Before The Public Service Commission
Of the State of Montana

DOCKET NO. D2013.12.85

Application for Approval to Purchase and Operate PPL Montana's Hydroelectric Facilities, for Approval of Inclusion of Generation Assets Cost Of Service in Electricity Supply Rates, for Approval Of Issuance of Securities to Complete the Purchase, and for Related Relief

REBUTTAL

TESTIMONY AND EXHIBITS

MAY 2014

Department of Public Service Regulation
Montana Public Service Commission
Docket No. D2013.12.85
PPLM Hydro Assets Purchase
NorthWestern Energy

PREFILED REBUTTAL TESTIMONY OF

ROBERT C. ROWE

ON BEHALF OF NORTHWESTERN ENERGY

Q. Please state your name and business address.

A. My name is Robert (Bob) C. Rowe. My business address is 40 East Broadway, Butte, MT 59701.

Q. By whom are you employed and in what capacity?

A. I am employed by NorthWestern Energy ("NorthWestern") as the President and Chief Executive Officer. I have held this position since August 2008. I also serve as the only non-independent Director on NorthWestern Corporation's Board of Directors.

Q. Are you the same Robert C. Rowe who submitted prefiled direct testimony in this docket?

A. Yes.

Q. What is the purpose of your rebuttal testimony?

A. My testimony addresses the direct testimony provided on behalf of the Montana Consumer Counsel ("Consumer Counsel" or "MCC") in this matter by Dr. John Wilson and Mr. Albert Clark.

Q. From your perspective, does the Consumer Counsel support or oppose NorthWestern's acquisition of the Hydros?

A. The Consumer Counsel, speaking through the testimony and proposed adjustments of his two witnesses, without directly saying so, is essentially opposed to NorthWestern acquiring the Hydros.

Dr. Wilson recommends that the Montana Public Service Commission ("Commission") modify NorthWestern's filing, rather than reject it. Mr. Clark does not recommend that the purchase be allowed or disallowed, but rather he recommends that certain test period adjustments be made, if the transaction is to be preapproved by the Commission.

I place the MCC's proposed adjustments in the following three general categories:

1. Purchase Price-Related
    a. Kerr Dam Acquisition Adjustment;
    b. Carbon Tax Rate Base Reduction; and
    c. "Intergenerational Ratepayer Inequity Adjustment."

2. Revenue Requirement-Related:
    a. Return on Equity;
    b. Capital Structure; and
    c. Plant/Depreciation Life.
3. Other:
    a. Carbon Tax; and
    b. Future Hydros Capital Cost Cap.

In addition to my rebuttal testimony below, which addresses a number of these, the Consumer Counsel's views and recommendations are addressed in greater detail by a number of other NorthWestern rebuttal witnesses.

Q. If the Commission were to accept the Consumer Counsel's Purchase Price-Related recommendations, would NorthWestern be able to close on the acquisition of the PPL Montana, LLC ("PPLM") Hydros as set out in the Purchase and Sale Agreement ("PSA") between the two parties?

A. No. The $900 million purchase price in the PSA between NorthWestern and PPLM is not renegotiable and cannot be changed. If these Consumer Counsel recommendations are accepted by the Commission, NorthWestern would be required to terminate the acquisition of the Hydros.

As illustrated in the table below, a Commission order granting approval of the Consumer Counsel Kerr Dam Acquisition Adjustment and the Intergenerational Ratepayer Inequity Adjustment would reduce the amount of the $900 million purchase price (after conveyance of Kerr Dam to the Confederated Salish and Kootenai Tribes ("CSKT")) that would be allowed for inclusion in rate base to $677 million.

	Dollars in Millions
NorthWestern Purchase Price	$900
Kerr Dam PSA Conveyance Price	($30)
Net Purchase Price	$870
MCC Kerr Dam Adjustment	($89)
MCC Intergeneration Inequity Adjustment	($104)
MCC Adjusted Price	$677

NorthWestern would pay $870 million for the Hydros (without Kerr Dam), but with the Consumer Counsel's recommendations, if adopted by the Commission, it would only be allowed to earn a return on and receive a return of $677 million. We have a responsibility to our customers to remain financially sound so that we can make long-term investments in all aspects of our system. We also have a legal fiduciary duty to our shareholders. A $193 million disallowance would not allow us to honor either commitment. It is an unacceptable outcome.

Q. What is your general reaction to the Consumer Counsel's testimony?

A. I am disappointed that the Consumer Counsel's position is extremely short-sighted. When we announced the transaction, based on the

Consumer Counsel's past advocacy and unique role in Montana, I had hoped there would at least be an acknowledgement that we were working in good faith to accomplish something worthwhile and that we would be able to work through the matter constructively in an effort to achieve a positive outcome for all involved, but especially NorthWestern's customers.

The MCC is unique. The office is provided for by the Montana Constitution,[1] while the Commission is created by statute.[2] The Consumer Counsel is overseen by the Legislative Consumer Committee, which is one of the few Montana legislative committees established by statute.[3] The Consumer Counsel is an office for which I have high respect. What the Counsel and his consultants, witnesses and staff say and do matter a great deal.

The public policy of the State of Montana enacted in 2007 by House Bill

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[1] Article XIII, Section 2, states, "The legislature shall provide for an office of consumer counsel which shall have the duty of representing consumer interests in hearings before the public service commission or any other successor agency." The Consumer Counsel is considered such an important office that even the Counsel's minimum qualifications are stated in statute:

> § 5-15-201, M.C.A. **Consumer counsel -- appointment and qualifications.** The committee shall appoint a consumer counsel and set the consumer counsel's salary. The consumer counsel must have the following minimum qualifications and additional qualifications that the committee determines appropriate:
>
> (1) a bachelor's degree or equivalent from an accredited college or university with a major or minor in accounting or allied fields;
>
> (2) be admitted to practice law in Montana courts and in the United States district court for the state of Montana.

[2] Section 69-1-102, MCA.

[3] Section 5-15-101, MCA.

25, the "Electric Utility Industry Generation Reintegration Act," directs NorthWestern to limit its exposure to the wholesale market, own more of its generation assets (which are then dedicated to serve customers at prices based on cost), and reintegrate them as part of an integrated utility service model.

The Consumer Counsel, in comments on NorthWestern's 2007 Electric Supply Procurement Plan, stated, "*NorthWestern must get off the market path as soon as possible*" through the *"acquisition of an owned resource.*" Future market risks have not subsided since then; actually they have likely increased due to existing and future environmental regulations. The Consumer Counsel's 2007 comments in their entirety were as follows:

> *"NorthWestern must get off the market path as soon as possible, and it should have done so before now. Reliance on the market commits ratepayers to long term escalation and volatility as contracts expire and are replaced at the then current price and future market expectation. By contrast, acquisition of an owned resource fixes the path of at least part of the cost of power from that resource at OC-D, which declines over time, and permits the possibility of long term hedging or fixing of fuel cost risk.*
>
> *This is not to suggest that the utility place all its eggs in one basket, which could expose ratepayers to unacceptable levels of risk.*

However in the current climate of uncertainty some degree of risk is necessary and a fraction of the portfolio with long term price stability but some risk on future environmental regulation might be acceptable to consumers and regulators. The Commission should direct NorthWestern to begin defining the potential risks and benefits of such a strategy."

Consistent with the Consumer Counsel's past advocacy, we have not "put all our eggs in one basket" and have assembled a diverse portfolio that helps us manage multiple risks. As advocated by the Consumer Counsel, we are acquiring or building resources that are dedicated to serve our customers and are priced going forward at "OC-D, which declines over time." And, especially for the Hydros resources, we are "fixing . . . fuel cost risk."

As the song says, "Is you is, or is you ain't?"[4] After urging us to commit to long-term actions, the Consumer Counsel seems to now ignore reality, the existing and emerging environmental regulations, and the continual future risks of the marketplace. Absent the successful acquisition of the Hydros, NorthWestern will likely remain in the marketplace for a substantial portion of its electricity supply portfolio, as discussed in the Prefiled Rebuttal Testimony of John Hines.

[4] Louis Jordan and Bill Austin, 1944 – much more pleasant than fighting over what shouldn't be a fight at all.

As presented in this filing, it is important for the Commission to understand that absent the Hydros acquisition, the natural gas plant option is the next-best most realistic baseload alternative to continued reliance upon market purchases, especially for baseload schedulable power. So it is hard to believe that given the Consumer Counsel's reaction to this Hydros application, that it would view building a comparably sized natural gas plant as a viable option either. However, it is also hard to imagine that if a natural gas plant were the best option, the Consumer Counsel would advance a serious proposal to allow recovery for only portion of its cost, pending future carbon regulation.

Q. What do you think the public and regulatory response would have been if NorthWestern had not actively pursued and successfully reached an agreement to acquire the PPLM Hydros?

A. I believed all along that we had an obligation to pursue, on sensible terms, an acquisition. I believed and still believe we would have been subject to strong criticism if we had not attempted to acquire these assets for our Montana customers. I also believed that the Commission and even the Consumer Counsel would have been very critical of our failure. It is not hard to conceive scenarios where we would be threatened with future disallowances if we had not pursued these resources and instead proposed other resources or continued reliance on the market long term.

Q. Did you have an expectation or hope about how the Hydros transaction might have been received?

A. Yes, I did. Fundamentally, people from across the company have worked amazingly hard to do the right thing for our customers and Montana. A number of them have real-life on-the-ground experience with the Hydros over the years, and in particular some have spent the better part of their utility careers operating and maintaining the Hydros. They are passionate and excited about what they are doing because they deeply believe it is right.

The public response in support of the transaction has been overwhelming. Most people appear to be surprised that there is controversy.

Given the public response and the previously stated desire of the Consumer Counsel for NorthWestern to acquire more owned resources, my hope had been that the Consumer Counsel would recognize the value of the transaction and be able to start with a general agreement on long-term direction, consistent with Montana law, reflecting each of our responsibilities to our customers, and then focus on realistic ways to reach a great outcome for all stakeholders.

Q. Discuss the effect of the Purchase Price-Related Adjustments (Kerr Dam Acquisition Adjustment and the Intergenerational Ratepayer Inequity Adjustment) proposed by the MCC.

A. Certainly. These two adjustments would result in the termination of NorthWestern's purchase of the Hydros.

Q. What is the proper way for the Commission to view Kerr Dam as it relates to NorthWestern's acquisition of the Hydros?

A. First, Mr. Clark's view of Kerr Dam and his proposed Kerr Dam Acquisition Adjustment do not properly reflect the treatment of Kerr Dam as part of this transaction. His view should be rejected.

Kerr Dam is simply a timing issue as it relates to NorthWestern's purchase of the Hydros. NorthWestern fully expected the transfer of Kerr Dam to CSKT by PPLM, or by NorthWestern if we were successful in acquiring the Hydros. This was confirmed by the final results of the arbitration decision between PPLM and CSKT, and the establishment of the $18.2 million conveyance price. While NorthWestern takes over operation and control of Kerr Dam through September 5, 2015 when it will be conveyed to the CSKT, we are simply the transfer agent, given the timing of our acquisition of the Hydros. Not knowing the actual ultimate conveyance price, NorthWestern established a $30 million placeholder value, which was the approximate mid-point of the positions of the two parties in the

Kerr Dam Conveyance Price Arbitration. NorthWestern was therefore indifferent to an actual conveyance price that was higher or lower, as it would be made whole and reimbursed $30 million. Now, we know the outcome.

Q. Given Kerr Dam and its $30 million placeholder value, how should the Commission view the purchase of the Hydros without Kerr Dam as it makes a determination under § 69-3-109, MCA, Ascertaining Property Values, and establishes an acquisition adjustment?

A. Given that we now know the final disposition of Kerr, the Commission should ignore Kerr Dam for this purpose. As planned, NorthWestern is acquiring all of the remaining Hydros for $870 million. Therefore, the Commission should authorize that NorthWestern account for this purchase in the aggregate as follows:

Account 102 – Electric Plant Purchased or Sold	\$523.1
Account 114 – Electric Plant Acquisition Adjustments	346.9
Total (\$= millions)	\$870.0

The Prefiled Rebuttal Testimony of Kendall Kliewer ("Kliewer Rebuttal Testimony") addresses Mr. Clark's proposed Kerr Acquisition Adjustment.

Finally, given the above, as described in the Prefiled Rebuttal Testimony of Brian Bird and as reflected in the Rebuttal Hydros Revenue

Requirement analysis attached as Exhibit__(PJD-5) to the Prefiled Rebuttal Testimony of Patrick DiFronzo ("DiFronzo Rebuttal Testimony"), NorthWestern is modifying its filing to exclude a return on the $30 million for Kerr Dam during the approximately one-year period preceding conveyance. NorthWestern's initial filing already excluded a return of the depreciation expense on Kerr Dam.

Q. What do you recommend regarding Mr. Clark's (and Dr. Wilson's) Intergenerational Ratepayer Inequity Adjustment?

A. This adjustment should also be rejected. Mr. Clark's and Dr. Wilson's contrived attempt to reduce rates using the so-called Intergenerational Ratepayer Inequity Adjustment is inappropriate and well beyond the scope of this proceeding.

As required by Montana Law and consistent with Commission Rules, NorthWestern developed and presented the rate base component of the Hydros' Revenue Requirement similar to our Colstrip Unit 4, Dave Gates Generating Station, and Spion Kop Wind Project's pre-approval filings (See § 69-8-421, MCA, Approval of electricity supply resources, and ARM 38.5.123 Statement C – Utility Plant Accounts).

The Consumer Counsel is aware that a pre-approval filing is not the place to change established Commission practice.

Finally, I point again to the MCC's comments on NorthWestern's 2007 Electric Supply Procurement Plan, where the Consumer Counsel advocates owned generation and the use of Original Cost less Depreciation:

> *"By contrast, acquisition of an owned resource fixes the path of at least part of the cost of power from that resource at OC-D, which declines over time, and permits the possibility of long term hedging or fixing of fuel cost risk."*

The Commission has provided a remarkable service in holding approximately twenty listening sessions all across Montana. Customers have asked good questions and shared their views. At least to date, it is clear that customers strongly support having the Hydros under Commission regulation, priced based on cost. They do not appear concerned that all benefits are not realized right away. Indeed, they perceive very compelling benefits, and have expressed that paying more upfront, in order to realize the long-term benefits makes sense.

It is our responsibility to plan long-term to serve our customers. Good regulation enables and supports that. It is the nature of utility investments to serve customers for a long time. Just as we are investing in long-term supply assets, we are planning and investing in other aspects of our system, through initiatives such as the Distribution System Infrastructure Project ("DSIP"). Those expenditures produce both near-term and long-term benefits, and we work to manage the overall level of investment. I have heard nothing but appreciation that we are replacing poles and tending to other parts of our electric and natural gas systems.

Q. In light of the Commission process so far, including the feedback from customers during the Listening Sessions, has NorthWestern made any adjustments to the Revenue Requirement Related portion of its original proposal to help mitigate the immediate impact to its customers' electric rates?

A. Yes, as discussed above and in the Kliewer and DiFronzo Rebuttal Testimonies, NorthWestern has reduced its initial revenue requirement request as follows:

Original Revenue Requirement	$128,402,190
Adjustments:	
Book Depreciation (from 40 to 50 yrs)	(4,401,890)
Kerr Dam (eliminate Return On)	(3,036,610)
Revised Rebuttal Revenue Requirement	$120,963,690

Q. Given the Consumer Counsel's advocacy, what should the Commission focus on as it deliberates NorthWestern's proposed acquisition of the Hydros?

A. Unfortunately, the Consumer Counsel is focused on the short-term. This is a long-term decision; the Commission knows that, under the electricity supply resource planning and procurement statute, § 69-8-419, MCA:

(1) NorthWestern is responsible to:

(a) plan for future electricity supply resource needs;

(b) manage a portfolio of electricity supply resources; and

(c) procure new electricity supply resources when needed.

(2) NorthWestern is required to pursue the following objectives in fulfilling its duties pursuant to (1):

(a) provide adequate and reliable electricity supply service at the lowest long-term total cost;

(b) conduct an efficient electricity supply resource planning and procurement process that evaluates the full range of cost-effective electricity supply and demand-side management options;

(c) identify and cost-effectively manage and mitigate risks related to its obligation to provide electricity supply service;

(d) use open, fair, and competitive procurement processes whenever possible; and

(e) provide electricity supply service and related services at just and reasonable rates.

Through ARM 38.5.8204(1)(c), the Commission requires us to "assemble and maintain a balanced, environmentally responsible portfolio of electricity supply resources." We take our job serving our electric and natural gas customers very seriously. In our filing, we have clearly met and addressed each of the above duties and objectives set out in § 69-8-419, MCA, Electricity supply resource planning and procurement -- duties of public utility -- objectives -- commission rules.

The Consumer Counsel's proposed future event adjustments (including a cap on future capital expenditures) should be rejected, as addressed elsewhere in NorthWestern's rebuttal testimony. The Commission already has the means by which to properly address these as part of future general rate case prudency reviews. This was specifically reaffirmed in the context of granting "approval of electricity supply resources" under § 69-8-421(9) MCA, which reads as follows:

> *"Nothing limits the commission's ability to subsequently, in any future rate proceeding, inquire into the manner in which the public utility has managed, dispatched, operated, or maintained any resource or managed any power purchase agreement as part of its overall resource portfolio. The commission may subsequently disallow rate recovery for the costs that result from the failure of a public utility to reasonably manage, dispatch, operate, maintain, or administer electricity supply resources in a manner consistent with* 69-3-201, 69-8-419, *and commission rules."*

Q. In addition to reviewing capital investments for inclusion in rate base, as the Commission always has and always will, do you have other thoughts about how the Commission might stay informed of this project?

A. Yes. We work hard to inform the Commission (and all of our stakeholders, but especially the Commission) about all aspects of providing utility service. We do this through mechanisms such as regular written reports; more formal – and I believe exceptionally substantive – public informational briefings, often "deep dives" into specific aspects of our operation; informal briefings to staff; and, encouraging Commissioners, staff, the Consumer Counsel and his staff, to observe the many aspects of our operations first-hand.

We are honored to provide the essential services that we do. It is a big responsibility. We are proud of our operations. We are especially proud of the employees who make it happen. We believe the more our regulators, customers, and others know about what we are doing, the better. And, we greatly value informed feedback – questions, comments, and suggestions – about what we are doing, and how we could do it better.

In particular situations, we have used more formal and structured methods to provide recurring data and reports to the Commission.

For example, we filed regular reports while the Dave Gates Generating Station (then, Mill Creek) was under construction. Now, we are providing quarterly progress reports on DSIP, along with in-depth presentations in noticed meetings, including reports on specific aspects of DSIP such as project management and controls.

The Hydro project is large. There are many work processes involved. I suggest that we work with the Commission to implement a process of regular, noticed meetings and reports, and establish a work group of Commission staff members (and a representative of the Consumer Counsel, if he chooses to participate) who would be kept informed of developments on a regular basis. I expect that initially, formal and informal meetings and reports would be more frequent. The form and frequency would likely evolve over time.

Q: In summary, what do you request of the Commission?

A: We ask the Commission to find that this Application is in the public interest and that procurement of the Hydros is consistent with § 69-3-201, MCA, the objectives in § 69-8-419, MCA, and the duties and objectives set out in the Commission's administrative rules identified in NorthWestern's application.

Q. Do you have a final observation?

A. Yes. Throughout this project, everyone involved at NorthWestern recognized they were working on something exceptionally important that will matter both immediately and for generations to come. The Commissioners clearly understand how consequential this matter is, as reflected in their focus, in the commitment to hold twenty or more public meetings, and in their statements. This is a long-term decision for present and future generations of our Montana customers, our children, grandchildren and even our great grandchildren. That's not hyperbole.

Throughout this process, and in much of what we do, I keep in mind an exceptionally wise statement by Commission Chairman Bill Gallagher. It may be the most thoughtful and far-sighted thing I have heard any commissioner say, and it is great advice for all of us.

Earlier in his service on the Commission, when asked what he wanted to accomplish in his position, Chairman Gallagher said, "I want to leave our customers, the utility, and our state healthier when I leave than when I started." I have quoted that statement repeatedly. I take it to heart. I have had it in mind throughout this huge project.

Q. Does this conclude your testimony?

A. Yes, it does.

PREFILED REBUTTAL TESTIMONY OF

JOHN D. HINES

ON BEHALF OF NORTHWESTERN ENERGY

Witness Information

Q. Please state your name and business address.

A. My name is John D Hines. My business address is 40 East Broadway, Butte, Montana 59701.

Q. By whom are you employed and in what capacity?

A. I am employed by NorthWestern Energy ("NorthWestern") as the Vice President of Supply.

Q. Are you the same John Hines who submitted prefiled direct testimony and prefiled supplemental testimony in this docket?

A. Yes.

Purpose of Testimony

Q. What is the purpose of this testimony?

A. The purpose of this testimony is to rebut certain representations or statements made by the Montana Consumer Counsel ("MCC") through the direct testimony of its consultants, Dr. John Wilson and Mr. Al Clark ("Consultants"). The Consultants have omitted key facts that the Montana Public Service Commission ("Commission") needs to be aware of, potentially creating a biased and erroneous perception on several important pieces of NorthWestern's Application. This rebuttal testimony provides the Commission a more comprehensive record on which to base its final decision. In addition, I correct a misleading representation in Dr. Wilson's Direct Testimony regarding my response to a data request.

Specifically, this rebuttal testimony will discuss the impact on NorthWestern's electricity portfolio if many of the Consultants' recommendations are adopted by the Commission, clarify the basis for and the reasonableness of NorthWestern's treatment of carbon risk in its price forecast used to support the acquisition analyses, address Dr. Wilson's mischaracterization of the level of carbon used by NorthWestern in its analyses, and correct the record regarding Dr. Wilson's misrepresentation of my response to Data Request MCC-004.

<u>Impact on Electricity Supply Portfolio</u>

Q. In the Rebuttal Testimony of Robert Rowe ("Rowe Rebuttal Testimony"), he states that NorthWestern will not be able to close on

the acquisition of the Hydros if the Commission were to accept the Consultants' purchase price related recommendations. What are the implications for NorthWestern's electricity supply portfolio if the Purchase and Sale Agreement ("PSA") for the Hydros is terminated?

A. The implications are significant and I believe extremely adverse to the long-term public interest of Montana, our customers, and NorthWestern. As set forth in the Rowe Rebuttal Testimony, adopting the Consultants' suite of recommendations will immediately result in the termination of the PSA between NorthWestern and PPLM. It is disingenuous for the Consultants to represent that they are "not recommending either that the preapproval of the purchase be allowed or disallowed" (Albert Clark's Direct Testimony, page 7, lines 3-4), or that it is "preferable to modify and improve it" (Dr. Wilson's Direct Testimony, page 9, line 4). If the Commission follows their recommendations, some other entity not regulated by the Montana Commission, perhaps a utility regulated in another state, will likely own and control these assets.

I believe a regulatory rejection of the Hydros creates a "Deregulation Two" scenario. Without the Hydros, the electricity supply portfolio will likely rely upon market purchases which results in significant market risks (calculated at a $457 million risk premium) being borne by Montana consumers. The Consultants ignore or disregard the risks of continued reliance upon the market.

Q. Please explain what you mean by "Deregulation Two."

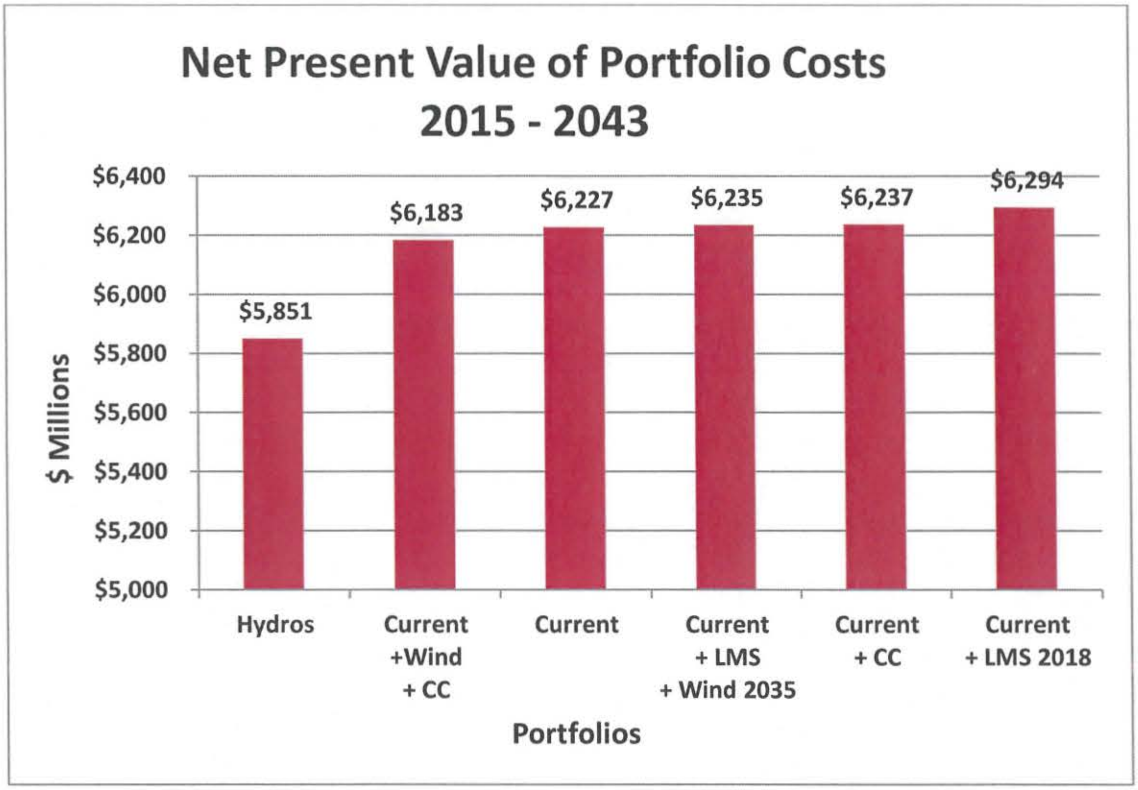
A. When I speak of "Deregulation Two," I am referring to a policy approach of relying on market purchases to serve our customers' future electricity requirements. This means relying once again on the variability and risk of market purchases and to some degree Qualifying Facility ("QF") contracts to meet future portfolio requirements. The result is obviously contrary to existing public energy policy which encourages utility owned generation coupled with regulatory oversight. I believe this would be a huge step backwards, to basically rejecting many of the substantial policy steps Montana's leaders have taken to address the adverse effects of the 1997 SB 390 legislation ("Deregulation").

With a successful Hydros acquisition, NorthWestern forecasts that the portfolio would consist in the intermediate term of approximately 10 percent market purchases, primarily at peak or super peak times. Absent the acquisition of the Hydros, NorthWestern will be purchasing approximately 50 percent of the portfolio's needs from the short to intermediate term market.

Q. Why do you state NorthWestern would likely have to rely on market purchases?

A. The Prefiled Direct and Supplemental Testimonies of Joseph Stimatz ("Stimatz Direct Testimony" and "Stimatz Supplemental Testimony") present the stochastic analysis. This analysis shows the current resources plus Hydros portfolio significantly outperforms (in terms of lower risk and costs) the alternative portfolios considered, including market. The total net present value ("NPV") costs for the portfolios are summarized in Chart 1 below. In addition to the current resources plus market scenario (Current), various combinations of natural gas-fired generation and or wind additions were analyzed (see Stimatz Supplemental Testimony page 4, lines 6-7 and the Chart: Net Present Value of Portfolio Costs, 2015-2043). The Hydros portfolio has the lowest NPV Portfolio Costs compared to any of the other portfolios. The Commission should understand that absent the Hydros acquisition, the natural gas plant plus wind option is the most realistic physical asset alternative to continued reliance upon market purchases. However, this alternative has a $332 million cost greater than the Hydros.

Chart 1.



Absent knowledge of the Hydros opportunity, the 2011 Electricity Supply Resource Procurement Plan ("2011 Plan") concluded that the addition of a combined cycle combustion turbine is the preferred resource alternative because of the balance achieved between resulting portfolio cost and risk when compared to alternative portfolios, including market. Since the Consultants' recommendations effectively terminate the Hydros transaction, their focus on short-term portfolio costs, and the fact that the combined cycle plus wind option is more costly than the Hydros, continued reliance upon the market is the likely outcome.

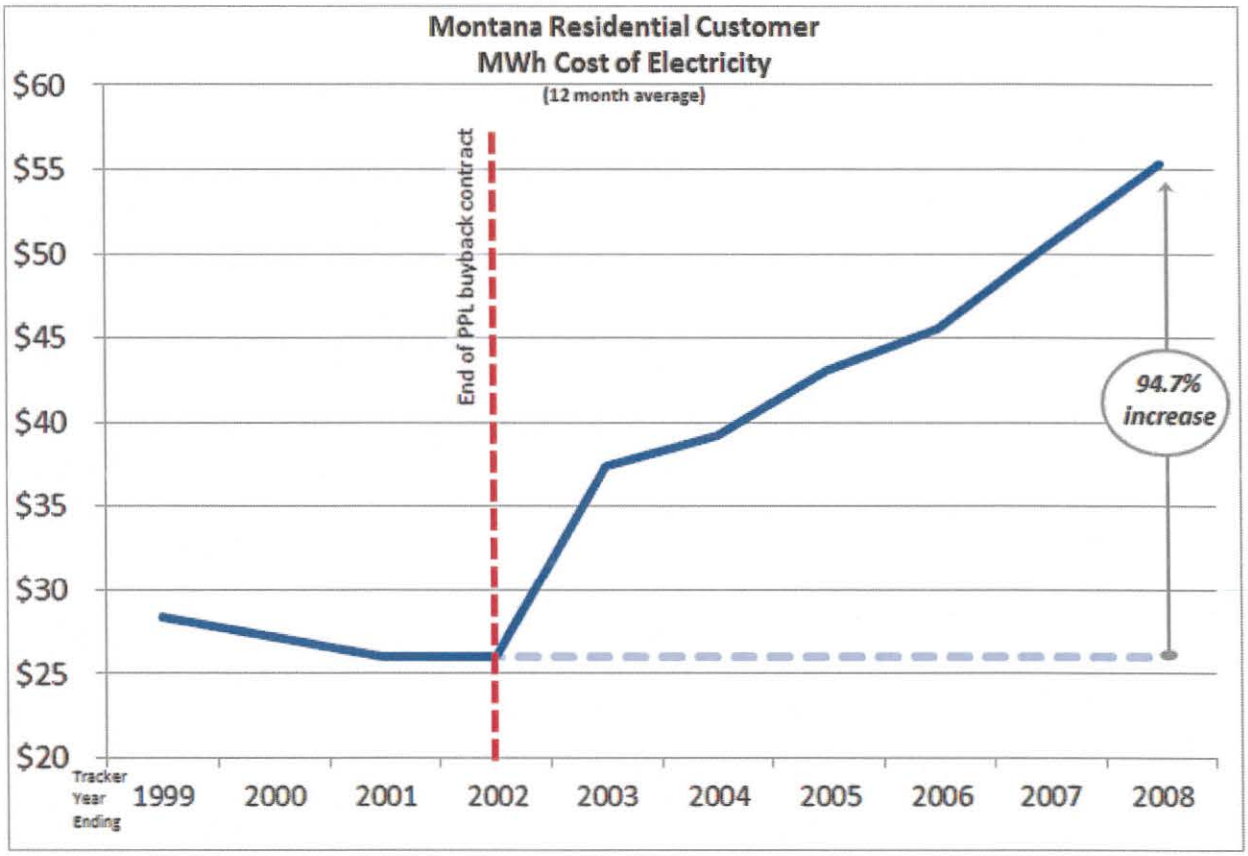
As the Rowe Rebuttal Testimony discusses, the MCC's position is contrary to existing public policy. In fact, a result of the Consultants' recommendations would be a fundamental redirection of Montana energy policy. Since the purchase of the Hydros appears to be unacceptable to the MCC, as Vice President of Supply, I can't envision what type of owned baseload generation resource would be acceptable to the MCC given the characteristics of cost and risk that NorthWestern has demonstrated for the Hydros.

Q. Given your responsibility of overseeing the management of the electricity supply portfolio, what are some of your concerns with Deregulation Two?

A. To be very clear, I believe this would be a horrible mistake for Montana consumers. One repercussion from Deregulation was the sale of the Montana Power Company's electricity generation assets and the resulting exclusive reliance on market purchases and QF contracts to serve consumers' electricity supply needs. The effect on consumers' electricity costs was extremely large – see Chart 2 below. Electricity supply costs increased by 94.7 percent in the period between the end of the buyback contract and Colstrip Unit 4 being placed into rate base in 2008.

NorthWestern has been unambiguous that purchasing the Hydros will result in an immediate rate increase (the Rowe Rebuttal Testimony provides the means of decreasing its original revenue requirement request). The tradeoff is a portfolio that provides lower costs and risks compared to any other option.

Chart 2.



The Consultants, purportedly representing Montana consumers, are essentially saying "no" to a great opportunity to acquire the Hydros which will provide a renewable, carbon free, and stably priced fleet of generation assets for customers' benefit and "yes" to greater market volatility, risks, and costs. Dr. Tom Power, on behalf of the Human Resource Council District XI and the Natural Resources Defense Council, testifies in this docket:

"NorthWestern correctly concluded that the costs associated with the risk of heavily depending on the regional electric market to obtain a large proportion of the electricity needed to serve its customers' loads were significant and should not be ignored." Power Direct Testimony, page 3, lines 19-22

Q. The Consumer Counsel is charged with representing consumers. Please provide your perspective on how consumers view the potential hydro acquisitions, as presented in the Commission sponsored listening sessions ("Sessions").

A. There seems to be a huge disconnect between the Consultants' vision and what Montanans want, and in fact in many instances, are demanding. At the Sessions which I have attended there has been nearly unanimous support for NorthWestern to acquire the Hydros, including many citizens stating that they are willing to initially pay more in their electric bill for the Hydros, recognizing that many of the benefits are in the intermediate to long-term. Frankly, while Dr. Wilson claims to be providing "clear-eyed" recommendations, in this instance it is clear that the MCC is out-of-touch with what Montana consumers want.

Q. Are there other themes emanating from these Sessions?

A. Yes. There are two themes which I think are especially worth mentioning. In Bozeman, Billings, and Butte, business owners testified regarding the value of owned generation and the need for rate stability, something that they see the Hydros contributing to immediately. Also, many people expressed strong support in having an electric supply portfolio that is comprised of over 50 percent wind and water. People noted that this quantity of renewable generation can provide an immediate inducement for economic development.

Q. Hasn't the MCC also voiced strong concerns about NorthWestern continuing to rely on short-, medium-, and long-term market purchases?

A. Yes, the MCC has. As discussed in the Rowe Rebuttal Testimony, the Consultants' testimony is inconsistent with the position the MCC's staff took when it commented on NorthWestern's 2007 Electric Procurement Plan. At that time the MCC basically upbraided the utility for its continued reliance on short-, medium-, and long-term market purchases. The Consultants' recommendations are inconsistent with this concern.

<u>NorthWestern's Analysis of Carbon Risk</u>

Q. The Consultants attack NorthWestern's incorporation of carbon risk in its resource planning and evaluation methodology. Please discuss why NorthWestern includes carbon as a risk in its analyses.

A. NorthWestern is responsible for developing a portfolio that is both least-cost and lowest-risk. Dr. Wilson repeatedly attacks NorthWestern for including carbon in its market price forecast throughout his testimony, but fails to acknowledge that addressing risk is a fundamental planning responsibility for the utility. Addressing environmental risk, and carbon, which is obviously such a risk, is required by both Montana statute and the Commission's planning and procurement rules.

Dr. Wilson repeatedly references that carbon risk is "hypothetical." I agree that this cost is not known; if it was known, NorthWestern would not have modeled it as a risk. While later in my rebuttal testimony I provide numerous examples of why carbon regulation is a legitimate risk, I want to emphasize that to be consistent with and comply with Montana statutes and Commission rules, NorthWestern must consider environmental risks in its analyses. Further, for someone to claim that there is no risk of increasing market prices due to future regulation of greenhouse gas – specifically carbon – is just plain wrong.

The impact from carbon on NorthWestern's forecast market electricity price can come in a variety of ways – decreased supply (due to shutdown of thermal generation plants), increased costs of operating plants (fixed or variable), cap and trade, or direct taxation. The 2013 Electricity Supply Resource Procurement Plan ("2013 Plan") (Chapter 5, page 5-5,) states:

> "Consistent with prior resource plans, NorthWestern incorporates a carbon penalty forecast into its planning work and views it as a proxy for the eventual form of greenhouse gas regulation implemented."

The Direct Testimony of Dr. Tom Power concludes that NorthWestern's assumptions regarding carbon are reasonable, and prudent.

> *"NorthWestern's inclusion of the risks of environmental regulation in its analysis of portfolios containing its proposed hydro purchase and alternative portfolios followed the Montana Public Service Commission's (MPSC) rules for Electric Supply Procurement that require consideration of the risks and cost of environmental regulation when making procurement decisions."* Power Direct Testimony, page 2, lines 11-15

Q. Please discuss the policy direction the state of Montana has enacted regarding how utilities should consider environmental risks.

A. Montana statutes and Commission rules address the consideration of environmental risk in the utility's planning and acquisition analyses. Under Montana's preapproval statute, the Commission requires a utility to include carbon offsets on new natural or synthetic gas plants.

- Specifically: MCA 69-8-421 (6)(e) states: "When issuing an order for the acquisition of an equity interest or lease in a facility or equipment that is constructed after January 1, 2007, and that is used to generate electricity that is primarily fueled by natural or synthetic gas, the commission shall require the applicant to implement cost-effective carbon offsets. Expenditures required for cost-effective carbon offsets pursuant to this subsection (6)(e) are fully recoverable in rates."

Montana law also addresses the inclusion of carbon offsets for a new coal plant. Specifically, MCA 69-8-421 (8) states:

- "Until the state or federal government has adopted uniformly applicable statewide standards for the capture and sequestration of carbon dioxide, the commission may not approve an application for the acquisition of an equity interest or lease in a facility or equipment used to generate electricity that is primarily fueled by coal and that is constructed after January 1, 2007, unless the facility or equipment captures and sequesters a minimum of 50% of the carbon dioxide produced by the facility. Carbon dioxide captured by a facility or equipment may be sequestered offsite from the facility or equipment."

These statutes effectively increase the cost of electricity and therefore the price of electricity from new thermal generation. It is ironic that the MCC was an active intervener in Docket No. D2008.8.95 (Dave Gates Generating Station) where a carbon implementation plan and its associated costs were presented for Commission approval and yet in this docket, Dr. Wilson testifies that future costs of carbon are just "speculation."

The Commission's rules governing a utility's electricity supply resource planning, procurement, and decision-making also require a utility to consider environmental impacts such as carbon emissions when considering resource acquisitions. Two rules are provided below that direct the utility to evaluate environmental factors:

- ARM 38.5.8213(1)(e)(i) requires a utility to "develop methods for: weighting resource attributes…includ[ing] … underlying fuel source and associated price volatility and risk, including risks related to future regulatory constraints on environmental impacts such as emissions of carbon dioxide."
- ARM 38.5.8204(1)(c) "assemble and maintain a balanced, environmentally responsible portfolio of electricity supply resources . . ."

The Commission itself has agreed that carbon regulation should be included in NorthWestern's procurement analyses. The Commission provided the following comment on NorthWestern's 2011 Plan (Docket No. N2011.12.96):

> ". . . . *it is correct practice to analyze the planning impacts of carbon regulation . . .*"

In 2005, NorthWestern included carbon as a risk in its electricity procurement plan and has included carbon cost considerations in all of its electricity supply plans since. In its most recent 2013 Plan, NorthWestern stated:

"Consistent with prior resource plans, NorthWestern incorporates a carbon penalty forecast into its planning work and views it as a proxy for the eventual form of greenhouse gas regulation implemented."

Q. Please discuss activities regarding carbon regulation taking place outside of Montana.

A. There is substantial evidence that more stringent and more broadly applicable carbon regulations are likely. The U.S. Environmental Protection Agency ("EPA") is currently moving forward on a variety of fronts to regulate greenhouse gas ("GHG") emissions. For example:

- In September 2013, EPA proposed across-the-board standards for *new* fossil fuel-fired power plants. The final regulations should be promulgated in September 2014.

- The EPA is also preparing to propose standards for *existing* fossil fuel-fired power plants. The timeline for these standards is: proposed carbon pollution standards no later than June 1, 2014; final standards no later than June 1, 2015; and states are required to provide implementation plans no later than June 30, 2016.

Q. Can you provide examples in the Pacific Northwest where thermal baseload electricity is expected to shut down over the next decade?

A. Yes. The 150 MW Corette coal plant in Billings is expected to be mothballed in 2015. Boardman, a 585 MW coal plant in Oregon, is expected to close in 2020. In Washington, the owner of the Centralia coal plant has announced it will close Centralia Unit 1 in 2020 and Unit 2 in 2025 for a total of 1,340 MW.

Also, on April 29, 2014, Governor Inslee of Washington signed Executive Order 14-04 (attached as Exhibit__(JDH-1)). This Executive Order creates a task force to provide recommendations on the design and implementation of carbon emission limits and market mechanisms for Washington. These recommendations are intended to be used by Governor Inslee for 2015 legislation. The Executive Order also specifically calls on Washington utilities to reduce and eliminate over time the use of electrical power produced from coal, even from those facilities located outside their state.

