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b. NorthWestern Brief On Exceptions

31. NorthWestern contends that the Presiding Judge erred by excluding the capacity needed to provide regulation down service, the effect of which was to reduce the formula rate numerator, i.e., the amount of capacity dedicated to regulation load, by approximately 41 MW.[35]

32. NorthWestern asserts that the Presiding Judge denied the company compensation for regulation down capacity, based in large part, on a misapplication of the Commission's holdings in *Kentucky Utilities* and *Allegheny Power*. Specifically, NorthWestern argues that the Initial Decision incorrectly finds that *Kentucky Utilities* and *Allegheny Power* demonstrate a Commission policy of disallowing compensation for the capacity needed to provide regulation down service. NorthWestern explains that the holding in *Kentucky Utilities* and *Allegheny Power*—that the most accurate way to determine the regulation obligation applicable to transmission customers is by calculating the average of all hourly load variations on the transmission provider's system—only applies where there is an absence of any data to support a transmission provider's regulation requirement.[36] By contrast, NorthWestern states that all parties here agreed to calculate regulation obligations by reference to the amount needed to satisfy CPS 2 and, furthermore, that NorthWestern presented enough data to calculate the amount of regulating reserves necessary to comply with CPS 2. Thus, NorthWestern concludes that there was no reason for the Presiding Judge to revert to the default method provided by *Kentucky Utilities* and *Allegheny Power*.[37]

33. NorthWestern also asserts that Order Nos. 755 and 764 demonstrate that Commission policy favors compensating resources for regulation down services. For example, NorthWestern notes that Order No. 755 states that a "resource's performance must be measured based on the absolute amount of regulation up and regulation down it

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[35] NorthWestern Brief On Exceptions at 34. As explained by NorthWestern, the Initial Decision did not include any actual calculations, but rather adopted by reference the calculations of a Montana Large Customer Group witness, James Dauphinais, who made adjustments to a NorthWestern witness's, Dr. Tabors, calculations. NorthWestern states that Mr. Dauphinais started from 73 MW, which represents the regulating reserves Dr. Tabors determined were needed to achieve 95 percent CPS 2 compliance. Furthermore, NorthWestern states that Mr. Dauphinais arrived at 19 MW by subtracting 41 MW for regulation down capacity and 16 MW for diversity benefits. *Id.* n.111.

[36] *Id.* at 35 (citing October 15 Hearing Order at P 23).

[37] *Id.*

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provides in response to the system operator's dispatch signal."[38] NorthWestern states that the Presiding Judge erred in finding this directive applies only to organized markets and that the "performance payments" set forth in Order No. 755-A are materially different from the compensation NorthWestern seeks in the present case. First, NorthWestern states that, in addition to "performance payments," Order No. 755 mandates capacity payments, which includes both regulation up and down. Second, while NorthWestern acknowledges that Order No. 755, by its terms, applies only to organized wholesale electricity markets, NorthWestern maintains that the Order embodies a broader policy establishing "that resources provide compensable value when they supply the capacity needed for regulation 'down.'"[39]

34. NorthWestern avers that, in Order No. 764, the Commission affirmed this broader policy in favor of compensating resources for regulation down services. Moreover, NorthWestern argues that the Presiding Judge offered no legitimate rationale for dismissing the policy reflected by Order No. 764. Regarding the Initial Decision's finding that no party argued the effect of Order No. 764 on this case by way of a motion to reopen the record after Order No. 764 was issued, NorthWestern states that consideration of Order No. 764 would not have prejudiced any parties, the record need not be reopened to consider the impact of a ruling in another case,[40] and, if the Presiding Judge believed it to be appropriate, she could have reopened the record under Rule 716 on her own initiative.[41]

35. NorthWestern asserts that the Presiding Judge's dismissal of Order No. 764 was also based on an erroneous finding that the company did not prove that it suffers opportunity costs by providing regulation down. NorthWestern states that it did not base its Schedule 3 rate on a claim that the company was deprived of other opportunities. Instead, NorthWestern explains that its Schedule 3 rates are based exclusively on the

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[38] *Id*. at 36 (quoting Order No. 755, FERC Stats. & Regs. ¶ 31,324 at P 133). *See also* Order No. 755-A at P 14 ("[A] resource must be measured [and compensated accordingly] based on the absolute amount of regulation up and regulation down it provides in response to the system operator's dispatch signal . . . .").

[39] NorthWestern Brief On Exceptions at 37.

[40] *Id*. at 38-39 (citing *Pacific Gas and Electric Co.*, 109 FERC ¶ 61,205, at P 7 (2004) ("This Commission and the courts can take official notice of any judicial decision at any time, so there is no need to reopen the record for this purpose.")).