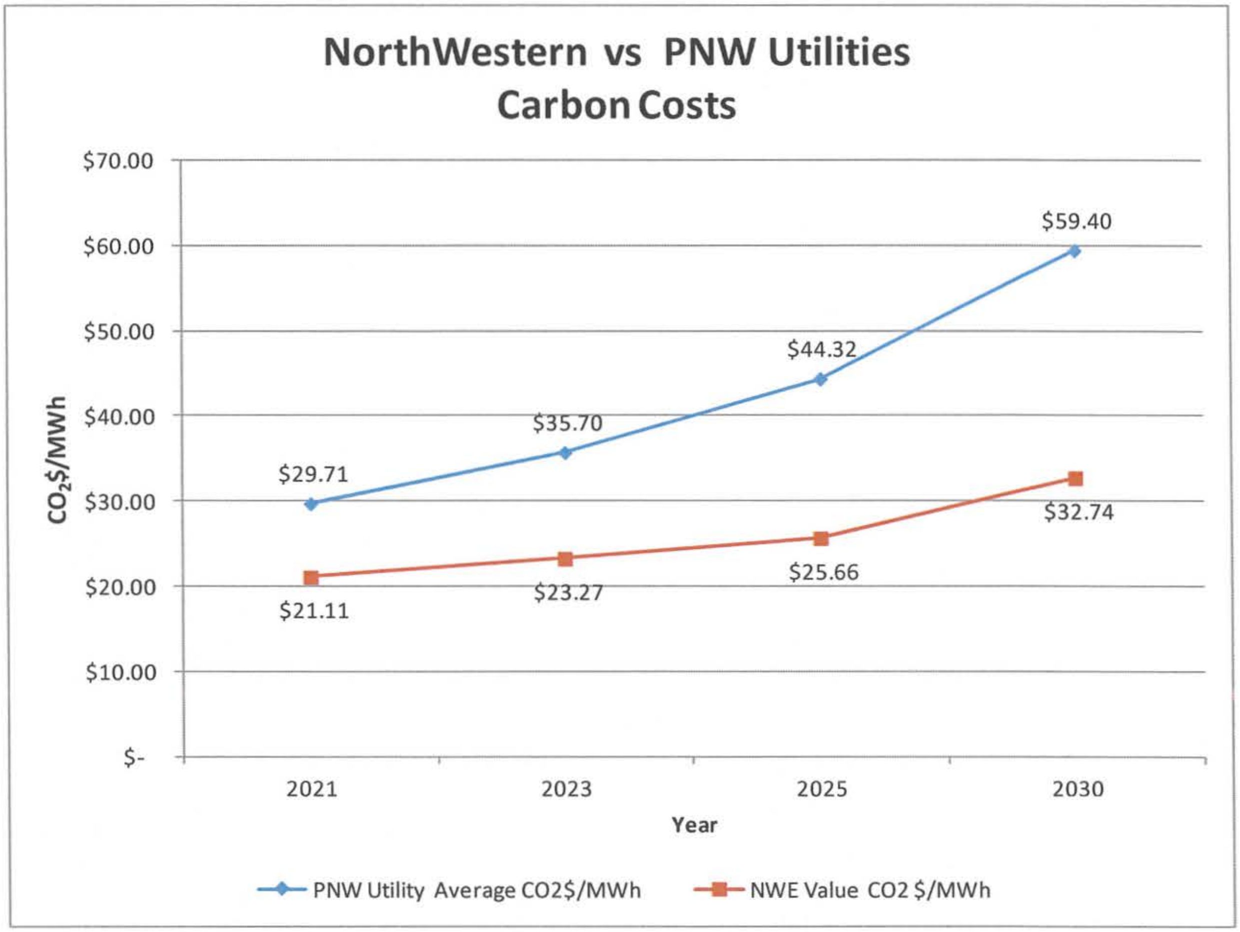
Q. Given that NorthWestern must consider environmental risks, and carbon is clearly an environmental risk, please discuss the appropriateness of the carbon values NorthWestern used in its price forecast.

A. In Dr. Wilson's testimony, without any basis, he describes NorthWestern's values as: "very large," "high level," and "substantial." NorthWestern strongly disagrees with his unsubstantiated assertions. NorthWestern has demonstrated that the context of including carbon risk in its market price forecast is extremely reasonable and the carbon costs NorthWestern used are consistent with the other regulated utilities in the Pacific Northwest.

There are six investor owned utilities in the Pacific Northwest in Montana, Idaho, Oregon, and Washington all regulated by state commissions. Chart 3 below provides four separate years of the average of carbon values used by Avista, Idaho Power, Portland General Electric, Puget Sound Electric, and PacifiCorp. These averages are then compared to NorthWestern's estimated carbon values for those years. The comparison starts in 2021, when NorthWestern's carbon risk is first included in its price forecast, and shows that NorthWestern's values are substantially lower than the values used by the other utilities, not higher, as Dr. Wilson's assertions suggest.

In summary, as demonstrated in my discussion here, NorthWestern's inclusion of carbon as a risk has a strong foundational basis. Moreover, the value associated with NorthWestern's incorporation of carbon cost is actually lower than the average of the other regulated utilities in the Pacific Northwest. Dr. Wilson's representations should be dismissed.

Chart 3.



1 **NorthWestern's Portfolio Analysis**

2 **Q. Please comment on Dr. Wilson's assertion that NorthWestern biased**
3 **its stochastic analysis by including risks such as carbon in its**
4 **assessment.**

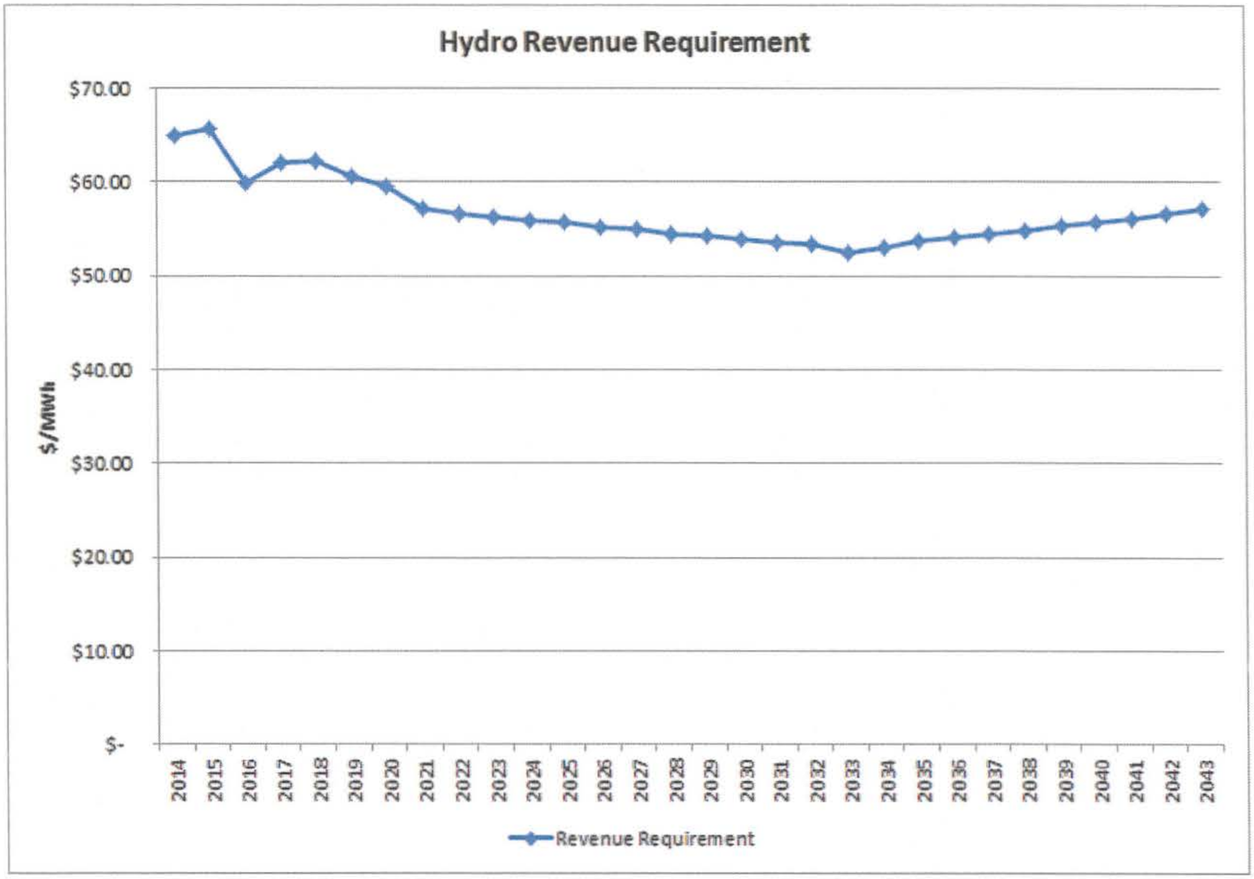
5 **A.** Again, this testimony lacks candor regarding Montana's procurement
6 statues and rules, as it ignores NorthWestern's obligation to consider
7 environmental risks. As stated in the Prefiled Rebuttal Testimony of Gary

Dorris ("Dorris Rebuttal Testimony"): "NorthWestern has . . . used industry best practices to analyze the hydro acquisition . . ."

Q. Do the Consultants ignore other planning or acquisition attributes identified in the Commission's rules?

A. Yes, specifically price stability and lowest long-term cost. ARM 38.5.8204(1)(a), as an objective, requires utilities to: "provide customers adequate and reliable electricity supply services, stably and reasonably priced, at the lowest long-term total cost." Unlike Dr. Wilson's short-term emphasis, NorthWestern's analysis does not focus exclusively on the short-term benefits of relying on the market, or of any other resource alternative. As stated previously, the Hydros are the lowest long-term risk adjusted resource for meeting the portfolio's future needs.

Chart 4.



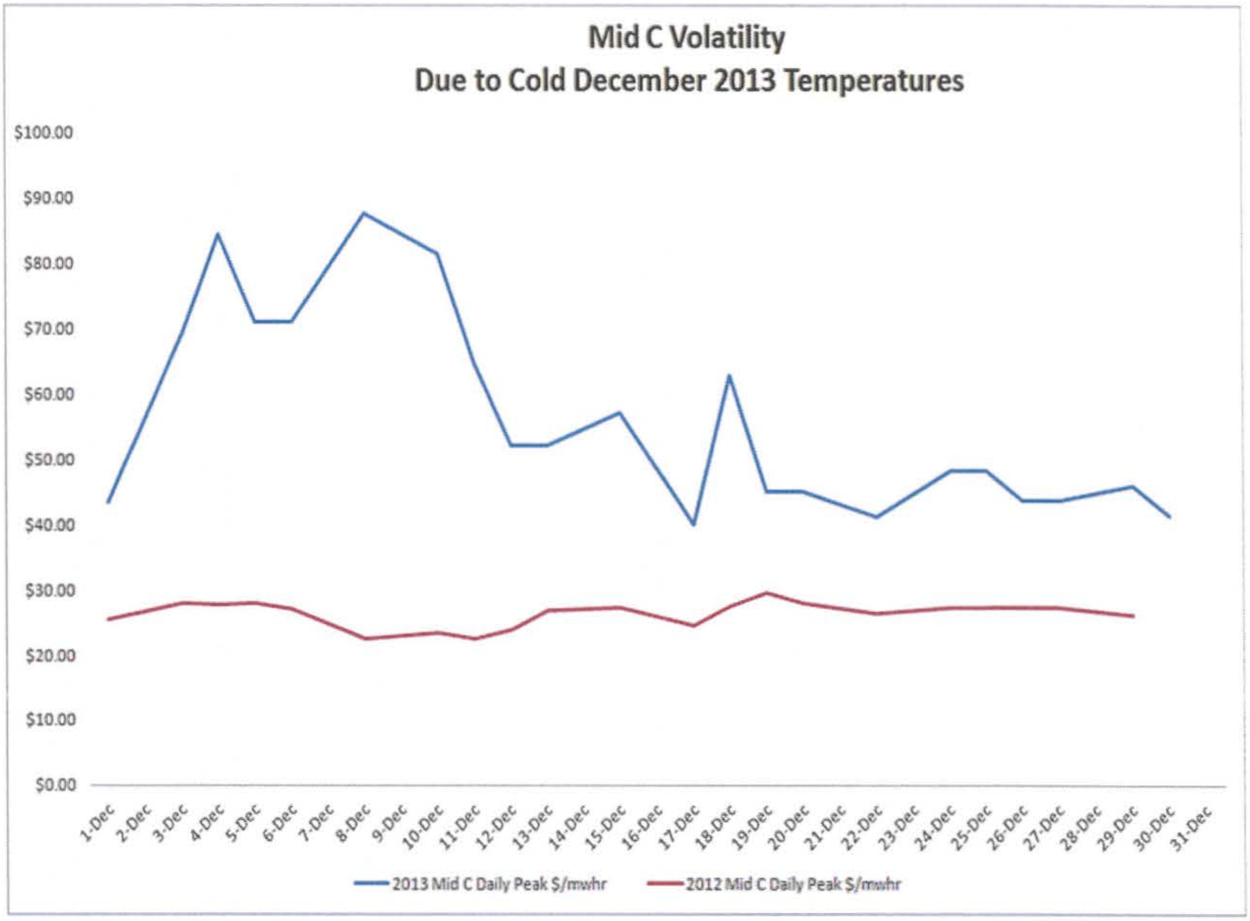
In fact, over time, the projected revenue requirement of the hydro assets is stable or declining. Compare this to the increasing projections of market prices (and also $376 million in higher portfolio costs). When one considers that the Hydros would provide nearly 40 percent of the electricity portfolio's resource needs, a key attribute of the Hydros is its contribution to cost stability. The stability of the Hydros' forecasted revenue requirement as presented in Exhibit__(TEM-2) of the Prefiled Direct Testimony of Travis Meyer is illustrated in Chart 4 above.

Q. Can you provide an illustration of the recent volatility associated with the market for electricity?

A. Yes. The relative risks of the supply portfolio that includes the Hydros compared with the risks of reliance on the market are described in detail in the Stimatz Direct and Supplemental Testimonies and the Dorris Rebuttal Testimony, but a recent example is illustrative of the point. Even though the Mid Columbia ("Mid-C") market has recently been trading at a relatively low level, at times actual price volatility has been significant. In Chart 5 below I provide an illustration of this volatility using actual pricing at Mid-C for December 2012 and December 2013.

Chart 5 illustrates pricing differentials or market volatility (which was not foreseen) and is a good illustration of market risk to consumers. This graph provides actual on-peak prices for December 2012 and December 2013 at the Mid-C trading hub (the reference point for NorthWestern's market transactions). Daily prices in 2013 were at times about 300 percent higher than just the previous year. Clearly, exposing customers to this type of volatility is a risky proposition and should be avoided when possible for all those reasons I have already discussed.

Chart 5.



<u>Response to Data Request MCC-004</u>

Q. Please explain how your response to Data Request MCC-004 was misrepresented in Dr. Wilson's Direct Testimony

A. On pages 15-16 of Dr. Wilson's Direct Testimony, he attempts to leave the impression that I believe the benefit of owning a percentage of Colstrip Unit 4 flows just to the utility's shareholders. While he provides my full data response buried in a footnote, it is unfortunate that he does not speak to my entire MCC-004 response in the body of his text. Data Request MCC-004 reads as follows:

"Does NWE believe that its owned interest in Colstrip Unit 4 has a negative value to the utility currently? Please explain in detail."

NorthWestern provided the following response:

"NorthWestern does not believe that its owned interest in Colstrip Unit 4 has a negative value to the utility. NorthWestern views its owned interest in Colstrip Unit 4 as a valuable component of its current electricity supply portfolio providing essential baseload electricity for its customers."

My response repeats the wording from the question ("value to the utility") but is clearly focused on the value of this resource to the supply portfolio. Dr. Wilson mischaracterizes my response.

Q. Does this complete your rebuttal testimony?

A. Yes it does.

JAY INSLEE
Governor

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EXECUTIVE ORDER 14-04

WASHINGTON CARBON POLLUTION REDUCTION AND CLEAN ENERGY ACTION

WHEREAS, the University of Washington, as required by statute, recently released its summary of existing knowledge regarding the causes, impacts, and effects of climate change on Washington State, concluding:

- Human activities have increased atmospheric levels of greenhouse gases to levels unprecedented in at least the past 800,000 years;

- Washington has experienced long-term warming, a lengthening of the frost-free season, and more frequent nighttime heat waves. Sea level is rising along most of Washington's coast, coastal ocean acidity has increased, glacial area and spring snowpack have declined, and peak streamflows in many rivers have shifted earlier in the year;

- Three key areas of risk, specifically changes in the natural timing of water availability, sea level rise and ocean acidity, and increased forest mortality, will likely bring significant consequences for the economy, infrastructure, natural systems, and human health of the region; and

- Decisions made today about greenhouse gas emissions will have a significant effect on the amount of warming that will occur after mid-century;

WHEREAS, studies conducted by the University of Oregon found that the effects of climate change on water supplies, public health, coastal and storm damage, wildfires, and other impacts, will cost Washington almost $10 billion per year after 2020, unless we take additional actions to mitigate these effects;

WHEREAS, actions to reduce the State's carbon pollution emissions will also improve the State's energy independence and the strength and competitiveness of the State's economy, by:

- Improving job growth in clean energy businesses and technologies, increasing energy efficiency, reducing costs and increasing productivity, and improving competitiveness in manufacturing, transportation, agriculture, and building operations;

- Benefitting farm and forest landowners who provide the feedstock for cleaner energy fuels while also providing a means to offset carbon emissions; and

- Increasing energy efficiency investments that will benefit consumers and ratepayers while growing jobs in construction and associated sectors;

WHEREAS, studies conducted for the Western Climate Initiative indicated that a program to limit carbon emissions, implemented through market mechanisms, would result in a net increase of 19,300 jobs and increased economic output of $3.3 billion in Washington by 2020;

WHEREAS, Engrossed Second Substitute Senate Bill 5802 (2013 Session) established the Climate Legislative and Executive Workgroup and required it to recommend a state program of actions and policies to reduce greenhouse gas emissions, that if implemented would ensure achievement of the state's emissions limits outlined in RCW 70.235.020;

WHEREAS, the Climate Legislative and Executive Workgroup secured an independent review of existing state and federal policies, and the progress made towards the carbon pollution limits; it concluded that, despite significant progress, Washington will not meet our statutory limits without additional action;

WHEREAS, Washington recently joined British Columbia, Oregon, and California through the Pacific Coast Collaborative, in calling for additional West Coast actions on climate leadership, clean transportation, and clean energy and infrastructure;

WHEREAS, it is critical to Washington's economic future that greenhouse gas reduction strategies be designed and implemented in a manner that minimizes cost impacts to Washington citizens and businesses; and

WHEREAS, Washington needs to take additional actions now, to meet our statutory commitment, to do our part in preventing further climate change, to capture the job growth opportunities of a clean energy economy, and to meet our obligation to our children and future generations.

NOW THEREFORE, I, Jay Inslee, Governor of the state of Washington, by virtue of the power vested in me by the Constitution and statutes of the state of Washington do hereby order and direct as follows:

CARBON EMISSIONS REDUCTION TASKFORCE

The Governor's Carbon Emissions Reduction Taskforce is hereby created to provide recommendations on the design and implementation of a carbon emission limits and market mechanisms program for Washington. The Taskforce's advice and recommendations will inform legislation to be requested by the Governor for consideration during the 2015 legislative session.

The carbon emissions reduction program must establish a cap on carbon pollution emissions, with binding requirements to meet our statutory emission limits, and it must include the market mechanisms needed to meet the limits in the most effective and efficient manner possible. The program must be designed to maximize the benefits and minimize the implementation costs, considering our emissions and energy sources, and our businesses and jobs.

The Taskforce will include Governor-appointed representatives of business, labor, public interests, and public health. Members will be asked to participate in the best interests of the current and future citizens of the State. The Governor will invite representatives of federal, tribal, and local governments to participate as full members of the Taskforce.

The Governor's Legislative Affairs and Policy Office (LAPO) will organize and secure support for the work of the Taskforce, through state agencies, expert consultants, and others, as needed and allowed by law. LAPO will develop and provide background information and program design options for review by the Taskforce. The Office of Financial Management (OFM) will oversee the economic analysis of program designs, as detailed below.

In developing its recommendations, the Taskforce must consider measures to help offset any cost impacts to consumers and workers, protect low-income households, and assist energy-intensive, trade-exposed businesses in their transition away from carbon-based fuels. It must also evaluate how best to provide oversight and regulation of the markets. Where possible, the program must:

- Be fair in allocating responsibility to emission sources;
- Minimize shifting of emissions and jobs to out-of-state locations ("leakage");
- Provide clear accountability for, along with appropriate flexibility in, compliance; and
- Provide for ongoing monitoring, evaluation, and adjustment of the program, as needed to secure benefits and minimize unintended consequences.

OFM will oversee the economic analysis of program designs and options, with the assistance of qualified consultants as needed. The analysis will include cost effectiveness of emission reductions (cost per ton), evaluation of a range of costs and benefits for the overall economy and specific business sectors (manufacturing, agriculture, construction, industrial, transportation, etc.), and the effects (positive, negative, and net) on jobs, households, and fuel and energy prices.

The analysis will estimate the costs of inaction, and describe the potential environmental and human health benefits of carbon pollution emission reduction. As warranted by the economic analysis, the program designs will be revised to maximize benefits and minimize costs to Washington consumers, businesses, and citizens.

The director of LAPO will ensure that the State Legislature's committees on energy and environment, and other interested legislative members, are fully informed on the Taskforce's work, and she or he will solicit their early and ongoing advice and guidance.

The Taskforce will convene on April 29, 2014, with its final recommendations delivered by no later than November 21, 2014.

COAL-FIRED ELECTRICITY

LAPO will seek negotiated agreements with key utilities and others to reduce and eliminate over time the use of electrical power produced from coal. LAPO, working with the Departments of Commerce and Ecology, and other state agencies, will engage key electrical utilities that generate electricity through coal-fired facilities located outside the state and that rely on this electricity to meet their Washington electrical loads, with the objective of reducing overall greenhouse gas emissions from the generation of electricity. LAPO will seek assistance and support from federal energy agencies to successfully facilitate this transition from coal to cleaner electricity sources.

I ask the Washington Utilities and Transportation Commission (UTC) to actively assist and support the reduction in the use of coal-fired electricity, within the scope of its jurisdiction and authority.

I ask the Northwest Power and Conservation Council to pursue the reduction of coal-fired electricity through its Seventh Power Plan and other appropriate means.

CLEAN TRANSPORTATION

The Department of Transportation, in collaboration with federal, state, regional, and local partners, will develop an action plan to advance electric vehicle use, to include recommendations on targeted strategies and policies for financial and non-financial incentives for consumers and businesses, infrastructure funding mechanisms, signage, and building codes. The Department will continue to build out the electric vehicle charging network along state highways and at key destinations, as funding and partnerships allow.

The Departments of Transportation, Commerce, and Ecology will work with the Regional Transportation Planning Organizations, counties, and cities to develop a new program of financial and technical assistance to help local governments implement measures to improve transportation efficiency, and to update their comprehensive plans to produce travel and land-use patterns that maximize efficiency in movement of goods and people, and reduce costs and greenhouse gas emissions.

The Department of Transportation, in consultation with the Freight Mobility Strategic Investment Board, the Transportation Improvement Board, and the County Road Administration Board, will conduct a review of existing state transportation grant programs in order to identify and implement opportunities to increase statewide investments in multimodal transportation. The review will also identify methods of securing transportation funding for local governments that have adopted plans and performance measures to enhance multimodal transportation systems. The Department of Transportation will identify and recommend both immediate and longer-term reforms to grant making that will increase multimodal investments.

The Department of Transportation will develop, adopt, and implement new planning policies and guidance documents for conducting multimodal transportation corridor studies. New corridor studies shall prioritize both capital investments and operating strategies that increase transportation choices, foster innovative land use, and reduce transportation emissions. The Department of Transportation will identify both immediate and longer-term reforms to its corridor study work.

The Department of Transportation will develop, adopt, and implement the multimodal, federally-compliant, long-range statewide transportation plan with a renewed focus on transportation strategies to increase efficiency and reduce both costs and greenhouse gas emissions. The plan must explore alternative revenue sources to fund our transportation system, including vehicle-miles-traveled fees, system-wide tolling, demand-management and trip-reduction strategies, and other reforms such as least-cost planning, transit-oriented land use, freight-corridor development, prioritized-project selection, and similar innovative tools. This new focus will be developed based on scenario analyses of how investments in the transportation system move our state in the direction of a multimodal, coordinated, cost-effective, safe, and low-carbon transportation system. In developing the plan, the Department shall utilize a multi-modal statewide model that allows for analysis of economic benefits, vehicle miles traveled, health, greenhouse gas emissions, and a least-cost planning methodology in order to develop outcomes to be achieved at five, ten, and twenty years from the plan's adoption date. The Department shall develop the transportation model to reflect the current local, state, and national trend showing a decrease in driving, and to evaluate how actions will contribute to achieving the state's enacted limits for greenhouse gas emission reductions.

The Department of Ecology will review the State's clean car law, RCW 70.120A.010, to identify and recommend needed updates to the statute, including the use of zero emission vehicles.

OFM, working with other state agencies, and with advice from subject matter experts, affected industries, and public interests, will evaluate the technical feasibility, costs and benefits, and job implications of requiring the use of cleaner transportation fuels through standards that reduce the carbon intensity of these fuels over time.

The director of LAPO will ensure that the State Legislature's committees on transportation and environment, and other interested legislative members, are fully informed on the clean transportation work under this executive order, and she or he will solicit their early and ongoing advice and guidance.

CLEAN TECHNOLOGY

The Department of Commerce, in cooperation with Washington State University (WSU) and other appropriate stakeholders, will develop and make recommendations for a new state program to assist and support our research institutions, utilities, and businesses to develop, demonstrate, and deploy new renewable energy and energy efficiency technologies. The Department's recommendations must include specific proposals for dedicated and sustained funding for implementing and supporting the program.

I ask that the WSU Energy Program, in consultation with the Utilities and Transportation Commission, the Department of Commerce, and other state agencies as appropriate, convene and work with utilities, solar manufacturers, installers, and other stakeholders, to review current statutes, rules, policies, and incentives for solar energy in the state. I ask that this review address how to ensure effective state financial incentives, consistent with the benefits and costs of solar energy, and how to better target those incentives, and make them available to a broader range of organizations and individuals that can help advance and deploy solar energy in the state. Further, the review should evaluate how best to ensure consumer protection, how to ensure continued grid reliability, and where we must change state statutes to clarify jurisdiction and establish necessary policies. I ask the WSU Energy Program to work with the agencies and stakeholders on recommendations for how to significantly expand the use of solar energy in our state.

ENERGY EFFICIENCY

The Department of Commerce, working with the WSU Energy Program, the State Building Code Council, and others, will develop, and implement to the extent possible and consistent with state and federal law, a new statewide program to significantly improve the energy performance of both our public and private buildings, taking into account existing state and utility efforts. The program must accelerate the cost-effective energy efficiency retrofit of existing buildings, with a support system that provides information, consumer protection, and assistance to businesses and homeowners. The program must ensure that all new buildings are as energy-neutral as possible, with advanced envelopes, efficient appliances, on-site generation, smart controls, and other features, where practicable.

The program must include the following measures:

- Provide businesses and homeowners with access to energy use, efficiency, and cost information such as building energy efficiency disclosure requirements and other means;
- Improve access to financing for energy-efficiency upgrades, including meter-based financing that ties efficiency investment to the building;
- Support vulnerable and low-income populations through weatherization assistance, setting minimum standards for rental housing energy efficiency, and securing funding for energy efficiency for non-utility fuel sources such as oil heat;
- Achieve early and widespread deployment of energy-neutral buildings prior to the 2031 statutory requirement in RCW 19.27A.160;
- Upgrade the energy efficiency of all street lighting within the state; and
- Ensure that the cost-benefit tests for energy-efficiency improvements include full accounting for the external costs of greenhouse gas emissions.

The program must include a branded campaign to effectively inform businesses and citizens of the new program and encourage its use. The program should enhance, and be compatible with, similar programs offered by utilities and others, where possible.

I ask the State Building Code Council to actively work on the needed code requirements for new buildings as described above, with assistance and support from the Department of Commerce and technical support, as appropriate, from the WSU Energy Program.

I ask the WSU Energy Program, working with the Department of Agriculture and other relevant state, federal, and private sector partners, to develop, and implement to the extent possible, an expanded energy efficiency program for the agricultural sector. The program should be developed with Washington farmers and its original pilot partners, building on the Farm Energy pilot program statewide. The program should be designed to accelerate the assessment and funding of energy savings options for the state's agriculture sector, including preparing our agricultural sector to capitalize on the millions of federal dollars available for efficiency improvements each year.

I ask the WSU Energy Program to develop and launch an Industrial Energy Services Center, to provide a range of energy efficiency services, including energy systems engineering, combined heat and power, and financial incentives to catalyze energy efficiency and carbon reduction investments. The program should build on previous experience providing financial incentives to help offset the costs of energy efficiency equipment, and it should be designed to leverage regional efforts made by the Northwest Combined Heat and Power Technical Assistance Partnership for Washington. I ask that the WSU Energy Program seek additional funding to support the Center's activities from Washington utilities, the Bonneville Power Administration, the Northwest Energy Efficiency Alliance, and the U.S. Department of Energy, as well as from regional energy services and equipment providers and the industry participants themselves.

STATE GOVERNMENT OPERATIONS

The Department of Enterprise Services, in collaboration with other agencies, will evaluate progress and develop recommendations for improving efficiency and reducing emissions from state government operations, as needed to meet the targets established by Results Washington.

The Department of Commerce, in collaboration with the Departments of Enterprise Services and Ecology, will evaluate incentives and life-cycle costs for the purchase of electric vehicles and other clean-fuel cars, for use in the state and other public fleets. The Department of Enterprise Services will move forward with state procurement of these vehicles where the life-cycle costs and benefits are comparable, including consideration of the benefits of emission reductions.

The Department of Enterprise Services, in collaboration with the Department of Commerce, OFM, and the WSU Energy Program, will evaluate progress and develop recommendations for improving the energy efficiency of public buildings.

CARBON POLLUTION LIMITS

The Department of Ecology, as required by RCW 70.235.040, will review the State's enacted greenhouse gas emissions limits and recommend any updates to the limits by July 15, 2014.

INTERGOVERNMENTAL RELATIONS AND PUBLIC OUTREACH

LAPO will ensure that the State Legislature is fully informed on all work conducted under this executive order, and it will solicit advice and guidance from legislative committees with jurisdiction and other interested legislative members.

LAPO will invite consultation, on a government-to-government basis, with Sovereign Tribal Governments, on all aspects of this executive order. LAPO will invite federal agencies with expertise and jurisdiction to assist in implementing this executive order. LAPO will work with other state agencies to coordinate implementation of the West Coast climate and clean energy agreement executed under the Pacific Coast Collaborative.

Agencies acting under this executive order will work with Washington's local governments to maximize coordination and effectiveness of local and state climate initiatives. Agencies will inform affected and interested parties, and the general public, of the work under this executive order, and solicit comments and involvement, as appropriate.

LAPO, working with state agencies, will establish the Climate Response and Clean Energy Forum as a broad venue for distributing information and securing feedback on the work under this executive order. The Forum will maintain an electronic distribution list and website, sponsor an annual conference and webinars, or use other appropriate means to maintain active and ongoing communication with interested and affected parties.

STATE AGENCY COORDINATION

The Energy, Transportation and Climate subcabinet (ETC) is created to organize, coordinate and implement state agency work under this executive order. The ETC members will include the director, secretary, or senior designee of the Departments of Ecology, Commerce, Transportation, Enterprise Services and OFM, and the chair of the UTC. The Departments of Health, Agriculture, and Fish and Wildlife, and the WSU Energy Program, are asked to attend as needed. The Department of Natural Resources, the Office of the Attorney General, the Office of the Insurance Commissioner, the Northwest Power and Conservation Council, and the State Building Code Council are invited and encouraged to participate, as appropriate.

LAPO shall convene and facilitate the ETC.

All state agencies with expertise or jurisdiction, otherwise not directed above, are encouraged to assist in the implementation of this executive order.

GENERAL

Agencies directed under this executive order will report to me as work is completed, with an annual report on progress to be provided by November of each year, beginning in November 2014.

The Taskforce will conduct its business in an open, transparent manner, and its meetings will be open to the public.

This Order is not intended to, and does not confer, any legal rights, and shall not be used as a basis for legal challenges to rules or other actions or to any inaction of the governmental entity subject to it.

This Executive Order, which supersedes Executive Orders 07-02 and 09-05, shall take effect immediately.

Signed and sealed with the official seal of the state of Washington on this 29th day of April, 2014, at Shoreline, Washington.

By:

/s/
Jay Inslee
Governor

BY THE GOVERNOR:

/s/
Secretary of State

Department of Public Service Regulation
Montana Public Service Commission
Docket No. D2013.12.85
PPLM Hydro Assets Purchase
NorthWestern Energy

PREFILED REBUTTAL TESTIMONY OF

JOSEPH M. STIMATZ

ON BEHALF OF NORTHWESTERN ENERGY

TABLE OF CONTENTS

Witness Information

Q. Please state your name and business address.

A. My name is Joseph (Joe) M. Stimatz. My business address is 40 East Broadway, Butte, Montana 59701.

Q. Are you the same Joseph Stimatz who submitted prefiled direct testimony, prefiled supplemental testimony, and prefiled additional issues testimony in this docket?

A. Yes.

Purpose of Testimony

Q. What is the purpose of this rebuttal testimony?

A. The purpose of my testimony is to rebut certain claims made by the Montana Consumer Counsel ("MCC") in the Direct Testimonies of John Wilson ("Wilson Testimony") and Albert Clark ("Clark Testimony") regarding the impact on residential bills from the purchase of the Hydros, NorthWestern's discounted cash flow ("DCF") analysis, and NorthWestern's stochastic modeling.

Residential Rate Impact

Q. In his testimony on page 6, Mr. Clark takes issue with the accuracy of NorthWestern's estimate that the residential bill will increase by 4.2%. Is his claim justified?

A. No, it is not. As Mr. Clark states, NorthWestern calculated the 4.2% impact to the total bill based on rates that were in effect at the time that the filing was prepared, which has been NorthWestern's standard practice. In fact, though Mr. Clark first states that he does not believe that the 4.2% is accurate, he does not provide any testimony or calculations that dispute the NorthWestern calculation or call into question its accuracy. Rather, he proposes alternate comparison calculations that use the rates forecasted for late 2014 as the base and use only the supply portion of customers' bills rather than the total bill.

Q. Are Mr. Clark's alternate comparisons more appropriate than NorthWestern's?

A. No, they are not. Mr. Clark's comparisons use an estimated electric supply rate, calculated as of a future date but based on a forward market price curve from June of 2013 (the period when NorthWestern developed its bid for the Hydros). Mr. Clark's comparison assumes that, absent the Hydros acquisition, NorthWestern would have done nothing to address the portfolio's baseload needs for the intermediate or long term and instead would have relied on the spot market to meet customers' load. Further, his comparisons assume that the spot market beginning in July 2014 would be unchanged from the June 7, 2013 estimates. This assumption does not reflect the actions that NorthWestern would have taken to meet electricity load absent the Hydros acquisition.

Q. Please explain.

A If the Hydros acquisition opportunity had not arisen, NorthWestern most likely would have sought three- to five-year power purchase agreements ("PPAs") to meet customers' needs in the intermediate term. As described in the 2011 Electricity Supply Resource Procurement Plan, three- to five-year PPAs were a key component in NorthWestern's action plan, and absent the Hydros opportunity, NorthWestern would have pursued these PPAs to meet the portfolio's needs. The exact terms and prices of the potential contracts cannot be known, but the prices certainly would have been higher than the short-term prices reflected in Mr. Clark's comparisons. NorthWestern calculated the percentage change based on the rates that were in effect at the time it prepared the filing. This calculation was meant to provide the scope of what the bill impacts may be if the Hydros acquisition is approved. In any case, while immediate bill impact is a relevant consideration, the acquisition of the Hydros is a long-term action with price and stability benefits that must be judged over a long horizon.

Discounted Cash Flow ("DCF") Analysis

Q. Dr. Wilson provides several criticisms of NorthWestern's DCF analysis. Are his criticisms valid?

A. No, they are not. Dr. Wilson misunderstands or mischaracterizes many aspects of the DCF modeling. I will address each of these in turn.

Q. Does the Wilson Testimony accurately portray the role of the DCF model in NorthWestern's analysis and bid decision?

A. No, the Wilson Testimony overstates the role that the DCF model, and particularly the initial DCF valuation of $826 million, played in NorthWestern's decision. As described in the Prefiled Direct Testimony of Brian Bird ("Bird Direct Testimony") on pages 16-21, the DCF analysis provided an indication of the market value of the Hydros and was just one of several value measures that NorthWestern considered. Mr. Bird described NorthWestern's DCF model, including sensitivities; the Long-Term 30-Year Revenue Requirement model; and Credit Suisse's analyses including its own DCF analysis, its comparable sales analysis, and its new-build opportunity analysis. The Wilson Testimony focuses on the initial DCF valuation and ignores the other valuation methodologies and DCF sensitivities that NorthWestern considered.

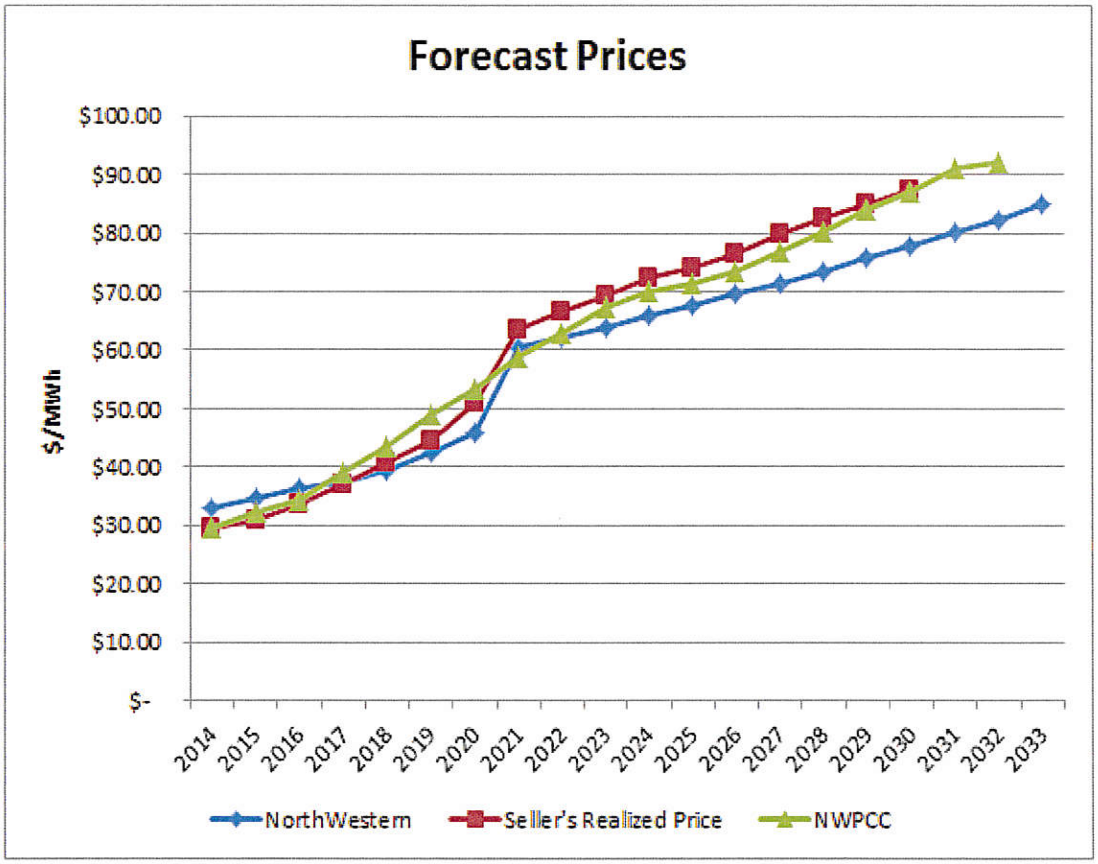
Q. Please describe how NorthWestern used carbon prices in the DCF valuation.

A. In developing its valuation, NorthWestern estimated future market prices for electricity. To estimate future market prices, NorthWestern made assumptions regarding the cost of CO_2 emissions and the resulting impact on market prices for electricity.

Q. Is NorthWestern's price curve out of line with other forecasts?

A. No. NorthWestern's estimated future market prices are comparable to future price estimates from other sources. The chart below compares

NorthWestern's estimated future prices at Mid-Columbia with those of the Northwest Power and Conservation Council's ("NWPCC")[1] and PPL's projected realized power prices.[2]



As shown in the chart, NorthWestern's estimated future market prices are conservative relative to the other estimates. As NorthWestern described in its direct testimonies and in numerous responses to discovery requests, NorthWestern's assumptions regarding carbon are conservative relative to its peers and consistent with what it has used in planning activities for

[1] NWPCC Update to the Wholesale Electricity Price Forecast, February 2013, Delayed Federal CO_2 Case; adjusted to nominal dollars.
[2] See Exhibit__(AO-02) Public, page 16 of 51.

many years, including in electricity supply resource procurement plans filed with the Montana Public Service Commission ("Commission").

If, as Dr. Wilson asserts, NorthWestern's estimate of the effect of future carbon prices on electricity prices were inflated and the resulting DCF value overstated, Credit Suisse would have found comparable asset sale prices to be much lower than the price of this transaction. In fact, Credit Suisse found the price of this transaction to be in line with comparable asset sales prices. Please see the Prefiled Direct Testimony of Ahmad Masud ("Masud Direct Testimony").

Q. Is NorthWestern proposing to include future carbon taxes in the rates associated with the Hydros?

A. No. Dr. Wilson repeatedly characterizes this consideration of carbon as "hypothetical and speculative capitalized CO_2 tax costs" and "hypothetical CO_2 taxes that may not be recoverable." He asserts that NorthWestern proposes to include "future carbon taxes" in current rates and repeatedly refers to the imposition of carbon taxes on customers. He implies that NorthWestern is proposing to include carbon taxes in customer rates and even proposes an elaborate system under which the rate base would be reduced by some arbitrary amount that he associates with future CO_2 taxes. However, contrary to Dr. Wilson's assertions, there are no CO_2 tax costs in the rates proposed for the Hydros, either now or in the future. In fact, since the Hydros do not emit carbon, there will never be a carbon tax associated with them. NorthWestern is proposing to recover the revenue requirement associated with the purchased assets. The Prefiled Direct Testimony of Patrick DiFronzo and Exhibit__(PJD-1) describe in detail the items that NorthWestern proposes to include in rates, and future carbon taxes are certainly not among them.

Q. The Wilson Testimony implies that alternative, unregulated buyers would not have considered the potential future impact of carbon regulation on the value of the Hydros. Do you agree?

A. No I do not agree. On the contrary, the likelihood of increasing carbon regulation is one of the factors that make the Hydros valuable to NorthWestern, its customers, and to other potential bidders.

Q. Dr. Wilson also questions the assumption of a residual or terminal value for the Hydros that is higher than the price NorthWestern has agreed to pay. Is this criticism justified?

A. No, it is not. As NorthWestern has described throughout its testimony and in responses to discovery requests, hydro assets are very long lived resources, and NorthWestern expects the Hydros to last well beyond the 20-year period modeled in the DCF analysis. The MCC's other witness, Mr. Clark, apparently agrees with this assessment, since in his testimony he asserts that a 50-year depreciation life is more appropriate than the 40 years that NorthWestern proposed.

As described in my direct testimony on pages 14-16, NorthWestern's estimate of the terminal value is appropriate. NorthWestern based its terminal value estimate on a market multiple methodology. For the initial DCF analysis, NorthWestern used the low end of the market multiple range. The range was provided by Credit Suisse as described in the Bird Direct Testimony, page 17, lines 3-6. See also the Masud Direct Testimony. Dr. Wilson questions the terminal value assumption in his testimony, but offers no alternative means of estimating the value or any empirical information that contradicts NorthWestern's methodology.

Q. On page 23 of his testimony, Dr. Wilson asserts that since NorthWestern assumed positive terminal value in its analyses, it should forego any attempt to recover decommissioning costs and any net salvage claims for these dams. Do you agree?