[41] *See* 18 C.F.R. § 716(a).

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Gates Station revenue requirement, which does not include any type of opportunity cost component (other than a stipulated return on equity).[42]

36. Finally, NorthWestern states that the Presiding Judge ignored three key facts in determining that the company is not entitled to compensation for regulation down services. First, NorthWestern states that, typically, opportunity costs are associated with a resource that has already been built and can be deployed for a number of reasons. NorthWestern maintains that Gates Station was built for the singular purpose of providing reliable and fast regulation service. Thus, NorthWestern states that Gates Station is similar to a reliability must-run resource, which the Commission has determined is entitled to reimbursement based on the cost of service, not the ability to generate revenues through other uses.[43] Second, NorthWestern points out that Gates Station's revenue requirement essentially compensates NorthWestern for the costs of building Gates Station (including depreciation and return on equity). NorthWestern notes that Gates Station had to be sized larger in order to provide regulation up and down service. NorthWestern states that Gates Station could have been sized smaller if it were to only provide regulation up service, but that would not enable Gates Station to decrease output to offset a drop in load or a spike in wind generation. Third, NorthWestern emphasizes that Gates Station capacity is not dedicated to retail load. NorthWestern states that, given the fluidity of the set point, Gates Station is not able to assure the retail load or any other customers of any definitive amount of capacity.[44]

c. <u>Other Briefs on Exception</u>

37. Montana Consumer Counsel, Montana Commission, and Bonneville argue that the Initial Decision errs in excluding regulation down. Like NorthWestern, Montana Consumer Counsel urges that *Kentucky Utilities* and *Allegheny Power* only apply in situations where a transmission provider fails to present any historical data to determine the necessary regulation requirement.[45] Both Montana Consumer Counsel and Montana Commission also allege that the Initial Decision's assumption that capacity required for regulation down can be devoted to other purposes fails to appreciate that Gates Station is the only indigenous, rampable generating unit fitted with automatic generation control

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[42] NorthWestern Brief On Exceptions at 39-40.

[43] *Id*. at 40-41 (citing *GenOn Power Midwest, LP*, 140 FERC ¶ 61,080 at P 3 (2012)).

[44] NorthWestern Brief On Exceptions at 41-42.

[45] Montana Consumer Counsel Brief On Exceptions at 10.

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and capable of responding to Area Control Error signals. The Initial Decision, according to Montana Consumer Counsel and Montana Commission, also overlooks the fact that the Montana Commission authorized NorthWestern to construct Gates Station solely to provide regulation service, not to conduct off-system sales or supply energy to retail customers.[46] Relatedly, Montana Commission states that NorthWestern lacks the ability of a vertically-integrated system to absorb load reduction into its system and vary the output from multiple generators to accommodate load variations.[47] Finally, Bonneville argues that, as opposed to *Kentucky Utilities* and *Allegheny Power*, the most relevant Commission precedent is *Westar Energy, Inc.*, in which, according to Bonneville, the Commission approved a method for calculating the balancing reserves purchase requirement of Westar's proposed Schedule 3A service.[48]

38. Regarding Order No. 755, Montana Consumer Counsel and Bonneville argue that, even though NorthWestern is not a member of an organized market, the Initial Decision should have embraced the Commission's broader policy goal in that Order of compensating generators "based on performance, as measured by the amount of MWh up and down movement the resource provides."[49] Bonneville remarks that the Presiding Judge's failure to apply Order No. 755's mandate in the present case will hinder the development of capacity markets by disallowing the recovery of legitimate costs. As to Order No. 764, Montana Consumer Counsel and Bonneville allege the Commission's policy of compensating generators for the costs of providing regulation down service in Schedule 10 should apply equally to Schedule 3. Montana Consumer Counsel claims that the Presiding Judge's finding that NorthWestern did not present evidence regarding opportunity costs misses the point that NorthWestern's decision to invest in Gates Station is the incurrence of an opportunity cost.[50] Bonneville contends that the Presiding Judge erred in finding that NorthWestern can file a Schedule 10 to recover its opportunity costs because Schedule 10 is intended to recover costs associated with providing capacity for

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[46] Montana Consumer Counsel Brief On Exceptions at 11-14; Montana Commission Brief On Exceptions at 7-8.

[47] Montana Commission Brief On Exceptions at 7-8.

[48] Bonneville Brief On Exceptions at 4 (citing *Westar Energy, Inc.*, 130 FERC ¶ 61,215, P 3, 18 (2010)).