A. No. Dr. Wilson criticizes NorthWestern for not including decommissioning costs for the plants without providing any support for his assertion that such costs should be included, when the costs might be incurred, or what those costs might be. NorthWestern provided detailed testimony describing the reasons that it expects the Hydros to have positive value at the end of the evaluation period and how it estimated that value. If at some distant future date, NorthWestern determines that decommissioning one or more of the dams is the appropriate course of action, a future Commission will determine the prudence of that decision and any related expenditures. If the costs are prudently incurred, NorthWestern can and should be able to recover them from customers.

Q. Are there other DCF analysis assumptions that Dr. Wilson questions?

A. Yes. Dr. Wilson asserts that NorthWestern's capital expenditure assumptions are too low and that a "competitive buyer" would not assume such capital costs.

Q. What is Dr. Wilson's justification of this claim?

A. His justification appears to be that capital costs at the plants have been higher in recent years than NorthWestern's forecast for future years.

Q. Is that a valid criticism?

A. No. As described in the Prefiled Direct Testimony of William Rhoads and in the Prefiled Additional Issues Testimonies and Prefiled Rebuttal Testimonies of Mr. Rhoads, John VanDaveer ("VanDaveer Additional Issues Testimony"), Gary Wiseman, Mary Gail Sullivan and Rick Miller, NorthWestern's capital forecasts are sound and supported by extensive due diligence. Despite Dr. Wilson's assertion, capital expenditures are expected to be lower in future years in part because PPLM has heavily invested in the assets over the last decade.

Q. If, for some reason, NorthWestern's actual capital expenditures turn out to be higher than forecast, would this mean a significant change in the overall value of the Hydros relative to other alternatives?

A. No. As described in my additional issues testimony, the VanDaveer Additional Issues Testimony, and the Prefiled Additional Issues Testimony of Travis Meyer ("Meyer Additional Issues Testimony"), for purposes of comparison, NorthWestern calculated the effect of capital expenditures that are 30% higher than NorthWestern's forecast in each year. The analysis shows that these higher expenditures would have minimal effect on the costs to customers and would not change the attractiveness of the Hydros relative to other alternatives available to NorthWestern to serve its customers.

If capital expenditures turn out to be 30% higher than NorthWestern's forecasts in each and every year over the next 30 years, the levelized cost of the Hydros to customers over that period is estimated to be \$59.36/MWh. (See Exhibit__(TEM-3) attached to the Meyer Additional Issues Testimony). As described in the Prefiled Direct Testimony of Travis Meyer and Exhibit__(TEM-2), NorthWestern estimates the levelized cost of the Hydros to customers to be \$58.04 per MWh. In other words, in the unlikely event that capital expenditures turn out to be 30% higher than forecast every year for 30 years, the increased cost to customers will be $1.32/MWh, or 2.3%.

Further, as described in my additional issues testimony, even with 30% higher than forecast capital expenditures, on a risk adjusted net present value basis, the cost of the supply portfolio including the Hydros would be nearly $300 million lower than the cost of the next best alternative.

Comparison to Other Alternatives

Q. Did either the Wilson or Clark testimonies address NorthWestern's stochastic comparison of the Hydros to other alternatives?

A. Partially. Dr. Wilson addressed the stochastic comparison to reliance on the wholesale market for NorthWestern's customers' needs, but he ignored the comparison to other alternatives such as the addition of a combined cycle natural gas-fired plant. As described in my prefiled direct testimony and the Prefiled Direct Testimony of John Hines, NorthWestern does not view reliance solely on the wholesale market to meet unfilled customer needs as a viable alternative. Further, as described in my supplemental testimony, the market portfolio was not even the second-best performing portfolio in the stochastic analysis. The portfolio that included a combined cycle plant along with additional wind generation was the next-best performing portfolio in that analysis, but Dr. Wilson inexplicably chose not to even mention that alternative.

Q. What are Dr. Wilson's criticisms of the stochastic modeling?

A. Dr. Wilson's criticisms of the stochastic modeling process are addressed in detail in the Prefiled Rebuttal Testimony of Gary Dorris. Dr. Wilson does not offer specific changes to the stochastic modeling or identify any specific shortcomings to the modeling approach. His main criticism appears to be that the modeling accounts for market risk but not risk related to capital expenditures. As described earlier in my testimony, NorthWestern's capital forecasts are sound and well supported, and even significantly higher capital expenditures would not change the results of the stochastic modeling.

Q. Does this conclude your testimony?

A. Yes, it does.

Prefiled Rebuttal Testimony of

Gary W. Dorris

on Behalf of NorthWestern Energy

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I: Witness Information

Q. Please state your name, occupation, and address.

A. My name is Gary W. Dorris. I am the Chief Executive Officer of Ascend Analytics, LLC. Our headquarters are at 1877 Broadway Street, Suite 706, Boulder, CO 80302. We have additional offices at 222 E. Main, Suite 201, Bozeman, MT 59715 and 440 Grand Avenue, Suite 360, Oakland, CA 94610.

Q. Please summarize your educational and professional background.

A. I am founder and Chief Executive Officer (CEO) of Ascend Analytics. Ascend Analytics is an energy analytics software and consulting company that provides economic, financial, and technology solutions for the energy industry, particularly in the area of portfolio risk management, energy supply procurement, asset valuation, quantitative modeling, and complex litigation. I have led the growth of Ascend to one of the foremost energy analytic companies in the country, providing software solutions to three of America's top five largest utilities to address portfolio management, risk analytics, and planning strategies.

I have been involved in the energy industry for over 25 years and have extensive experience in counseling corporations in complex decision analysis, portfolio management strategies, and risk management. I have also provided independent expert reports to support the valuation and financing of over $5 billion in electric generating assets. I have written and delivered expert testimony regarding risk management, energy procurement, trading practices, asset valuation, market power, and emissions trading. I have also led the analytic architecture of over ten analytic software products used by 30 of the top 100 energy companies.

Before founding Ascend Analytics, I served as CEO and Chief Model Architect for e-Acumen, a 60 person energy consultancy and software analytics firm. I have also directed the development of the analytic infrastructure and risk management policies for the launching of the trading floors of Entergy Solutions, Duke Solutions, The Energy Authority, and Consolidated Edison, and led the development of the analytic infrastructure solutions for portfolio and risk management solutions at over a dozen other utilities. I have traded power and structured power sales contracts and completed one of the first above cost power transactions in the U.S. in 1988.

I was also a faculty member at Cornell University in 1996, where I taught a doctoral-level course in modeling competitive energy markets, and have been adjunct faculty at University of Colorado's Leeds Business School from 1997 to 2007. I have published papers on energy trading and risk management in peer-reviewed scholarly journals, and have spoken at over 50 conferences on resource planning, portfolio management, risk analysis, and modeling of competitive energy markets. I hold a PhD in applied economics and finance from Cornell University and both a BS in mechanical engineering and a BA in economics with Magna Cum Laude distinction from Cornell University. Further details on my qualifications are set forth in my Curriculum Vitae (Exhibit GD-3).

I reserve the right to update and supplement my expert testimony as may be necessary.

II: Overview Of Testimony

Q. On whose behalf are you testifying in this proceeding?

A. I am testifying on behalf of NorthWestern Energy ("NorthWestern" or "the Company").

Q. Please summarize your testimony.

A. My testimony deals with NorthWestern's proposed acquisition of PPL Montana LLC's ("PPLM") hydroelectric dams ("Hydros"). Specifically, I am responding to the Direct Testimony of Dr. John Wilson on behalf of the Montana Consumer Counsel ("MCC"). Dr. Wilson's conclusions are fundamentally flawed and lack the cogent economic rationale NorthWestern used to substantiate the economic merit for the acquisition of the Hydros. NorthWestern's goal and intent has been to realize the best economic investment for Montana customers without assuming excessive risks. Dr. Wilson incorrectly assumes market risk and reliable energy supply are irrelevant to the planning process. His suggestions on behalf of the MCC reflect a planning risk profile of unimpeded speculation and reckless assumption of market risks when the consequences of such a rogue planning strategy are known and have been calculated. On the other hand, NorthWestern has fully embraced its responsibility to make strategic investments that adhere to the highest standards of prudent resource planning decision analysis and realize least-cost *and* least-risk for its customers.

In addition to overlooking the prudent resource planning requirements adhered to in NorthWestern's 2013 Electricity Supply Resource Procurement Plan ("2013 Plan"), Dr. Wilson makes several other errors and misrepresentations in his economic analysis. First, Dr. Wilson focuses on the risk of capital outlays for ongoing plant operation and maintenance in excess of NorthWestern's budgeted amounts; however, when examined on a net present value ("NPV") basis, these risks are small relative to market price and carbon risk, and do not tip the balance against the Hydros as the least-cost and least-risk asset choice.

Second, Dr. Wilson contends that NorthWestern has counted on an increase in the value of the Hydros over time, and presents this salvage value in undiscounted future value. Dr. Wilson's economic sleight of hand obscures the fact that NorthWestern has, in fact, only grown the purchase price of the Hydros at inflation in order to represent the continued right past the end of the study horizon to generate power at the sites in question.

Finally, and most importantly, Dr. Wilson adopts an unsubstantiated view of the likely future state of regional carbon prices and their impacts on electricity system costs. Dr. Wilson ignores three current and highly salient regional precedents that distinguish low- from high-emissions resources in current markets without a region-wide price on CO_2. These examples substantiate that emissions-free resources are more highly valued than high-emissions resources, and should be treated as such by potential buyers. Therefore, Dr. Wilson's use of the term "speculative" to describe NorthWestern's treatment of future CO_2 prices is inaccurate. NorthWestern has chosen a conservative and robust approach to modeling the impact of CO_2 on its long-term portfolio costs. The Company correctly concluded in its 2013 Plan that the Hydros acquisition represents the least-cost and least-risk resource choice available.

Q. Please outline the remainder of your testimony.

A. Section III describes the analysis I have performed as part of NorthWestern's 2013 Plan and related filings on behalf of NorthWestern. Section IV outlines the standards that prudent portfolio planning managers should be held to, and demonstrates that NorthWestern has adhered to those standards. Section V examines several flaws in Dr. Wilson's critique of the comparative cost analysis presented by NorthWestern in the 2013 Plan. Section VI defends the prudency of modeling carbon price risk. Section VII summarizes and concludes my testimony.

III: Overview Of Analysis Supporting NorthWestern's 2013 Plan

Q. What analysis have you done that supports your testimony?

A. As part of the 2013 Plan filed by NorthWestern, I examined the costs and risks of alternative supply resources to meet NorthWestern's load obligation in addition to its currently-owned or contracted assets, including:

a. Market purchases;
b. A new combined-cycle combustion turbine (CCCT), online in 2018;
c. The proposed acquisition of the Hydros;
d. A new LMS 100 simple-cycle gas turbine, online in 2018;
e. A new LMS 100 and 100 MW of wind above RPS requirements, online in 2025; and

f. A new CCCT and 100 MW of wind above RPS requirements, online in 2025.

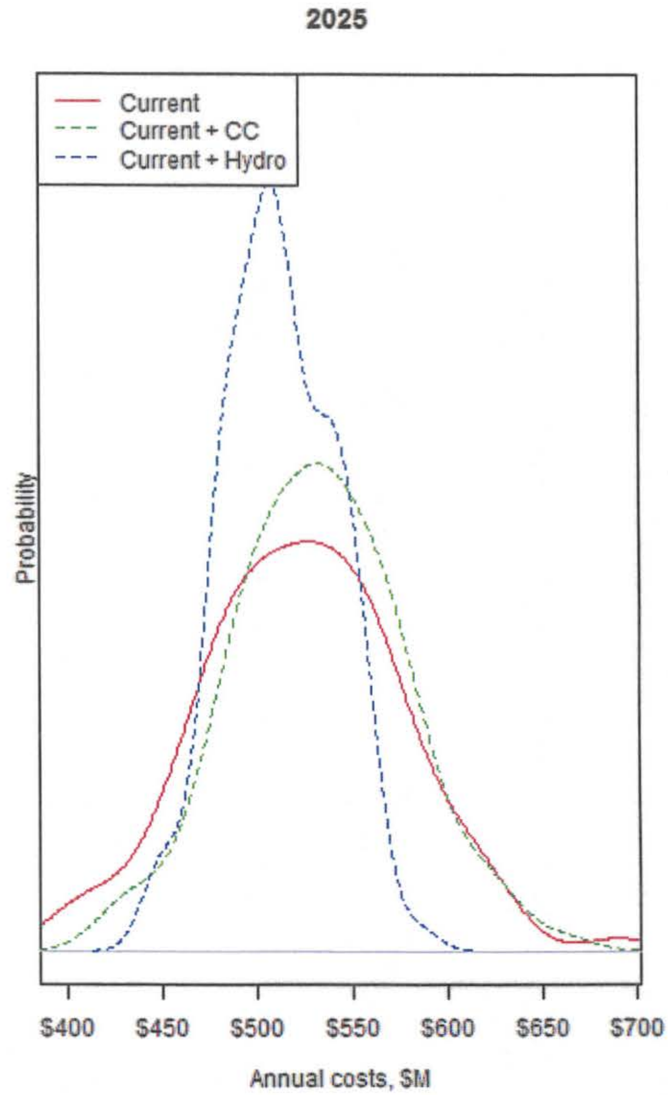
I have examined all relevant costs and major sources of risk for each of the above resource portfolios, using validated simulations of future conditions for the duration of the planning horizon in conjunction with an hourly dispatch optimization model; the details of NorthWestern's analysis are found in the 2013 Plan and its Supplement[1]. My analysis has given me an opportunity to thoroughly examine the model inputs and outputs that underlie NorthWestern's comparative cost analysis, and I have confirmed and believe strongly that the findings are sound.

Q. What are the findings of your analysis?

A. Adding the Hydros reduces the present value of portfolio costs while dramatically reducing the risks of market price shocks. Figure 6-30 from the 2013 Plan (copied below) shows the probability distribution of expected annual costs in 2025; the distribution of costs for the "Current + Hydro" portfolio are lower in expected value while also removing the risks caused by market price shocks in the other portfolios that rely more on market purchases.

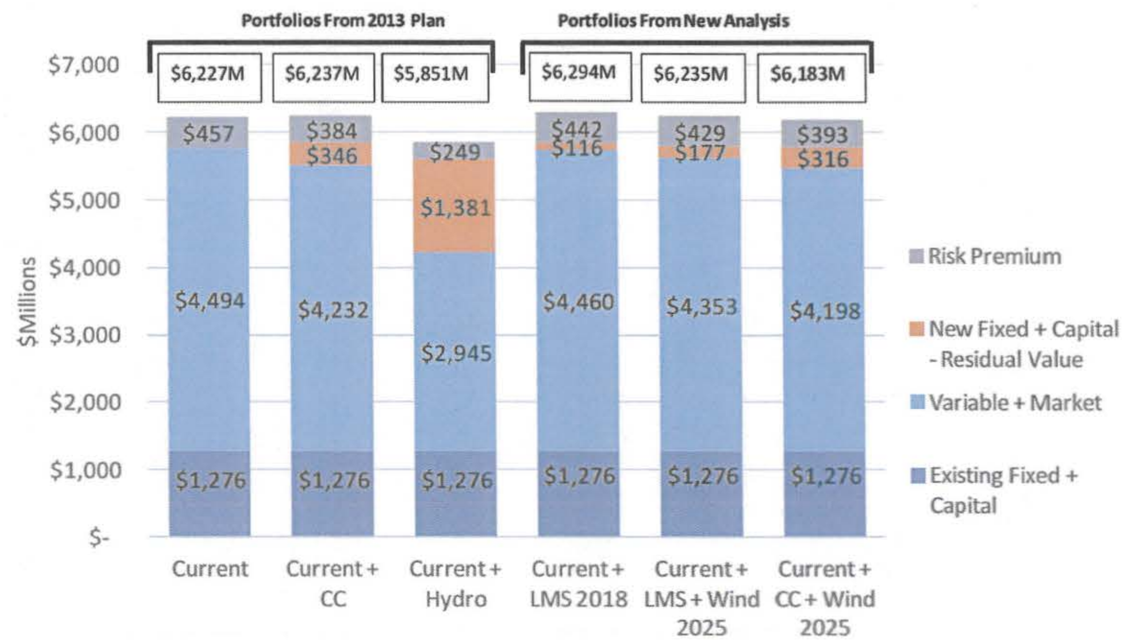
[1] The Supplement (APP-4S) was filed on February 14, 2014 in this docket.

Figure 1: Cost Distributions by Portfolio: 2025



The combined effect of lower exposure to high market prices is manifested in the "risk premium" component of each portfolio's costs. The risk premium captures the expected value of costs exceeding the mean in each year, allowing for a direct comparison of portfolios and resources with very different risk profiles. Added to the expected costs of each portfolio, the risk premium allows for an apples-to-apples comparison of all practical portfolio choices. Figure 6-1 from the Supplement to the 2013 Plan (copied below) highlights the differences in risk-adjusted NPV of costs between the "Current + Hydro" portfolio and all other options.

Figure 2: Costs of Portfolio Options



Q. What have you done to substantiate the merits of the economic modeling used to arrive at these findings?

A. The analysis conducted for the 2013 Plan was based on a rigorously validated set of simulated data representing possible future conditions. As detailed extensively in Volume 2, Chapter 4 of the 2013 Plan, the simulated data conform to structural relationships observed in historic data between key system variables: weather and load, load and price, renewable generation (including hydro) and weather/load/price, etc. By performing this rigorous validation, NorthWestern has shown that the economic modeling that underlies the comparative cost analysis in the 2013 Plan is based on sound resource planning practices and properly reflects meaningful uncertainty about the nature of future conditions. "Meaningful uncertainty" is defined as variability in simulated future states that conforms to key structural relationships (e.g. relationship of weather, load, and market price) as well as observed market data (e.g. volatility of forward and spot prices), in contrast to the simplistic practice of adding random noise to expected value forecasts that does not capture key physical and financial drivers of risk.

Q. Is it your testimony that NorthWestern is meeting its obligation to perform prudent power supply procurement with the acquisition of the Hydros?

A. Yes. NorthWestern's procurement of the Hydros represents the best supply resource option. NorthWestern's acquisition of the Hydros provides a low cost alternative that substantially reduces the excessive market risk that exists today with a short position of over 50%[2] of its load requirements over the long-term planning horizon.

Q. What do you mean by a short position?

A. The term short position refers to the amount of supply that has not been secured.

Q. Why is the concept of a short position important?

A. The concept of a short position is important because it measures NorthWestern's physical exposure arising from its obligation to satisfy its customers' load.

Q. At present, what makes the Hydros the best candidate resource to meet NorthWestern's supply needs?

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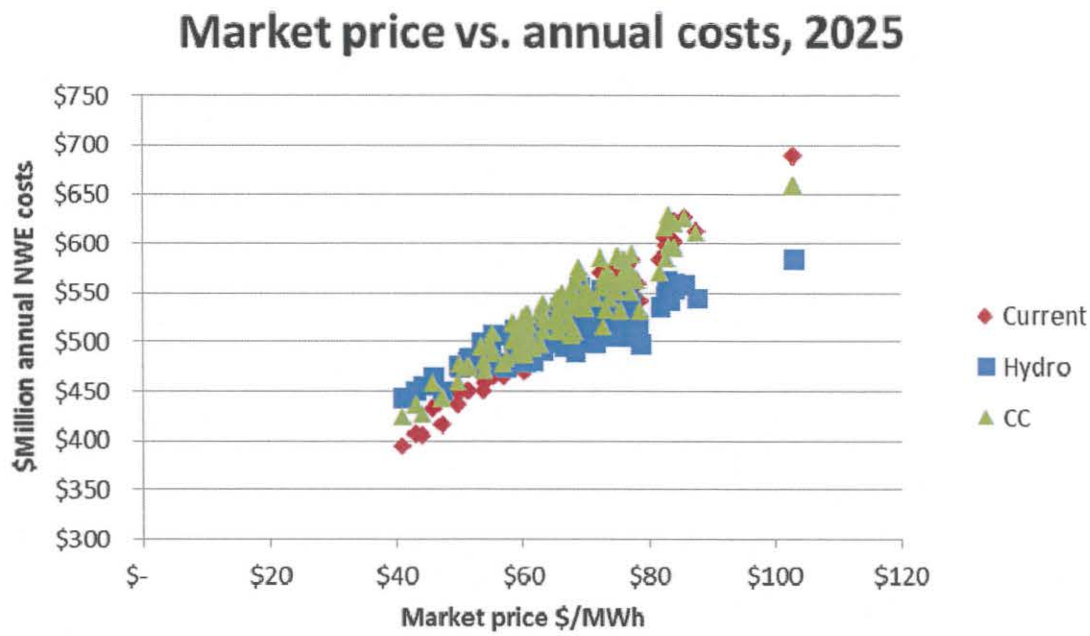
[2] Average of annual short position as reported from 2014-2043 in NorthWestern's 2013 Plan.

A. The Hydros represent the best resource to meet NorthWestern's supply needs for several reasons.

1. The Hydros hedge market and fuel price uncertainty with a physical resource with very low marginal costs.
2. The Hydros hedge carbon price uncertainty with a physical resource with zero CO_2 emissions.

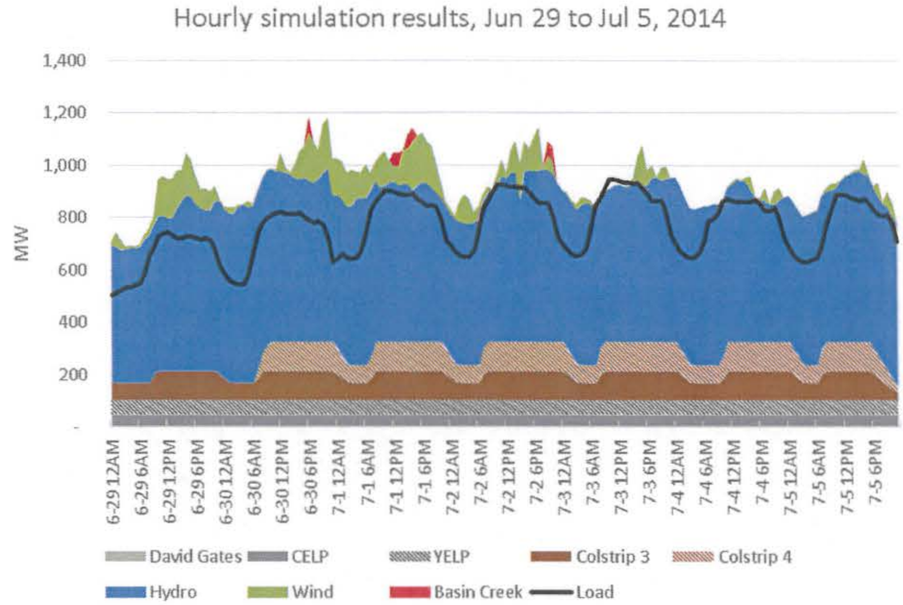
The "payoff diagrams" shown in Volume 2, Chapter 4 of the 2013 Plan (example copied below) are a good illustration of the above points: as market price (X-axis; with or without any carbon adder) increases, the revenue requirements (Y-axis) of more "open" portfolios (such as relying on market purchases or combined cycle ("CC") gas generation) increase dramatically, while the costs of the Hydros portfolio rise only moderately.

Figure 3: Risk Profiles of Portfolio Options



3. The Hydros, unlike wind or other variable renewable resources, provide relatively steady, "baseload" power for Montana consumers, increasing reliability of supply within the state. Notably, the economic analysis performed by NorthWestern left out any monetary value of this output stability or potential ancillary service revenues, as a conservatism. Figure 6-33 of the 2013 Plan (copied below) illustrates this reliability value.

Figure 4: Example Hourly Operations



Q. What events since the original divesture of NorthWestern's generation assets have retrospectively shown the value of the Hydros?

A. I have prepared Table 1 to illustrate the impacts of recent historical events on customer costs under two scenarios: 1) including the Hydros in the NorthWestern portfolio, and 2) relying solely on market purchases. I have taken historic prices at the Mid-Columbia trading hub starting in June, 1998 and, as an illustration, assumed that this price trajectory (adjusted for inflation) is replicated starting in June, 2015. I then compare the revenue requirements (customer costs) associated with the Hydros with the pass-through costs of market purchases for equivalent energy, by month and peak period, and sum up to an annual total and 15-year net present value (NPV).

Table 1: Comparison of Costs of Hydros vs. Market Purchases, Using Historical Data[3]

	Hydros	Market
NPV of Customer Cost:	**$1,184,528,679**	**$1,578,270,520**

Hist. Year	Model Year	Annual Cost of Hydros	Annual Cost of Market
1999	2016	$143,893,834	$82,168,570
2000	2017	$144,409,962	$416,573,807
2001	2018	$143,766,230	$478,883,035
2002	2019	$142,775,643	$78,011,691
2003	2020	$141,851,837	$135,686,563
2004	2021	$141,182,444	$151,417,295
2005	2022	$140,279,600	$200,077,489
2006	2023	$139,595,688	$154,659,493
2007	2024	$139,113,590	$177,168,736
2008	2025	$138,516,230	$200,074,533
2009	2026	$137,416,242	$111,151,809
2010	2027	$136,634,930	$113,476,366
2011	2028	$135,854,867	$80,031,468
2012	2029	$135,067,546	$63,269,335
2013	2030	$134,339,619	$112,540,193

The price spikes associated with the period of market infirmity in 1999-2000, the events following Hurricane Katrina in 2005, and the price run-up in 2008 provide a good illustration of the cost savings and risk reduction value of the Hydros. The Hydros avoid an enormous exposure to market price shocks that, history proves, can be large enough to dramatically increase ratepayer costs over the course of months and even years. NorthWestern, during these historical periods, was fortunate to avoid the most grievous rate shocks to its customers; the Hydros represent the least-cost and least-risk to maintain this rate stability into the future.

[3] Table 1 illustrates the magnitude of risk faced by NorthWestern should they fail to hedge their short position, and the benefits offered by the Hydros in mitigating the customer cost impacts of market price spikes. This analysis compares the cost of supply under two scenarios: acquiring the Hydros, and relying on market purchases for an equivalent amount of energy, using market price data from 1999-2013 (adjusted for inflation). The 1999-2013 period contained many price spikes in the Pacific Northwest market; Table 1 summarizes at an annual level the cost and risk benefits of the hydro acquisition, using the historical market price trend as an example of the actual risks NorthWestern faces with the current portfolio and short position.

IV: Actions Of The Prudent Manager Of Power Supply Planning

Q. Please summarize what a prudent power supply manager would know to effectively evaluate, manage, and hedge risks for NorthWestern.

A. A prudent manager would understand:

1. The large risk inherent in leaving a substantial short position open;
2. The need to build a power supply portfolio that mitigates the risk of future market movements in power and fuel prices, as well as the likely realities of future carbon regulations;
3. How to utilize all the available information in supply and demand fundamentals as well as the uncertainty in future market conditions to analyze supply resource options with respect to their imputed risk mitigation value and expected benefits; and
4. How to quantify the potential of non-market risks and how to mitigate those risks.

Q. Why is it prudent to lock in costs through constructing an energy supply portfolio to hedge against risks?

A. Failure to engage in development of a cost-effective energy supply portfolio that is designed to mitigate the risks of future supply costs reflects go-for-broke or gambling behavior. Dr. Wilson's speculative tendencies of relying excessively on the market are unacceptable for stewarding the future costs of energy supply and would only be appropriate if he believed he was playing with somebody else's money with an enormous appetite for risk. In this case, the other peoples' money is that of Montana customers.

Wilson's type of precarious power planning is imprudent. Furthermore, it creates conditions that threaten the reliability of supply to NorthWestern customers by relying extensively on market purchases to complete the Company's energy requirements.

Q. Would it be prudent for a resource manager to leave a short position unfilled that corresponded to 50% of a utility's load for extended periods of time when a cost-effective physical hedge was available?

A. No, customers should not be expected to absorb the risks of inter-temporal disequilibrium events that produce a rapid rise in supply costs. As discussed above and illustrated in Table 1, a retrospective analysis of the impact of recent events on the cost of power with and without the Hydros shows that the Hydros would serve to insulate Montana customers from substantial rate shocks and, on average, lead to lower costs than market reliance, even without an assumed carbon price. Prudent portfolio planning mitigates the financial duress that such disequilibrium events pose to customers.

Q. How could a prudent manager of resource planning incorporate uncertainty into the planning process?

A. A prudent manager of resource planning would have undertaken the exact analysis, validation activities, and presentation of results performed by NorthWestern in developing its 2013 Plan. The underpinnings of the economic analysis have been examined and recognized by an independent consultant retained by the Montana Public Service Commission ("Commission") to introduce "meaningful uncertainty" (Evergreen Economics). Table 6-1 of Volume 1, Chapter 6 of the 2013 Plan (copied below) lists the key factors that drive the decision analysis in NorthWestern's resource planning activities.

Table 2: Treatment of Uncertainty in Resource Planning

Treatment Of Uncertainty In Resource Planning Modeling Tools		
Uncertainty Factor	**Traditional Tools**	**Integrated Risk Planning Models**
Load growth	Fixed	Simulated uncertainty
Load patterns	"Typical" profile	Uncertainty in profile and usage pattern
Weather	Fixed	Weather drives demand and causes renewable generation
Hydro	Fixed	Simulated seasonal, daily operations
Wind	Fixed	Simulated with weather
CO_2 emissions	Fixed	Simulated based on uncertainty in costs
Gas & power prices	Fixed	Simulated monthly, daily & hourly prices
Transmission	Fixed Input/Output	Variable flow contingent factors
Forward/Forecast prices	N/A	Simulated forward curves

Modeling of the risk factors listed above is based on historic data, using robust statistical models to enforce key structural relationships between uncertain variables that are simulated into the future. For example, the fundamental relationships between weather and load, load and price, renewable (including hydro) generation and weather/load/price, etc., are all preserved within NorthWestern's modeling framework. This introduces meaningful uncertainty rather than just adding noise to expected value forecasts, and produces distributions of possible future costs that are far more robust than would be possible with more simplistic analysis. Furthermore, NorthWestern systematically incorporated uncertainty into the decision making process by monetizing the value of risk associated with the resource options evaluated through its use of the "risk premium" adder. Through use of this sophisticated approach, the Company's decision analysis is consistent with the actions of a prudent energy supply planner.

V: Comparative Cost Analysis Of Feasible Resource Options

Q. Is it your opinion that NorthWestern must evaluate options that represent a physical ability to provide energy to Montana customers, rather than relying indefinitely on market purchases?

A. Yes. As stated in the 2013 Plan, page 6-7 of Volume 1, NorthWestern has a critical need to economically serve native load. As mandated by Montana law[4], NorthWestern must select resources based both on least-cost and least-risk considerations. Failing to acquire enough capacity to meet a large portion of load fails the least-risk criteria, because of the demonstrable risk of relying on the regional market for stable energy prices. As explained above, Table 1 illustrates the role of NorthWestern-owned supply resources in mitigating price shocks for Montana customers. The clear conclusion is that NorthWestern would be imprudent to rely exclusively on market purchases to fill its customers' growing energy needs in the coming decades.

Dr. Wilson's emphasis on market purchases as a feasible alternative to the hydro acquisition is flawed; the real alternatives are other physical resources, and evaluation of the hydro acquisition should be based on comparison to these options. The Supplement to the 2013 Plan contains an evaluation of five alternative supply portfolios. The Hydros represent the least-cost and least-risk choice when compared to feasible combinations of other thermal and renewable resources. Given that "a full set of realistic resource alternatives to the hydro facilities was represented within the six portfolios considered",[5] it

[4]Section 69-8-419,(2)(c) MCA.
[5] Evergreen Economics, "Review of NorthWestern's Application to Purchase Hydroelectric Facilities," page ii.

is clear that the Hydros offer the least-cost and least-risk planning option in comparison to all other feasible resource acquisitions.

Q. In the context of resource planning, is it appropriate to examine the stochastic analysis presented in NorthWestern's 2013 Plan, rather than the earlier, deterministic analysis upon which the bid price was based?

A. Yes. Dr. Wilson suggests, on page 28 of his testimony, that NorthWestern "favors" the stochastic analysis; this is an inaccurate statement, because the models serve different purposes. In the context of comparative analysis for resource planning, the stochastic approach in the 2013 Plan is the relevant analysis to examine. The stochastic analysis supports the prudency of NorthWestern's bid price by demonstrating the Hydros acquisition's advantages over other physical resource options (and market purchases) in both cost and risk. The stochastic analysis framework represents industry best practice for comparative portfolio analysis[6] and robustly values the impacts of future uncertainty on potential future costs for Montana customers. Further, the stochastic analysis supports Montana law and the Commission's administrative rules requiring least-cost and least-risk resource planning.

The Discounted Cash Flow ("DCF") model, used by NorthWestern to inform their bid strategy for the Hydros, was a prudent means of evaluating the approximate value of the assets in the marketplace. However, as I argue above, only new, physical supply options represent feasible alternatives to the Hydros acquisition in the context of NorthWestern's

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[6] *See* Evergreen Economics, "Review of NorthWestern's Application to Purchase Hydroelectric Facilities," page i.

responsibility to provide low-cost and low-risk energy to its customers. Thus, the comparative cost analysis of the 2013 Plan is the appropriate analysis to evaluate the cost-effectiveness of the Hydros acquisition. Dr. Wilson's attacks on the DCF model do not detract meaningfully from the core conclusion of NorthWestern's 2013 Plan analysis: foremostly, the Hydros represent the best future supply option by providing the least-cost means of ensuring stable rates for Montana customers over the long term.

Q. Is Dr. Wilson's use of undiscounted cash flows and future values appropriate in the context of a long-term comparative analysis?

A. No. Dr. Wilson makes many references in his testimony to dollar amounts that are presented in future value, or the sum of undiscounted cash flows over a number of years. For example, in the table on page 39 of Dr. Wilson's testimony and in subsequent discussion, he refers to a \$400M total premium of the Hydros' costs from 2014-2021; this number represents a sum of undiscounted cash flows and therefore does not consider the time value of money for either NorthWestern or its customers, and should more appropriately be expressed as a NPV calculation. Similarly, Dr. Wilson presents a value of \$1.375B as the cost increase caused by modeled CO_2 price impacts, but again, this is a sum of undiscounted cash flows and should be summarized as an NPV for planning and comparative analysis purposes. Finally, Dr. Wilson presents, on page 27 and other places, a value of \$1.68B for assumed residual value of the Hydros, which, again, is undiscounted and as such only reflects the value of the purchase price scaled at inflation to 2043; NorthWestern does not, in fact, assume any real growth in value of the Hydros, and the present value of this residual value (\$212M) is much smaller than the purchase price.

Q. Are Dr. Wilson's concerns about the risk of capital improvement or maintenance costs in excess of projected values relevant to the comparative cost analysis?

A. No. Unanticipated capital improvement or maintenance costs pose a risk for any potential physical resource, but, following industry standard practice, are not included in the stochastic model's risk assessment for any resources under consideration by NorthWestern. A review of the planning entity documents (mainly Northwest regional utility Integrated Resource Plans) cited by NorthWestern in their review of regional carbon price forecasts indicates that no other utility includes any explicit representation of capital upkeep or maintenance cost risks in assessing the comparative costs of different resources (See Exhibit GD-1).

Even if NorthWestern included unanticipated capital upkeep or maintenance costs in its comparative cost analysis, the magnitude of the impact is likely inconsequential when compared to other, higher-magnitude cost risks (e.g. carbon and market price risks). Exhibit GD-2 illustrates the impacts of including Dr. Wilson's potential cost increases for a large capital improvement project between 2024-2026 (Exhibit JW-4), as well as his proposed doubling of fixed maintenance costs starting in 2018 (Exhibit JW-2). On an NPV basis, these projects total to $350M in revenue requirement, which is not insignificant, but is less than the $373M cost advantage of "Current + Hydro" portfolio over the "Current" portfolio presented in the 2013 Plan. Thus, even if both of Dr. Wilson's proposed, aggressive cost increases were realized, the Hydros would still be cost-competitive with market purchases and other physical supply options.

Q. Does Dr. Wilson overstate the impact of the "positive salvage value" assumptions made in evaluating the total NPV costs of the "Current + Hydro" portfolio?

A. Yes. As noted above, Dr. Wilson presents this number in nominal, undiscounted, future value, which is misleading when the rest of the analysis has been performed in terms of NPV. NorthWestern's analysis does not increase the value of the Hydros in real terms, only at inflation, consistent with the recognition of persistent rights to generate power at the Hydros facilities that do not depreciate into the future. Even if the salvage value ($212M in present value) were assumed to be zero in 2043, the "Current + Hydro" is still lower-cost than other supply options, and much lower risk. Table 3, below, illustrates this point.

Table 3: Comparative Cost Analysis Without Residual Value

Portfolio	NPV Costs $M (2013 Plan)
Current	$6,229
Current + Hydro	$5,856
Current + Hydro (w/ zero residual value for Hydros)	$6,068

VI: Prudence Of Carbon Risk Modeling

Q. Should NorthWestern include the potential future impacts of the price of CO_2 in its comparative cost analysis?

A. Yes. As outlined above, NorthWestern has a core obligation to make least-cost and least-risk planning decisions in order to provide low and stable rates for Montana customers into the future under many different scenarios of market conditions and other exogenous factors out of NorthWestern's control. Given the precedent and success of California's cap-and-trade system, the near-misses of Federal climate legislation, and pending Federal regulation of CO_2, it is crucial for NorthWestern to explicitly consider the costs that national or regional CO_2 pricing would impose on Montana customers.

Q. Does NorthWestern's use of carbon risk modeling represent industry best practices?

A. Yes. Rather than just using a single value of the CO_2 price in its stochastic analysis, NorthWestern instead simulates many different CO_2 prices for each year in the planning horizon. The distribution of these prices is informed by the values used by other regional utilities in their own planning studies, and centered on NorthWestern's own CO_2 price forecasts, which lie on the lower end of regional utility projections. The simulated CO_2 price range reflects the future uncertainty in carbon prices while maintaining conservative CO_2 price levels relative to other utilities' planning studies.

The stochastic modeling of carbon prices also follows the historical precedent of emissions markets whose prices vary greatly from year to year as the balance of supply and demand and other economic drivers impact the availability of emissions allowances, permits, or offsets. The range of costs that this volatility in prices would impose on NorthWestern's customers is substantial. The inclusion of these risks as part of the Risk Premium, a calculation that uses "widely accepted methods of financial analysis"[7] to value the risk of costs exceeding the mean, represents an adherence to the standards of prudency and industry best practices in considering not only expected costs but also the magnitude of cost risks.

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[7] Evergreen Economics, "Review of NorthWestern's Application to Purchase Hydroelectric Facilities," page 18.

Q. Is Dr. Wilson's characterization of NorthWestern's CO_2 modeling as "speculative" correct?

A. No. NorthWestern's carbon price risk modeling is not "speculative" because instead of assuming one, fixed value for CO_2 price each year, the analysis simulates a plausible range of future CO_2 prices that sits at the lower end of the range used in other regional utilities' planning studies. A "speculative" analysis of the potential impact of carbon pricing on NorthWestern portfolio costs would not include the conservative price simulation component of NorthWestern's stochastic analysis; rather it would impose a deterministic CO_2 price trajectory and report only the expected value of cost impacts. In contrast, NorthWestern's analysis incorporates a conservative range of uncertainty for future CO_2 prices and reports not only the expected value of cost impacts, but also the range of potential cost impacts dependent on future CO_2 price realizations (reflected in the Risk Premium calculations as well as Figures 6-10 and 6-11 of Volume 2, Chapter 4 of the 2013 Plan).

Q. Are there other errors in Dr. Wilson's objections to the prudency of NorthWestern's carbon price modeling?

A. Yes. Dr. Wilson also refers to a "possible doubling" of the CO_2 price modeled in NorthWestern's stochastic analysis presented in the 2013 Plan. This is a misleading statement. The expected value of the CO_2 price in the stochastic analysis is identical to NorthWestern's assumed case in the DCF analysis, and although there are values represented near the top of the simulated range (double the expected value), there are just as many values represented near zero. The inclusion of these values near zero is an inherent conservatism, given the existing regional precedents for CO_2 price, while the high ("doubled") values are well within the range of other regional utilities' planning cases.

Dr. Wilson also objects to the use of a 5% (nominal) annual growth rate for the expected value of CO_2 prices. This annual growth rate is in keeping with regional precedents, and is in fact more conservative than the auction floor price in California, which rises at 5% over inflation annually[8].

Finally, Dr. Wilson contends that a competitive owner of the Hydros would not be able to pass CO_2-related costs along to customers until such CO_2 emissions prices actually take effect, and therefore the ratemaking proposal should be amended to not include CO_2 cost recovery until such a time as a price on CO_2 is realized. However, this argument is flawed, given the three important regional precedents described below.

First, sales of power into California from the broader Western market are tagged with the source generator's emissions factor[9], and thus energy from high-emissions generators is less valuable to California's power retailers than that from lower-emissions resources under existing cap-and-trade legislation (AB 32). NorthWestern has correctly taken this regional precedent into account when assessing the value of high- versus low-emissions factor resources, and has done so conservatively given the delayed (2021) start date of

[8] Center for Climate and Energy Solutions; "California Cap-and-Trade Program Summary" - http://www.c2es.org/docUploads/calif-cap-trade-01-14.pdf
[9] Cal. Code Regs., tit. 17, § 95811(b)

carbon pricing in its models. NorthWestern or any other prospective owner of the Hydros is correct to recognize that the value of the Hydros is enhanced by their ability to provide emissions-free sales to regional markets with a current and potential future price on carbon.

Second, Dr. Wilson's argument ignores another important regional precedent that impacts the value of high- versus low-emissions factor resources. The Utilities and Transportation Commission ("UTC") in Washington recently disallowed the use of a zero-CO_2 price "base case" in Puget Sound Energy's ("PSE's") Integrated Resource Planning process[10]. In doing so, the UTC effectively increased the value of low-carbon resources relative to that of the resource in question (Colstrip). As a result of this UTC requirement, owners of existing or new low-carbon resources that are selected as part of PSE's IRP process with a non-zero CO_2 price forecast effectively have the ability to recover CO_2 costs from customers, even though a CO_2 price is not yet in effect in Washington. Potential buyers of the Hydros, whether NorthWestern or a competitive supplier, are correct to take this regional precedent into account in determining the value of the Hydros.

Third, the Oregon Public Utility Commission ("PUC") has recently proposed an order that requires PacifiCorp to consider a non-zero price of carbon in its future IRPs. In a Proposed Order dated March 11, 2014 in Docket LC 57 regarding the PacifiCorp IRP, the PUC required PacifiCorp to work with IRP participants to identify ways to accommodate

[10] Attachment B of UTC Comments on PSE's Colstrip Study, Docket UE-120767

the impacts of Environmental Protection Agency Section 111(d) rulemaking on future carbon emissions. Oregon thus joins Washington in requiring utilities to explicitly consider the risks of future carbon pricing in their IRPs, even though no current regional price exists.

In summary, NorthWestern's carbon price modeling reflects currently acknowledged differences between high- and low-emissions factor resources, and its treatment of CO_2 price uncertainty explicitly accounts for the risks imposed by this uncertainty. As such, Dr. Wilson's assertion that NorthWestern's CO_2 price risk modeling is "speculative" is incorrect; rather, NorthWestern has prudently valued the cost uncertainty imposed by carbon in its comparative cost analysis and has come to the correct conclusion that the Hydros represent the least-cost and least-risk resource.

VII: Conclusions

Q. Can you please conclude your testimony with a summary of your key points?

A. My testimony, rebutting the conclusions of Dr. Wilson on behalf of the MCC, can be summarized as follows. First, Dr. Wilson's objection to the Hydros acquisition reflects a disregard for prudent resource planning practices. Dr. Wilson's proposal to rely on the market to meet NorthWestern's load obligation ignores large, demonstrable market price risks that should be hedged by a prudent resource planning manager.

Second, Dr. Wilson's critiques of NorthWestern's DCF model used to inform the bid strategy, and his focus on that model in highlighting the cost impacts of the Hydros acquisition, are not relevant to the identification of the least-cost, least-risk physical supply resource. Rather, the stochastic analysis presented in the 2013 Plan is the more robust, comparative analysis upon which NorthWestern's determination of the optimal resource portfolio to pursue is based. Third, Dr. Wilson's critiques of both the DCF and the stochastic analysis are weakened by his misrepresentation of costs as future values or undiscounted cash flow sums, rather than a consistent NPV basis as used in the 2013 Plan.

Fourth, Dr. Wilson's focus on NorthWestern's choice not to model the risk of capital outlay required for operations and maintenance of the Hydros above budgeted values is not pertinent given industry standards for modeling supply cost risks, and, furthermore, including his high estimates for future operations and maintenance costs would not reverse the Hydros' cost advantage.

Fifth, Dr. Wilson's focus on the alleged assumed increase in the Hydros' value in 2043 is misleading, as he presents the number in future value rather than NPV, and, again, even if this residual value were assumed to be zero, the Hydros would still represent the least-cost resource option.

Sixth, Dr. Wilson presents an unsubstantiated view of the risks imposed by the potential for CO_2 pricing within NorthWestern's planning horizon. Several regional precedents provide compelling support for the inclusion of carbon price in resource investment decision analysis, and NorthWestern has used a relatively conservative distribution of possible CO_2 prices compared to other regional utilities. NorthWestern has adhered to industry best practices in simulating and valuing the uncertainty in carbon prices, and has correctly identified the Hydros as the best, least-cost and least-risk resource option.

Q. Does this conclude your testimony?

A. Yes it does

Exhibit GD-1: Fixed O&M / Capital Upkeep Risk in Western Utility Planning Documents

APS, 2012 IRP:
No quantitative treatment of risks of unplanned maintenance costs.
Page 133: "The primary construction, capital, and operating cost risks are associated with the engineering, procurement, and construction (EPC) of new generating units. **Engineering, procurement, and construction of modifications to generating units also have similar risks but the total costs at risk are typically smaller.**" *[emphasis added]*

Avista, 2013 IRP:
No mention of FOM or capital expansion cost risk for new or existing resources.

EWEB, 2011 IRP:
No quantitative treatment of risks of unplanned maintenance costs.
Page 25: "There are other uncertainties that would have significant impacts to EWEB but do not impact the relative cost-effectiveness of future choices. These uncertainties are not as important to model in the IERP. For instance, **there is no need to model the risk that the Snake River dams will be breached** or that the Columbia Generating Station nuclear power plant will close early." *[emphasis added]*

Idaho Power, 2013 IRP:
No mention of FOM or capital expansion cost risk for new or existing resources.

PacifiCorp, 2013 IRP:
Page 157: "The Monte Carlo runs capture stochastic behavior of electricity prices, natural gas prices, loads, thermal unit availability, and hydro availability" – no mention of new or existing unit FOM or maintenance cost risks.

PGE, 2013 IRP:
Page 187 lists the risk drivers for the model – capital additions and FOM risks are not included.

PSE, 2013 IRP:
Pages 4-23 and K-3 list risk drivers for the model – capital additions and FOM risks are not included.

SCL, 2012 IRP:
Page 23-24 describe risk drivers (hydro, load, NG price) – does not include capital additions or FOM.

Snohomish, 2010 IRP:
Risk discussion starting on Page 87; no mention of capital addition or maintenance cost risk.

Tacoma, 2012 update to 2010 IRP: Risk Adder (Page 9) includes gas price, load growth, and hydro year; no mention of capital addition or maintenance cost risk.

Tri-State, 2010 IRP:
Page 29 begins a section outlining the planning risks faced by Tri-State, including load growth, carbon pricing, and other environmental regulations; no mention of capital addition or maintenance cost risk.

TEP, 2012 IRP:
Page 89 begins an outline of resource option characteristics, including risks associated with each class of resource; no mention of capital addition or maintenance cost risk.

Exhibit GD-2: Comparative Cost Analysis with Dr. Wilson's Assumed Additional Fixed Costs

Table 2-1: Impact of Major Project on Portfolio NPV

NPV: $150,570,584

Year	Expenditure (Exhibit JW-4)
2024	$114,415,000
2025	$114,644,000
2026	$114,906,000

Table 2-2: Impact of Increased Annual Expenses on Portfolio NPV

NPV: $199,054,008

Year	Expenditure (Exhibit JW-2)
2018	$17,800,000
2019	$18,245,000
2020	$18,701,125
2021	$19,168,653
2022	$19,647,869
2023	$20,139,066
2024	$20,642,543
2025	$21,158,606
2026	$21,687,572
2027	$22,229,761
2028	$22,785,505
2029	$23,355,143
2030	$23,939,021
2031	$24,537,497
2032	$25,150,934
2033	$25,779,707
2034	$26,424,200
2035	$27,084,805
2036	$27,761,925
2037	$28,455,973
2038	$29,167,373
2039	$29,896,557
2040	$30,643,971
2041	$31,410,070
2042	$32,195,322
2043	$33,000,205

Table 2-3: Comparative Cost Analysis

Portfolio	NPV Costs $M (2013 Plan)
Current	$6,229
Current + Hydro	$5,856
Current + Hydro (incl. JW-2 and JW-4 additional costs)	$6,206

Curriculum Vitae of Gary W. Dorris

Employment History

President & Founder	*Ascend Analytics*	Boulder, CO (2002-present)
CEO and Chief Model Architect	*e-Acumen (Acquired from Stratus)*	Boulder, CO (2000-2001)
Director of Energy Practice	*Stratus (Hagler Bailly spinoff)*	Boulder, CO (1998-1999)
Manager and Senior Associate	*Hagler Bailly*	Boulder, CO (1997-1998)
Faculty	*Cornell University*	Ithaca, NY (1996)
Power Marketing Manager	*Citizens Power & Light*	Boston, MA (1990-1991)
Power Supply Supervisor	*UNITIL Power Corp*	Exeter, NH (1988-1990)
Project Engineer: CO-OP	*Electric Power Research Inst.*	Barker, NY (1987)

Summary

- Developed a suite of industry-leading analytic products that support physical and financial risk management, and trading. Sold to 30 of top 100 energy companies. Grew e-Acumen to leader in energy trading and risk analytics with 60 people before sale of company. Has grown Ascend to a 30+ person company with reputation as an industry leader for portfolio management analytics.
- Chief model architect and engagement director to implement solutions for portfolio risk management and trading analytic infrastructure at AES, ACES Power Marketing, BC Hydro, Dayton Power and Light, Duke Solutions, Entergy Solutions, Essent, Exelon, InterGen, PG&E, Puget Sound Energy, Riverside Public Utilities, The Energy Authority, Tri-State G&T, NRG, Tennessee Valley Authority, Pennsylvania Power & Light, and American Electric Power.
    - Developed and deployed solutions to capture the financial and physical dynamics of energy markets and operations including: 1) derivative instrument valuation, 2) asset valuation, 3) risk management and portfolio optimization, 3) forward and spot prices, 4) transmission/transportation, 5) load, 6) gas storage, and 7) credit risk.
    - Developed energy supply procurement and trading risk reports, policies, and procedures to compliment risk management software.
- Performed numerous independent market assessments for financial structure and valuation of electric generating assets and gas storage facilities:
    - Assessments for financing of over $5 billion in generating and gas storage assets.
    - Valuations performed for leading energy developers, banks, and S&P and Moody's.
- Performed one of the first above cost electricity transaction in US in (1988).
- Developed methods and systems to measure and price volumetric risk for competitive wholesale and retail providers of electricity and gas.

Education

Cornell University, Ph.D., Applied Economics and Finance, 1996

Cornell University, B.S., Mechanical Engineering, B.A., Economics, Magna cum Laude 1988

EXHIBIT GD-3 – CV OF GARY DORRIS

PROFESSIONAL EXPERIENCE

Gary Dorris has pioneered innovative solutions for energy portfolio planning, risk management, and asset valuation for over two decades. His expertise with large-scale physical and financial risk modeling has proved his company, Ascend Analytics, and its resource planning and portfolio management solution to be indispensable to over 50 energy companies throughout the US and Europe. Industry leaders have appealed to Dr. Dorris for his delivery of expert testimony regarding resource planning, risk management, energy procurement, trading practices, asset valuation, market power, rate design, and emissions trading. He has also provided independent expert reports to support utility acquisition of rate based generation assets and the financing of merchant generation of over $5 billion in electric generating assets. Prior to founding Ascend, he served as CEO and Chief Model Architect for e-Acumen, a 60 person energy consultancy and software analytics firm that he successfully grew and has been sold. He directed the development of the analytical and risk infrastructure for the launching of the trading floors of Entergy Solutions, Duke Solutions, The Energy Authority, and ConEdison. Before e-Acumen, he founded and directed the energy practice at Stratus Consulting and was a manager at Hagler Bailly.

Before joining Hagler Bailly in 1997, he was a faculty member at Cornell University, where he taught a doctoral-level course in modeling competitive energy markets. Dr. Dorris actively publishes research articles and speaks on resource planning, portfolio management, risk analysis, and modeling of competitive energy markets. He has been honored in 2001 by the International Petroleum Exchange for his innovations and contributions to the field of energy risk management.

Dr. Dorris holds a PhD in applied economics and finance from Cornell University and both a BS in mechanical engineering and a BA in economics with Magna Cum Laude distinction from Cornell University.

EXPERT TESTIMONY

Risk Management and Trading
Merrill Lynch v. Enron Shareholder. Federal District Court of Texas, Case Nos. H-01-3624.

Asset Valuation and Hydro Production
Montrose Energy Partners (Sithe Energy) v. Trout Unlimited. Colorado Water Court, Case Nos. 4-2002CW204 and 4-2002CW205.

Commodity Hedging, Risk Management and Derivative Accounting
Owens Corning v. Dennis Mangan. Federal Bankruptcy Court, District of Delaware, 2004. Case Nos. 00-3837 (JKF), Claim No. 6923.

Energy Risk Management and Trading Practices
Nevada Power v. MGM Grand. Nevada Regulatory Proceeding, 2002. PUCN Docket No. 01-11029.

EXHIBIT GD-3 – CV OF GARY DORRIS

Asset Valuation and Emissions Trading
AES Corp. v. Allegheny Power. Pennsylvania Arbitration Proceeding, 2000. Arbitration No. 71 198 00004 00.

Environmental Damages
US EPA v. Mid-west Ozone Group, Washington D.C. Federal Court, 1998 (expert report used in proceedings).

ENERGY COSTING AND SUPPLY PROCUREMENT 1988-2013

- ***Resource Planning:***
  - Developed one of the nation's first integrated "risk based" energy supply resource plans for Xcel Energy in Colorado (2004) and PG&E (2003). Analysis included portfolio assessment of multiple resource options with respect to the expected costs and costs at risk.
  - Currently leading the resource planning analysis, report development, and providing facilitation support for the stakeholder process and expert testimony.
  - Provided thought leadership to the development of Ascend's PowerSimm software applied at over a dozen electric utilities for portfolio management, resource planning and asset valuation.
  - Provided supply portfolio analysis for North Carolina Electric Membership Cooperative, Southern Maryland Electric Cooperative, and Old Dominion Electric Cooperative Oglethorpe Power Corporation
- ***Energy Costing and Supply Procurement:***
  - Developed methodology and software system for cost of supply analysis for competitive retail offerings of Duke Solutions and Entergy Solutions.
  - Executed energy supply procurement for UNITIL Power Corp.
- ***Power Trading:***
  - Executed of over 100 short-term and long-term power sale agreements for both utilities and IPPs.
  - Performed one of (if not) the first above cost electricity transaction in the US in 1988.
  - Marketed and structured complex long-term tolling contracts.
- ***Trading Floor Launches:***
  - Launched the trading floors of Entergy Solutions, Duke Solutions, The Energy Authority, and ConEdison including top to bottom analytics and trading/supply procurement practices.
  - Supplied major risk management and deal analysis infrastructure for Entergy, TXU, PZ Oil, ACES Power Marketing, PG&E, Arizona Public Service, and BC Hydro.

ELECTRIC MARKET ANALYSIS 1998-2004

- ***Asset Valuation:***

EXHIBIT GD-3 – CV OF GARY DORRIS

Developed independent expert reports on the value and acceptable financial structure for valuing power generation and gas storage assets for the following clients:

Developers
AES Corporation
Columbia Electric
Mosbacher Power
PP&L Global
Edison International
Enron
Xcel Energy
Sempra Energy
Tampa Electric Co.
Select Energy
El Paso
Energetix

Financial Institutions
Investment Banks
- CS First Boston
- Lehman Brothers

Commercial Banks
- GE Capital
- Bank of Tokyo
- Citibank

Credit Rating Agencies
- S&P
- Moody's

- ***Risk Management***: Developed and implemented risk management policy and procedures for four trading floors.
- ***Sarbanes Oxley***: Performed internal audits, implemented policies and procedures, defined corporate structure governance, and implemented software solutions
- ***Supply Procurement***:
  - Developed least cost resource plan filing with risk analysis for PG&E.
  - Executed energy supply procurement for UNITIL Power Corp.
- ***Trading from Fundamental***: Trained power traders on short-term trading strategies and identification of hedging strategies based on real-time market fundamentals. Clients included: Duke, TXU, PP&L, ConEd, Coral, El Paso, Reliant, CMS, and BP.

EXHIBIT GD-3 – CV OF GARY DORRIS

- ***Market Power:***
  - Estimated HHI and Lerner index for PJM deregulation initiatives. Filed results as part of market design report to state commission.
- ***Capacity Market Design*:** Drafted design of a capacity market for the CAISO.

ENERGY RISK AND POWER TRADING 1988-2004

- ***Resource Planning**:* Developed one of the nation's first integrated "risk based" energy supply resource plans for Xcel Energy in Colorado (2004). Analysis included portfolio this is assessment of multiple resource options with respect to the expected costs and costs at risk.
- ***Energy Costing and Supply Procurement***:
  - Developed methodology and software system for cost of supply analysis for competitive retail offerings of Duke Solutions and Entergy Solutions.
  - Developed least cost resource plan filing with risk analysis for PG&E.
  - Executed energy supply procurement for UNITIL Power Corp.
- ***Power Trading*:**
  - Executed of over 100 short-term and long-term power sale agreements for both utilities and IPPs.
  - Performed one of (if not) the first above cost electricity transaction in the US in 1988.
  - Marketed and structured complex long-term tolling contracts.
- ***Trading Floor Launches:***
  - Launched the trading floors of Entergy Solutions, Duke Solutions, The Energy Authority, and ConEdison including top to bottom analytics and trading/supply procurement practices.
  - Supplied major risk management and deal analysis infrastructure for .
- ***Trading from Fundamental***: Trained power traders on short-term trading strategies and identification of hedging strategies based on real-time market fundamentals. Clients included: Duke, TXU, PP&L, ConEd, Coral, El Paso, Reliant, CMS, and BP.
- ***Market Power:***
  - Estimated HHI and Lerner index for PJM deregulation initiatives. Filed results as part of market design report to state commission.

EXHIBIT GD-3 – CV OF GARY DORRIS

RETAIL PROGRAMS 1990-2004

- ***Retail Offerings:*** Developed a suite of retail product offerings for open market competition in Texas, PJM, and California.
- ***Retail Time Pricing:*** Developed retail time price offerings in competitive offerings and for regulated companies.
- ***Risk Based Pricing:*** Developed and implemented a system of risk based pricing for competitive retail offerings.

PROJECT FINANCE ANALYSIS 1998-2002

- ***Asset Valuation:***

  Developed independent expert reports on the value and acceptable financial structure for power generation and gas storage assets for the following clients:

Developers	**Financial Institutions**
AES Corporation	*Investment Banks*
Columbia Electric	- CS First Boston
Mosbacher Power	- Lehman Brothers
PP&L Global	*Commercial Banks*
Edison International	- GE Capital
Enron	- Bank of Tokyo
Xcel Energy	- Citibank
Sempra Energy	*Credit Rating Agencies*
Tampa Electric Co.	- S&P
Select Energy	- Moody's
El Paso	
Energetix	

OIL AND GAS MARKET ANALYSIS 2002-2005

- ***Portfolio Analysis*:** Developed corporate strategy for portfolio risk analysis and capital investment allocation for a large oil field service company.
- ***Market Assessment and Gas Storage Valuation:***
  Dr. Dorris developed *GasVal* to capture the full value of storage assets for project analysis, mark to market energy accounting, and deal structuring. With the use of state-space modeling to capture the underlying dynamics of gas market behavior, his market analysis and asset valuations have been performed for industry leaders in gas storage including:

  - TXU
  - Pinnacle West
  - TECO Energy

EXHIBIT GD-3 – CV OF GARY DORRIS

- *Energy Cycle Forecasting:*
  - Forecasting of rig counts for Halliburton and Baker Hughes Christensen
  - Development of Pasche price index and index forecast for energy services

DISTRESSED UTILITIES 1990-2004

- ***PG&E:*** Developed energy supply portfolio analysis for commission filings and credit risk mitigation for the bankrupt utility. Implemented energy risk management policies and software solutions.
- ***Cajun Electric COOP:*** Economic support for bankruptcy trustee including workout scenarios, power purchasing strategy, and preparation of expert testimony.
- ***Colorado Utah:*** Sold excess generation to mitigate losses and maintain operations.
- ***PSNH*:** Developed counter party protective measures to continue supply trading.

ANALYTIC SOFTWARE DEVELOPMENT 1997-2013

Developed a suite of analytic software products for energy risk management, asset decision analysis, and energy trading that were sold to 30 of the 100 energy companies. After merging his business activities and software from Stratus with e-Acumen, he served as CEO and Chief Model Architect. Since founding Ascend, he has developed a second generation suite of analytic products which include:

- ***PowerSimm:*** Monte Carlo simulation of physical assets and financial instrument for energy costing, portfolio management, risk measurement, and deal analysis.
- ***PowerSimm Planner:*** Performs resource planning with the inclusion of uncertainty. Automatic resource selection based on market dynamics and planning constraints.
- ***HydroOps:*** Optimization of hydro generation assets.
- ***CurveDeveloper:*** Provides complete monthly forward curves using no-arbitrage strip reduction along with volatilities and correlations.
- ***WeatherSimm:*** Simulates climatic variables temporally and spatially to integrate with HydroSimm, LoadSimm, and PriceSimm.
- ***LoadSimm:*** Simulates system load, industrial customer load, or load profile demand.
- ***GasVal:*** Values gas storage assets that address the new dynamics of gas market spot and forward prices combined with the physical operating dynamics of storage assets.
- ***DataScrubber:*** An automated data cleaning system that analyzes analytic data, reviews it for accuracy, and identifies and remedies errors or omissions in the data.
- ***OptionModeler:*** A series of option models from complex regime switching and jump diffusion with mean reversion to Black's standard model.

INTELLECTUAL PROPERTY/BUSINESS VALUATION 2000-2001

- Conducted a number of business transactions as CEO of e-Acumen involving the valuation of a business and acquisition of intellectual property.

EXHIBIT GD-3 – CV OF GARY DORRIS

- Provided expert support concerning intellectual property ownership.

ENVIRONMENTAL ANALYSIS/DAMAGES 1994-1999

Dr. Dorris developed the Regional Economic Model for Air Quality (REMAQ), an integrated framework to assess the costs and air quality implications of different emission trading strategies. He has also applied REMAQ to assess the joint benefits of air quality regulations and been used to evaluate regulations of NO_x emissions from power plants and address critical environmental policy question about electric utility restructuring. He was the principal investigator for the expert report to evaluate the air quality impacts and cost effectiveness of EPA's SIP Call for NO_x point sources, the most expensive environmental legislation for the state of New York, Illinois, North Carolina, the province of Ontario Canada, wide emission standards, and has been central to the development of transboundary emission policy between the US and Canada. In addition, his environmental analysis of emission markets and regulations has been used by numerous electric generators for development of compliance strategy and the financing of over $15 billion in generation.

INSTRUCTION 1996-2004

- ***Academic:***
  - Taught a course in Risk Management at the Leeds Business School of University of Colorado
  - Taught a course at Cornell University on Modeling Competitive Energy Markets in Spring of 1996.
  - Teaching assistant for advanced doctoral course in econometrics at Cornell University.
- ***Industry:***
  - Lead instructional seminars regarding:
    - Financial Risk Management
    - Portfolio Optimization
    - Techniques for Forward Curve Development
    - Energy Supply Planning
    - Trading Electricity from Fundamental
    - Option Pricing and Stochastic Process

EXHIBIT GD-3 – CV OF GARY DORRIS

RELATED WORK EXPERIENCE 1986-1991

At Citizens Power & Light, Dr. Dorris conducted electric power transactions and developed strategies for power sales; managed international project feasibility studies in Poland, Czechoslovakia, the Dominican Republic, and India. He directed project development for a $700 million power plant in Poland. He negotiated conditions for a joint venture with the national oil refinery and a power sales agreement with Polish National Power grid, and pursued project financing with the World Bank and EBRD.

At UNITIL, he negotiated power purchase contracts with independent power developers and utilities, and was responsible for the technical and economic analysis of new power projects. Conducted short-term power procurement and sales and was responsible for production costing and NEPOOL regulatory affairs.

At EPRI, Dr. Dorris performed pilot testing of spray dryer scrubbers for coal power plants. He also developed and coordinated a pH negative corrosion test program.

HONORS AND PROFESSIONAL AFFILIATIONS

- International Petroleum Exchange (IPE) recognition for developments of "Earnings at Risk", a conceptual framework for measuring financial and physical risk (2001).
- Second person in history of Department of Applied Economics and Management to receive special exemption from Master thesis requirement, Cornell University (1992).
- Who's Who
- Graduated *Magna cum Laude,* Cornell University, 1988
- Nation Association of Business Economists
- American Economic Association
- International Association of Energy Economists
- General Association of Risk Professionals

SELECTED PUBLICATIONS

1) "Application of Backwardation to Natural Gas Futures" with Sean Burrows and Vena Kostroun, *Energy Risk.* August 2006.

2) "Risk Based Retail Pricing" with Sean Burrows, *Public Utilities Fortnightly, March 2004.*

3) "Energy Risk Management, Making Risk Management an Affirmative Tool to Provide Stable Returns on Investment," with Andy Dunn, *Energy & Power Risk Management* and the *New Frontiers* supplement, December, 2001.

4) "Using Modern Risk Measurement Techniques to Understand the Risk Exposure of an Energy Company," *Energy & Power Risk Management*, February 2001.

5) "Making the Shift to Earnings at Risk," with Andy Dunn, *Electric Light & Power*, October, 2001.

6) "Evaluating Generation Using Modern Energy Risk Management," with Andy Dunn, *Power Industry Development,* August 2001.

7) "Portfolio Optimization Technology and Techniques: Making Risk Management an Affirmative Tool for Adding Value to the Bottom Line," with Andy Dunn, *Energy & Power Risk Management*, July, 2001.

8) "Using Modern Energy Risk Management," with Andy Dunn, *Global Energy Business,* May/June 2001.

9) "Electricity Pricing: How to Make Electricity Pricing Models More Accurate by Incorporating Price Spike," with R. Ethier, *Energy & Power Risk Management*, July/August 1999.

10) "Behavioral Transportation Controls Impact on Air Quality," with John Kim, *Transportation,* October, 1999.

11) "Power Purchase Contracts and the Cost of Debt," *The Fortnightly,* May, 1996.

12) "Rethinking Power Contracting: Implications of Dispatchable Power Purchase Contracts," with Timothy Mount, *Energy Journal, 15(4): 167-187.*

13) "Cogeneration Implication for Pollutant Reduction and Energy Conservation," with Timothy Mount, Cornell University, Department of Agricultural, Resource and Managerial Economics, Working Paper, December, 1991.

EXHIBIT GD-3 – CV OF GARY DORRIS

SELECTED CONFERENCE PROCEEDING/WORKING PAPERS/PRESENTATIONS

1) "Innovations in Stochastic Modeling: Weather Conditions and the Impact on Modeling Integrated Physical and Financial Energy Portfolios," *Energy Risk USA*, Houston, TX, May 20-22, 2014. (pre-conference workshop)

2) "Utility Resource Planning: Integrated Decision Analysis for Resource Selection, Conversion and Retirement," *Electric Utilities Consultants*, Chicago, IL, May 13-14, 2014. (pre-conference workshop)

3) "Portfolio and Risk Management: California Carbon Policy Impacts on Western Power Markets," *Electric Utilities Consultants,* San Francisco, CA, January 27-28, 2014.

4) "Fast Ramp and Intra-hour Market Incentives," *Electric Utilities Consultants*, San Francisco, CA, January 29-30, 2014.

5) "California Power Markets and the West: Implications for Electricity Trade between California and the NW Panel Discussion," *Symposium of Northwest Power Coordinating and Conservation Council,* Portland, OR, September 12, 2013.

6) "Hydro Optimization: Realizing Maximum Value from Generation," *HydroVision International*, Denver, CO, July 24, 2013.

7) "Review of Resource Planning Model" *Northwest Power and Conservation Council*, June 2013.

8) "Resource Planning: IRP, Asset Valuation and Power Modeling," *Electric Utilities Consultants*, Westminster, CO, May 20-21, 2013.

9) "Resource Planning Under Uncertainty," *Electric Utilities Consultants,* Boulder, CO, March 21, 2013.

10) "Improving Settlement Processes for Organization Markets," *Electric Utilities Consultants*, Dallas, TX, February 20-21, 2013.

11) "Portfolio Management: Operational & Intermediate Term Best Practices," *Electric Utility Consultants*, Houston, TX, December 10-11, 2012.

12) "Decision Analysis for Converting Coal to Gas," *Electric Utilities Consultants*, Charlotte, NC, October 22-23, 2012.

13) "Resource Planning: A Practitioner's Toolkit for Current Issues," *Electric Utilities Consultants*, Portland, OR, May 15-16, 2012.

14) "Best in Breed and Best in Show Resource Planning," *Proceedings: Electric Utilities Consultants,* Portland, OR, March 8, 2012.

EXHIBIT GD-3 – CV OF GARY DORRIS

15) "Hydropower's Evolving Role in Western Power Grid Reliability," *Electric Utilities Consultants*, Sacramento, CA, December 12-13, 2011.

16) "Case Studies in Hedge Optimization: Hedging Strategies to Increase Cash Flow and Minimize Risk," *SNL's Power Risk Analysis Workshop*, New York, NY, November 9-10, 2011.

17) "Hedge Optimization to Increase Cash Flow and Minimize Risk," *Energy Central*, New York, NY, June 8-9, 2011.

18) "Building a Resource Plan that Addresses the Five Questions Regulators Want to Know," *Electric Utilities Consultants,* Atlanta, GA, May 16, 2011.

19) "Hedge Optimization to Increase Cash Flow and Minimize Risk," *Electric Utilities Consultants,* Chicago, IL, May 4, 2011.

20) "Hedge Flow to Increase Cash Flow and Minimize Risk," *PGS*, Houston, TX, March 9, 2011.

21) "Electricity Storage: Business and Policy Drivers," *Electric Utilities Consultants,* Houston, TX, January 24, 2011.

22) "What Techniques Work in a High Renewables and Demand-Side Resources Environment," *Electric Utilities Consultants,* San Francisco, CA, November 1-3, 2010.

23) "Mixing Financial and Physical Simulations through Time," *European Energy Trading Summit*, London, England, September 23-24, 2010.

24) "Optimization Strategies to Increase Cash Flow and Minimize Risk," *Energy Risk USA*, Houston, TX, May 25, 2010.

25) "Making Your Scenario Analyses More Robust: Meaningful Uncertainty in Price Simulations," *Electric Utilities Consultants,* Denver, CO, May 6, 2010.

26) "Hedge Optimization Strategies to Increase Cash Flow and Minimize Risk," *Electric Utilities Consultants,* Denver, CO, May 5, 2010.

27) "Forward Curve Generation and Data Management," *Electric Utilities Consultants Webinar*, April 20, 2010.

28) "Selection of Optimal Resource Plan in an Uncertain World," *Electric Utilities Consultants,* San Francisco, CA, April 12, 2010.

EXHIBIT GD-3 – CV OF GARY DORRIS

29) "Software and Consulting Solutions for the Energy Industry," *Marcus Evans CFO Summit*, Gold Coast, Australia, February 20, 2010.

30) "An Integrated Monte Carlo Simulation Framework," *Energy Risk Europe*, London, England, October 13-15, 2009.

31) "Resource Planning and Risk Analysis: Dealing with Renewable Resources," *Electric Utilities Consultants Webinar*, October 1, 2009.

32) "Resource Planning and Risk Analysis: Dealing with Demand Side Resources," *Electric Utilities Consultants Webinar*, September 3, 2009.

33) "Integrated Physical and Financial Risk Management: Using an Integrated Simulation Framework," *Proceedings: Electric Utilities Consultants,* Boulder, CO, March 6, 2008.

34) "Using Measures of Hedge Effectiveness to Design Retail Rates," *Proceedings: Electric Utilities Consultants,* Denver, CO, February 28, 2008.

35) "Best Practices for Addressing FERC Order 2004," *Proceedings: Electric Utilities Consultants,* San Antonio, TX, February 28, 2008.

36) "Building a No Regrets Energy Supply Portfolio," *Proceedings: Electric Utilities Consultants,* Austin, TX, January 28, 2008.

37) "Balancing Energy Portfolios Physical and Financial Risks," *Proceedings: Electric Utilities Consultants,* New York, NY, August 3, 2006.

38) Retrospective of Electricity Regulations and Markets," *Proceedings: Electric Utilities Consultants,* Denver, CO, May 18, 2006.

39) "Estimating Uncertainties for Volumetric Risk: Using an Integrated Simulation Framework," *Electric Utilities Consultants*, Denver, CO, March 2, 2006. (conference chair)

40) "Merchant Wind Financing: Maximizing the Value of Wind Generation" Denver, CO, February 27, 2006. (conference chair)

41) "Developing a No Regrets Energy Supply Portfolio," San Diego, CA, January 31, 2006.

42) "Building a Hedge Portfolio to Mitigate Earnings Volatility, "*Proceedings: Electric Utilities Consultants,* Boston, MA, August 10, 2005. (conference co-chair)

43) "Managing Earnings Volatility," *Proceedings: Electric Utilities Consultants,* Denver, CO, February 24, 2005. (conference chair)

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44) "Techniques for Portfolio Optimization," *Proceedings: Electric Utilities Consultants, Denver, CO,* September 29, 2004. (conference co-chair)

45) "Maximizing the Value of Wind Generation," *Proceedings: Electric Utilities Consultants,* Denver, CO, September 24, 2004.

46) "Developing Risk Based Rates," *Proceedings: Electric Utilities Consultants,* Denver, CO, September 22, 2004. (conference co-chair)

47) "Building a No Regrets Energy Supply Portfolio," *Proceedings: Electric Utilities Consultants,* Denver, CO April 29, 2004. (conference chair)

48) "New Techniques for Developing Forward Price Curves," *Proceedings: Energy Central,* Denver, CO, March 25, 2004.

49) "Avoiding Regulatory Disallowances," *Proceedings: Energy Central,* Denver, CO, June 10, 2003.

50) "Portfolio Management for Shareholder Value," *Proceedings: SunGard World,* New Orleans, LA, October 23, 2002.

51) **"**Portfolio Management As An Affirmative Business Tool,**"** *Proceedings: Enterprise Wide Risk Management by EUCI,* Denver, CO, September 19, 2002.

52) "Portfolio Optimization: An Affirmative Tool to Maintain Earnings and Maximize Value," *Proceedings: Portfolio Optimization by Infocast,* Houston, TX, November 14-16, 2001.

53) "Time2Trade: Trading Power from Fundamentals," *Proceedings: Power Trading by e-Acumen,* New York, NY, June 20, 2001.

54) "Portfolio Optimization to Reduce Risks and Increase Profits," *Proceedings: Electric Utility Consultants,* Washington, D.C. May 5-7, 2001.

55) "Minimizing Earnings at Risk," *Proceedings: Electric Utility Consultants,* Denver, CO, March 17-18, 2001.

56) "Risk Measurement and Analysis," *Proceedings: Risk Conference, April, 2000.*

57) "Portfolio Optimization under Uncertainty," *Proceedings: Portfolio Risk Management and Analysis by Infocast,* Houston, Texas, February, 2000.

58) "Utility Capital Structure and Non-Utility Power Purchase Agreements," *Proceedings of the Cornell University Workshop,* August, 1992

EXHIBIT GD-3 – CV OF GARY DORRIS

59) "Design and Operation of Combined Cycle Turbo Expanders for Gas Distribution Companies," *Proceedings of the New England Gas Association,* March, 1990.

60) "Developing Dispatchable Cogeneration Facilities: A Case Study," *Proceedings of the Joint Power Conference*, ASME Publication, October, 1990.

61) "Clean Power Supply through Cogeneration," Cornell University, Undergraduate Honors Thesis, June 1988.

62) "A Time-Dependent Endowment of Emission Allowances," *Proceedings of the Ozone Transport Assessment Group,* January 17, 1997.

63) "Least Cost Solutions for Ozone Attainment," *Proceedings of the Ozone Transport Assessment Group. May 8, 1997*

64) "An Application of the Regional Economic Model for Ozone Compliance for the Northeast," *Federal Advisory Committee Act. July 27, 1997.*

65) "Utility Capital Structure and Non-Utility Power Purchase Agreements," *Proceedings of the Cornell Utility Workshop*, August, 1992.

SELECTED TECHNICAL REPORTS AS PRINCIPAL INVESTIGATOR

1) "Comparative Market Design Analysis," Prepared for California Independent System Operator, April, 2002.

2) "Evaluation of US EPA SIP Call for NO_x Point sources," Prepared for US EPA, September, 1999.

3) "Environmental Analysis of Arizona Public Service Generating Assets," Prepared for Sempra Energy Resources, September, 1999.

4) "Economic and Air Quality Analysis of Episodic Controls to Reduce Ozone Concentrations in the State of Illinois," Prepared for Illinois department of Commerce and Community Affairs, October, 1998.

5) "Development of a Multivariate Ozone Response Surface," Prepared of Electric Power Research Institute, February, 1999.

6) "Least Cost Steps to Reduce Ozone in the Northeast Urban Corridor," Prepared for New York State Energy Research Development Authority, with Timothy Mount and S.T. Rao, November, 1998.

7) "Exploratory Analysis of Power Plant Retirements and Auctions," Prepared of US EPA, May 1998.

EXHIBIT GD-3 – CV OF GARY DORRIS

8) "Application of Option Models for Electricity," Prepared for The Energy Authority, July, 1997.

9) "Estimating Emission Weights for the Greater Chicago Metropolitan Area," Prepared for Illinois EPA, July 1997.

10) "Measuring Value at Risk," Prepared for the Energy Authority, August, 1997.

11) "Development of a Forward Price Curve for Electricity," Prepared for The Energy Authority, Jun 1997.

12) "Least Cost Solutions for Ozone Attainment in the Greater New York Metropolitan Area," Prepared for Niagara Mohawk Power Corp., with Timothy Mount and S.T. Rao, August, 1997.

13) "Capital Investment and risk of Private Sector Energy development in Egypt," Prepared for the Egyptian Electricity Authority by Arthur Anderson, August, 1996.

14) "Least Cost Strategies for Ozone Attainment," Prepared for New York Department of Environmental Conservation, with Timothy Mount, S.T. Rao, G. Sisla, P. Brandford, and Kurvila John, March, 1995.

PREFILED REBUTTAL TESTIMONY
OF WILLIAM T. RHOADS
ON BEHALF OF NORTHWESTERN ENERGY

Witness Information

Q. Please state your name and occupation.

A. My name is William T. Rhoads. I am the General Manager, Generation at NorthWestern Energy ("NorthWestern").

Q. Are you the same William Rhoads who submitted prefiled direct testimony and prefiled additional issues testimony in this docket?

A. Yes.

Purpose of Testimony

Q. What is the purpose of your rebuttal testimony in this proceeding?

A. The Montana Consumer Counsel ("MCC") raised a number of issues that I address in this testimony. I address claims made in the Direct Testimony of John Wilson ("Wilson Testimony"). Specifically, I will explain why the Commission should find that 1) NorthWestern's due diligence process and the budget assumptions used in its 20-year Discounted Cash Flow ("DCF") model are more than adequate and 2) Dr. Wilson's criticism of NorthWestern's due diligence and its budget assumption is inadequately supported to demonstrate problems with NorthWestern's review and analysis.

Overall Assessment of MCC Testimony

Q. What is your overall assessment of the MCC's testimony?

A. The MCC witnesses used faulty assumptions, drew conclusions on technical matters without having expertise or any indication of having used consulting expert advice, and chose to ignore the long-term benefits of hydropower. Overall, the witnesses' arguments challenging NorthWestern's Hydros purchase are faulty, without merit, and contrary to the MCC's previous positions in other proceedings as noted in the Prefiled Rebuttal Testimonies of Bob Rowe and John Hines.

Comments to Specific MCC Rebuttal

Q. Referring to NorthWestern's stochastic results, Dr. Wilson says on page 7, lines 4-7 that NorthWestern has not incorporated "risks or uncertainties for certain critical Hydros cost assumptions – such as very optimistic and comparatively low (but highly uncertain) long term repair, refurbishment, and rehabilitation costs for the aging

hydro plants." Do you agree that NorthWestern did not use the proper future repair and rehabilitation costs in its analysis?

A. No. Dr. Wilson's assertions are untrue and misleading. NorthWestern conducted a thorough and comprehensive due diligence process using internal technical personnel with years of experience with these specific hydro assets. NorthWestern's thorough due diligence was then supplemented by highly regarded hydro experts who understand costs associated with the long-term operation of hydro assets, who interviewed PPLM management personnel and conducted actual site visits to each of the hydro developments included in the transaction. NorthWestern's thorough due diligence process provided the basis for a realistic determination of future repair and rehabilitation costs.

NorthWestern considered the major capital expenditures incurred by PPLM from 2008 to 2012 in its analysis and projection of future costs. The high level of expenditures in this historic period will definitely impact future capital expenditures; lower costs will be incurred in the future because of these major rebuilding and repair costs incurred in the recent past. And NorthWestern's independent technical experts have further confirmed the low cost scenario over the next 20 years because of the significant historical expenditures.

Dr. Wilson asserts that PPLM's average cost of expenditures for the past five years is a more reliable forecast of future expenditures than NorthWestern's estimate. Dr. Wilson takes this position without supporting documentation, personal expertise, or supporting expert advice[1]; he had no discussions with PPLM personnel and did not conduct actual site visits. Dr. Wilson's reliance solely on the historical average cost as a basis for future cost is a very narrow and limited analysis that should be ignored in favor of NorthWestern's diligent and expert analysis.

NorthWestern's forecast includes provisions for long-term repair, refurbishment, and rehabilitation. Items such as generator rewinds and turbine replacements are included in the 20-year budget forecast. The majority of anticipated dam repairs are included in the Operation and Maintenance ("O&M") expense category due to the expected limited scope of the repairs. The budget adequately covers those costs needed to operate, maintain, upgrade, and relicense the hydro developments. The foundation of NorthWestern's 20-year forecasts for both capital expenditures ("CapEx") and O&M was fully encompassed in the CB&I Independent Engineer's Report attached as Exhibit__(WTR-2) to my prefiled direct testimony, and further details were provided in the Prefiled Direct Testimony of Joseph Stimatz (including Exhibit__(JMS-1), in

[1] Dr. Wilson's experience and expertise included at the beginning of his testimony (Wilson, p. 1-4) does not include a single reference to experience in operating and maintaining a Federal Energy Regulatory Commission ("FERC")-licensed hydroelectric plant so it is difficult for NorthWestern to understand the basis for his assertion.

numerous responses to data requests, and in the Additional Issues Testimonies of John VanDaveer ("VanDaveer Additional Issues Testimony"), Mary Gail Sullivan ("Sullivan Additional Issues Testimony"), Gary Wiseman ("Wiseman Additional Issues Testimony"), and Rick Miller ("Miller Additional Issues Testimony"). Additional information is provided in the Prefiled Rebuttal Testimonies of John VanDaveer ("Vandaveer Rebuttal Testimony"), Mary Gail Sullivan ("Sullivan Rebuttal Testimony"), Gary Wiseman ("Wiseman Rebuttal Testimony") and Rick Miller ("Miller Rebuttal Testimony").

The purpose of the CB&I Independent Engineer's analysis was to identify any material reason(s) why NorthWestern should not pursue an acquisition of the Hydros – including the possibility of exorbitant future CapEx. CB&I's in-depth review of the civil, electrical, mechanical, and environmental aspects of the projects demonstrated that there is no known material issue or item of such significant consideration so as to preclude the acquisition. Thus there was no reason why NorthWestern should not have made an offer to purchase the Hydros. Following from that conclusion, NorthWestern staff members, with their extensive institutional knowledge of the PPLM assets, developed a realistic, comprehensive 20-year CapEx investment plan that has been validated by two independent hydropower engineering firms.

In reference to NorthWestern's CapEx forecast (Wilson page 34, lines 4-5), Dr. Wilson said that, in his view, "...it is unreasonable, if not foolish, to assume that over the next thirty years there will be no costly repairs...." However, NorthWestern has, in fact, included funds for necessary refurbishment and repair in both the CapEx and the O&M budgets. What would have been "foolish" is if NorthWestern had attempted to ignore years of historical information and its own institutional knowledge associated with these assets and if it had conducted its due diligence without assistance from experts.

Q. Dr. Wilson claims that NorthWestern's underlying assumptions regarding the future Hydros' costs are quite modest and make the Hydros' costs appear as low as possible. (Wilson page 8, lines 13-14) Do you agree?