[49] Montana Consumer Counsel Brief On Exceptions at 15 (quoting Order No. 755, FERC Stats. & Regs. at P 78); Bonneville Brief On Exceptions at 8-9 (quoting Order No. 755, FERC Stats. & Regs. ¶ 31,324 at P 78).

[50] Montana Consumer Counsel Brief On Exceptions at 16-17.

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Variable Energy Resources. Bonneville further states that a Schedule 10 filing would subsidize Schedule 3 customers by imposing the cost of regulation down only on NorthWestern's retail customers that are purchasing all of the variable energy resources in the NorthWestern balancing authority.[51]

d. Briefs Opposing Exceptions

39. Montana Large Customer Group, Central Montana, and Trial Staff all argue that the Presiding Judge properly applied the Commission precedent set forth in *Kentucky Utilities* and *Allegheny Power*, which, according to these parties, defines how to calculate a transmission provider's regulation service capacity needs and excludes recovery for regulation down.[52] Montana Large Customer Group explains that, because NorthWestern did provide actual data that can be used to do the calculation, the Presiding Judge correctly determined that it was not necessary to use historical hourly FERC Form 714 load data. However, Montana Large Customer Group goes on to state that *Kentucky Utilities* and *Allegheny Power* make clear that only deviations above the amount scheduled, i.e., where regulation up is needed, are to be considered when determining the capacity needed to serve Schedule 3 customers. Montana Consumer Counsel states that the Commission reinforced these policies in *Consumers Energy Company*[53] and *Otter Trail Power Company*.[54] Montana Large Customer Group contends that NorthWestern failed to produce any compelling evidence as to why it would be unable to utilize the energy used to maintain the set point for regulation down for non-regulation purposes. In addition, Montana Large Customer Group states that the operation of NorthWestern's regulation down capacity by necessity provides capacity and energy to NorthWestern's bundled retail customers.[55]

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[51] Bonneville Brief On Exceptions at 9-10.

[52] Montana Large Customer Group Brief On Exceptions at 17-18; Central Montana Brief On Exceptions at 26-28; Trial Staff Brief On Exceptions at 13-15.

[53] *Consumers Energy Co*., 86 FERC ¶ 63,004 (1999).

[54] *Otter Trail Power Co*., 99 FERC ¶ 61,019 (2002).

[55] Montana Large Customer Group Brief On Exceptions 19-21.

40. Montana Large Customer Group, Central Montana, and Trial Staff aver that the Presiding Judge correctly concluded that Order No. 755 applies only to organized markets.[56] Montana Large Customer Group adds that if the Commission intended for Order No. 755 to apply more broadly as a policy for compensation for regulation down in all circumstances, it would have done so explicitly.[57] Furthermore, Trial Staff explains that the Commission's rationale for compensating (in the form of "performance payments" that are determined by a markets-based clearing house) organized market participants for regulation down service does not extend to vertically-integrated utilities, such as NorthWestern, which are compensated in the form of cost-based rates. According to Trial Staff, the Commission's purpose in providing performance payments to organized market participants is to encourage resources with the lowest costs to enter the regulation market, thereby increasing market efficiency. Trial Staff states that, here, there is no need to incentivize NorthWestern to enter into the (non-existent) market or to mobilize (non-existent) faster ramping resources by providing a performance payment for regulation down capacity.[58]

41. Similarly, Montana Large Customer Group, Central Montana, and Trial Staff contend that Order No. 764 is inapplicable to this case.[59] Montana Large Customer Group explains that Order No. 764 concerns the impacts of Variable Energy Resources on the transmission system. Montana Large Customer Group also notes that Order No. 764 concerns Schedule 10, not Schedule 3, and that NorthWestern is not precluded from presenting evidence on foregone opportunity costs in a subsequent Schedule 10 filing should it choose to do so.[60] Trial Staff adds that Order No. 764's compensation for regulation down capacity is explicitly a means to compensate generators for the opportunity cost of deploying resources to provide potentially less lucrative ancillary services, and because NorthWestern is not a market participant, there is no need to incentivize NorthWestern to forgo sales to provide ancillary services. Also, Trial Staff

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[56] Montana Large Customer Group Brief On Exceptions at 24; Central Montana Brief On Exceptions at 28-30; Trial Staff Brief On Exceptions at 15-17.

[57] Montana Large Customer Group Brief On Exceptions at 26.

[58] Trial Staff Brief On Exceptions at 17.

[59] Montana Large Customer Group Brief On Exceptions at 26-29; Central Montana Brief On Exceptions at 30-32; Trial Staff Brief On Exceptions at 18-20.