A. No, I do not agree. As described above, NorthWestern's CapEx and O&M forecasts reflect the expected necessary expenditures. The CapEx and O&M budgets contain funding levels that, when combined with reprioritization of approved budgets, will cover most unexpected items. These forecasts are based upon the condition of the assets. Neither of the forecasts attempts to inflate or deflate the expected costs for those items needed to keep the civil, electrical, mechanical, or environmental related items in good operating condition to extend the life of the assets beyond their depreciated accounting life. Dr. Wilson makes his assertions based on nothing more than a very simple paper exercise and an incorrect evaluation of past expenditures.

Q. Dr. Wilson states: "...both the magnitude and timing of possible long term *benefits* [emphasis added] are unknown..." (Wilson page 9, lines 9-10) Do you agree with this statement?

A. No, I strongly disagree with his statement. Again, the Hydros were evaluated by engineers and other individuals who have the legacy knowledge of operating and maintaining the system; site visits were conducted; FERC dam safety-related items and other O&M items were reviewed; and NorthWestern had not one but two independent consulting engineers review the materials and opine on topics including dam safety and CapEx. Both of the hydropower consulting engineers engaged by NorthWestern have extensive industry experience, and HDR Engineering, Inc. ("HDR") provided a confirming 20-year CapEx forecast based upon conditions known at this time with reasonable expectations forward.

Contrary to Dr. Wilson's statement, the benefits of hydropower are known. Hydropower is affordable, reliable, available, and sustainable. Linda Church Ciocci, Executive Director for the National Hydropower Association ("NHA"), said in a March 5, 2014 press release regarding the President's fiscal year 2015 budget request:

> *"Hydropower is the nation's most affordable and reliable renewable electricity resource and NHA applauds President Barack Obama's*

> *FY 2015 budget proposal for recognizing the crucial role that expanding hydropower will play in the country's diverse energy future.*
> *The budget continues and improves vital investments in water power research and development. We also applaud the president for his commitment to grow hydropower and other renewable energy generation by recognizing the need to provide long term financial certainty to developers through permanent tax incentives…."*

The benefits of the Hydros also include diversity resulting from generation spread across 40 generating units, 11 hydroelectric projects, and one storage reservoir in two major river basins on two different sides of the Continental Divide, and a transmission system that was built around these hydro projects allowing for the most efficient delivery of power to where the load exists while minimizing line losses. Both unit and geographic diversity of the Hydros contribute to unique benefits. In addition, the Hydros are immune to fossil fuel-fired generation regulation, volatility in natural gas prices, and future regulation of greenhouse gases.

Q. On page 13 at lines 1-3, Dr. Wilson states "actual and budgeted capital expenditures over the last ten years (2008-2017) averaged $35.6 million." He goes on to suggest that if an alternative buyer assumed that capital expenditures would be half of historical levels, the value would be over $300 million less than NorthWestern calculated. Do you agree with his statement?

A. No, I do not agree. PPLM invested in the upgrade of selected existing equipment to extend the life of the Hydros while accomplishing operational, economic, and reliability benefits. Dr. Wilson's analysis ignores the fact that the equipment PPLM has already replaced and has budgeted to replace in 2013-2017 either replaces original equipment or upgrades equipment that improves station reliability. The focus has been on the larger plants where the benefits regarding unit and plant reliability were more substantial than at the smaller plants. Plans to refurbish the smaller plants are included in NorthWestern's 20-year DCF model and revenue requirements forecast. NorthWestern and its technical advisors would expect an alternative buyer knowledgeable in hydro facilities to make the same assumptions it did with respect to such costs.

A sound 20-year forecast considers the historical operating performance of the portfolio, <u>plus</u> the investment completed over that time period. The historical CapEx provides the framework and puts the 20-year forecast into context, but it should not be used as a proxy for the future. Much like a homeowner investing in significant renovations over the past five or ten years, that past spending provides the context for expectations that spending over the next five or ten years will be lower.

Q. Dr. Wilson opines on page 13, lines 13 through 17 that he is "...very doubtful that a competitive merchant buyer would...assume that capital expenditures for repairs and renovation would be only 25

percent of historical levels..." Do you agree with Dr. Wilson's opinion?

A. No, I do not agree. Again, NorthWestern conducted a thorough due diligence process where previous CapEx and O&M costs were examined and budgets were developed to address future work. NorthWestern did more than just a "first order" analysis based upon past expenditures to develop CapEx and O&M budgets used in the DCF. In addition to the knowledge of NorthWestern's own internal hydro experts, the due diligence process included a review of compliance with FERC and environmental regulations, operating history, site visits, review by independent engineers, and interviews with PPLM management personnel.

In addition, refer to the due diligence reports included with my prefiled direct testimony as Exhibit__(WTR-2), the testimonies filed in this docket by John VanDaveer, Mary Gail Sullivan, Gary Wiseman, and Rick Miller, and NorthWestern's responses to voluminous discovery related to its due diligence process and the results. Expenditures for "repairs" as cited by Dr. Wilson include capital expenditures and expense-related funding which is already planned and budgeted – meaning these expenditures have already been accounted for appropriately in NorthWestern's analysis. Again, the historical level of CapEx helps put into context what the CapEx forecast should be, but it is not appropriate to judge the adequacy of the forecast based solely on a comparison of the two.

Dr. Wilson uses a simple and unsophisticated historic average expense to derive an arithmetic average as his basis to conclude that it would be "...very doubtful that a competitive merchant buyer would ...assume capital expenditures for repairs and renovation would be only 25 percent of historical levels..." A buyer, no matter whether that buyer was a merchant buyer or an investor-owned utility, would never use just an historic average expense to derive an historical arithmetic average as the basis of capital expenditure expected in the future. Instead, a buyer would complete a comprehensive due diligence analysis and project future expenses to understand the relationship of the current operations' physical, operational, and regulatory health to value a realistic supporting cost forecast, as NorthWestern has completed in this case.

Q. Dr. Wilson claims that the environmental benefits of the Hydros will be the same regardless of who owns the assets. (Wilson, page 21, lines 13-14) Dr. Wilson states: "Total hydro generation and total gas-fired generation will likely remain the same whether or not NWE purchases the Hydros, and there is likely to be very little change, if any, in environmental impacts whether NWE acquires the Hydros or

purchases generation from the market." (Wilson page 21, lines 17-21) Do you agree?

A. No, I do not agree. If NorthWestern acquires the Hydros, the amount of renewable generation in NorthWestern's supply portfolio will increase to 51%[2] and will result in more stable rates for NorthWestern customers. If NorthWestern does not acquire the Hydros, the next-best alternative is the construction of a natural gas-fired combined cycle power plant to meet NorthWestern's electric supply needs. This alternative would decrease the amount of renewables in NorthWestern's supply portfolio and increase the use of fossil fuel in Montana. NorthWestern's customers would be subject to increased risk of fossil fuel-fired generation regulation, volatility in natural gas prices, and possible regulation of greenhouse gases. NorthWestern's supply customers will be better served with the acquisition of the Hydros.

Unlike Dr. Wilson, employees of these facilities live in the Montana communities in which they work. Also unlike Dr. Wilson, NorthWestern already does business in the communities and along the 700 miles of river where these projects are located. NorthWestern and its current and future hydro employees are accountable to their neighbors; local, county, and state governments; and other stakeholders who have an interest in the operation of these hydro developments. NorthWestern's efforts in

[2] Based on 2016 loads.

environmental protection, mitigation, and enhancement will be strong since we also live in the environment in which we work.

Q. Dr. Wilson claims on page 22, lines 5-7 that NorthWestern's comparative cost analysis ignores potentially substantial costs that could add significantly to the Hydros' revenue requirement. He also claims on lines 13-17 that NorthWestern's assumption is that no further large expenditures for major repair, refurbishment, and restoration similar to the Rainbow Dam rehabilitation will be necessary. Do you agree?

A. No, I do not agree. As stated earlier, NorthWestern's 20-year CapEx forecast as provided in the response to Data Request PSC-018 and as discussed in the VanDaveer, Wiseman and Miller Additional Issues Testimonies as well as in the Wiseman and Miller Rebuttal Testimonies shows that future rehabilitation efforts will focus on plants where unit rewinds and turbine refurbishment can be completed on a unit basis. The testimonies also provide a plan for the timing of such events. The specific upgrade/rehabilitation one-time costs incurred recently by PPLM, for the Rainbow Development, for example, are not an indication of future costs. These costs are special projects which should be factored out of the financial model so there is no bias with respect to costs which are not expected to occur in the future, especially without including the benefit of increased generating capacity or efficiency improvements, as was seen with the Rainbow redevelopment expenditures.

NorthWestern will continue to evaluate opportunities for hydro capacity upgrades, but there are no plans to perform rehabilitations to the extent of Rainbow Redevelopment or Thompson Falls Unit #7. Rehabilitation can take place on a unit basis at each of the plants to maintain their longevity and efficiency, just as they are modeled into the CapEx plan. There is not sufficient remaining excess hydraulic capacity available to justify major upgrades similar to Rainbow Redevelopment. The plants on the system are near hydraulic design capacity. Therefore, the required benefit needed to justify undertaking major redevelopments does not exist. As a matter of prudence, NorthWestern will continue to monitor the benefits of upgrades and dam rehabilitations. As stated in the Prefiled Rebuttal Testimony of Brian Bird, future commissions will retain the ability to decide on the inclusion of future costs in rates based upon prudence review.

Q. Dr. Wilson claims that NorthWestern "...fails to recognize and account for certain substantial future hydro plant uncertainties, such as capital expenditure requirements..." (Wilson, page 23, lines 19-2) Do you agree?

A. No. First, the costs needed to operate and maintain the Hydros in the future (which include both CapEx and O&M expenditures) are at the proper level. However, NorthWestern performed a sensitivity analysis to determine the effect of higher CapEx. As noted in the Additional Issues Testimony of Joseph Stimatz on page 4, "Even if capital expenditures turn out to be 30% higher than NorthWestern's forecasts, the Current Plus Hydro portfolio would still be far superior to the other alternatives."

Q. On page 26, lines 10-11, Dr. Wilson asserts "...the significant and long term uncertainty regarding additional unknown future capital investment increases for project refurbishment and maintenance poses essentially zero risk for company stockholders." Do you agree that there is significant and long-term uncertainty regarding additional unknown future capital investment increases?

A. No, I do not. Contrary to Dr. Wilson's assertion, there is significant certainty regarding these investments. The civil structures are highly regulated by the FERC and meet all current requirements. Risks are managed through stringent dam safety requirements including annual dam safety inspections, required FERC Part 12 inspections every five years, and thorough, ongoing monitoring, surveillance, and reporting requirements. The FERC also focuses on proper utilization of the water resource. The FERC's expectation is that during the duration of the license these assets will be operated and maintained in accordance with the rigorous terms of the license.

Q. Dr. Wilson claims (Wilson page 29, lines 1-8) that a substantial portion of the $300 million in 2008-2012 capital expenditures relates to Rainbow and Hebgen and that no such major renovation or repair needs for *__any__* of the dams going forward over the next 30 years are forecasted. Dr. Wilson implies that NorthWestern's annual CapEx requirements do not include such renovation or repairs and will be only $8.5 million per year (escalated at 2.5 percent for inflation). Do you agree?

A. No, I do not agree. Dr. Wilson's statement is false. As described earlier in my testimony, NorthWestern's forecast was developed by removing the special projects costs for the historical one-time costs for Rainbow, Hebgen, and Thompson Falls, assessing historical capital investment on the remaining fleet, using the near-term forecast through 2017 to complete the major renovations, and projecting the subsequent (2018 forward) CapEx requirements. The basis for NorthWestern's forecast is sound and is described in more detail in the VanDaveer Rebuttal Testimony. Over the last ten years, PPLM's focus has been on renovation of the larger hydro developments where the benefits to sustain the asset would be greatest. Next, upgrades to the hydro system shifts from the completed renovation of the larger projects to individual unit upgrades including generator rewinds and turbine replacements.

Q. Dr. Wilson says that "... while capital expenditures of only $8.5 million per year may be required in years with those fortunate circumstances, it would be extremely good fortune. . . to achieve that result...in every year over the next three decades...". (Wilson page 29, lines 13-18) Do you agree?

A. No I do not agree. NorthWestern's forecast of average annual capital expenditures of $11.7 million (nominal dollars) over the 30-year capital period is ample and appropriate. Dr. Wilson again bases his conclusions on a limited analysis conducted on paper as opposed to NorthWestern's thorough due diligence. The sustainability of these projects is not based upon "good fortune" but has been through proper operation and maintenance and planning by competent craft, engineering, and management personnel. This situation will continue under NorthWestern's ownership.

Q. Dr. Wilson says on page 30, lines 2-8, "In the event that these dams, which are not going to get any younger as time goes on, continue to experience refurbishment costs in the future that are more in line with their past experience (and the probability that old facilities and equipment will require more, not less, refurbishment and replacement as they continue to age) the risk of incurring these additional costs will be the burden of Montana ratepayers (not NWE

stockholders) as the future unfolds." Is there a problem with Dr. Wilson's assumption?

A. Yes. Again, Dr. Wilson offers no documentation to support his assertion or professed expertise in hydro generation. His statement is speculation. It is possible that costs could be lower than predicted. He must rely on speculation to establish a basis for his continuous position that customers bear the risk of significant additional costs. However, Dr. Wilson fails to acknowledge the facts – the proven performance and overall low level of risk of these facilities, the value of the previous upgrade work performed by PPLM, geographic diversification, many units or "shafts," intense oversight by FERC, transmission adequacy, and relatively steady and predictable "fuel supply."

Q. On page 30, line 18 through page 31, line 9, Dr. Wilson comments on NorthWestern's independent engineer's statement (Gary Wiseman) regarding concrete conditions at Mystic that now appear to be only "fair to good" (but not requiring *immediate* remedial measures). Dr. Wilson cites this as an example showing that future capital expenditures and the need for future major capital projects cannot now be foreseen with any great certainty. Is this correct?

A. No. This and several other examples that Dr. Wilson cited from the due diligence report only signifies the independent nature of the CB&I report, the thoroughness of the report, and the work that was done to support it.

But his interpretation of this detailed information is wrong. Dr. Wilson obviously read the independent expert engineer's statement regarding the condition of the concrete at Mystic. However, if Dr. Wilson has come to the conclusion about that concrete that he indicates, he apparently does not possess the necessary background to correctly evaluate the information. Otherwise, he would have known that Mr. Wiseman was referring to surface condition of the concrete, not the structural condition. If there was a substantive dam safety concern, it would have been identified in the FERC Part 12 Independent Consultant's reports over the years and appropriately addressed by PPLM and included in their workplan forecast. Dr. Wilson's implication that simply due to the age of these dams, the required future maintenance for these dams is uncertain is quite frankly "foolish."

Costs for repairs such as these, if ever necessary, will be funded from the O&M budget, not the CapEx budget. And while an exact figure for repair costs is not known until the work is performed, the magnitude is likely less than $100,000.

Q. Dr. Wilson on page 31, lines 10-15, quotes from the independent engineer's report, *"Mystic flow line is exposed to the environment and is susceptible to rock falls"* and uses this as an example of

future unknown repair costs which may occur. What is your assessment of this selected example?

A. Again, Dr. Wilson does not provide any documentation or cite any experience to pass judgment about Mystic or the other examples he cites in his testimony.

The risk of a major rockfall is low. The original wooden flowline was replaced in the 1990s with a steel flowline which reduces the potential impact of a rockfall. In addition, rock and snow sheds are maintained to protect the flowline in the most susceptible areas.

Q. On page 31, line 16 through page 32, line 4, Dr. Wilson cites an example from the CB&I report contained in Exhibit__(WTR-2.1) related to the Black Eagle leakage and the possible need for a buttress to support the argument throughout his testimony that NorthWestern's CapEx forecast in the DCF model is too low. What is your conclusion about the example he has chosen to use?

A. Again, Dr. Wilson does not know how budgets are managed related to these resources. The independent engineer, CB&I, is correct that this item is not in the post-2017 CapEx budget because the leakage is monitored and managed as an O&M expense. A buttress would be a nominal capital cost which, if needed, would be adequately covered in the CapEx budget.

Dr. Wilson's assertion that NorthWestern's CapEx forecast is too low in future years cannot be substantiated in any case, and especially not with examples such as those cited. He has not developed a credible basis for a forecast budget greater than the forecast budget that was developed by NorthWestern's analyses. This issue is fully addressed in the VanDaveer Rebuttal Testimony.

Q. On pages 32-33, Dr. Wilson discusses potential groundwater contamination caused by the Anaconda Mining Company operations adjacent to Black Eagle Dam, potential future Superfund Site costs at Thompson Falls, and the potential for Arctic grayling listing as under the Endangered Species Act and cites NorthWestern's independent engineer's statement: "Unforeseen events are possible in a given future year, but not expected every year. (See MCC-181)" What is your assessment of Dr. Wilson's apparent conclusion that an allowance should have been made for these costs?

A. The Sullivan Rebuttal Testimony specifically addresses the limited potential risk of each of these areas. These potential issues were identified, thoroughly examined, and their future potential impacts to the Hydros are not material and/or cannot be defined at this time.

Q. In response to a question on page 33, Dr. Wilson discusses Potential Failure Modes ("PFMs"), states, "they generally mean that a potential

problem is indicated," (page 33, lines 14-15), and opines about costly repairs in the future. (Wilson, page 33, line 5 – page 34, line 9) What is your assessment of Dr. Wilson's discussion on pages 33-34?

A. My assessment is that Dr. Wilson's observations support NorthWestern's acquisition of the Hydros because his statements on page 33, lines 12-20 demonstrate that the Hydros are well maintained and well managed through FERC regulation, oversight, and adherence to FERC's PFM process. This not only helps to protect the public, but also reduces risk to NorthWestern's customers and shareholders. The simple identification of PFMs does not automatically translate into future higher costs, and NorthWestern has CapEx and O&M budgets in place which will provide sufficient funds to maintain the reliability of these projects.

Q. Dr. Wilson states on page 34, lines 2-4 that NorthWestern observes "in response to numerous data requests, in many or most cases potential ultimate cost exposure cannot be accurately known years in advance." What is your assessment of Dr. Wilson's statement on page 34?

A. I have cited numerous times the components of the extensive due diligence effort conducted by NorthWestern and why the budget derived by NorthWestern is sound. The foundation of the cost estimates was developed and reviewed by professionals with years of hydro-related experience. Again, Dr. Wilson's assertions are unfounded. As already discussed, the due diligence analyses completed by NorthWestern and our consultants are thorough and sound; the purchase of the Hydros is in the public interest. Dr. Wilson's criticism of NorthWestern's due diligence and its budget assumption is inadequately supported to demonstrate problems with NorthWestern's review and analysis.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

Department of Public Service Regulation
Montana Public Service Commission
Docket No. D2013.12.85
PPLM Hydro Assets Purchase
NorthWestern Energy

PREFILED REBUTTAL TESTIMONY OF

JOHN C. VANDAVEER

ON BEHALF OF NORTHWESTERN ENERGY

Witness Information

Q. Please state your name and business address.

A. My name is John C. VanDaveer. My business address is 40 East Broadway, Butte, Montana.

Q. Are you the same John VanDaveer who submitted prefiled additional issues testimony in this docket?

A. Yes, I am.

Purpose of Testimony

Q. What is the purpose of your testimony?

A. My testimony responds to the speculative comments presented in the Direct Testimony of John Wilson ("Wilson Direct Testimony") on behalf of the Montana Consumer Counsel regarding NorthWestern's capital expenditure ("CapEx") forecasts that support the hydroelectric system over the next 20 years.

NorthWestern's CapEx Forecast

Q. Are the concerns identified by Dr. Wilson regarding the inadequacy of the NorthWestern CapEx forecast realistic?

A. No. Dr. Wilson is concerned that NorthWestern's CapEx forecast is inadequate to support future operation of the hydroelectric system. He bases his concern on the age of the facilities, past large investments in the system, and assumed regulatory uncertainty. His concern is the result of a document review and generalized assumptions without any citation or evidence of direct experience in such matters. This is compared to NorthWestern's comprehensive due diligence process which was further confirmed by a subsequent independent engineering firm – HDR Engineering, Inc. ("HDR").

Q. Is NorthWestern's forecast of future CapEx adequate to support continued reliable performance of the hydroelectric system?

A. Yes. NorthWestern developed its CapEx forecast through a comprehensive due diligence process. NorthWestern evaluated the current status of the actual known regulatory, operational aspects and physical condition of the system to develop a comprehensive cost forecast. The due diligence effort has been described in detail in numerous testimonies submitted by NorthWestern and in its responses to voluminous discovery on this matter in this docket. I provide further support of the CapEx forecast in this testimony.

Q. Has the adequacy of NorthWestern's CapEx forecast been confirmed by other entities?

A. Yes. Two highly qualified independent consulting firms verified the competency of the NorthWestern due diligence team's complete evaluation and resulting cost forecasts. CB&I performed due diligence in parallel with NorthWestern's due diligence work. HDR reviewed NorthWestern's and CB&I's due diligence efforts and developed an independent CapEx forecast. Each of the consulting firm's teams confirmed the adequacy of NorthWestern's conclusions regarding future CapEx projections. The Prefiled Rebuttal Testimonies of Gary Wiseman of CB&I and Rick Miller of HDR discuss their respective work and conclusions.

Q. Why is NorthWestern's CapEx forecast adequate to support the continued reliable performance of the hydroelectric system?

A. NorthWestern's due diligence work supports the adequacy of the CapEx forecast. Dr. Wilson implies that the system's age drives the need for significant future investment and provides no other evidence to support his assertion that component age is the sole decision criteria. Simply because assets, in this case the hydroelectric developments, are mature does not mean it will be expensive to maintain them in order to provide continued reliable and efficient operation.

The actual age of the majority of the generating units on the system is not as great as the chronological age of the developments themselves suggest. The table below defines the actual age of a majority of the system's turbine and generator units:

Unit	**Plant Capacity**	**Component "Age" Less Than 20 Years**
Rainbow Unit No.9	60 MW*	Commissioned in 2013
Thompson Falls Unit No.7	54 MW*	Commissioned in 1995
Thompson Falls Units 1-6	40 MW	All generators rewound 1979-82
Thompson Falls Units 1&3		New Turbines installed 2000-01*
Cochrane (2 Units)	69 MW*	Generators rewound 2004-05 Cochrane development commissioned in 1958
Morony (2 Units)	48 MW	Unit 1 turbine and generator upgrade 2013-14* Unit 2 rewound 1983
Mystic (2 Units)	12 MW*	Generators rewound 2009-10 New turbines installed 2007-08
Ryan (5 Units)	60 MW	Units 2&4 rewound 2009-10* Units 2, 4, and 5 new turbines 2011-2013

A majority of the system's generation capacity is less than 20 years old. Rainbow Unit 9 and Thompson Falls Unit 7 represent 114 MW that are new units and powerhouses, and the asterisked units have had both a turbine and generator upgrade investment that total 252 MW that are all less than 20 years old. Additional partial unit upgrades that have been accomplished on the above developments are not included in this total but are identified in the Hydro Unit Upgrade Summary provided as Exhibit__(WTR-9) to the Prefiled Direct Testimony of William Rhoads ("Rhoads Direct Testimony"). The total capacity of the listed developments is 343 MW of the 439 MW, which is more than 75% of the total system capacity excluding Kerr. This major strategic group of units is well positioned to operate reliably and efficiently far beyond the 20-year forecast valuation period.

Q. What about the developments not listed above?

A. The remaining developments are scheduled for investment and are specifically included in the 20-year CapEx forecast. These plants include Madison (4 units-8 MW), Hauser (6 units-19 MW), Black Eagle (3 units-21 MW), and Holter 4 units-48 MW).

The generation units' historical capital investments have been strategically planned and implemented to ensure continued effective operation of the major system developments, and the future CapEx forecast addresses the balance of the units.

Q. You have explained the recent and significant investments made or planned that support the continued reliable and efficient operations of the prime movers of the system. What has been or is being done regarding the balance of the hydroelectric system?

A. A parallel strategy that covers the material balance of the hydroelectric system associated with the units has already been implemented. This scope of investment includes the governor, excitation, relays, and controls at the developments. The Hydro Unit Upgrade Summary clearly describes this scope. I will not repeat that description here. Again, the limited scope of the balance of plant remaining to be upgraded is specifically addressed in the 5-year capital plan and the remainder in the 20-year forecast.

Q. Is it realistic to expect a major expenditure of the magnitude of the Rainbow Unit No.9 project during the next 20-year period as suggested by Dr. Wilson?

A. No. Dr. Wilson focuses on the cost of the new Rainbow Unit No. 9 and assumes that expenditures of this magnitude can be expected elsewhere on the system in the future. This is incorrect. Two fundamental considerations led to the decision to build the new Rainbow generation plant. First, the original generation units were built in 1910 to meet the service needed at the time; they were not sized to utilize the full hydraulic capacity of the annual available flow. PPL Montana, LLC had the choice to rehabilitate the existing eight units for the same or slightly better performance or to construct a larger modern facility that eliminated the need to rehabilitate the existing plant and gain the added capacity from full utilization of the available project flow. Second, associated economic benefit to the downstream Cochrane project was attainable from the construction of the new powerhouse at Rainbow. The Cochrane project could now be operated at its licensed full reservoir elevation. The elevation of the retired powerhouse at Rainbow restricted this ability. The operational and economic decision was to construct the new project.

The Thompson Falls Unit No. 7 50-MW addition in 1995 was similar in context to the Rainbow project. Unit No. 7 was an addition to the existing Thompson Falls development and was designed to optimize the available flow at the development for generation. The existing generation machines and powerhouse were, and still are, in good condition and do not require replacement.

These two projects were unique because additional hydraulic capacity was available for energy production. The remaining developments do not have material unused hydraulic capacity like Rainbow or Thompson Falls. Therefore, it is not realistic to expect investment of the magnitude of the Rainbow redevelopment in the future. Additionally, the historical investment at the other developments would not have occurred at the magnitude that it did if there was unused hydraulic capacity available similar to Rainbow or Thompson Falls.

Finally, all of these hydroelectric developments operate in a clean air and water environment and operate at low speeds of 300 revolutions per minute or less. This is an operational regime that is conducive to long equipment life. Further, the unit modernizations include current generator winding technology and stainless steel runner fabrication that provides even longer life than the original components that have stood the test of time.

FERC Dam Safety and Cost Exposure

Q. Is the cost exposure suggested by Dr. Wilson in his reference to structural condition regarding the Federal Energy Regulatory Commission ("FERC") Potential Failure Mode ("PFM") dam safety process realistic considering the regulatory environment governing the hydroelectric system?

A. No. The regulatory process is mature and provides a level of certainty regarding the hydroelectric system specifically regarding structural competency confirmed by NorthWestern's due diligence work. Again, Dr. Wilson's unfounded assumption is that because some of the dams and associated structures are old, they are at high risk of requiring significant cost remediation. The opposite is actually the case. FERC dam safety regulations and the agency's history with and knowledge of this system support NorthWestern's conclusion regarding the appropriate level of future costs.

The FERC's fundamental regulatory purpose is to ensure hydroelectric development structural and operational integrity for public and project safety. The level and type of regulation is, therefore, maintained at an intensity to achieve this objective.

This hydroelectric system has been under FERC dam safety regulation since the Federal Power Act established the dam safety program in 1965. These developments have been inspected, analyzed, and evaluated for project adequacy for 50 years by the FERC, the licensee, and the FERC-required independent consultants. The FERC regulations established structural evaluation engineering criteria for various load cases that projects are required to meet. The current engineering requirements are aggressive and exceed original design criteria used for many projects that were constructed prior to the implementation of FERC regulations. It is important to understand current regulatory structural evaluation requirements to assess future cost risk.

The seismic (earthquake) and probable maximum flood ("PMF") load criteria determinations are consistent with the FERC engineering guidelines. These extreme analyses cases have traditionally been developed by the independent consulting engineering firm required by the FERC to perform project analyses for licensees. These analysis cases are generally based on available site-specific information and then

maximized using current technology to represent a **potential extreme or worst** case event that has very limited probability of occurring. The structural analysis of FERC-regulated projects utilizes this type of applied load development in addition to normal load operating condition. Additionally, the structural evaluation cases are also required to meet load case factors of safety ("FS") under the worst case scenarios. These scenarios include the PMF load and earthquake analysis cases. The probable maximum theoretical flood case must meet a safety factor of 1.3 times the maximum flood magnitude. The earthquake analysis case is required to be structurally adequate for acceptable structure stresses after a theoretical earthquake event. In addition to the worst case scenarios, the normal operating conditions at the developments must be adequate for three times the normal operating load conditions.

The majority of project regulatory work on the system during the 1970s and 1980s focused on installations that improved the stability of project structures. The predominant technology for dam stabilization enhancement was the installation of post-tensioned anchors. The specific load cases that required additional support were the seismic (earthquake) and PMF load cases described above. That is why a number of the "older" projects have post-tensioned anchors installed in various dam sections.

Q. Why is the stability analysis context relevant to the future CapEx forecast?

A. There are a number of reasons why the above information is relevant to the concerns questioning the condition and risk of the system:

- The physical stabilization that has been implemented on the system was required to meet the FERC dam safety requirements for the extreme theoretical loading conditions plus an additional factor of safety.
- During all of the actual post-tensioned anchor installations at the dams, significant site information was determined that included concrete strengths and foundation rock conditions. Actual concrete tests result in compressive strengths comparable to concrete made today. Concrete exterior surfaces show signs of minor deterioration, but the body of the structures is sound; and
- Actual foundation conditions provide site-specific project information that has been used to substantiate the adequacy of current project stability even as theoretical load development evolves from modern technological advancements.

The then-current licensee, the Montana Power Company ("MPC"), implemented a program in 1988 to provide additional site-specific condition strengths for structural stability adequacy for the Great Falls projects. This program was designed and executed to understand the condition and strength of the concrete-foundation rock interface of project structures and measure actual hydraulic uplift foundation loading at projects under load conditions other than normal load. MPC had two objectives for this project. One was to provide an added level of conservatism to the adequacy of developments in the Great Falls area to meet the FERC dam safety requirements. The second was to provide FERC an additional level of site-specific information to further support structure competency of the Great Falls developments for theoretical load case stability. Both objectives were met. Foundation strength at the dam and rock interface was demonstrated and actual hydraulic uplift was established and is still used to analyze and confirm stability of structures.

The following example illustrates the conservative flood load case structural evaluation required by the FERC for the Great Falls projects:

The highest flow on record of 140,000 cubic feet per second ("cfs") occurred in 1908 prior to the construction of and regulation provided by the upstream U.S. Bureau of Reclamation Canyon Ferry Hydroelectric Development. Subsequently, the highest flow recorded was 72,000 cfs that occurred in 1964. This actual flood flow of 72,000 cfs has been maximized to a magnitude of 298,000 cfs or 4.1 times greater than the 1964 actual amount. This flood flow has been developed by the independent consultant that the FERC approves to conduct the analyses as part of the Independent Consultant Part 12 Report for the licensee. Add the required factor of 1.3 to this flood magnitude and the result is that the Great Falls developments need to be structurally adequate for a worst case flood event that is 5.3 times greater than the highest applicable flow on record.

The Great Falls projects are adequate for this "worst case" loading condition. The Cochrane development latest FERC Part 12 Inspection analysis suggests that it does not analytically meet this stringent criteria using conservative site information. It has not been a concern because the FERC has not recommended additional stabilization for over 20-plus years.

The discussion above puts into context the FERC Potential Failure Mode Analysis process and the "risk" of the specific modes considered at the developments.

<u>The majority of the Potential Failure Modes identified and included in the developments' FERC dam safety independent consultant inspection reports are related to the probable maximum flood load condition.</u> The potential that an occurrence would actually develop is unrealistic in the context of the explanation provided above. The cost to the project owner and its customers to remedy such conservative theoretical situations is not justifiable. Dr. Wilson's conclusion that "in my view it is unreasonable, if not foolish, to assume that over the next thirty years there will be no costly repairs......in order to maintain and continue efficient operation of these aging 'high hazard' dams, many of which will be well over 100 years old during this projected time frame" is unfounded, unreasonable, and unsubstantiated.

It does not make sense structurally or from a business perspective to spend money and resources to reduce risk of a condition that is not going to occur. Therefore, the FERC has implemented the Potential Failure Mode Analysis ("PFMA") risk-based, proactive process. This direction began in the mid-2000s and is focused on project component awareness under various situations and a high level of monitoring and identification of proactive actions, if necessary. This process includes licensees, independent consulting engineering firms, and FERC personnel. A detailed summary of the FERC PFMA process is included in the Prefiled Additional Issues Testimony submitted by Rick Miller of HDR.

Q. What are your conclusions regarding the results of the FERC dam safety process?

A. FERC's confidence in the hydro assets' current condition and operation is evidenced by the fact that FERC has recently relicensed the nine developments under the 2188 license, including Cochrane, for a second 40-year term.

This FERC dam safety Part 12 Independent Consultant structural evaluation process with the annual operational inspection, emergency action plan program, and licensee-FERC working relationship results in regulatory stability, low exposure to major issues, and associated low risk of incurring significant related costs. This is confirmed by past and current Part 12 Independent Consulting Engineer's Reports and Annual Inspection Reports provided in Exhibits (WTR-5) and (WTR-6) to the Rhoads Direct Testimony.

The years of system knowledge and regulation gained by the licensee and the FERC have provided a thorough, practical, and physical knowledge of the developments resulting in substantial regulatory assurance and low cost risk exposure. Because of this, NorthWestern's CapEx forecast is not improper or "foolish" as suggested by Dr. Wilson.

<u>Other Factors that Support CapEx</u>

Q. Are there other factors that add to the credibility of the NorthWestern cost forecast?

A. Yes. First, the organization responsible for managing and operating the hydroelectric system ("Hydro Organization") is key to the reliable and efficient operation of the system including cost management. The Hydro Organization's maturity adds a critical component to understanding the system's future operational and cost stability. In my experience, the Hydro Organization has traditionally experienced very low employee turnover. Attrition is generally through retirement, succession has been implemented effectively, and institutional knowledge is responsibly transferred. The value to the hydroelectric system is that the employees are very knowledgeable about the Hydros' condition, operating characteristics, and influences that could affect their operation. Additionally, this extensive working knowledge strategically directs the most efficient investment and maintenance plans for operational efficiency, condition sustainability, and realistic regulatory outcomes. This organizational influence is confirmed by the actual system upgrade investment work described herein and the regulatory adequacy fully defined in the current FERC Part 12 Independent Consultant Inspection reports and Annual Operational Inspection reports.

The Hydro Organization focuses on proactive management of the system. The newer units on the system, Thompson Falls and Rainbow, have installed condition monitoring systems. Unit vibration and temperature monitoring are being installed throughout the system as described in the five-year plan. The Hydro Organization's employees are dedicated to predictive maintenance management and generation machine condition monitoring for proactive care of the system. This aspect of the operation specifically targets proactive management to avoid unanticipated cost and unplanned outage risk.

Second, the annual Operations and Maintenance ("O&M") expense forecast further supports the adequacy of the level of capital expenditures of $8.5 million in 2018 and escalated at 2.5% annually. The analysis of O&M expense developed through the due diligence process defines an approximate annual level of internal labor of $8.2 million and an amount of $3 million for special expense projects. A portion of basic employee labor amount of $8.2 million is directed to the maintenance of the facilities. Special expense is defined for use at projects that do not meet capital criteria and is available for work designed to proactively improve the performance of the developments. The CapEx forecast is supported by this reasonable level of O&M.

Conclusion

Q. What is your overall conclusion regarding the Wilson Direct Testimony?

A. Dr. Wilson's assertion that NorthWestern's forecast CapEx is inadequate to support future operation of the hydroelectric system is unfounded and incorrect. Dam safety regulatory risk is low. Significant major expenditures, similar to Rainbow Unit 9, are not justified. Future cost support for the operation will be directed to completing strategic plans through 2017 and including the incremental upgrades of units that have not been addressed substantially to date. The average annual capital budget forecast of $8.5 million starting in 2018 and escalated at 2.5% annually is adequate to complete the major equipment and support system strategies. The forecast will also sustain general capital investments defined by annual workplans. The CapEx forecast is supported by the reasonable O&M forecast.

NorthWestern's CapEx forecast is adequate to support the continued safe and reliable operation of the Hydros. The NorthWestern due diligence team's full and detailed work supports this conclusion as compared to Dr. Wilson's face value determination based on generalizations and assumptions for cost forecasts.

Q. Does this conclude your testimony?

A. Yes, it does.

PREFILED REBUTTAL TESTIMONY OF

MARY GAIL SULLIVAN

ON BEHALF OF NORTHWESTERN ENERGY

Witness Information

Q. Please state your name and business address.

A. My name is Mary Gail Sullivan. My business address is 40 East Broadway, Butte, Montana.

Q. Are you the same Mary Gail Sullivan who submitted prefiled additional issues testimony in this docket?

A. Yes.

Purpose of Testimony

Q. What is purpose of your testimony?

A. The purpose of my testimony is to address capital expenditures ("CapEx") related to certain environmental topics raised in the Direct Testimony of John Wilson on behalf of the Montana Consumer Counsel ("MCC"). Specifically, I rebut Dr. Wilson's assertions regarding environmental issues at Black Eagle, sedimentation at Thompson Falls, shoreline erosion litigation, and potential endangered species listing of the Arctic grayling.

Black Eagle

Q. At page 32, Dr. Wilson asserts that NorthWestern was remiss in not including, or not including enough, costs associated with the final boundary definition of the Anaconda Copper Mining ("ACM") and Refinery Superfund site in its CapEx forecast. Do you agree with this assertion?

A. No. As Dr. Wilson acknowledges, NorthWestern included a one-time allowance of $375,000 in 2025 for costs at Black Eagle that might be associated with the ACM Smelter and Refinery Superfund site. This amount is included in the financial models as Operations and Maintenance ("O&M") in the approximate year it is expected to occur. Therefore, it is not necessary to also include costs for this item in the CapEx forecast.

As to the sufficiency of the amount, $375,000 is NorthWestern's best estimate, which it has no reason to change. The cost for remediation of the Milltown Dam Superfund site was used as a point of reference to estimate a base case and a high case considering the probability that the owner/operator of Black Eagle would be liable for remediation and, if so, the amount the owner might be allocated. The table below shows NorthWestern's calculations. Nominal percentages were used (as a reflection of risk) because if NorthWestern, as the owner/operator of Black Eagle, is named a potentially responsible party ("PRP") at the ACM Smelter and Refinery Superfund site, the majority of costs to address the contaminated sediments would be the obligation of the party that caused the contamination and not the obligation of NorthWestern. In addition, as is stated in response to Data Request MCC-067, if NorthWestern were named as a PRP, it would have a strong case to shift the costs to the companies that owned and operated the facility from which the pollutants were released and insurance may be available for any remaining costs for which NorthWestern is responsible.

Black Eagle is downstream from the former ACM facility; past mining activities at the ACM site are responsible for hazardous substances at the site; and there is no evidence establishing that Black Eagle operations aggravate the contamination. Therefore, while NorthWestern included costs for this item in its O&M forecast based on its assessment of the risk, the geographic location of Black Eagle as well as the type of hazardous substances released from the smelter activities form a reasonable basis for apportioning all Superfund liability to ACM and its successors.

Estimate of Costs Associated with Superfund at Black Eagle				
Milltown Reference	Probability of being named a PRP	Contribution Percentage	Contribution	
$100,000,000	0.3	0.050	$1,500,000	High Case
$100,000,000	0.15	0.025	$375,000	Base Case

Q. Is this the same reason potential groundwater contamination at Black Eagle, referenced in Dr. Wilson's testimony on page 32, was not included in the CapEx forecast?

A. No. Dr. Wilson's statement about potential groundwater contamination at Black Eagle refers to NorthWestern's response to Data Request MCC-179, which pertains to a petroleum sheen observed when a hole was drilled at the substation downstream of the dam. In a letter dated February 12, 2013, the Montana Department of Environmental Quality stated that the sheen was noted on surface water (not groundwater) and that the "petroleum contamination appears stable and does not pose a risk to the public or the environment." It also stated that the source was likely the former ACM plant site and that petroleum contamination would be determined by the ACM Superfund remedial investigation. No further action was required of PPL Montana, LLC ("PPLM"). Therefore, NorthWestern did not include costs in the CapEx forecast or the O&M forecast for this item.

Thompson Falls

Q. On page 32 of his testimony, Dr. Wilson also asserts that NorthWestern was remiss in not including costs to address contamination at Thompson Falls in the CapEx forecast. Do you agree?

A. No. Dr. Wilson is referring to contaminated sediments that flowed into Thompson Falls reservoir when Milltown Dam was breached as part of the U.S. Environmental Protection Agency's ("EPA") remediation/restoration plan to clean up the Milltown Reservoir Sediments/Clark Fork River Superfund Site ("Milltown Site"). The Milltown Site, which is some 130 miles upstream of Thompson Falls, was included on the Superfund National Priorities List under the federal Superfund statute because sediments in the reservoir had been contaminated from many years of upstream hard rock mining, milling, and smelting operations. In 2004, the EPA issued a Record of Decision for the removal of Milltown Dam. In a consent decree for the Milltown Site, both the federal government and the State of Montana provided a covenant not to sue for natural resource damages associated with the migration of contaminated sediments from Milltown to Thompson Falls and beyond. In 2008, the Milltown Dam was breached for removal.

Monitoring by PPLM in 2008 showed an increase in heavy metal concentrations at Thompson Falls with the source being the Milltown remediation project. Since then, PPLM monitoring has shown no increase in reservoir sediment contaminant levels, and, as a result, PPLM believes that there is no further concern regarding sediment contamination resulting from the Milltown remedial action. NorthWestern made an allowance in the O&M forecast of $187,500/year from 2021-2030 for monitoring of reservoir sediments at Thompson Falls. The levelized amount and timing were a best estimate by the NorthWestern environmental team during NorthWestern's early due diligence and remained unchanged in later due diligence. No additional costs are necessary in the CapEx forecast for this matter.

Shoreline Erosion Litigation

Q. On that same page of his testimony, page 32, Dr. Wilson asserts that NorthWestern was remiss in not including costs for shoreline erosion litigation in the CapEx forecast. Do you agree with this assertion?

A. No. Dr. Wilson did not identify the shoreline erosion litigation to which he was referring. However, if he was referring to the shoreline erosion litigation at Kerr, this situation was addressed in the terms of the Purchase and Sale Agreement ("PSA"). The PSA provides that PPLM will be responsible for all pre-Closing damages, which NorthWestern expects to constitute the majority of any possible damages. If NorthWestern were to be liable for any possible damages, those damages would not be a capital expense but would be covered in O&M.

The only other potential shoreline erosion litigation of which I know is the alleged erosion on Lake Helena. NorthWestern evaluated the allegations as having limited merit, and the alleged damages were less than $50,000.

For these two reasons, no allowance was made in either the CapEx or O&M forecasts to address this shoreline erosion litigation (this explanation is also addressed in the response to Data Request PSC-031).

Arctic Grayling

Q. Dr. Wilson asserts on page 32 that NorthWestern was remiss in not including costs for potential Endangered Species Act ("ESA") exposure related to migration of Arctic grayling in the CapEx forecast. Do you agree with this assertion?

A. No. This matter was also addressed in my prefiled additional issues testimony. NorthWestern's O&M forecast includes the cost of fishery studies and protection, mitigation and enhancement measures ("PM&E") required by the Federal Energy Regulatory Commission ("FERC") license. To the extent the studies and PM&E address Arctic grayling, those costs are included in the O&M forecast. Beyond this, it would be extremely premature and speculative to presume what a recovery plan might entail and/or what the costs might be if the Arctic grayling is listed under the ESA.

Q. Why would it be premature to presume what a recovery plan might entail or what the costs might be?

A. Listing a species under the ESA and implementing a recovery plan is a lengthy and complex process. The U.S. Fish and Wildlife Service

("USFWS") published a notice in the Federal Register in November 2013 that it was initiating a status review of the Arctic grayling in the Upper Missouri River Basin. The notice indicated that either a proposed rule to list or a not-warranted finding would be published in the Federal Register by September 2014. After publication, the public will have 60 days to comment. If the proposed rule is to list, no more than a year after the comment deadline, the USFWS must publish a final rule on the listing, and within another year, it must designate critical habitat for the Arctic grayling. If a decision is made to list the Arctic grayling as threatened or endangered, the species would receive legal protection from adverse effects of qualifying federal activities.

To this end, and based on the sequence of events that transpired when PPLM worked through the bull trout ESA listing at Thompson Falls, NorthWestern, as the licensee, would request to be FERC's designee to prepare a Biological Evaluation of effects based on necessary multi-seasonal studies and submit the Biological Evaluation to FERC and USFWS. NorthWestern (on FERC's behalf) would then complete a Biological Assessment, from which USFWS would conduct its own analysis to determine if there are gaps in the information necessary to determine a project's effects.

This process, which includes formal consultation with numerous resources agencies, additional studies to fill in data gaps, and scientific peer review of results, could take several years. It culminates in a USFWS Biological Opinion, which would include reasonable alternative actions required of FERC, as regulator, and NorthWestern, as licensee, to mitigate adverse impacts. All of these steps would take time.

As a point of reference for the timeline, the process for the Columbia River bull trout took 12 years. The Columbia River population of bull trout, which includes Thompson Falls, was listed as a threatened species under the ESA in 1998. It was not until 2010 that PPLM completed construction of the fish ladder on Thompson Falls that was appropriate for this particular site and resolution. This example serves to illustrate that the timeline for studies of Arctic grayling in the Upper Missouri River Basin and mitigation measures that might be required are simply unknown.

Q. Why would it be speculative to presume what a recovery plan might entail or what the costs might be?

A. As I just described, if the Arctic grayling is listed, numerous studies over multiple seasons involving multiple stakeholder groups must be completed before impacts would be known and a recovery plan defined to address impacts. It would be pure conjecture to presume what the recovery plan would be, when it might be implemented, or what it might cost.

Q. Is this why NorthWestern did not include the cost of fish migration in the CapEx forecast?

A. Yes and because if a listing is made under the ESA and an Arctic grayling recovery plan were to include a fish ladder at Madison (that is if one were warranted from a scientific or management perspective), the cost could likely be managed in the normal course of business. During due diligence, NorthWestern considered the possible installation of a fish ladder for upstream passage of Arctic grayling at the Madison Development. NorthWestern compared a possible fish ladder at Madison to PPLM's experience at Thompson Falls. PPLM's 2008-2012 CapEx shows approximately $8 million was spent over three years on the fish ladder at Thompson Falls. However, because of the much smaller configuration of the Madison Dam, its low hydraulic head, long apron, and proximity to solid substrate (which was a problem at Thompson Falls), it would be much less expensive, perhaps a fraction of the cost, to install a fish ladder at Madison Dam than it was at Thompson Falls.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

PREFILED REBUTTAL TESTIMONY OF

GARY T. WISEMAN

ON BEHALF OF NORTHWESTERN ENERGY

Witness Information

Q. What is your name and occupation?

A. My name is Gary T. Wiseman. My business address is 9201 E. Dry Creek Road, Centennial, Colorado. I am Project Manager in Generation Services - Power for CB&I.

Q. Are you the same Gary Wiseman who submitted prefiled additional issues testimony in this docket?

A. Yes.

Purpose of Testimony

Q. What is the purpose of your rebuttal testimony?

A. I am testifying, on behalf of NorthWestern Energy ("NorthWestern"), in rebuttal to the Direct Testimony of John Wilson, filed in this docket on behalf of the Montana Consumer Counsel ("MCC"). Dr. Wilson questions the level of capital expenditures ("CapEx") planned over the 20-year study period of the discounted cash flow analysis. My testimony addresses forecast capital expenditures.

Q. What is the basis of your testimony?

A. The basis of my testimony is my personal involvement as Project Manager responsible for CB&I's due diligence effort to assist in the evaluation of NorthWestern's acquisition of the hydro assets ("Hydros") from PPL Montana, LLC ("PPLM"). This effort has been ongoing since the fall of 2012. I have been directly involved in the due diligence process, including review of materials contained in the PPLM data room, information in the public domain, personal discussions with PPL Corporation and PPLM management personnel, and site visits. CB&I's due diligence effort paralleled that of NorthWestern's, but was independent. CB&I's due diligence effort focused on the condition of Hydros, CapEx and Operation and Maintenance ("O&M") costs, license compliance, and environmental aspects.

Q. What is your assessment of Dr. Wilson's testimony regarding forecast of capital expenditures?

A. Dr. Wilson provides generalized observations about capital expenditure requirements. He gives limited consideration to the actual status and program plan for the structures, equipment, and facilities of the hydro system. NorthWestern conducted its due diligence effort to fully identify, review, and consider the entire range of material aspects related to the hydro acquisition. Due diligence reporting by NorthWestern was detailed, it documented numerous items, and it demonstrated the rigorous and focused effort. Dr. Wilson interpreted all or most items mentioned in the reporting as material issues that will require substantial CapEx in the future. He is wrong. The items that are material in scope or extent need to be considered in evaluating future CapEx requirements, but this does not mean that substantial CapEx will be needed in the future.

NorthWestern did this CapEx evaluation with input from PPLM and with reliance upon its own employees who have extensive historical and working knowledge of the system and its status. NorthWestern identified the historic level of CapEx and specific future line-item projects of significant cost to determine an appropriate CapEx forecast. Furthermore, in the due diligence effort, NorthWestern identified potential CapEx items as part of the thoroughness of the due diligence reporting. For any item, the likelihood or probability, not the mere possibility, needs to be considered to determine whether the item involves a potential significant cost. Dr. Wilson does not consider the likelihood of occurrence of some items that have been identified, but are of very limited definition. I address these considerations in more detail in my testimony below.

Q. What is your assessment of NorthWestern's CapEx forecast?

A. NorthWestern's current CapEx budget projection is valid and appropriate. The bases for that conclusion follow.

First, one must consider the condition and status of the hydro system. It is effectively monitored under PPLM/Federal Energy Regulatory Commission ("FERC") programs. Information is regularly and formally documented and reviewed. As a result, the condition of structures and equipment as well as license compliance efforts are well known. This is a basis upon which to consider future costs. But in so doing, one must also know and consider PPLM's extensive capital program over the last 10 years as well as previous improvements and upgrades by the Montana Power Company. NorthWestern evaluated the capital program in developing its CapEx forecast. Some recent notable capital expenditures will not be needed going forward because the associated work is completed and the system is in improved condition. This current capital program is continuing and specifics of forecast costs related to it are identified through 2017. Finally, NorthWestern identified capital projects to be done after 2017 and included them in its forecast. Considering each of these items, NorthWestern accordingly has credibly established a CapEx forecast that is valid and acceptable to adequately sustain the hydro system through the forecast period. This reiterates CB&I's findings in its due diligence reporting.

Q. Dr. Wilson compares NorthWestern's forecast capital expenditures, which he describes as $8.5 million per year, to $35.6 million average per year for 2008-2017 (reference Wilson: page 22, line 18). Is that a valid comparison?

A. No, the comparison is not valid for two reasons. First, NorthWestern's CapEx forecast is not $8.5 million per year; it averages $11.7 million per year over the 30-year forecast term starting in 2018. Second, as identified in this docket, PPLM has been and is planning to continue implementing significant rehabilitation and upgrade efforts on the system in the general timeframe of 2008-2017. NorthWestern accounted for the remaining projects related to this effort through 2017 and included the costs in its CapEx forecast. These significant efforts will not be needed going forward and accordingly are not included in CapEx budgeting in the planned forecast beyond 2017. As examples, significant rehabilitation and upgrade efforts have included the rehabilitation of the intake at Hebgen; work on the spillway is to follow in 2016. The Rainbow redevelopment occurred in 2008-2012. The Thompson Falls fish ladder was constructed in 2009-2010, and Morony Unit 1 generator replacement and turbine refurbishment was performed in 2012-2013. So accordingly, capital expenditures have been higher in recent years and are planned into the 2017 timeframe. After that, considering the significant work such as that described above, capital funding is expected to be comparatively reduced going forward.

One of Dr. Wilson's concerns is the prospect of notable future redevelopment projects like the Rainbow redevelopment project being necessary but not included in NorthWestern's forecast (reference Wilson: page 22, lines 13-17). Based on the current condition of assets, and knowing the history of O&M efforts, no such project of significant cost is expected at this time. In the future, studies may identify the opportunity to increase efficiency or rework a facility to accommodate compliance features. Any such project would be a future business decision that would be subject to review by the Montana Public Service Commission and, as needed, adopted into the existing or reprioritized budgets. So, the current approach to maintenance and rehabilitation planned for and embodied in NorthWestern's forecasts is appropriate for the sustained operation of the hydro system.

Q. Dr. Wilson's testimony characterizes the existing NorthWestern capital budget as NorthWestern going forward with operation and budgeting "without any need for additional major restoration or repairs in the future" (reference Wilson: page 23, lines 1-2). Is this correct?

A. No. To be very clear, the NorthWestern CapEx forecast does indeed include funding for capital expenditures for "restoration or repairs in the future." "Base" level of funding plus identified specific, line-item project costs are included based on status and condition of the facility or item and knowledge of the hydro system.

NorthWestern's capital projection defines an average annual expenditure of $11.7 million. Incurred capital expense will not be the same each year. CapEx in any given year could be higher or lower than the projected amount. Refer to the response to Data Request MCC-181. As indicated therein, unforeseen events could cause higher capital expense in a particular year. But as previously stated, unforeseen events are possible in any given year, but not expected every year. Thus, over the long term, capital expenditures are expected to average $11.7 million per year. CB&I considers NorthWestern's capital forecast to be ample to cover the year-to-year variation. If an expenditure of significance arises, it will be addressed in the normal course of business.

Dr. Wilson further states that "it is unreasonable, if not foolish, to assume that over the next thirty years there will be no costly repairs" (reference Wilson: page 34, lines 4-5). This, of course, is not the case for the NorthWestern capital forecast. Repairs are indeed budgeted for these facilities, at the forecast levels. NorthWestern's CapEx forecast totals $350 million over 30 years. That is significant capital funding that is ample and appropriate to properly maintain these hydro facilities.

Q. Dr. Wilson has concerns about the costs of potentially large future projects and labels them as "actually required" (reference Wilson: page 30, line 9). Please comment.

A. NorthWestern also wants to identify potentially large future projects of significant cost. Accordingly, this was reviewed in detail with PPLM during the due diligence process. NorthWestern believes that appropriate capital projects are identified and covered in its capital forecast. CB&I and HDR Engineering, Inc. reviewed and opined on the subject independently and agree.

Not all items mentioned in the due diligence reporting are going to be realized as actual implemented capital items. Some may be <u>potential</u> but undefined concerns (e.g., Arctic grayling). Others may not be as significant as implied or characterized by Dr. Wilson. Some are specific line items with funding in the capital forecast. If not specifically identified, it is expected that they will be covered by the overall forecast budget. So, it is important to understand that <u>not all</u> items identified in the thorough process of due diligence are "actually required" capital expenditures.

Dr. Wilson cites the example of weathering of concrete on the upstream face of Mystic dam (reference Wilson: page 30, line 18 through page 31, line 1). This condition is not significant and is mainly surficial. The structure is in satisfactory condition. The Independent Consultant engaged by the licensee in connection with the FERC Part 12 process found that the integrity of the structure is not threatened. Going forward, the status of the structure will be considered as part of the ongoing surveillance and monitoring plan. Any needed concrete remediation is expected to be covered in the projected O&M budget.

Dr. Wilson also cites the example of Mystic flowline being susceptible to rock falls (reference Wilson: page 31, lines10-15). This is not expected to be a significant cost item. Rockfalls are reportedly infrequent. The headgate at the upstream end of the flowline automatically closes, if needed, based on differential pressure, to limit water release and downstream impacts. Some rock scaling or installation of shields or covers at select locations and/or discrete flowline repairs can be implemented, if needed, in the normal course of business under the projected O&M budget. This was the case for the local repair made a few years ago.

Dr. Wilson also cites the example of the condition of the Black Eagle intake forebay wall (reference Wilson: page 31, line16). This example concerns adequacy of the forebay walls for the extreme case of Probable Maximum Flood ("PMF") loads. The overall condition of the right forebay wall has been a point of some attention and discussion for several years. It is not clear that the intake forebay right wall needs a new buttress, but that is one option being considered. PPLM is considering several options to effectively address this issue. Going forward, surveillance and evaluation of the structure will continue, including alignment surveys, piezometer measurements, and visual monitoring. Any needed forebay remediation is expected to be covered in the projected O&M budget.

Q. Dr. Wilson refers to Potential Failure Modes ("PFMs") in the context of issues that may involve significant future capital expenditures (reference Wilson: page 33, lines 9-12). Is that appropriate?

A. No. Dr. Wilson's statement implies that the list of PFMs is an action list of issues to "fix" and then remove from the list. This is <u>not</u> the case (reference response to Data Request MCC-108). As indicated therein, the PFMs are risk-based considerations (not problems or issues) to factor into the monitoring, operation, and, if necessary, rehabilitation of the project. The PFM list is maintained for each project or development and reviewed and modified as necessary at least every five years as part of the FERC Part 12 safety inspection. The FERC regulatory dam safety inspections, annual operations inspections, required Dam Safety Surveillance and Monitoring Plans and Potential Failure Mode Analysis processes are all designed and executed to monitor and maintain structural and operational competency. This is all implemented under FERC guidelines and FERC review to address and maintain safety and adequacy of structures.

PFMs are identified for each development on a detailed basis. There are several PFMs for a project – in some cases as many as 20. These are all identified as part of the FERC dam safety program. The intent is to identify and classify all theoretical PFMs. These are all hypothetical. They are not expected to happen and indeed their probability of occurrence is very low. They mostly apply to extreme loading cases (PMF, seismic, ice). The focus is not to fix something, except in the unusual case that there is an immediate need to address a problem, but to prioritize and implement an appropriate structure monitoring and surveillance program to effectively know and maintain the structure(s). Therefore, PFMs are not items that go to a list of capital expenditures.

Q. Does this conclude your testimony?

A. Yes, it does.

Department of Public Service Regulation
Montana Public Service Commission
Docket No. D2013.12.85
PPLM Hydro Assets Purchase
NorthWestern Energy

PREFILED REBUTTAL TESTIMONY OF

RICK MILLER, P.E.

ON BEHALF OF NORTHWESTERN ENERGY

Witness Information

Q. What is your name, occupation, and business address?

A. My name is Rick Miller. I am a Registered Professional Engineer and the Senior Vice President for Hydropower Services at HDR Engineering, Inc. ("HDR"). My business address is 440 S. Church Street, Charlotte, North Carolina.

Q. Are you the same Rick Miller who submitted prefiled additional issues testimony in this docket?

A. Yes I am.

Purpose of Rebuttal Testimony

Q. What is the purpose of this rebuttal testimony?

A. I am testifying in response to the Direct Testimony of John Wilson on behalf of the Montana Consumer Counsel ("MCC") in its March 28, 2014 filing. I address Dr. Wilson's characterization of NorthWestern Energy's ("NorthWestern") capital expenditure ("CapEx") forecast.

Q. Please describe HDR's role relative to NorthWestern's acquisition of the Hydros.

A. NorthWestern retained HDR to provide consulting services in the areas of hydropower engineering, operations, maintenance, and dam safety related to NorthWestern's acquisition of the PPL Montana, LLC ("PPLM") hydropower assets (the "Hydros"). HDR reviewed the following Shaw/CB&I due diligence documents:

- Independent Engineer's Report dated 01/03/2013 (Exhibit__(WTR-2.1)), attached to the Prefiled Direct Testimony of William Rhoads ("Rhoads Direct Testimony");
- Addendum to Engineer's Report dated 06/25/2013 (Exhibit__(WTR-2.2)) attached to the Rhoads Direct Testimony; and
- Due Diligence Report supplementing Independent Engineer's report dated 09/06/2013 (Exhibit__(WTR-2.3)) attached to the Rhoads Direct Testimony.

HDR also interviewed selected NorthWestern staff with extensive knowledge of the Hydros during the period of February through April 2014 regarding the age and condition of assets, the historical maintenance and capital investment activities, and the future need for maintenance and capital expenditures. HDR developed its independent opinion regarding the sufficiency of NorthWestern's due diligence effort including its assessment of the individual facilities' structural integrity, physical condition, and environmental liabilities. In addition, HDR independently developed a 20-year CapEx forecast and compared its forecast to NorthWestern's forecast in Exhibit__(JMS-1), attached to the Prefiled Direct Testimony of Joseph Stimatz.

HDR's Capital Investment Forecast

Q. What is HDR's 20-year forecast of capital investments?

A. HDR independently developed a 20-year forecast of capital investments ("HDR Forecast") that incorporated the information provided in the Shaw/CB&I due diligence reports and the interviews with NorthWestern staff that have knowledge of the facilities and their condition. The HDR Forecast accounts for the age of the components and the operating and investment history of the assets, utilizing the standard of care for professional engineering, consulting, and related services ordinarily used by members of the hydropower engineering profession. The HDR Forecast is a year-by-year assessment of each project's major elements and HDR-anticipated capital investments based upon the available information and HDR's hydropower industry experience. Unlike Dr. Wilson's approach, HDR's approach was not generalized based upon a selected period of historical capital investment and capital investment planned in the near term that he interpreted to be representative of future CapEx (Wilson p. 29, lines 8-11 and p.45. lines 12-14).

The HDR Forecast, which varies year by year based upon the reported historical and planned CapEx, recommends an average annual capital budget of $7.1 million in 2014 dollars (and $7.8 million in 2018 dollars).

The HDR Forecast includes both specific CapEx projects such as anticipated generator rewinds and turbine overhauls and an unspecified annual allocation of CapEx investments available for each development. In developing this forecast, HDR confirmed that the majority of the expected capital investment for a hydropower fleet of this vintage was undertaken prior to 2014. This historical investment included the modernization of the critical controls and other station systems required for reliable unit operations and is complemented by the investments on the larger units' turbines and generators already completed and planned through 2017.

Q. What is HDR's opinion about NorthWestern's CapEx forecast?

A. NorthWestern's due diligence and the resulting CapEx forecast accurately document the actual PPLM hydropower modernization program and the planned expenditures out to 2017. The implemented and the planned investments are consistent with HDR's experience for the level of expenditure generally required to maintain similar hydropower assets in good reliable operating condition.

HDR's analysis confirms that NorthWestern's CapEx forecast is sufficient to account for the material liabilities known at this time. HDR did not identify any required Part 12 Independent Consultant recommendations that were not included in the forecasted CapEx. Projected CapEx and Operations and Maintenance ("O&M") cost estimates for known compliance requirements have been included.

HDR concludes that NorthWestern's 20-year CapEx forecast (Exhibit__(JMS-1)) incorporates targeted investments for identified specific needs that have not been addressed by planned investments prior to 2018. HDR concurs with NorthWestern that the hydro fleet modernization program has largely been completed and those historical higher levels of CapEx investment will not be required during the 2018 – 2033 time frame.

HDR's recommended average CapEx budget of $7.1 million per year in 2014 dollars (and $7.8 million in 2018 dollars) compares favorably to NorthWestern's projected average budget of $8.5 million (in 2018 dollars) per year of capital expense escalated at 2.5% annually to safely operate and maintain the Hydros and confirms the adequacy and sufficiency of NorthWestern's due diligence.

HDR'S Assessment of Dr. Wilson's Testimony

Q. What is HDR's assessment of Dr. Wilson's testimony on page 11 as it relates to the comparison to similar hydropower asset transactions?

A. NorthWestern's comparative acquisition data identified in its testimony for recent industry transactions supports NorthWestern's assumption on the Hydros' market value on a dollars-per-installed-kW basis. I would point out that of NorthWestern's four representative examples, HDR provided due diligence services to Brookfield Renewable Energy for the Tapoco (Alcoa) asset transaction and ArcLight's acquisition of the Black Bear assets in Maine. Both of these acquisitions involved hydropower projects of similar vintage and historical capital investment as the Hydros.

If NorthWestern were to consider a longer history of hydropower transactions, it would find that the longer historical perspective would further support NorthWestern's assumption on the cost/kW of acquired capacity. Dr. Wilson provides no evidence that hydropower assets decline in value. Dr. Wilson also provides no evidence that the comparative acquisition data does not support the transaction.

Q. Dr. Wilson states that PPLM's actual and budgeted capital expenditures for 2008-2017 averaged $35.6 million and argues that if projected capital expenditures were one-half of historical levels, the DCF value would be lower (page 13, lines 2-5). What is HDR's

assessment of Dr. Wilson's methodology of using only historical CapEx to determine expected future CapEx?

A. Throughout his testimony, and specifically on page 13, lines 2-5, and page 22, line 7 to page 23, line 2, Dr. Wilson does not differentiate between the unique capital costs associated with the redevelopment of the Rainbow project, and other historical relicensing compliance costs (all of which are accurately represented in NorthWestern testimony), from the future CapEx and major maintenance requirements of ongoing investments in the existing fleet.

As noted above, the HDR Forecast determined that a lower average annual rate of investment is required compared to what NorthWestern forecasted, when taking into account the 2008-2017 expenditures. HDR also believes that NorthWestern's due diligence effort was adequate and comprehensive. NorthWestern's proposed CapEx plan set forth in Exhibit __(JMS-1) and NorthWestern's response to Data Request PSC-018a is sufficient.

HDR's methodology is based upon its years of hydropower due diligence experience and is more accurate than Dr. Wilson's approach. HDR's analysis isolates and excludes specific one-time costs, such as the cost of the Rainbow redevelopment and the historical license compliance costs that were required subsequent to the Missouri-Madison projects' license reissuance, and then assesses the remaining anticipated investments based upon both age and operating history. Once that historical capital investment has been identified and put into a long-term planning perspective, NorthWestern's lower annual average rate of future capital investment is more than adequate.

HDR's educated and informed conclusion after review of the extensive historical CapEx investments and the planned investments between 2014 and 2017 is that the bulk of the hydropower assets have been upgraded and the remaining assets require an overall lower average annual investment going forward. These remaining assets are specifically identified in the NorthWestern CapEx forecast (See NorthWestern's response to Data Request PSC-018a).

Q. Dr. Wilson states, "PPLM's historic capital expenditures on the hydro plants have increased substantially as they have aged" (page 22, lines 7-9). He also expresses concern that the facilities will require more, not less, refurbishment and replacement as they continue to age (page 30, lines 2-8). What is HDR's assessment of Dr. Wilson's implication that the historical CapEx and future CapEx assumptions were based on the age of the assets?

A. Dr. Wilson states that the significant historical expenditures by PPLM were driven by age, and he appears to ignore the redevelopment opportunities and license compliance requirements. This statement contradicts NorthWestern's testimony and responses to discovery that describe in detail those significant one-time costs and the reasons for them.

It is HDR's experience that continued investment in the turbines and generators and civil infrastructure enhances project operations, often resulting in returning components to service in better than original condition. The NorthWestern due diligence effort documents the extensive historical turbine and generator and related mechanical and electrical capital investments implemented by PPLM during its ownership of the assets. Hydropower assets are long-lived assets that after the initial capital expense of construction require minimal, but routine, investment over time to maintain their reliability and functionality. Much like other large capital infrastructure projects such as roads, bridges, and water supply systems, there does come a time when a more extensive rehabilitation is required to assure the reliability and functionality of the components for additional life-cycle capability. The evidence of that rehabilitation cycle resides in the historical investment implemented by PPLM, and the planned investments by NorthWestern.

NorthWestern's comprehensive due diligence documented the condition assessment of the Hydros that led PPLM to invest significantly in the hydropower stations that were most critical to the portfolio. PPLM's modernization plan that was also documented in the Shaw/CB&I due diligence reports demonstrated that the fleet-wide investment is anticipated to be substantially complete by 2017. HDR's interviews with NorthWestern staff confirmed that future investments in the remaining units that were not modernized by PPLM, including Black Eagle, Hauser, Holter, Madison, and the original smaller units at Thompson Falls, are accounted for in NorthWestern's 20-year CapEx forecast.

Developing a fleet-wide modernization program to the extent done by PPLM must take into account numerous elements such as unit generating history in terms of capacity factor and its cycle duty, local staff knowledge of the uniqueness of each unit for items such as runner cavitation repairs or generator rewedging, and the basic requirements of reliably providing generation and safely moving water through the river system. Unlike other forms of electrical generation, owners of hydropower stations must be cognizant of reliably passing flow from the individual facilities to meet downstream water requirements and managing flood flows, independent of electrical grid needs. For example, if the components of a generator, such as the rotor spider, had evidence of cracking or fatigue, it would typically manifest in chronic vibration or out of roundness. This condition would affect unit operations and potentially lead to a forced outage and impact the ability to move flow downstream. If there are known equipment reliability concerns that remain to be addressed beyond what PPLM has planned, NorthWestern's CapEx forecast accounts for these concerns due to its staff's intimate knowledge of the Hydros.

HDR believes that the documented investments in the electrical and mechanical components of the Hydros have been implemented in a planned and comprehensive manner to assure future reliable operations of the system. HDR's review of NorthWestern's 20-year CapEx forecast confirms it incorporates not only the age of the components but more critically the Hydros' extensive operational history and condition assessment. HDR is unable to find evidence to support Dr. Wilson's implication that age, and age only, should be the criteria for determining the historical and forecasted CapEx.

Q. What is HDR's assessment of Dr. Wilson's assertion that NorthWestern's future CapEx does not account for additional major restoration or repairs (page 29, lines 4-8)?

A. HDR's hydropower business model is primarily focused on the hydropower rehabilitation and relicensing market in North America. The United States encompasses approximately 100,000 MW of installed hydropower capacity. The vast majority of that installed capacity was constructed prior to the 1980s, with little new construction since. That translates into an engineering and equipment supply market that is focused almost exclusively on the rehabilitation and modernization of this aging fleet. HDR's primary hydropower engineering services work is targeted to this rehabilitation market. As stated above, HDR's experience confirms the appropriateness of PPLM's historical capital investments completed and planned to be completed by 2017. HDR's independently developed CapEx Forecast also confirms that NorthWestern's 20-year forecast adequately accounts for the additional restoration and repairs in the future.

Q. What is HDR's assessment of Dr. Wilson's assertion that future capital investment in the aging plants is highly uncertain and could potentially be far greater (page 7, lines 4-8)?

A. HDR's hydropower engineering experience confirms the adequacy of NorthWestern's capital forecast which includes the planned investments over the next 20 years as well as the unspecified CapEx needs of a hydro system of this vintage. The anticipated costs of turbine/generator upgrades, and spillway modifications, are dictated by either the size of the machine, or the length and height of the spillway. With over three decades of experience focusing on just this type of scope of work, HDR's experience is that the station specific costs are generally well understood and that appropriate contingencies can be established to account for the unique attributes of a specific unit or site. This would include civil infrastructure investments such as the Mystic flowline which vary over time as with any similar infrastructure, and those costs will be site and event dependent.

Additionally, HDR's review of NorthWestern's due diligence confirmed that the extensive PPLM environmental and license compliance record was reviewed. The robust Federal Energy Regulatory Commission ("FERC") license compliance record is reflected in the historical costs, and NorthWestern's CapEx forecast includes known and knowable compliance requirements.

It is HDR's practice to not include the costs of unknown major projects that cannot be foreseen with any great certainty in future CapEx and expense forecasts. This is a business risk issue and in the absence of a defined, specific project it is not HDR's experience to include the costs of additional risk mitigation projects in future CapEx and expense forecasts. Hydropower assets represent large infrastructure with many elements, and forecasting risk dollars for unforeseen projects creates an untenable financial plan.

Q. Dr. Wilson's testimony seems to imply that NorthWestern's due diligence effort and the resulting CapEx forecast were inadequate. What is HDR's assessment of Dr. Wilson's testimony in this regard?

A. As described above, HDR reviewed the Independent Engineer's Final Report and the two supplemental reports and conducted interviews with NorthWestern staff. HDR believes that the due diligence reports, in conjunction with a review of NorthWestern's 20-year CapEx and O&M costs provided in Exhibit__(JMS-1), provide sufficient detail for the material issues related to the individual assets. The due diligence reports identify that each of the facilities was visited, the current condition assessment was documented, the available dam safety and environmental compliance-related documents were reviewed, and the historical capital and O&M expenditures were assessed in view of the age and condition of the assets and the projected investments going forward. HDR reviewed the available FERC Part 12 Independent Consultant dam safety inspection reports including the remediation plans completed or currently underway and required to be completed by the end of 2017 in those Part 12 reports. HDR did not identify any required Part 12 Independent Consultant recommendations that were not included in NorthWestern's CapEx forecast. The robust FERC license compliance record is also reflected in the historical costs, and projected CapEx and O&M cost estimates for known and knowable compliance requirements have been included.

Thus, based on HDR's review, Dr. Wilson's assessment of NorthWestern's CapEx forecast should be disregarded.

Q. In your testimony, you refer to HDR's opinion. Has HDR formally issued any documents reflecting its opinions?

A. Yes. On April 17, 2014, HDR delivered an Opinion Letter to Mr. William Rhoads of NorthWestern. The Opinion Letter is the basis for my testimony. A copy of the Opinion Letter and supporting documentation was attached as Exhibit__(RM-1) to my prefiled additional issues testimony. The Opinion Letter is also attached here as Exhibit__(RM-2).

Q. Does this conclude your testimony?

A. Yes it does.

April 17, 2014

Mr. William T. Rhoads, P.E., M.P.E.M.
General Manager, Generation
NorthWestern Energy
40 East Broadway Street
Butte, MT 59701-9394

SUBJECT: NorthWestern Energy's Application for Acquisition of PPL Montana's Hydro Assets
Independent Assessment of NorthWestern's Due Diligence Effort
Docket No. D2013.12.85

Dear Mr. Rhoads:

HDR Engineering, Inc. (HDR) was retained by NorthWestern Energy to provide consulting services in the areas of hydropower engineering, operations, maintenance, and dam safety related to NorthWestern's acquisition of the PPL Montana hydropower assets. This memo documents HDR's independent opinion regarding the sufficiency of the due diligence effort conducted by NorthWestern including its assessment of the structural integrity, physical condition, and environmental liabilities of the facilities involved in the potential transaction.

HDR's Hydropower Services organization includes hydropower subject-matter experts located across North America. The HDR team has evaluated over 300 generating stations in over 20 countries, including the United States, Canada, China, and Brazil, representing more than 54,000 MW of hydroelectric capacity. The basis of our conclusions is the review of the due diligence reports completed by Shaw/CB&I, interviews with NorthWestern staff, our knowledge of and expertise in hydropower assets, and our extensive transaction support experience.

HDR reviewed the following Shaw/CB&I due diligence documents:

- Independent Engineer's Report dated 01/03/2013 (Exhibit_WTR-2.1)
- Addendum to Independent Engineer's Report dated 06/25/2013 (Exhibit_WTR-2.2)
- Due Diligence Report supplementing Independent Engineer's report dated 09/06/2013 (Exhibit_WTR-2.3)

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April 17, 2014

HDR also interviewed selected NorthWestern staff with extensive knowledge of the PPL Montana hydroelectric assets during the period of February through April 2014 regarding the age and condition of assets, the historical maintenance and capital investment activities, and future need for capital and expense expenditures. HDR independently developed a 20-year capital expenditure forecast and compared that HDR forecast to NorthWestern's that was submitted in the docket (Exhibit__JMS-1).

It is HDR's opinion that the due diligence report and its supplements, in conjunction with a review of NorthWestern's 20-year capital expenditures (capex) and operations and maintenance (O & M) costs provided in the docket (Exhibit__JMS-1), provide sufficient detail for the material issues related to the individual assets. The due diligence report identifies that each of the facilities were visited, the current condition assessment was documented, the available dam safety and environmental compliance-related documents were reviewed and the historical capital and operations and maintenance (O & M) expenditures were assessed in view of the age and condition of the assets and the projected investments going forward. The dam safety documents reviewed included the available FERC Independent Consultant dam safety inspections plus the remediation plans completed, currently underway and required to be implemented up through 2017. HDR did not identify any required Part 12 Independent Consultant recommendations that were not included in the forecasted capital expenditures.

Additionally, the extensive PPL Montana environmental and license compliance record was reviewed in the due diligence and its supplemental reports. The robust FERC license compliance record is reflected in the historical costs, and projected CapEx and O & M cost estimates for known and knowable compliance requirements have been included.

HDR independently developed a 20-year capex spreadsheet that was based upon the age of the facilities, the identified historical investments provided in the docket, and known regulatory compliance requirements. HDR's analysis confirms that NorthWestern's projected CapEx cost estimates are sufficient to account for the known liabilities at this time.

<u>Civil Elements and Water Retaining Structures Due Diligence:</u>

For decades, the FERC has required that each licensee facilitate a thorough dam safety inspection by an Independent Consultant once every five years. These inspections are known as Part 12 inspections, and their purpose is to identify any actual or potential deficiencies, whether in the condition of the projects works or in the quality or adequacy of project maintenance, surveillance, or methods of

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operation that might endanger public safety. These independent inspections and record review are performed in compliance with the FERC's established dam safety criteria in place at that time. The licensee is required to address all recommendations make by the Part 12 Independent Consultant.

The hydropower industry, at the direction of the FERC, incorporated the Probable Failure Modes Analysis (PFMA) process in 2004. This created a rigorous and defined methodology where a team of dam safety experts independently assess the condition of the facilities and identify possible failure modes, their likelihood of occurrence, and identify potential risk-reduction measures. This state-of-the-practice process is documented in the due diligence report and facility-specific issues are addressed by the PFMA process. Each licensee is accountable to the FERC to implement the required actions resulting from that process and all recommendations made by the Part 12 Independent Consultant. The Shaw/CB&I final due diligence report (Exhibits_WTR-2.1 through 2.3) has identified the actions PPL Montana has undertaken, and is planning to undertake, to comply with all dam safety requirements. In particular, the routine assessment of post-tensioned rock anchors is conducted and re-analysis is performed should post-tensioning relaxation be identified during the Five Year Part 12 Independent Consultant inspections.

HDR's review of the due diligence report confirms that there are no current recommendations for the installation of additional post-tensioned rock anchors, nor should there be, based on our review of the record on this matter. Should future testing indicate the occurrence of post-tension relaxation or find evidence of tendon corrosion, then additional dam stability re-analysis would be performed and the most effective solution identified which then must be approved by the FERC. This is a business risk issue; and in the absence of a defined, specific recommendation, it is not HDR's experience to include in future expense forecasts the costs of additional post-tensioned rock anchors as a contingency for non-specific, unidentified anchor performance concerns.

HDR's review of the due diligence report and the Part 12 Independent Consultant Inspection reports confirms there are no current recommendations for replacing or modifying the remaining flashboard/stanchion systems or any of the other flashboard operating systems at the Hydros that would affect the CapEx investment projected beyond 2017. As demonstrated by decades of acceptable service, these systems have functioned safely and are a proven, low-technology method accepted by the FERC. HDR's experience is that similar systems remain in service at many facilities in the United States and Canada. This is especially true where the number of annual operation cycles is low, which is the case with the PPL Montana facilities.

Where there are site-specific factors that prevent the flashboard/stanchion system from functioning as designed, HDR has worked with project owners to redesign the flashboard system to allow for a manual tripping system, or a rubber dam or Obermeyer-type installation. Each of these solutions present their own site-specific requirements, operational reliability issues, and maintenance requirements. As such, there is no risk-free or standard industry-accepted solution. The operation of flashboards during flood events is routinely assessed by the FERC during their annual inspections and by the Part 12 Independent Consultant every 5 years. HDR does not recommend establishing a future replacement budget in the absence of any current or known recommendations for changing the flashboard and stanchion systems at any of the PPL Montana projects. Specifically, as it relates to the Holter Project where the flashboard/stanchion design is currently in service on the spillway (and apparently the only project where that design is in service), HDR reviewed the most current Holter Part 12 Independent Engineer's report. HDR concurs with the Shaw/CB&I due diligence report that this issue was identified by the Part 12 Independent Consultant, PPL Montana proposed and tested a modified design in 2011, and the FERC concurred in 2012 with PPL Montana's plan and schedule to complete the modifications in 2013.

This does not preclude the initiation of an elective project if the project savings from labor and O & M costs at any site justify the investment in an alternative system to pass water. As stated previously, it is HDR's opinion, supported by the evidence of the Part 12 Independent Consultant's reports and the Shaw/CB&I due diligence, that no additional specific CapEx investments need to be budgeted for flashboard/stanchion modifications. Several of the replacement options identified in the Essex report have previously been implemented by PPL Montana where it made good engineering sense, and public safety sense, to do so. There is no evidence to support the concerns identified in the Essex memo that the existing systems create the potential to incur significant capital investment.

Mechanical and Electrical Due Diligence:

The Shaw/CB&I due diligence reports document the extensive historical prime mover and related mechanical and electrical capital investments implemented by PPL Montana during their ownership of the assets. Hydropower assets are long-lived assets that after the initial capital expense of construction require minimal, but routine, investment over time to maintain their reliability and functionality. Much like other large capital infrastructure projects such as roads, bridges, and water supply systems, there does come a time when a more extensive rehabilitation is required to assure the reliability and functionality of the components for additional life-cycle capability.

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The age of the assets led PPL Montana to invest significantly in the hydropower stations that were most critical to the portfolio. PPL Montana's modernization plan that was documented in the Shaw/CB&I due diligence and its supplemental reports demonstrated that the fleet-wide investment is anticipated to be substantially completed by 2017. The interviews with the NorthWestern staff confirmed that future investments in the few remaining smaller units that were not modernized by PPL Montana, including Black Eagle, Hauser, Holter, Madison, and Thompson Falls are accounted for in NorthWestern's 20-year capital expense forecast (Exhibit__JMS-1).

Developing a fleet-wide modernization program to the extent done by PPL Montana must take into account numerous elements such as unit generating history in terms of capacity factor and its cycle duty, local staff knowledge of the uniqueness of each unit for items (such as, runner cavitation repairs or generator rewedging), and the basic requirements of reliably providing generation and safely moving water through the river system cascade. Unlike other forms of electrical generation, owners of hydropower stations must be cognizant of passing flow from the individual facilities to meet downstream water quality requirements and managing flood flows independent of electrical grid needs. This means that hydropower owners must incorporate into their long-term plans the ability to sequence outages in a manner that supports the ability to safely implement water management requirements of the river system. This also means that it is incumbent on a hydropower owner to implement a broad enough scope of turbine overhauls and generator rewinds to address any known issues that would affect that future reliability and the ability to safely move water. For example, if the components of the generator such as the rotor spider had evidence of cracking or fatigue, it would manifest in chronic vibration or out of roundness that would affect unit operations and future reliability. If there were known equipment reliability concerns that remain to be addressed beyond what PPL Montana has planned, NorthWestern's staff's intimate knowledge of the assets has accounted for that projected work scope in the 20-year forecast of CapEx expenditures (Exhibit__JMS-1)

The Essex checklist and memorandum offers without evidence the notion that due to age metal fatigue can cause cracking in the rotor components and ultimately lead to a catastrophic failure and that replacing the rotor components is a potential remedy. While this may hypothetically be true, due to the robustness of the actual design of these vintage units, it has not been HDR's experience that the rotor structural component replacements are required after 80 or 100+ years of service. Certainly, the electrical elements such as the windings and rotor poles do require periodic refurbishment, and that is entirely the point of performing a generator rewind. HDR's experience indicates this is also true of the turbines where the embedded structural elements are robust and rarely require replacement, but the rotating elements also require rehabilitation after a period of years of reliable operations.

HDR also noted the extensive historical investment in the electrical and mechanical Balance-of-Plant systems at each station. It is HDR's experience that these systems are often the Achilles Heel reducing station reliability but are frequently overlooked by hydro asset owners who often focus more funding on the prime mover elements. The investment in the governors, excitation, instrumentation, and controls at the PPL Montana facilities has allowed the creation of a central operations office in the Rainbow Station with remote control and alarm monitoring capability. This allows continuous monitoring of all system alarms, and supports a regional O & M program focused on a higher level of condition-based maintenance on a much more proactive basis, as compared to being reactive and performing maintenance when something breaks. The maintenance teams can spend the needed time to increase system reliability and be less distracted by routine operations tasks such as unit starts and stops, which can be safely handled remotely.

HDR's opinion is that the documented investments in the electrical and mechanical components of the hydropower fleet have been implemented in a planned and comprehensive manner to assure future reliable operations of the system. HDR's review of NorthWestern's 20-year capital expenditure forecast (Exhibit__JMS-1) indicates the components at Black Eagle, Hauser, Holter, Madison, and Thompson Falls and facility components at other stations of the fleet that are anticipated to not be completed by 2017 have been accounted for.

Environmental and Regulatory Compliance

The extensive record of license compliance was documented in the due diligence report and its supplements, and the supporting memo from Skadden, Arps, Slate, Meagher & Flom LLP for the four FERC licenses that comprise the fleet of assets including the Missouri-Madison Project, the Thompson Falls project, the Kerr Project, and the Mystic Lake Project. With the issuance of the FERC license for the Missouri-Madison Project in 2000, a significant capital investment program was required. The due diligence report and its supplements document the rigorous history of compliance, known future compliance requirements and the staffing that is in place to continue to monitor and implement future compliance requirements.

It is HDR's opinion that NorthWestern has sufficiently accounted for the known environmental and regulatory requirements of the hydropower assets. The

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historical capital expenditures for license compliance, once complete, allow the facilities to remain in compliance. HDR's experience is that the long record of O & M costs, once the capital investment is complete, are a good predictor of future O & M expenditures.

HDR's 20-Year Forecast of Capital Investments:

HDR independently developed a 20-year forecast of capital investments that incorporated the information provided in the Shaw / CB&I due diligence reports and the interviews with NorthWestern staff with knowledge of the facilities and their condition. The HDR forecast accounts for, to the degree possible utilizing the standard of care for professional engineering, consulting and related services ordinarily used by members of hydropower engineering profession, the age of the components, the history of investments, and the operating environment of the assets.