[60] Montana Large Customer Group Brief On Exceptions at 26-27.

states that NorthWestern is capable of using the energy generated to maintain a set point for non-regulation purposes, such as off-system sales or for serving retail load.[61]

42. Montana Large Customer Group argues that excluding regulation down is also consistent with principles of cost causation, and that excluding regulation down capacity will ensure Schedule 3 customers do not unreasonably pay NorthWestern for capacity in excess of that needed to provide the regulation services. According to Montana Large Customer Group, excluding regulation down capacity prevents Schedule 3 customers from subsidizing other customers.[62]

43. Trial Staff states that NorthWestern was given and continues to have a reasonable opportunity to recover the costs of Gates Station. Trial Staff asserts that, as a factual matter, NorthWestern presently has the opportunity to recover the remaining unallocated, prudently-incurred costs of Gates Station by selling excess capacity beyond what is necessary to meet NorthWestern's CPS 2 obligations. Moreover, Trial Staff avers that, because it has a market-based tariff, NorthWestern is free to charge whatever level the market will bear to recover the remaining portions of the Gates Station revenue requirement.[63]

44. Finally, Trial Staff claims that the purpose of this proceeding is to determine NorthWestern's just and reasonable Schedule 3 rate, not allocate all Gates Station costs. Trial Staff concludes that the Initial Decision has comported with Commission precedent, and has afforded NorthWestern the opportunity to recover costs to which it is entitled.[64]

e. <u>Commission Determination</u>

45. We affirm the Presiding Judge's determination to exclude from NorthWestern's Schedule 3 those costs associated with capacity that NorthWestern claims is needed to support regulation down service. We base our decision in part upon the fact that NorthWestern failed to provide evidence as to why it would be unable to utilize the energy generated by the reserved regulation down capacity for non-regulation purposes.

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[61] Trial Staff Brief Opposing Exceptions at 15-20.

[62] Montana Large Customer Group Brief On Exceptions at 21.

[63] Trial Staff Brief Opposing Exceptions at 23-24.

[64] *Id*. at 24-26.

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46. As an initial matter, we note that the Commission's precedent in *Kentucky Utilities* and *Allegheny Power* is distinguishable from the present case, and therefore, that precedent is not necessarily controlling here if those distinguishing facts warrant a different result. Both *Kentucky Utilities* and *Allegheny Power* involved a vertically-integrated system that had several power plants operating to serve native load that could be backed down to absorb energy when needed to provide regulation down service. In those cases, the utilities were already maintaining their capacity at a specific level to serve existing schedules. In other words, the capacity costs were being recovered from customers for whom power was already scheduled.

47. Here, NorthWestern indicates that it will not rely on Gates Station to serve the electricity demand of its customers, but uses Gates Station exclusively to provide regulation service to maintain CPS 2 compliance. We acknowledge that NorthWestern may be in a situation different from most other suppliers of regulation service. Further, in several recent orders that addressed specific situations, the Commission has acknowledged that regulation service is a product for which suppliers must be equitably compensated.[65] Thus, circumstances might exist where a transmission provider with no generation other than that used for regulation service may be able to make the case that it should be compensated for capacity it must hold in reserve solely to allow for regulation down. For example, such a transmission provider may be able to justify compensation for regulation down capacity if it demonstrates that, based on the location of the generating facility, there are no accessible markets into which it could sell energy generated by its regulation down capacity, and that it had no retail or other load that could be served with such energy. However, NorthWestern has not made such a case in this proceeding.

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[65] *See Third-Party Provision of Ancillary Services; Accounting and Financial Reporting for New Electric Storage Technologies*, Order No. 784, 144 FERC ¶ 61,056, at P 82 (2013) (permitting market-based sales of regulation service to public utility transmission providers at rates not to exceed the buying public utility transmission provider's OATT rate for the same service); Order No. 764, FERC Stats. & Regs. ¶ 31,331 at P 316 (stating that "public utility transmission providers that choose to propose a rate schedule for generator regulation service may include opportunity costs for generator regulation service"); Order No. 755, FERC Stats. & Regs. ¶ 31,324 at P 1 (revising the Commission's regulations to remedy undue discrimination in the procurement of frequency regulation in the organized wholesale electricity markets and ensuring that providers of frequency regulation receive just and reasonable rates, including performance payments for both regulation up and regulation down).