It is HDR's opinion that the due diligence report accurately documents the actual PPL Montana hydropower modernization program to date and the planned expenditures out to 2017. The already implemented and the planned investments are consistent with HDR's experience for the level of expenditure generally required to maintain similar hydropower assets in reliable operating condition.

HDR's review of NorthWestern's 20-year capital expenditure forecast (Exhibit__JMS-1) concludes that it incorporates targeted investments for specific needs identified at this time that have not been addressed by planned investments prior to 2018.

HDR's independent capital investment forecast, which varies year by year based upon the reported historical and planned capital expenditures (and the time available to complete this independent review), recommends an average annual budget of $7.1 million per year dollars (in 2014 dollars). The HDR 20-year forecast includes both specific CapEx projects (such as, anticipated remaining generator rewinds and turbine overhauls) and an unspecified allocation of CapEx investments for each station for each year. In developing its 20-year capital investment forecast, HDR confirmed that the majority of recommended capital investment for a hydropower fleet of this vintage was undertaken prior to 2014, with the completion of the balance-of-plant systems at each of the stations and the critical units' turbines and generators.

This compares favorably to NorthWestern's projected $8.5 million per year (in 2014 dollars) of capital expense to safely operate and maintain the hydropower assets,

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and in our opinion confirms the adequacy and sufficiency of NorthWestern's due diligence. HDR concurs with NorthWestern's assertion that the increased levels of capital expenditures prior to 2014 were necessary and prudent, that the majority of the hydro fleet-wide modernization program has been completed, and those historical higher levels of CapEx investments are not required beyond 2017.

If you have any questions or require further information, please do not hesitate to contact me.

Sincerely,

Richard R. Miller, P.E.
Senior Vice President
Hydropower Services

Department of Public Service Regulation
Montana Public Service Commission
Docket No. D2013.12.85
PPLM Hydro Assets Purchase
NorthWestern Energy

PREFILED REBUTTAL TESTIMONY OF
BRIAN B. BIRD
ON BEHALF OF NORTHWESTERN ENERGY

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Witness Information

Q. Please state your name and business address.

A. My name is Brian B. Bird. My business address is 3010 West 69th Street, Sioux Falls, South Dakota 57108.

Q. Are you the same Brian Bird who submitted prefiled direct testimony in this docket?

A. Yes.

Purpose of Testimony

Q. What is the purpose of this rebuttal testimony?

A. The purpose of my testimony is to rebut certain claims made by the Montana Consumer Counsel ("MCC") in this docket. I address claims made in the Direct Testimony of John Wilson ("Wilson Direct Testimony") and in the Direct Testimony of Albert Clark ("Clark Direct Testimony").

NorthWestern Profit and Value of Colstrip Unit 4 ("CU4")

Q. Do you believe Dr. Wilson is implying that the return on rate base on the Hydros transaction is profit to NorthWestern?

A. Yes. Dr. Wilson calculates NorthWestern's return on rate base of approximately $61.8 million and later discusses the excessive amount of profit with the implication that the $61.8 million was profit. Return on rate base is not the same as net income (or profit). If NorthWestern collected the amount shown in Exhibit__(TEM-2) attached to the Direct Testimony of Travis Meyer, NorthWestern's net income (or profit) from the first year of operations of the Hydros transaction would be approximately $41.6 million.

Q. What is the difference between profit and return on rate base?

A. Profit, or net income as we define it, is the income available for investors. That net income is the return on equity ("ROE") available to investors. Return on rate base is based on the combination of ROE, cost of debt, and NorthWestern's capital structure. The cost of debt is the interest that must be paid to the debt holders of the transaction. This return, return on debt, is not available for equity investors or, in other words, NorthWestern's shareholders.

Q. Do you believe that Dr. Wilson is implying the "profit" on this transaction is excessive?

A. Yes. He believes there would be an excessive rate of return and profit on this investment and also accumulates the total profit in the shareholders' equity over 30 years.

Q. Is the profit excessive?

A. No. The calculation of revenue requirement on this investment is no different than for any other regulated capital investment that NorthWestern would make. It is a substantial investment, and, thus, the dollar magnitude of the related revenue requirement and the resulting net income are also large, but that alone does not make it excessive.

Q. Would any other parties who would buy these assets have the same opportunities to make as large a profit?

A. Yes. In fact, with a non-regulated entity, the profit would be driven to a large extent by what happens to market prices. These assets were initially very profitable for PPLM as market prices rose dramatically during the period that deregulation was in place. A new, non-regulated buyer would be hoping for that situation to happen again, and if it did, that buyer may have a much larger profit and our customers would ultimately pay a steep price via pass through of purchased power costs in our electricity supply tracker.

Q. Do you believe Dr. Wilson feels this transaction is "risk free"? If so, why?

A. Yes. Dr. Wilson, on behalf of the Consumer Counsel, believes the fact we get preapproval for this transaction makes it risk free.

Q. Do you agree with Dr. Wilson that preapproval makes the transaction "risk free"?

A. No. I do acknowledge preapproval allows us to manage risk to an acceptable level for investment by investors, but certainly not to a risk free level. This benefits our customers by lowering the cost of capital of the transaction. In our most recent filings we have been successful in providing to our customers the lowest overall rates of return the Montana Public Service Commission ("Commission") has seen.

The preapproval statute is an important part of state law which reversed the failure of supply deregulation. It provides the Commission specific and timely access to information and allows all parties to manage risk. The

Consumer Counsel appears to have a fundamental disagreement with a statutory policy that is core to the structure of current public utility regulation as it pertains to NorthWestern. Critically, because we are a fully regulated utility – and only a utility – customers receive the benefit of a transaction at a very reasonable cost of debt and equity. If the preapproval statute did not exist, the financial risk of a transaction of this magnitude would dramatically increase the cost to customers.

It is hard to believe that Dr. Wilson, on behalf of his client, is suggesting that the Federal Energy Regulatory Commission, the Federal Fair Trade Commission, and the United States Department of Justice should all have the opportunity to review this transaction before it closes, and that only the Commission should be denied such a review until after the deal closes. Let's consider the consequences for customers if, as Dr. Wilson suggests, we obtained all the federal approvals, closed on the transaction, financed it, and then filed an application for approval with this Commission.

First, no buyer would have done this transaction or any other major transaction without obtaining all necessary regulatory approvals, regardless of whether it had a "preapproval" statute or not. Regulatory approval would be required by any prudent regulated buyer. Additionally, the Bankruptcy Stipulation between the Commission, the MCC, and

NorthWestern essentially requires preapproval of this transaction as well, due to its size and characteristics.

Second, it is hard to imagine an investor's expected return if we did not obtain approval on this transaction before a binding close and financing. Finding an entity to invest or lend (be it an equity or debt investor) a total of $900 million (approximately a third of our enterprise value) at reasonable rates on a transaction they won't receive a rate basing decision on for nearly a year would be very difficult. My expectation is the expected return would be significantly higher than the requested rate of return (7.14%) on this transaction. NorthWestern has been able to command lower cost of capital from the market because of an acceptable regulatory and legislative environment which allows reasonable and reasonably predictable regulatory outcomes. This includes the Montana preapproval statute. The preapproval statute has saved customers money in lower financing costs while enabling the state to unwind supply deregulation, just as the Consumer Counsel advocated in its 2007 comments on NorthWestern's supply plan (discussed in the Prefiled Rebuttal Testimonies of John Hines and Robert Rowe). If preapproval was not utilized, our investors would take more risk and thus raise the financing costs that – because we are a fully regulated utility – we must recover from our utility customers.

It is notable that the Hydro project concerns existing resources. Previously, the Commission has considered applications for new resources (Dave Gates Generating Station and Spion Kop). In those cases, the Commission approved the projects, but retained authority to determine prudency of the specific investments. Both of those projects were brought in under budget. Even there, it is hard to see how the pre-approval statute transferred risk. Rather, it is a vehicle to implement state policy while managing risk for all parties.

Q. Do you agree with Dr. Wilson's comments that due to our valuation of the Colstrip assets in this transaction that CU4 is "now recognized to be an exceedingly high cost resource"?

A. No. In my prefiled direct testimony, I noted that the negative value for the other Colstrip assets was due to the combination of environmental risks of coal-fired assets and the restrictive sale-leaseback to which these assets were subject. This negative value applied just to the older Colstrip Units 1 & 2. We assigned a positive value to Unit 3, which is the sister unit to CU4. CU4 is a valuable asset that is part of a well-diversified generation portfolio that will prove to be low-cost to our customers over the long term. It is not meaningful to consider the value of CU4 just during this period of low market prices.

Q. Do you agree with Dr. Wilson's comment that "it cannot necessarily be assumed that NorthWestern had great incentive to minimize the price bid..."?

A. No. As I noted in my prefiled direct testimony, one of the primary filters we had in terms of what we could bid for the assets was the impact on customers' rates. We understood that if this transaction was perceived to be too costly to customers the Commission would likely issue an order not approving the transaction. Additionally, the scrutiny on all of the supply resource acquisitions we have made has been significant, and when you consider the size of this transaction, we were very aware that we needed to pay as low a price as possible that PPLM would still accept. We were and still are striving to ensure that the purchase of the Hydros does not have a significant impact on rates, and we remain well aware that too high a purchase price would risk a rejection of the acquisition by the Commission.

Capital Structure

Q. Do you agree with Dr. Wilson's statement that NorthWestern is requesting an equity/debt ratio of approximately 45% equity/55% debt for this rate filing?

A. No, I do not agree with Dr. Wilson's conclusion that NorthWestern is requesting an equity/debt ratio of 45/55. The long-term rate base proposed by NorthWestern will be $870 million ($900 million initial purchase price less the $30 million 'buy out' of Kerr Dam in 2015). NorthWestern expects to finance the $870 million related to this transaction with about $400 million in equity and about $450 million in debt, with the remainder in cash flows produced by the business from September 2013 (the date the transaction was announced) to June 2014. Those figures produce an equity/debt ratio of approximately 48% equity and 52% debt.

The table below depicts how NorthWestern analyzes the financing of the rate base request in this filing absent the purchase price of Kerr:

Capital raise related to Hydro				
Equity for Hydro Transaction	$	400	million	46.0%
Cash from operations from Sept 2013 - June 2014	$	20	million	2.3%
Debt for Hydro Transaction	$	450	million	51.7%
Rate base without Kerr Dam	$	870	million	100.0%

Q. Why do you think Dr. Wilson concluded that NorthWestern is requesting an equity/debt ratio of approximately 45/55 for this rate filing?

A. It appears that Dr. Wilson used amounts taken from our investor materials. In those investor materials, NorthWestern talks about a plan to issue "up to" $500 million in long-term debt and "up to" $400 million in common equity. Using just those two data points, the long-term debt ratio would be

$500 million in long-term debt divided by $900 million in total capital raised or 55% debt and the equity ratio would be $400 million in common equity divided by $900 million total capital raised or 45% equity.

Q. Is Dr. Wilson correct to assume the $500 million in long-term debt and $400 million in equity?

A. No. Both amounts were 'up to' amounts and I believe he just assumed we would issue $500 million of debt and $400 million of equity. Our original plan described in my prefiled direct testimony showed a capital structure that resulted in a ratio of approximately 48% equity and 52% debt. Our current plan displayed above will also result in an approximate 48% equity and 52% debt capital structure.

Q. Do you agree with Dr. Wilson's statement that since rating agencies view power purchase agreements ("PPAs") as quasi-debt, then NorthWestern's 47.65% / 52.35% equity/debt ratio should be changed to a 45% / 55% equity/debt ratio for this rate filing?

A. No. I disagree with Dr. Wilson for two reasons. First, one of the primary benefits of the Hydros transaction is to reduce NorthWestern's reliance on PPAs. The acquisition of 439 MW of additional generation capacity (excluding Kerr) would reduce NorthWestern's reliance on PPAs by approximately 46%, in terms of MWh. As a result of the significant reduction in PPAs, the debt imputation by rating agencies for PPAs would be substantially reduced. Therefore, to approve the Hydros transaction and propose a lower equity/debt ratio due to PPAs versus owned generation would be contradictory. Second, based on Standard & Poor's ("S&P") credit report for NorthWestern dated March 21, 2012 (the last available information on S&P's adjustments), S&P imputed a minimal $23.6 million of debt on NorthWestern's total debt calculation to account for PPAs. With the displacement of the PPAs due to the Hydros acquisition, this imputed debt amount would become even more minimal. Although Moody's and Fitch do consider PPAs in their criteria, these rating agencies have not historically imputed any debt related to PPAs on NorthWestern credit metrics.

Big Picture

Q. Does either Mr. Clark or Dr. Wilson suggest that the transaction should be rejected by the Commission?

A. No. They both suggest that if it is approved, some adjustments should be made.

Q. Do their testimonies support this indifference?

A. No. Each witness proposes adjustments that, if accepted by the Commission in full, are unacceptable to NorthWestern and would prevent this deal from closing. The Rowe Rebuttal Testimony explains that

NorthWestern would not close this transaction if the Commission imposes the MCC's conditions.

Q. What other issues do you have with the MCC's testimony?

A. First, it is difficult to ascertain the MCC's position since the testimonies of their two witnesses lack congruency. That is, neither Mr. Clark nor Dr. Wilson reconciles their respective positions to produce a revenue requirement number. NorthWestern acknowledges that Mr. Clark provides conventional recommended adjustments to the revenue requirement that the Commission could actually consider and evaluate (though we do consider unacceptable). He does not take any of the suggestions by Dr. Wilson other than capital structure and ROE, and he actually provides a revenue requirement amount ($114,597,373) for the Commission to evaluate. Unfortunately, he goes on to advocate an unacceptable Kerr rate base adjustment that has no merit in a fair market purchase transaction and to recommend that the Commission should "seriously consider" another adjustment regarding "intergenerational inequity." To make matters worse, it appears Dr. Wilson assumes the Commission should accept all of the adjustments of Mr. Clark and then the Commission should also accept all of his concepts to transfer risk to NorthWestern's stockholders. Dr. Wilson doesn't even try to quantify how this risk transfer might impact NorthWestern's financial position, which leads me to my second issue.

Second, I believe the MCC is being disingenuous in claiming it is indifferent on this transaction. I am fairly certain that the MCC is fully aware that the adjustments/conditions it is proposing, if accepted by the Commission, would result in a completely unacceptable financial situation, and NorthWestern would be unable to close the transaction. The MCC does not quantify the impact of its adjustments, likely because it would be extremely clear to the Commission that what it proposes is unacceptable. Therefore, I can only assume the MCC does not support the transaction but is unwilling to explicitly state this fact in its testimony. If the MCC is truly indifferent, its testimony leads one to believe that the MCC's strategy is to "throw everything against the wall and see what sticks" with the hope that the Commission will grab some of it and that any reduction in revenue requirement is a successful outcome. What NorthWestern, the Commission, and ultimately the consumers (whom the MCC is charged with representing) would have found more useful would have been a presentation of realistic and credible adjustments that could be considered by the Commission that may have reduced the revenue requirement without forcing NorthWestern to abandon the transaction.

Finally, Dr. Wilson's testimony hovers in the realm of theory rather than reality. First, he asserts that no merchant generator would pay purchase prices inclusive of carbon costs that they could not pass onto their customers. But, does he ever support this assertion with what actually happens in the real world? No. The Prefiled Direct and Rebuttal Testimonies of Ahmad Masud clearly show that assets similar to these Hydro assets have traded at higher prices per kilowatt than NorthWestern is paying in this transaction. In fact, many of these buyers in these transactions were not utility buyers but merchant players. Furthermore, does Dr. Wilson's advocacy reflect what authorized ROEs for electric utility assets are in the real world? No. In contrast, the Prefiled Rebuttal Testimony of Adrien McKenzie notes that out of the over 200 authorized ROEs to electric utilities over the past three years, only three were in the 8-9% range Dr. Wilson proposes for this transaction. Mr. McKenzie also notes that over the last 40 years the average authorized ROE for electric utilities has never been below 10%. This is the real world! This is the world in which NorthWestern operates every day in order to attract capital. NorthWestern is requesting an ROE of 10%, which is below the average in each of the last 40 years.

I must also note that Dr. Wilson's recommendation that NorthWestern renegotiate the transaction with PPLM is ridiculous. If NorthWestern cannot close this transaction, then PPLM will negotiate with any number of other buyers, such as hedge funds or out-of-state utilities that need to lessen their reliance on coal and increase their utilization of a renewable resource such as the Hydros, and sell these assets to one of them.

Q. Does NorthWestern propose any adjustments to help its customers?

A. Yes. As is noted in the Rowe Rebuttal Testimony and in the Prefiled Rebuttal Testimony of Patrick DiFronzo ("DiFronzo Rebuttal Testimony"), NorthWestern has reduced its requested revenue requirement. Based on discovery from the Commission, NorthWestern agrees to extend the depreciable life of the Hydros and amortization period for the acquisition adjustment to 50 years. NorthWestern also agrees to forego any return on its investment in Kerr during the short period before the Confederated Salish and Kootenai Tribes exercises its option. These changes reduce NorthWestern's annual revenue requirement by approximately $7.4 million for the first year (refer to the Updated Revenue Requirement presented in the DiFronzo Rebuttal Testimony).

Q. Does this conclude your testimony?

A. Yes, it does.

Department of Public Service Regulation
Montana Public Service Commission
Docket No. D2013.12.85
PPLM Hydro Assets Purchase
NorthWestern Energy

PREFILED REBUTTAL TESTIMONY

OF

ADRIEN M. MCKENZIE

on behalf of

NORTHWESTERN ENERGY

TABLE OF CONTENTS

EXHIBITS TO REBUTTAL TESTIMONY

I. INTRODUCTION

Q1. Please state your name and business address.

A1. My name is Adrien M. McKenzie, and my business address is 3907 Red River, Austin, Texas 78751.

Q2. In what capacity are you employed?

A2. I am a Vice President of FINCAP, Inc., a firm providing financial, economic, and policy consulting services to business and government.

Q3. Please describe your qualifications and experience.

A3. Since joining FINCAP in 1984, I have participated in consulting assignments involving a broad range of economic and financial issues, including cost of capital, cost of service, rate design, economic damages, and business valuation. I have extensive experience in economic and financial analysis for regulated industries, and in preparing and supporting expert witness testimony before courts, regulatory agencies, and legislative committees throughout the U.S. and Canada. I have previously prepared prefiled direct and rebuttal testimony in over 250 regulatory proceedings before the Federal Energy Regulatory Commission ("FERC"), the Canadian Radio-Television and Telecommunications Commission, and regulatory agencies in over 30 states.[1] I have personally sponsored testimony filed with FERC, the Kansas State Corporation Commission, the Washington Utilities and Transportation Commission, and the Wyoming Public Service Commission. Prior to joining FINCAP, I was employed by an oil and gas firm and was responsible for operations and accounting. I earned B.A. and M.B.A. degrees with a major in finance from The University of Texas at Austin, and hold the Chartered Financial Analyst (CFA®) designation. A resume containing the details of my qualifications and experience is attached as Exhibit__(AMM-1).

[1] This testimony was sponsored jointly with, or by Dr. William Avera, who is President of FINCAP, Inc.

Q4. What is the purpose of your rebuttal testimony?

A4. I rebut the Direct Testimony of John W. Wilson ("Wilson Testimony"), submitted on March 28, 2014 on behalf of the Montana Consumer Counsel ("MCC"), concerning the rate of return on equity ("ROE") and capital structure applicable to the hydro asset transaction that NorthWestern Energy ("NorthWestern") is requesting the Montana Public Service Commission ("Commission") to approve in this proceeding.

Q5. What ROE does Dr. Wilson recommend for NorthWestern in connection with the hydro asset purchase?

A5. Dr. Wilson asserts that the cost of equity for NorthWestern "is in the 8 to 9 percent range," and recommends an ROE of 9.0% in this proceeding. Rather than conducting any independent analyses of his own, Dr. Wilson arrives at this recommendation based on flawed modifications to the discounted cash flow ("DCF"), Capital Asset Pricing Model ("CAPM"), and expected earnings analyses sponsored in the Prefiled Direct testimony of Mr. Brian B. Bird ("Bird Direct Testimony"), and summarized on Exhibit__(BBB-5).[2]

Q6. Please summarize the principal conclusions of your Rebuttal Testimony concerning the ROE recommendations of Dr. Wilson.

A6. The ROE recommended by Dr. Wilson is unsupported and should be rejected. The suggestion that the ROE for NorthWestern should be set at 9.0% is contrary to economic reality. The Wilson Testimony fails to address important issues of regulatory policy, including the fact that his recommendation is far too low to meet established regulatory standards and is contrary to economic reality. It is the result reached, and not the method used, that determines whether an ROE is just and

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[2] The detailed analyses supporting the values summarized in Exhibit__(BBB-5) were provided in response to Data Request PSC-007.

reasonable and the result recommended by Dr. Wilson fails to meet established standard for a just and reasonable ROE.

My evaluation identified numerous failings associated with Dr. Wilson's proposals. These include his evaluation and retention of outliers from the DCF results, an incorrect interpretation and application of the CAPM method, and misguided adjustments to the expected earnings approach.[3] While my rebuttal testimony highlights numerous flaws in the analyses presented by Dr. Wilson, the most glaring shortcoming in his approach is the failure to evaluate the reasonableness of the end results produced by his flawed analyses. The ROE recommended by Dr. Wilson is extreme, and would not allow NorthWestern the opportunity to compete for capital by offering investors a return similar to that available from other investment opportunities of comparable risk.

II. MCC RECOMMENDED ROE VIOLATES REGULATORY STANDARDS

Q7. Is it widely accepted that a utility's ability to attract capital must be considered in establishing a fair rate of return?

A7. Yes. This is a fundamental standard underlying the regulation of public utilities. The Supreme Court's *Bluefield* and *Hope* decisions established that a regulated utility's authorized returns on capital must be sufficient to assure investors' confidence and that, if the utility is efficient and prudent on a prospective basis, it will be able to maintain and support its credit and have the opportunity to raise necessary capital.[4]

[3] Dr. Wilson did not discuss or otherwise rebut the risk premium analyses or the results of applying the DCF model to a low-risk group of non-utility firms. Thus, while these analyses serve to support the 10.0% ROE requested by NorthWestern, they are not discussed in my rebuttal testimony.

[4] *Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n*, 262 U.S. 679 (1923) ("*Bluefield*"); *FPC v. Hope Natural Gas Co.*, 320 U.S. 591 (1944) ("*Hope*").

The competition for capital is intense. While the details underlying a determination of the cost of equity are significant to a rate of return analyst, there is one fundamental requirement that any ROE recommendation must satisfy before it can be considered reasonable. The ROE recommendation must grant NorthWestern the opportunity to earn an ROE comparable to contemporaneous returns available from alternative investments of comparable risk if it is to maintain its financial flexibility and ability to attract capital.

Q8. Did Dr. Wilson acknowledge these standards or test his ROE recommendation against these fundamental regulatory requirements?

A8. No. Dr. Wilson ignored these regulatory standards and failed to compare his recommended ROE to any relevant benchmark.

Q9. Can allowed ROEs be used to evaluate whether Dr. Wilson's recommended ROE is sufficient to meet regulatory standards?

A9. Yes. Allowed ROEs provide a gauge of the reasonableness of the outcome of a particular analysis or decision; ROE values do not exist in a vacuum. As noted earlier, if a utility is unable to offer a return similar to that available from other investment opportunities posing equivalent risks, investors will become unwilling to supply the utility with capital on reasonable terms. In evaluating an investment in the electric power industry, investors will naturally seek to maximize their expected rate of return for a given level of risk. While the ROEs approved in other jurisdictions certainly do not limit the Commission's authority with respect to its findings in this case, there would be a disincentive to invest if the Commission were to apply an unreasonably low ROE to NorthWestern's hydro asset transaction compared to entities of comparable risk.

Q10. How does the 9.0% ROE proposed by Dr. Wilson compare to ROEs for other electric utilities?

A10. A 9.0% ROE would be one of the lowest ROEs in the country, and falls well below average returns authorized for other utilities. As documented in the application of the risk premium approach summarized on Exhibit__(BBB-5) and presented in response to Data Request PSC-007, between 1974 and 2013 the average allowed ROE for electric utilities ranged from 15.78% to 10.02%. In other words, at no time during this 40 year period has the average authorized ROE for electric utilities fallen into the single-digit territory recommended by Dr. Wilson. Focusing on recent experience, average ROEs for electric utilities reported by Regulatory Research Associates ("RRA") from 2010 through the first quarter of 2014 are displayed in Table 1, below:

TABLE 1
ALLOWED ROES FOR ELECTRIC UTILITIES

Year	ROE	No. Cases
2010	10.34%	59
2011	10.29%	42
2012	10.17%	58
2013	10.02%	50
2014 - Q1	10.23%	8
	10.21%	217

Regulatory Research Associates, *Regulatory Focus* (Apr. 9, 2014).

As illustrated above, the average authorized ROEs for other firms in the electric utility industry are far higher than the 9.0% that Dr. Wilson has proposed for NorthWestern in this case. In fact, of the 217 cases reported since 2010, only three ROEs fell in the 8% to 9% range advocated by Dr. Wilson, and these values were only approved in connection with revised rate structures implementing revenue decoupling and formula rate plans, including annual reconciliations to ensure timely cost recovery.

Q11. How does Dr. Wilson's recommended ROE compare to authorized returns for the utilities in the proxy group used to estimate the cost of equity?

A11. The current authorized rates of return for the electric utilities in the proxy group reported by AUS Utility Reports ("AUS") are shown on Exhibit__(AMM-2). As documented there, the firms in the proxy group of comparable risk utilities are currently authorized an average ROE of 10.34%. It is unreasonable to presume, as Dr. Wilson apparently does, that NorthWestern could attract capital for investment at an allowed ROE that falls so far below the opportunities available from other comparable utilities.

Q12. What are the implications of setting an allowed ROE below the returns available from other investments of comparable risk?

A12. If the utility is unable to offer a return similar to the returns available from other opportunities of comparable risk, investors will become unwilling to supply capital to the utility on reasonable terms. For existing investors, denying the utility an opportunity to earn what is available from other similar risk alternatives prevents them from earning their cost of capital. Both of these outcomes violate regulatory standards.

Q13. What other pitfalls are associated with an ROE that is so far below those authorized for other comparable companies?

A13. Adopting an ROE for NorthWestern that is well below the ROEs for comparable utilities could lead investors to view the Commission's regulatory framework as unsupportive, an outcome that would undermine investors' willingness to support future capital availability for investment in Montana. Security analysts study regulatory orders in order to advise investors where to invest their money. Moody's Investors Service ("Moody's") noted that, "Fundamentally, the regulatory environment is the most important driver of our outlook."[5] Similarly, Standard & Poor's Corporation ("S&P") concluded:

> The regulatory framework/regime's influence is of critical importance when assessing regulated utilities' credit risk because it defines the environment in which a utility operates and has a significant bearing on a utility's financial performance.[6]

If Commission actions instill confidence that the regulatory environment is supportive, investors will provide the necessary capital, even in times of turmoil in the financial markets. In evaluating NorthWestern's ROE in this case, the Commission has an opportunity to show that it recognizes the importance of continuity and a balanced regulatory regime.

Meanwhile, the inevitable result of adopting Dr. Wilson's recommendations would be an increase in the cost of capital to NorthWestern and other electric utilities in the state. The dangers of such an outcome were recognized at FERC, which Dr. Wilson cites in his testimony.[7] A Presiding Judge recently noted, "if ROE is set substantially below 10% for long periods … it could negatively impact future investment," and concluded that if "investment is substantially limited in the future, it will have a negative impact upon operational needs, reliability, and ultimately ratepayers' future costs."[8] It is only rational for potential investors to consider the regulatory treatment afforded to NorthWestern in evaluating whether to commit new capital to Montana jurisdictional utilities, and at what cost.

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[5] Moody's Investors Service, "Regulation Will Keep Cash Flow Stable As Major Tax Break Ends," *Industry Outlook* (Feb. 19, 2014).
[6] Standard & Poor's Corporation, "Key Credit Factors For The Regulated Utilities Industry," *RatingsDirect* (Nov. 19, 2013).
[7] Wilson Testimony at fn. 20.
[8] 144 FERC ¶ 63,012 at P 576 (2013) ("*Martha Coakley*").

Q14. Do customers benefit when investors have confidence that the regulatory environment is stable and constructive?

A14. Yes. The challenging capital market environment over the last few years highlights the benefits of stability in the ROE, and changing course from the path of financial strength would be extremely short-sighted. As noted above, regulatory signals are a primary driver of investors' risk assessment for utilities. When investors are confident that a utility has supportive regulation, they will make funds available on more reasonable terms, and even in times of turmoil in the financial markets.

Customers and the service area economy enjoy the benefits that come from ensuring that the utility has the financial wherewithal to take whatever actions are required to ensure reliable service. When NorthWestern can negotiate from a position of financial strength it will get a better deal for its customers. In evaluating NorthWestern's ROE in this case, the Commission has an opportunity to show that it recognizes the importance of continuity and a balanced regulatory regime. Dr. Wilson's recommended ROE is far outside the norms established for other utilities, fails to meet regulatory standards, and would be viewed negatively by investors.

Q15. What other benchmarks indicate that Dr. Wilson's recommended ROE is far too low to be considered reasonable?

A15. Expected earned rates of return for other utilities provide another useful benchmark to gauge the reasonableness of Dr. Wilson's ROE recommendation.[9] The expected earnings approach is predicated on the comparable earnings test, which developed as a direct result of the Supreme Court decisions in *Bluefield* and *Hope.* This test recognizes that investors compare the allowed ROE with returns available from other alternatives of comparable risk.

[9] Dr. Wilson recognized the relevance of this approach in his testimony (p. 54), but as discussed subsequently, his application of this method was flawed and led to distorted and unreliable results.

Moreover, regulators do not set the returns that investors earn in the capital markets – they can only establish the allowed return on the value of a utility's investment, as reflected on its accounting records. As a result, the expected earnings approach provides a direct guide to ensure that the allowed ROE is similar to what other utilities of comparable risk will earn on invested capital. This opportunity cost test does not require theoretical models to indirectly infer investors' perceptions from stock prices or other market data. As long as the proxy companies are similar in risk, their expected earned returns on invested capital provide a direct benchmark for investors' opportunity costs that is independent of fluctuating stock prices, market-to-book ratios,[10] debates over DCF growth rates, or the limitations inherent in any theoretical model of investor behavior.

Q16. Has the expected earnings approach been recognized as a valid ROE benchmark?

A16. Yes. This method predominated before the DCF model became fashionable with academic experts, and it continues to be used around the country.[11] A textbook prepared for the Society of Utility and Regulatory Analysts labels the comparable earnings approach the "granddaddy of cost of equity methods" and points out that the amount of subjective judgment required to implement this method is "minimal", particularly when compared to the DCF and CAPM methods.[12] The *Practitioner's Guide* notes that the comparable earnings test method is "easily understood" and

[10] Dr. Wilson (pp. 54-56) wrongly implies that utility earnings are generally too high because market-to-book ratios in the industry generally exceed one. I address the fallacy of this argument later in my rebuttal testimony.
[11] For example, the Virginia State Corporation Commission ("VSCC") is required by statute (Virginia Code § 56-585.1.A.2.a) to consider the earned returns on book value of electric utilities in its region. In orders issued on November 30, 2011 and July 15, 2010 in Dockets PUE-2011-00037 and PUE-2009-00030, the VSCC established the allowed ROE for Appalachian Power Company based solely on the earned returns on book value for a peer group of other electric utilities. Another example is the Idaho Public Utilities Commission, which continues to confirm the relevance of return on book equity evidence. *See, e.g.,* Order No. 29505, *Idaho Public Utilities Commission,* Case No. IC-E-03-13 at p.38.
[12] Parcell, David C., *The Cost of Capital—a Practitioner's Guide* at 115-116 (2010).

firmly anchored in the regulatory tradition of the *Bluefield* and *Hope* cases,[13] as well as sound regulatory economics. Similarly, *New Regulatory Finance* concluded that, "because the investment base for ratemaking purposes is expressed in book value terms, a rate of return on book value, as is the case with Comparable Earnings, is highly meaningful."[14]

Q17. What ROE is implied by the expected earnings approach for the proxy group of electric utilities?

A17. The year-end returns on common equity projected by Value Line over its forecast horizon for the firms in the electric utility proxy group are shown on Exhibit__(AMM-3). Because Value Line reports end-of-year book values, an adjustment factor was incorporated to convert these year-end returns to an average rate of return over the year.[15]

Given that earnings is a flow over the year while book value is a stock at a given point in time, the measurement of earnings and book value are distinct concepts. It is this fundamental difference between a flow (earnings) and a stock (book value) that makes it necessary to adjust to mid-year in calculating the return on equity, or "r" value. Given that book value will increase (decrease) over the year, using year-end book value (as Value Line does) understates (overstates) the average investment that corresponds to the flow of earnings. In other words, because earnings represents a flow over the year, it must be matched with a corresponding representative measure of book value, or the resulting return on equity will be distorted.

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[13] *Id.*.
[14] Roger A. Morin, "New Regulatory Finance," *Public Utilities Reports, Inc.* at 395 (2006).
[15] The need for this adjustment has been recognized in the financial literature and by FERC. *See*, Morin, Roger A., "New Regulatory Finance," *Public Utilities Reports, Inc.* (2006) at 305-306; *Bangor Hydro-Elec. Co.*, 122 FERC ¶ 61,265 (2008).

As shown on Exhibit__(AMM-3), reference to expected earnings implied an annual average cost of equity for the utilities referenced by Dr. Wilson of 10.1%, with a midpoint of 10.5%. Once adjusted to annual average basis, these book return estimates are an "apples to apples" comparison to the 9.0% ROE recommended by Dr. Wilson.

Q18. What would be the effect of authorizing a book return that is so far below the average earnings of the utilities that Dr. Wilson accepts as comparable to NorthWestern?

A18. Plain and simple, NorthWestern will find it difficult to compete for investors' capital and investors would not be earning up to the *Bluefield* standard of comparable earnings:

> A public utility is entitled to such rates as will permit it to earn on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties.[16]

Setting a return of 9.0% on the book value of NorthWestern's investment, while other opportunities of comparable risk offer investors expected returns of 10.1%, would be a clear violation of regulatory standards. If the utility is unable to offer a return similar to that available from other opportunities of comparable risk, investors will become unwilling to supply capital on reasonable terms. For existing investors, denying the utility an opportunity to earn what is available from other similar risk alternatives prevents them from earning their opportunity cost of capital. This results in the confiscation of the value of existing investors' capital without adequate compensation in return.

[16] *Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n*, 262 U.S. 679 (1923).

III. DCF OUTLIERS SHOULD BE ELIMINATED

Q19. What is Dr. Wilson's primary criticism of NorthWestern's DCF analyses?

A19. Dr. Wilson concludes that the DCF analyses submitted in support of NorthWestern's requested 10% ROE are "highly distorted by an "apparently arbitrary and extremely one-sided" elimination of outliers.[17] Dr. Wilson asserts that, "There was no apparent reason for excluding the thirty-six lowest values other than they reduced the calculated average."[18]

Q20. Is there any merit to Dr. Wilson's claim?

A20. No. In applying quantitative methods to estimate the cost of equity, it is essential that the resulting values pass fundamental tests of reasonableness and economic logic. Accordingly, DCF estimates that are implausibly low or high should be eliminated when evaluating the results of this method.

The evaluation of DCF estimates at the low end of the range was based on the fundamental risk-return tradeoff, which holds that investors will only take on more risk if they expect to earn a higher rate of return to compensate them for the greater uncertainty. Because common stocks lack the protections associated with an investment in long-term bonds, a utility's common stock imposes far greater risks on investors. As a result, the rate of return that investors require from a utility's common stock is considerably higher than the yield offered by senior, long-term debt. Consistent with this principle, DCF results that are not sufficiently higher than the yield available on less risky utility bonds must be eliminated.

[17] Wilson Testimony at 49.
[18] Wilson Testimony at 50.

Q21. Have similar tests been applied by regulators?

A21. Yes. FERC has noted that adjustments are justified where applications of the DCF approach produce illogical results. FERC evaluates DCF results against observable yields on long-term public utility debt and has recognized that it is appropriate to eliminate estimates that do not sufficiently exceed this threshold. The practice of eliminating low-end outliers that fail economic tests of logic has been affirmed in numerous FERC proceedings.[19] In its April 15, 2010 decision in *SoCal Edison*, FERC affirmed that, "it is reasonable to exclude any company whose low-end ROE fails to exceed the average bond yield by about 100 basis points or more."[20]

Q22. What interest rate benchmark was referenced in evaluating the DCF results for NorthWestern?

A22. S&P has assigned a corporate credit rating of "BBB" to NorthWestern. Companies rated "BBB-", "BBB", and "BBB+" are all considered part of the triple-B rating category. Accordingly, NorthWestern's DCF application referenced average yields on triple-B utilities bonds as one benchmark in evaluating low-end DCF results. Consistent with the time period when the DCF analyses were prepared, Moody's reported that monthly yields on triple-B bonds averaged 5.17% in October 2013.[21] Based on the risk-return principle that is fundamental to finance, it is inconceivable that investors are not requiring a substantially higher rate of return for holding common stock.

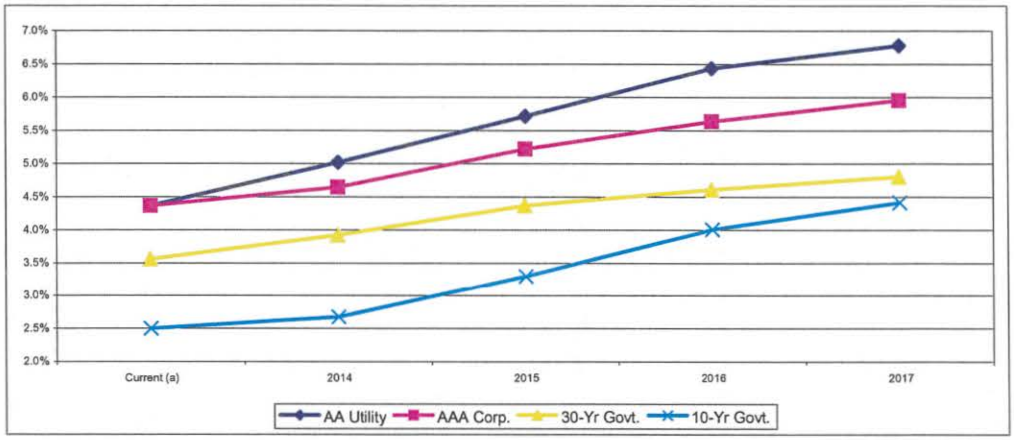
Q23. What else should be considered in evaluating DCF estimates at the low end of the range?

A23. Despite recent increases, the yields on utility bonds remain near their lowest levels in modern history. Investors do not anticipate that these low interest rates will continue.

[19] *See, e.g., Virginia Electric Power Co.*, 123 FERC ¶ 61,098 at para.64 (2008).
[20] *Southern California Edison Co.*, 131 FERC ¶ 61,020 at para. 55 (2010) ("*SoCal Edison*").
[21] Moody's Investors Service, http://credittrends.moodys.com/chartroom.asp?c=3.

It is widely anticipated that as the economy continues to stabilize and resumes a more robust pattern of growth, long-term capital costs will increase from present levels. Figure 1 below compares average interest rates on 30-year Treasury bonds, triple-A rated corporate bonds, and double-A rated utility bonds for October 2013 with near-term projections from the Value Line Investment Survey ("Value Line"), IHS Global Insight, Blue Chip Financial Forecasts ("Blue Chip"), and the Energy Information Administration ("EIA"):

FIGURE 1
INTEREST RATE TRENDS



(a) Based on monthly average bond yields for the six-month period May 2013 - Oct. 2013 reported at www.credittrends.moodys.com and http://www.federalreserve.gov/releases /h15/data.htm.

Sources:
Value Line Investment Survey, Forecast for the U.S. Economy (Sep. 13, 2013)
IHS Global Insight, U.S. Economic Outlook at 25 (June 2013)
Energy Information Administration, Annual Energy Outlook 2013 (Apr. 15, 2013)
Blue Chip Financial Forecasts, Vol. 32, No. 6 (Jun. 1, 2013)

These forecasting services are highly regarded and widely referenced. FERC incorporates forecasts from IHS Global Insight and the EIA in its preferred DCF model for natural gas pipelines. As evidenced above, there is a consensus in the investment community that the cost of long-term capital will be significantly higher over the 2014-2018 period than it is currently.

As shown in Table 2 below, forecasts of IHS Global Insight and the EIA imply an average triple-B bond yield of approximately 6.7% over the period 2014-2018:

TABLE 2
IMPLIED BBB BOND YIELD

	2014-17
Projected AA Utility Yield	
IHS Global Insight (a)	5.72%
EIA (b)	6.26%
Average	5.99%
Current BBB - AA Yield Spread (c)	0.75%
Implied Triple-B Utility Yield	**6.74%**

(a) IHS Global Insight, U.S. Economic Outlook at 25 (June 2013)
(b) Energy Information Administration, Annual Energy Outlook 2013 (Apr. 15, 2013)
(c) Based on monthly average bond yields from Moody's Investors Service for the six-month period May 2013 - Oct. 2013

The increase in debt yields anticipated by IHS Global Insight and EIA is also supported by the widely referenced Blue Chip Financial Forecasts, which projects that yields on corporate bonds will climb on the order of 165 basis points through 2018.[22]

Q24. What does this test of logic imply with respect to the DCF results for the electric utilities in the proxy group?

A24. As highlighted on Tab 4(3) provided in response to Data Request PSC-007, low-end DCF estimates ranged from 2.0% to 7.4%. In light of the risk-return tradeoff principle and the test of economic logic applied by FERC, it is inconceivable that investors are not requiring a substantially higher rate of return for holding common stock. As a result, consistent with the upward trend expected for utility bond yields, these values provide no meaningful guidance as to the returns investors require from utility common stocks and should be excluded.

[22] *Blue Chip Financial Forecasts*, Vol. 32, No. 12 (Dec. 1, 2013).

Q25. Were values at the high end of the range also excluded?

A25. Yes. The upper end of the DCF range for the proxy group of electric utilities was set by a cost of equity estimate of 25.5%, which was based on an estimated earnings per share growth rate of 21.5%. When compared with the balance of the remaining estimates, this value is an extreme outlier and should be excluded in evaluating the results of the DCF model. This is also consistent with the precedent adopted by FERC, which has repeatedly found that cost of equity estimates of 17.7% or greater are extreme, and has also expressed concern regarding the sustainability of growth rates of 13.3% or more.[23] Accordingly, this 25.5% DCF estimate was properly eliminated.

Q26. Is there a basis to exclude any remaining DCF estimates at the high end of the range?

A26. No. After excluding the 25.5% value discussed above, the upper end of the DCF range for the Electric Group was set by a cost of equity estimate of 14.5%. While this cost of equity estimate exceeds the remaining values, low-end estimates in the 7.5% range are assuredly far below investors' required rate of return, but were nonetheless also retained in the analysis. Taken together and considered along with the balance of the DCF estimates, these values provide a reasonable basis on which to evaluate investors' required rate of return.