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48. The regulation down capacity at issue here is that which the Gates Station purportedly places into operation at the start of each hour and is reserved to ramp down if necessary to accommodate system imbalances in its Balancing Authority Area. In affirming the Presiding Judge's determination regarding regulation down, we base our decision in part upon the fact that NorthWestern failed to provide evidence as to why it would be unable to utilize the energy generated by the reserved regulation down capacity for non-regulation purposes. NorthWestern's witness stated rather vaguely that the energy produced by that reserved capacity would be scheduled "off of the system" and "absorbed into the system."[66] However, NorthWestern did not demonstrate that the value of the energy produced by the regulation down capacity was so low as to require regulation customers to pay its full revenue requirement. Without this information, the Commission cannot determine what portion, if any, of the regulation down capacity costs were otherwise unrecovered by NorthWestern. Absent evidence that NorthWestern was unable to recover those costs, we are not persuaded to allow NorthWestern to include regulation down in calculating the capacity to serve Schedule 3 customers.

49. We agree with the Initial Decision that Order No. 755 does not require that regulation down capacity be included in the allocation of capacity costs for NorthWestern. The plain language of Order No. 755 pertains only to members of organized markets, of which NorthWestern is not a member.[67] Moreover, we find that the performance payments and capacity payments discussed in Order No. 755 are not the same as compensation that NorthWestern seeks in this proceeding. Order No. 755 adopted a uniform compensation methodology for frequency regulation in organized markets that consists of a market-based capacity payment and a market-based "performance" payment that compensates a resource for all movement in response to the dispatch signal.[68] Order No. 755 did not address the situation presented here, where NorthWestern is seeking a cost-of-service capacity payment for capacity it allegedly needs to provide regulation down.

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[66] Tr. 154-155 (Michael R. Cashell).

[67] Order No. 755, FERC Stats. & Regs. ¶ 31,324 at P 1 ("Pursuant to section 206 of the Federal Power Act (FPA), the Commission is revising its regulations to remedy undue discrimination in the procurement of frequency regulation in the organized markets . . . ."); *see also* Order No. 755 NOPR, 134 FERC ¶ 61,127, n.8.

[68] Order No. 755, FERC Stats. & Regs. ¶ 31,324 at PP 67, 128.

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50. NorthWestern contends that Order No. 764 affirmed the adoption of a broader policy in favor of compensating resources for regulation down services. In Order No. 764, the Commission adopted rules to accommodate scheduling for Variable Energy Resources, and also gave guidance for rates that a transmission provider might propose for Schedule 10—Generator Regulation and Frequency Response Service (Schedule 10).[69] At the paragraph cited by NorthWestern, Order No. 764 acknowledged that a resource used to provide generator regulation service is often dispatched in the middle of its operating range to allow the generator to provide regulation-up as well as regulation-down and, as a result, forego other opportunities.[70] The Commission stated that public utility transmission providers therefore may include opportunity costs for generator regulation service in certain circumstances.[71] A public utility transmission provider is not precluded from proposing a Schedule 10, as appropriate; however, it must demonstrate that it has forgone opportunities associated with its obligation to provide Schedule 3 service. Any proposed Schedule 10 should contain a per-unit rate and a volumetric component for regulation reserve capacity. While NorthWestern has failed in this case to demonstrate that it has unrecovered costs, NorthWestern is not precluded from making a showing in a separate proceeding to recover such costs under Schedule 10.

4. Compliance and Refunds

51. NorthWestern is directed to make a compliance filing within 30 days of the date of this order setting forth revised tariff sheets for its OATT Schedule 3 service that apply the determinations made in this order. Pursuant to the Hearing Orders issued in Docket Nos. ER10-1138-000 and ER12-316-000, NorthWestern is also required to refund Schedule 3 customers the difference between rates charged under the proposed rate schedule in this proceeding and the rate schedule found to be just and reasonable herein. All refunds shall include interest, from the date of collection until the date refunds are made, pursuant to the rate set forth in 18 C.F.R. § 35.19a(a)(2)(iii) (2013). NorthWestern must make refunds within 30 days of the date of this order and file a refund report within 30 days thereafter.

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[69] Order No. 764, FERC Stats. & Regs. ¶ 31,331 at P 4. Schedule 10 is a mechanism through which a public utility transmission provider may propose to recover certain costs associated with forgone opportunities resulting from holding capacity to provide Schedule 3 regulation service.

[70] NorthWestern Brief on Exceptions at 17 (quoting Order No. 764, FERC Stats. & Regs. ¶ 31,331 at P 316).

[71] Order No. 764, FERC Stats. & Regs. ¶ 31,331 at P 316.

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The Commission orders:

(A) The findings and conclusions in the Initial Decision in this proceeding are hereby affirmed.

(B) NorthWestern is ordered to make a compliance filing as discussed in the body of this order.

(C) NorthWestern must make refunds to Schedule 3 customers as discussed in the body of this order, and file a refund report with the Commission within 30 days thereafter.

By the Commission.

(S E A L)

Kimberly D. Bose,
Secretary.