Q27. Has Dr. Wilson also recognized that it is appropriate to eliminate illogical DCF estimates?

A27. Yes. Dr. Wilson testified in Docket No. D2009.9.129 that he does not disagree with the removal of outliers from statistical analyses, and granted that "it is sometimes appropriate to exclude outliers in evaluating calculated results."[24] In that case, Dr.

[23] *See, e.g., ISO New England, Inc.*, 109 FERC ¶ 61,147 at para. 205 (2004).
[24] Docket No. D2009.9.129, *Direct Testimony of John W. Wilson* at pp. 20-21 (June 3, 2010).

Wilson proposed to exclude DCF results "that are either 300 basis points (i.e., 3.0%) above or below NorthWestern's currently allowed equity return."[25]

Q28. Is that consistent with Dr. Wilson's proposed cut-off for low-end DCF estimates in this case?

A28. No. Here, Dr. Wilson proposed to exclude "eleven low values that are under 6 percent." As noted in the Bird Direct Testimony,[26] NorthWestern's current authorized ROEs for electric utility operations range from 10.00% to 10.25%. While there are serious conceptual problems associated with the methodology Dr. Wilson proposed in his 2010 testimony, consistency with his prior opinions would support excluding all DCF estimates of 7.25% or below in this proceeding.[27] This inconsistency provides another illustration of the downward bias inherent in Dr. Wilson's conclusions. Moreover, Dr. Wilson's evaluation ignores the fact that long-term capital costs are projected to increase significantly. Investors undoubtedly consider these expectations in evaluating their required rate of return on common stocks, including those of the utilities in the proxy group of electric utilities. As a result, the projected bond yields referenced above provide a useful benchmark in evaluating the extent to which DCF estimates at the low end of the range can be considered reasonable and sufficient. Because Dr. Wilson ignored the expected upward trend in capital costs in his evaluation, his DCF analysis retained low-end estimates that are not indicative of investors' forward-looking expectations, which biased his results downward.

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[25] *Id.* at p. 21.

[26] Bird Direct at 35

[27] Applying Dr. Wilson's own test would require excluding an additional 19 DCF estimates from the analysis presented on his Exhibit__(JW-5).

IV. DR. WILSON'S CAPM RESULTS SHOULD BE DISREGARDED

Q29. What were the results of Dr. Wilson's application of the CAPM approach?

A29. Dr. Wilson did not formulate a precise cost of equity estimate using the CAPM. After criticizing certain aspects of the CAPM application sponsored by Mr. Bird, Dr. Wilson simply concluded that "the CAPM cost of equity estimate would be less than 8 percent at the present time."[28]

Q30. Dr. Wilson argues (pp. 52-54) that it is incorrect to apply the CAPM using long-term government bond yields as the risk-free rate. Is there any merit to his assertions?

A30. No. Unlike debt instruments, common equity is a perpetuity and as a result, any application of the CAPM to estimate the return that investors require must be predicated on their expectations for the firm's long-term risks and prospects. This does not mean that every investor will buy and hold a particular common stock into perpetuity. Rather, it recognizes that even an investor with a relatively short holding period will consider the long-term, because of its influence on the price that he or she ultimately receives from the stock when it is sold. This is also the basic assumption underpinning the DCF model, which in theory considers the present value of all future dividends expected to be received by a share of stock.

Shannon P. Pratt, a leading authority in business valuation and cost of capital, recognized that the cost of equity is a long-term cost of capital and that the appropriate instrument to use in applying the CAPM is a long-term bond because:

- It most closely matches the often-assumed perpetual lifetime horizon of an equity investment.
- The longest-term yields to maturity fluctuate considerably less than short-term rates and thus are less likely to

[28] Wilson Testimony at 54.

> introduce unwarranted short-term distortions into the actual cost of capital.
>
> - People generally are willing to recognize and accept the fact that the maturity risk is impounded into this base, or otherwise risk-free rate.
> - It matches the longest-term bond over which the equity risk premium is measured in the Ibbotson Associates data series.[29]

In applying the CAPM, Ibbotson Associates (now *Morningstar*) recognized that the cost of equity is a long-term cost of capital and the appropriate interest rate to use is a long-term bond yield:

> The horizon of the chosen Treasury security should match the horizon of whatever is being valued. … Note that the horizon is a function of the investment, not the investor. If an investor plans to hold a stock in a company for only five years, the yield on a five-year Treasury note would not be appropriate since the company will continue to exist beyond those five years.[30]

Similarly, *New Regulatory Finance* concluded that:

> At the conceptual level, because common stock is a long-term investment and because the cash flows to investors in the form of dividends last indefinitely, the yield on very long-term government bonds, namely, the yield on 30-year Treasury bonds, is the best measure of the risk-free rate for use in the CAPM …[31]

Long-term Treasury bonds have an investment horizon that is closer to that of common stocks. Accordingly, proper application of the CAPM should focus on long-term government bonds and analyses based on short-term Treasury bills should be ignored.

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[29] Pratt, Shannon P., *Cost of Capital, Estimation and Applications* at 60 (1998).
[30] Ibbotson Associates, *2003 Yearbook* (Valuation Edition) at 53.
[31] Roger A. Morin, "New Regulatory Finance," *Public Utilities Reports, Inc.*, p. 151 (2006)

Q31. Did. Dr. Wilson provide any support for his recommended market equity risk premium?

A31. No. Dr. Wilson simply stated his opinion that "a reasonable risk premium" is in the range of "3 to 6 percent over the current cost of risk free debt."[32] Nowhere did Dr. Wilson discuss or otherwise support this range.

Q32. What cost of equity estimate is actually implied by Dr. Wilson's flawed CAPM approach?

A32. The CAPM is mathematically expressed as:

$$R_j = R_f + \beta_j(R_m - R_f)$$

where: R_j = required rate of return for stock j;
R_f = risk-free rate;
R_m = expected return on the market portfolio; and
β_j = beta, or systematic risk, for stock j.

The midpoint of Dr. Wilson's 3.0% to 6.0% risk premium range is 4.5%. Dr. Wilson makes the misguided argument that "one must use the interest rate on very short term Treasury debt." The average yield on 3-month Treasury bills during March 2013 was 0.05%. As shown on Exhibit__(AMM-4), with an average beta of 0.78 for the firms in the electric proxy group, Dr. Wilson's suggested CAPM analysis would result in a cost of equity estimate of 3.55%.

Q33. Does a cost of equity estimate of 3.55% make any economic sense?

A33. No. The 3.55% end-result of Dr. Wilson's suggested CAPM analysis is entirely illogical. This value falls almost 150 basis points below the average yield on triple-B utilities bonds, and is roughly equivalent to the return investors can currently earn by investing in long-term Treasury bonds. The outcome of Dr. Wilson's CAPM application violates the risk-return tradeoff that is fundamental to finance, and

[32] Wilson Testimony at 53.

demonstrates conclusively that his proposed "corrections" to the analyses sponsored by Mr. Bird are seriously flawed and should be ignored.

Q34. Is the market equity risk premium used in the analyses sponsored by Mr. Bird consistent with the CAPM method?

A34. Yes. The CAPM and the Empirical CAPM ("ECAPM") are *ex-ante,* or forward-looking models based on expectations of the future. As a result, in order to produce a meaningful estimate of investors' required rate of return, the CAPM must be applied using estimates that reflect the expectations of actual investors in the market. Consistent with this requirement, application of the CAPM and ECAPM to the electric proxy group was based on a forward-looking estimate for investors' required rate of return from common stocks. In order to capture the expectations of today's investors in current capital markets, the expected market rate of return was estimated by conducting a DCF analysis on the dividend paying firms in the S&P 500.

The use of forward-looking expectations in estimating the market risk premium is well accepted in the financial literature. For example, "The Market Risk Premium: Expectational Estimates Using Analysts' Forecasts" employed the DCF model and earnings growth projections from IBES [33] – which is exactly the same approach underlying the market risk premium underlying the ECAPM and CAPM analyses summarized on Exhibit__(BBB-5).

Q35. Have other regulators relied on a forward-looking market risk premium approach similar to the one presented in NorthWestern's analyses?

A35. Yes. The market equity risk premium used in NorthWestern's analyses was based on the methods used by the Staff at the Illinois Commerce Commission, whose witnesses have routinely relied on a forward-looking market rate of return to apply the CAPM.

[33] Robert S. Harris and Felicia C. Marston, "The Market Risk Premium: Expectational Estimates Using Analysts' Forecasts" *Journal of Applied Finance*, Vol. 11 No. 1, 2001.

For example, Illinois Staff witness Rochelle Langfeldt employed an expected market return of 15.31% based on an approach analogous to that contained in the analyses supporting Exhibit__(BBB-5) and provided in response to Data Request PSC-007:

> Q. How was the expected rate of return on the market portfolio estimated?
>
> A. The expected rate of return on the market was estimated by conducting a DCF analysis on the firms composing the S&P 500 Index ("S&P 500"). … Firms not paying a dividend as of June 28, 2001, or for which neither Zacks nor IBES growth rates were available were eliminated from the analysis. The resulting company-specific estimates of the expected rate of return on common equity were then weighted using market value data from Salomon Smith Barney, *Performance and Weights of the S&P 500: Second Quarter 2001*. The estimated weighted averaged expected rate of return for the remaining 365 firms composing 78.31% of the market capitalization of the S&P 500 equals 15.31%.[34]

Q36. Did Dr. Wilson address the implications of the ECAPM analyses presented in NorthWestern's analyses?

A36. No. Myriad empirical tests of the CAPM have shown that low-beta securities earn returns somewhat higher than the CAPM would predict, and high-beta securities earn less than predicted. In other words, the CAPM tends to overstate the actual sensitivity of the cost of capital to beta, with low-beta stocks tending to have higher returns and high-beta stocks tending to have lower risk returns than predicted by the CAPM. This empirical finding is widely reported in the finance literature.[35]

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[34] Illinois Commerce Commission, Docket No. 01-0423, *Direct Testimony of Rochelle Langfeldt* at 23-24 (2001). Ms. Langfeldt's recommended ROE was subsequently approved. Illinois Commerce Commission, Docket No. 01-0423, *Order* at 131.

[35] *See, e.g.,* Morin, Roger A., "New Regulatory Finance, *Public Utilities Reports, Inc.* at 175-176 (2006).

As discussed in *New Regulatory Finance*,[36] based on a review of the empirical evidence, the expected return on a security is related to its risk by the ECAPM, which is represented by the following formula:

$$R_j = R_f + 0.25(R_m - R_f) + 0.75[\beta_j(R_m - R_f)]$$

This ECAPM equation, and the associated weighting factors, recognize the observed relationship between standard CAPM estimates and the cost of capital documented in the financial research, but correct for the understated returns that would otherwise be produced for low beta stocks. Dr. Wilson fails to address this issue.

Q37. Did Dr. Wilson fail to consider other important factors in his review of the CAPM?

A37. Yes. As explained by *Morningstar*:

> One of the most remarkable discoveries of modern finance is the finding of a relationship between firm size and return. On average, small companies have higher returns than large ones. … The relationship between firm size and return cuts across the entire size spectrum; it is not restricted to the smallest stocks.[37]

Because empirical research indicates that the CAPM does not fully account for observed differences in rates of return attributable to firm size, a modification is required to account for this size effect.

According to the CAPM, the expected return on a security should consist of the riskless rate, plus a premium to compensate for the systematic risk of the particular security. The degree of systematic risk is represented by the beta coefficient. The need for the size adjustment arises because differences in investors' required rates of return that are related to firm size are not fully captured by beta. To account for this,

[36] *Id.* at 189.
[37] *Morningstar*, "Ibbotson SBBI 2014 Classic Yearbook," at 99.

Morningstar has developed size premiums that need to be added to the theoretical CAPM cost of equity estimates to account for the level of a firm's market capitalization in determining the CAPM cost of equity.[38] Accordingly, the ECAPM and CAPM analyses supporting NorthWestern's requested ROE incorporated an adjustment to recognize the impact of size distinctions, as measured by the average market capitalization for the electric proxy group.

The refinements to the results of modern capital market theory represented by the ECAPM and size adjustments reflect improvements to the general model of investor behavior that are designed to address the findings of empirical research. Dr. Wilson's failure to consider or otherwise address these findings highlights another serious failing of his CAPM analysis.

V. MARKET-TO-BOOK ADJUSTMENT IS MISGUIDED

Q38. Has Dr. Wilson previously acknowledged the economic premise underlying the expected earnings approach?

A38. Yes. The simple, but powerful concept underlying the expected earnings approach is that investors compare each investment alternative with the next best opportunity. As Dr. Wilson recognized in a previous docket before the Commission, this benchmark is a foundation on which investors evaluate alternative opportunities, and he concluded that the expected earnings approach provides an "essential reference point" in establishing a fair ROE.[39]

[38] *Morningstar,* "Ibbotson SBBI 2014 Market Report," at Table 10.
[39] Docket No. D2009.9.129, *Direct Testimony of John W. Wilson* at 34.

Q39. What is the relevance of Dr. Wilson's discussion of market-to-book ratios (Wilson Testimony, pp. 54-57) to the application of the expected earnings approach?

A39. Based on his testimony, I understand that Dr. Wilson is trying to argue that utility earnings are generally too high because the market-to-book ratios ("M/B") generally exceed 1.0. He wants the Commission to sacrifice NorthWestern's financial strength to favor a theoretical ideal of M/B equaling unity. The Commission does not regulate utility stock market prices, and as discussed below, there are many leaps between his economic theory and reality. But if the theory is correct, then Dr. Wilson is asking the Commission to order an ROE that would almost certainly lead to a capital loss on shareholders' investment in NorthWestern. From an economic perspective, such an action would violate the standards underlying a fair ROE.

Q40. Do you agree with Dr. Wilson that it is necessary to examine M/B in applying the expected earnings approach?

A40. No. Traditional applications of the expected earnings approach do not involve an M/B adjustment. Nor is such an adjustment recommended in recognized texts such as *New Regulatory Finance.*[40]

Q41. Is there a clear link between M/B for electric utilities and allowed rates of return?

A41. No. Underlying Dr. Wilson's criticism is the supposition that regulators should set an ROE to produce an M/B of approximately 1.0. This is fallacious. For example, *Regulatory Finance: Utilities Cost of Capital* noted that:

> The stock price is set by the market, not by regulators. The M/B ratio is the end result of regulation, and not its starting point. The view that regulation should set an allowed rate of return so as to produce an M/B of 1.0, presumes that investors

[40] Roger A. Morin, "New Regulatory Finance," *Public Utilities Reports, Inc.* (2006).

> are irrational. They commit capital to a utility with an M/B in excess of 1.0, knowing full well that they will be inflicted a capital loss by regulators. This is certainly not a realistic or accurate view of regulation.[41]

With M/B for most utilities above 1.0, Dr. Wilson is suggesting that, unless book value grows rapidly, regulators should establish equity returns that will cause share prices to fall. Given the regulatory imperative of preserving a utility's ability to attract capital, this would be a truly nonsensical result. M/B is determined by investors in the stock market, and a utility would be foreclosed from attracting capital if regulators were to push M/B to 1.0 while other firms command prices well in excess of 1.0 times book value.

Q42. Is there anything unusual about a stock price exceeding book value?

A42. No. In fact the majority of stocks currently sell substantially above book value. For example, Value Line reports that approximately 1,430 of the roughly 1,700 stocks it follows (including utilities and other industries) sell for prices in excess of book value.[42] Moreover, as noted above, the notion that regulators should establish the ROE so as to force M/B to 1.0 is misguided. Regulators can only establish the allowed return on the book value of a utility's investment, and as a result, the expected earnings approach provides a direct guide to ensure that the allowed ROE is similar to what other utilities of comparable risk will earn on invested capital. This opportunity cost test does not require theoretical models to indirectly infer investors' perceptions from stock prices or other market data. As long as the proxy companies are similar in risk, their expected earned returns on invested capital provide a direct benchmark for investors' opportunity costs that is independent of fluctuating stock prices, M/B, debates over DCF growth rates, or the limitations inherent in any theoretical model of investor behavior.

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[41] *Id.* at 376.
[42] www.valueline.com (retrieved Apr. 27, 2014).

Q43. Are adjustments based on M/B a common feature in determining allowed ROEs for utilities?

A43. No. While arguments regarding the implications of an M/B greater than 1.0 are not uncommon, I am not aware of a single instance in recent history which a state regulator has approved an M/B adjustment in establishing a fair ROE. Meanwhile, FERC has explicitly recognized the fallacy of relying on M/B in evaluating cost of equity estimates. For example, the Presiding Judge in *Orange & Rockland* concluded, and the FERC affirmed that:

> The presumption that a market-to-book ratio greater than 1.0 will destroy the efficacy of the DCF formula disregards the realities of the market place principally because the market-to-book ratio is rarely equal to 1.0.[43]

The Initial Decision found that there was no support in FERC precedent for the use of M/B to adjust market derived cost of equity estimates based on the DCF model and concluded that such arguments were to be treated as "academic rhetoric" unworthy of consideration. Similarly, in *Williston Basin*, FERC declined to accept a proposed adjustment for differences in financial leverage between book and market value capital structures, concluding:

> In a previous order, we rejected a similar proposal to adjust the allowed rate of return to reflect the difference between market and book value.[44]

Q44. Does the result of Dr. Wilson's M/B adjustment illustrate the serious shortcomings of his arguments?

A44. Yes. Based on the result of applying his M/B adjustment, Dr. Wilson ultimately concludes that "an equity return of 7.4 percent would be sufficient to sustain the stock price at book value."[45] But even in the unlikely event that the long trail of

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[43] *Orange & Rockland Utilities, Inc.*, Initial Decision, 40 FERC ¶ 63,053, 1987 WL 118,352 (F.E.R.C.).
[44] *Williston Basin Interstate Pipeline Co.,* 104 FERC ¶ 61,036 at P 52 (2003).
[45] Wilson Testimony at 57.

breadcrumbs between Dr. Wilson's theoretical postulations on M/B and allowed returns remained unbroken, his conclusion is directed at the wrong hypothesis. The question before the Commission is not what ROE will produce a M/B of 1.0 for electric utilities; rather, the question is what ROE will allow NorthWestern to maintain access to capital and grant stockholders the opportunity to earn a fair return on investment vis-à-vis alternatives of comparable risk. The 7.4% result of Dr. Wilson's misguided adjustment is far too low to be considered credible and provides no useful information regarding this question.

VI. MCC RECOMMENDED CAPITAL STRUCTURE IS UNSUPPORTED

Q45. What are the implications of the 45% common equity ratio under Dr. Wilson's recommended capitalization?

A45. Other things equal, a higher debt ratio, or lower common equity ratio, translates into increased financial risk for all investors. A greater amount of debt means more investors have a senior claim on available cash flow, thereby reducing the certainty that each will receive his contractual payments. This increases the risks to which lenders are exposed, and they require correspondingly higher rates of interest. From common shareholders' standpoint, a higher debt ratio means that there are proportionately more investors ahead of them, thereby increasing the uncertainty as to the amount of cash flow, if any, that will remain. Because a capitalization that contains relatively more debt leverage implies greater financial risk, it also implies a higher required ROE to compensate investors for bearing additional uncertainty.

Q46. How does Dr. Wilson's 45% recommended equity ratio compare with that of the proxy group of electric utilities used to estimate the ROE?

A46. Updated capital structure data for the proxy firms is presented in Exhibit__(AMM-5). As shown there, the average equity ratio for proxy utilities at year-end 2013 was 49.5%, with Value Line expecting an average equity ratio for its 3-5 year forecast horizon of 48.9% percent of long-term capital. Meanwhile, with respect to NorthWestern specifically, S&P noted:

> We also expect NorthWestern to fund the acquisition with a balance of debt and equity that is consistent with its capital structure and does not significantly affect cash flow measures in the long term," said Standard & Poor's credit analyst Michael T. Ferguson.[46]

The common equity ratio proposed by Mr. Bird is consistent with industry benchmarks and the expectations of the capital markets.

Q47. What does this data imply with respect to Dr. Wilson's recommended ROE?

A47. The cost of equity estimates developed for the proxy group reflect the return that investors require to accept the average risks associated with this group of utilities, including the financial risk implicit in the group's average capitalization. The 45% equity ratio recommended by Dr. Wilson implies greater investment risks than are associated with the proxy group, and investors would require greater compensation, in the form of higher returns on debt and equity capital.

As noted earlier, investors and bond rating agencies are increasingly focused on the importance of regulatory support. Making unwarranted adjustments to the capital structure or adopting an unreasonably low ROE would undoubtedly have a negative impact on investors' risk perceptions, and doing both would only compound these concerns.

Q48. Does Dr. Wilson correctly characterize the impact of power purchase agreements ("PPAs") on a utility's capital structure?

A48. No. Dr. Wilson (p. 58) argues that reliance on PPAs would somehow justify a downward adjustment to NorthWestern's equity ratio in this case, when exactly the

[46] Standard & Poor's Corporation, *Press Release* (Sep. 30, 2013).

opposite is true. Depending on their specific attributes, contractual agreements such as PPAs that require a utility to make specified payments may be treated as debt in assessing financial risk. These commitments have been repeatedly cited by major bond rating agencies in connection with assessments of utility financial leverage.[47] Because investors consider the debt impact of such fixed obligations in assessing a utility's financial position, they imply greater risk and reduced financial flexibility.

In order to offset the debt equivalent associated with off-balance sheet obligations, the utility must rebalance its capital structure by increasing its common equity in order to restore its effective capitalization ratios to previous levels. Unless NorthWestern takes action to offset the additional financial risk associated with PPAs by maintaining a higher equity ratio, the resulting leverage will weaken its creditworthiness, implying a higher required rate of return to compensate investors for the greater risks. Meanwhile, Dr. Wilson turns this reality on its head, and instead argues that the higher financial leverage implicit in PPAs justifies a *lower* equity ratio in this case. Dr. Wilson's position is contrary to financial realities and the requirements and perceptions of the investment community and should be ignored.

Q49. Are NorthWestern's requested capital structure and component costs favorable to customers when compared to the proxy group of electric utilities?

A49. Yes. Exhibit__(AMM-6) compares NorthWestern's requested overall rate of return of 7.14% to the overall rate of return implied for the electric proxy group. As shown there, combining an industry average capital structure composed of approximately 50% debt and 50% equity, the recommended ROE of 10.39% implied by NorthWestern's analyses, and assuming the same average embedded debt cost of 4.5%

[47] *See, e.g.,* Standard & Poor's Corporation, "Standard & Poor's Methodology For Imputing Debt For U.S. Utilities' Power Purchase Agreements," *RatingsDirect* (May 7, 2007); "Implications Of Operating Leases On Analysis Of U.S. Electric Utilities," *RatingsDirect* (Jan. 15, 2008).

results in an overall rate of return of 7.45%. The fact that NorthWestern's requested overall rate of return is 31 basis point lower than what is implied for the proxy group provides further support for the reasonableness of NorthWestern's proposal and its fairness to customers.

Q50. Please summarize your criticisms of Dr. Wilson's evaluation and recommendation.

A50. My rebuttal testimony demonstrates that Dr. Wilson's recommended 9.0% ROE fails the end-result test that is fundamental to economic and regulatory standards. MCC's ROE is too low to provide investors an opportunity to earn a return comparable to expectations for other alternatives of comparable risk, and would undermine NorthWestern's ability to attract capital on reasonable terms.

Dr. Wilson's testimony suffers from numerous deficiencies. His evaluation of DCF outliers is contrary to his own prior testimony and investors' expectations for higher capital costs. Dr. Wilson's application of the CAPM method is unsupported, and produces an implied cost of equity that falls below the yields available on public utility bonds. Meanwhile, his arguments concerning the implications of M/B imply capital losses for investors, which runs contrary to rational expectations in the capital markets and established regulatory principles. Finally, Dr. Wilson's recommended adjustment to NorthWestern's capital structure runs contrary to industry benchmarks and analysts' expectations, and his arguments concerning the impact of PPAs are misguided. My rebuttal testimony provides further support for the 10% ROE and capitalization requested by NorthWestern, both of which are fair and reasonable and should be approved.

Q51. Does this conclude your rebuttal testimony?

A51. Yes.

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Summary of Qualifications

Adrien McKenzie has an MBA in finance from the University of Texas at Austin and holds the Chartered Financial Analyst (CFA) designation. He has over 25 years experience in economic and financial analysis for regulated industries, and in preparing and supporting expert witness testimony before courts, regulatory agencies, and legislative committees throughout the U.S. and Canada. Assignments have included a broad range of economic and financial issues, including cost of capital, cost of service, rate design, economic damages, and business valuation.

Employment

Consultant,
FINCAP, Inc.
(June 1984 to June 1987)
(April 1988 to present)

Economic consulting firm specializing in regulated industries and valuation of closely-held businesses. Assignments have involved electric, gas, telecommunication, and water/sewer utilities, with clients including utilities, consumer groups, municipalities, regulatory agencies, and cogenerators. Areas of participation have included rate of return, revenue requirements, rate design, tariff analysis, avoided cost, forecasting, and negotiations. Develop cost of capital analyses using alternative market models for electric, gas, and telephone utilities. Prepare pre-filed direct and rebuttal testimony, participate in settlement negotiations, respond to interrogatories, evaluate opposition testimony, and assist in the areas of cross-examination and the preparations of legal briefs. Other assignments have involved preparation of technical reports, valuations, estimation of damages, industry studies, and various economic analyses in support of litigation.

Manager,
McKenzie Energy Company
(Jan. 1981 to May. 1984)

Responsible for operations and accounting for firm engaged in the management of working interests in oil and gas properties.

Education

M.B.A., Finance, University of Texas at Austin (Sep. 1982 to May. 1984)	Program included coursework in corporate finance, accounting, financial modeling, and statistics. Received Dean's Award for Academic Excellence and Good Neighbor Scholarship. Professional Report: *The Impact of Construction Expenditures on Investor-Owned Electric Utilities*
B.B.A., Finance, University of Texas at Austin (Jan. 1981 to May 1982)	Electives included capital market theory, portfolio management, and international economics and finance. Elected to Beta Gamma Sigma business honor society. Dean's List 1981-1982.
Simon Fraser University, Vancouver, Canada and University of Hawaii at Manoa, Honolulu, Hawaii (Jan. 1979 to Dec 1980)	Coursework in accounting, finance, economics, and liberal arts.

Professional Associations

Received Chartered Financial Analyst (CFA) designation in 1990.

Member – CFA Institute.

Bibliography

"A Profile of State Regulatory Commissions," A Special Report by the Electricity Consumers Resource Council (ELCON), Summer 1991.

"The Impact of Regulatory Climate on Utility Capital Costs: An Alternative Test," with Bruce H. Fairchild, *Public Utilities Fortnightly* (May 25, 1989).

Presentations

"ROE at FERC: Issues and Methods," *Expert Briefing on Parallels in ROE Issues between AER, ERA, and FERC*, Jones Day (Sydney, Melbourne, and Perth, Australia) (April 15, 2014)

Cost of Capital Working Group eforum, Edison Electric Institute (April 24, 2012)

"Cost-of-Service Studies and Rate Design," General Management of Electric Utilities (A Training Program for Electric Utility Managers from Developing Countries), Austin, Texas (October 1989 and November 1990 and 1991).

Representative Assignments

Mr. McKenzie has prepared and supported prefiled testimony submitted in over 250 regulatory proceedings. This testimony was sponsored jointly with, or by Dr. William Avera, who is President of FINCAP, Inc. In addition to filings before regulators in 33 states, Mr. McKenzie has considerable expertise in preparing expert analyses and testimony before the Federal Energy Regulatory Commission ("FERC") on the issue of rate of return on equity ("ROE"). Many of these proceedings have been influential in addressing key aspects of FERC's policies with respect to ROE determinations. Broad experience in applying and evaluating the results of quantitative methods to estimate a fair ROE, including discounted cash flow approaches, the Capital Asset Pricing Model, risk premium methods, and other quantitative benchmarks. Other representative assignments have included the application of econometric models to analyze the impact of anti-competitive behavior and estimate lost profits in the commercial explosives and chemical industries; development of explanatory models in connection with prudency issues surrounding nuclear generating facilities; and the analysis of avoided cost pricing for cogenerated power.

ALLOWED ROE

ELECTRIC PROXY GROUP

	Company	(a) Allowed ROE
1	ALLETE	10.38%
2	Ameren Corp.	9.49%
3	American Elec Pwr	10.50%
4	Avista Corp.	9.98%
5	Black Hills Corp.	10.72%
6	CMS Energy Corp.	10.30%
7	DTE Energy Co.	10.75%
8	Duke Energy Corp.	10.46%
9	Edison International	10.50%
10	El Paso Electric	11.25%
11	Empire District Elec	NA
12	Great Plains Energy	10.12%
13	Hawaiian Elec.	9.67%
14	IDACORP, Inc.	10.18%
15	NorthWestern Corp.	10.83%
16	Otter Tail Corp.	10.75%
17	PG&E Corp.	10.40%
18	PNM Resources	9.75%
19	Portland General Elec.	10.35%
20	PPL Corp.	10.72%
21	SCANA Corp.	11.48%
22	Sempra Energy	9.15%
23	UIL Holdings	9.92%
24	Westar Energy	10.20%
	Average (d)	**10.34%**

NA - Not Available.

(a) AUS Monthly Utility Report (Feb. 2014).

EXPECTED EARNINGS APPROACH

ELECTRIC PROXY GROUP

	Company	(a) Expected Return on Common Equity	(b) Adjustment Factor	(c) Adjusted Return on Common Equity
1	ALLETE	9.0%	1.0347	9.3%
2	Ameren Corp.	9.0%	1.0223	9.2%
3	American Elec Pwr	10.0%	1.0214	10.2%
4	Avista Corp.	9.0%	1.0237	9.2%
5	Black Hills Corp.	10.0%	1.0229	10.2%
6	CMS Energy Corp.	13.0%	1.0321	13.4%
7	DTE Energy Co.	10.0%	1.0269	10.3%
8	Duke Energy Corp.	8.0%	1.0140	8.1%
9	Edison International	11.0%	1.0271	11.3%
10	El Paso Electric	10.0%	1.0245	10.2%
11	Empire District Elec	9.0%	1.0240	9.2%
12	Great Plains Energy	7.5%	1.0147	7.6%
13	Hawaiian Elec.	8.5%	1.0504	8.9%
14	IDACORP, Inc.	8.5%	1.0195	8.7%
15	NorthWestern Corp.	9.5%	1.0269	9.8%
16	Otter Tail Corp.	13.0%	1.0272	13.4%
17	PG&E Corp.	8.5%	1.0246	8.7%
18	PNM Resources	8.5%	1.0343	8.8%
19	Portland General Elec.	10.5%	1.0265	10.8%
20	PPL Corp.	10.0%	1.0401	10.4%
21	SCANA Corp.	11.0%	1.0239	11.3%
22	Sempra Energy	10.5%	1.0207	10.7%
23	UIL Holdings	11.5%	1.0261	11.8%
24	Westar Energy	9.5%	1.0298	9.8%
	Average			**10.1%**
	Midpoint (d)			**10.5%**

(a) The Value Line Investment Survey (Jan. 31, Feb. 21 & Mar. 21, 2014).

(b) Adjustment to convert year-end return to average return using the formula 2*(1+5-Yr. Change in Equity)/(2+5 Yr. Change in Equity).

(c) (a) x (b).

(d) Average of low and high values.

WILSON CAPM RESULT

ELECTRIC PROXY GROUP

	Company	(a) Beta	
1	ALLETE	0.80	
2	Ameren Corp.	0.85	
3	American Elec Pwr	0.70	
4	Avista Corp.	0.75	
5	Black Hills Corp.	0.90	
6	CMS Energy Corp.	0.70	
7	DTE Energy Co.	0.85	
8	Duke Energy Corp.	0.70	
9	Edison International	0.75	
10	El Paso Electric	0.65	
11	Empire District Elec	0.75	
12	Great Plains Energy	0.90	
13	Hawaiian Elec.	0.80	
14	IDACORP, Inc.	0.75	
15	NorthWestern Corp.	0.70	
16	Otter Tail Corp.	0.95	
17	PG&E Corp.	0.60	
18	PNM Resources	0.95	
19	Portland General Elec.	0.75	
20	PPL Corp.	0.70	
21	SCANA Corp.	0.75	
22	Sempra Energy	0.75	
23	UIL Holdings	0.85	
24	Westar Energy	0.80	
	Average Beta		**0.78**
(b)	**Market Risk Premium**		**4.50%**
(c)	**Adjusted Risk Premium**		**3.50%**
(d)	**Risk-Free Rate**		**0.05%**
	Implied Cost of Equity		**3.55%**

(a) The Value Line Investment Survey (Jan. 31, Feb. 21 & Mar. 21, 2014).

(b) Midpoint of Dr. Wilson's 3% to 6% range. Wilson Testimony at p. 53.

(c) (a) x (b).

(d) Average yield on 3-month Treasury bills from http://www.federalreserve.gov/releases/h15/data.htm

CAPITAL STRUCTURE

ELECTRIC GROUP

		At Fiscal Year-End 2013 (a)			Value Line Projected (b)		
	Company	Debt	Preferred	Common Equity	Debt	Other	Common Equity
1	ALLETE	45.3%	0.0%	54.7%	41.5%	0.0%	58.5%
2	Ameren Corp.	47.5%	0.0%	52.5%	45.0%	1.0%	54.0%
3	American Elec Pwr	49.0%	0.0%	51.0%	50.0%	0.0%	50.0%
4	Avista Corp.	49.0%	0.0%	51.0%	48.5%	0.0%	51.5%
5	Black Hills Corp.	51.6%	0.0%	48.4%	57.5%	0.0%	42.5%
6	CMS Energy Corp.	68.7%	0.0%	31.3%	62.0%	0.5%	37.5%
7	DTE Energy Co.	50.2%	0.0%	49.8%	49.5%	0.0%	50.5%
8	Duke Energy Corp.	49.3%	0.0%	50.7%	51.5%	0.0%	48.5%
9	Edison International	47.1%	7.9%	44.9%	47.5%	7.5%	45.0%
10	El Paso Electric	51.4%	0.0%	48.6%	57.0%	0.0%	43.0%
11	Empire District Elec	49.8%	0.0%	50.2%	48.5%	0.0%	51.5%
12	Great Plains Energy	50.0%	0.6%	49.4%	43.5%	1.0%	55.5%
13	Hawaiian Elec.	46.4%	0.0%	53.6%	48.0%	1.0%	51.0%
14	IDACORP, Inc.	43.5%	6.6%	49.9%	49.0%	0.0%	51.0%
15	NorthWestern Corp.	29.8%	0.0%	70.2%	48.0%	0.0%	52.0%
16	Otter Tail Corp.	42.2%	0.0%	57.8%	47.0%	0.0%	53.0%
17	PG&E Corp.	48.2%	0.9%	50.9%	50.5%	1.0%	48.5%
18	PNM Resources	49.8%	0.3%	49.9%	51.0%	0.0%	49.0%
19	Portland General Elec.	51.3%	0.0%	48.7%	48.5%	0.0%	51.5%
20	PPL Corp.	62.6%	0.0%	37.4%	57.5%	0.0%	42.5%
21	SCANA Corp.	53.9%	0.0%	46.1%	53.0%	0.0%	47.0%
22	Sempra Energy	51.1%	0.1%	48.8%	55.0%	0.0%	45.0%
23	UIL Holdings	56.2%	0.0%	43.8%	54.5%	0.0%	45.5%
24	Westar Energy	51.4%	0.0%	48.6%	50.0%	0.0%	50.0%
	Average	**49.8%**	**0.7%**	**49.5%**	**50.6%**	**0.5%**	**48.9%**

(a) Company Form 10-K and Annual Reports.

(b) The Value Line Investment Survey (Jan. 31, Feb. 21 & Mar. 21, 2014).

OVERALL RATE OF RETURN

NWE PROPOSED VERSUS PROXY GROUP

	Allocation	Cost/ Return	Weighted Cost
NWE Proposed (a)			
Debt Capital	52.0%	4.50%	2.34%
Equity Capital	48.0%	10.00%	4.80%
Overall Rate of Return			**7.14%**
Electric Proxy Group (b)			
Debt Capital	50.0%	4.50%	2.25%
Equity Capital	50.0%	10.39%	5.20%
Overall Rate of Return			**7.45%**

(a) Bird Direct Testimony at 9.

(b) ROE from Exhibit__(BBB-5); Capitalization from Exhibit__(AMM-5).

PREFILED REBUTTAL TESTIMONY OF

AHMAD MASUD

ON BEHALF OF NORTHWESTERN ENERGY

Q. Please state your name and occupation.

A. My name is Ahmad Masud, and I am a Managing Director and currently a co-head of the U.S. Power and Utilities Group at Credit Suisse Securities (USA) LLC ("Credit Suisse"), a global investment banking firm based in New York. I participated on the Credit Suisse deal team assigned to Credit Suisse's engagement as NorthWestern Energy's ("NorthWestern") financial advisor in connection with its acquisition of the hydroelectric generation assets (the "Hydros") from PPL Montana, LLC.

Q. Please state your business address.

A. My business address is Eleven Madison Avenue, New York, NY, 10010.

Q. Have you testified previously in this docket?

A. Yes. I submitted prefiled direct testimony.

Q. Within testimony filed on March 28, 2014 on behalf of the Montana Consumer Counsel (" MCC"), amongst other assertions, John Wilson calls into question the reasonableness of aspects of NorthWestern's discounted cash flow ("DCF") analysis (which attempted to estimate competitive merchant generator valuation for the Hydros). Some of these matters were also considered by Credit Suisse in its financial analyses or otherwise during its engagement. Have you read Dr. Wilson's testimony?

A. Yes.

Q. What is your view of Dr. Wilson's statement that NorthWestern's assumption for terminal value is unreasonable?

A. I disagree with Dr. Wilson's view. While the purchase price of the Hydros may be fully depreciated for accounting purposes at the end of 40 or 50 years, I understand that the Hydros, as long-life assets, are expected to be operational at the end of the 20-year forecast period and have substantial economic value in the future if properly maintained. While we do not know what potential alternative buyers may have assumed in their analysis, we believe that some level of terminal value is appropriate, and consequently, Credit Suisse also estimated a terminal value in our financial analyses.

In NorthWestern's DCF analysis for the Hydros, the company assumed a terminal value based on a 7.5x EV/EBITDA multiple. We do not believe this is an unreasonable assumption. As I discussed in my prefiled direct testimony, in analyses we presented to NorthWestern, Credit Suisse applied a terminal EV/EBITDA range of 7.5x to 8.5x. That range was based on our assessment regarding the long-term historical valuation multiples of publicly traded independent power producers (as closest comparable businesses with public valuations). We also considered the dollars per kW multiples realized in recent precedent hydro transactions. Dr. Wilson notes that NorthWestern's 7.5x EV/EBITDA multiple equates to approximately $1.1 billion in future value at the end of 2033, which he characterizes as having "doubtful plausibility." I would first point out that Dr. Wilson does not account for inflation in his analysis. For the purpose of discussion, if we included a reasonable assumption for long-term average annual inflation of 2.5% (which is consistent with NorthWestern's inflation assumption in its DCF analysis), a $1.1 billion terminal value in 2033 equates to approximately $660 million or approximately $1,500 per kW in today's dollars, which I believe is not an unreasonable assumption for an on-going hydroelectric generation business. For support of my view, refer to the comparable company trading multiples provided as part of my prefiled direct testimony in this docket. Specifically, AM Exhibit 1 shows the EV/EBITDA trading multiples of publicly traded U.S. independent power producers ("IPPs") and selected Canadian power companies, including Brookfield Renewable Energy Partners. On average, the U.S. IPPs trade at above 7.5x EV/EBITDA multiple. It is important to note that the U.S. IPPs own a variety of generation assets, including coal-fired generation. I believe Brookfield, which trades at a premium to the U.S. IPPs, is the best pure-play hydroelectric generation comparable as it owns a portfolio of renewable power generation assets, including a large amount of hydroelectric assets. To further support my view, I also refer you to the precedent transaction multiples presented in AM Exhibit 1, which show a number of recent publicly disclosed hydro asset transactions with purchase prices that on average have been higher than $2,000 per kW. The median dollar per kW multiple of the selected transactions was $1,989. The low to high range of the selected transactions was $1,184 - $3,220 per kW. Excluding lowest price of $1,184 per kW, all the other transactions were above $1,500 per kW.

Q. Have there been any new hydroelectric generation transactions announced since your original testimony?

A. Since the submission of my prefiled direct testimony, there has been one other relevant hydroelectric generation transaction publicly disclosed. On February 6, 2014 LS Power, a financial investor focused on power generation, announced that it had entered into an agreement with Brookfield Renewable Energy Partners, L.P. to sell its 33.3% ownership in the 417 MW Safe Harbor facility for $303 million. This equates to approximately $2,182 per kW.

Q. Does this conclude your testimony?

A. Yes, it does.

PREFILED REBUTTAL TESTIMONY OF

KENDALL G. KLIEWER

ON BEHALF OF NORTHWESTERN ENERGY

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Witness Information

Q. Please state your name and business address.

A. My name is Kendall G. Kliewer, and my business address is 3010 West 69th Street, Sioux Falls, South Dakota 57108.

Q. Are you the same Kendall Kliewer who submitted prefiled direct testimony in this proceeding?

A. Yes, I am.

Purpose and Summary of Rebuttal Testimony

Q. What is the purpose of your rebuttal testimony?

A. My rebuttal testimony offers NorthWestern's proposed revision to depreciation rates from those in its initial filing and responds to various arguments made by the Montana Consumer Counsel ("MCC") witness Albert Clark in direct testimony that was filed on March 28, 2014. In particular, I propose that the depreciation rate should be reduced from 2.5% to 2.0% for the hydro generation assets, with a 50-year life for both the hydro generation assets and the amortization period for the acquisition adjustment. I also address Mr. Clark's proposed adjustment related to the presumed sale of the Kerr project in 2015.

Depreciation Rate

Q. Does NorthWestern propose to reduce the depreciation and amortization rates for the hydro assets and the acquisition adjustment from 2.5% to 2.0% and that the life of the assets should be increased to 50 years?

A. Yes, these are long-lived assets and NorthWestern believes an initial 2.0% overall depreciation rate would be reasonable for setting a first-year revenue requirement. It is important to note, however, that using a lower depreciation rate now may put additional upward pressure on depreciation rates at the time NorthWestern conducts its next depreciation study, if such study indicates shorter asset lives. The amortization period for the acquisition adjustment should be changed to 50 years to be consistent with the depreciable life of the assets.

These changes to the depreciation rate and amortization period are reflected in the Updated Revenue Requirement presented on Exhibit__(PJD-5) included with the Prefiled Rebuttal Testimony of Patrick DiFronzo ("DiFronzo Rebuttal Testimony").

Kerr Acquisition Adjustment

Q. Should the Commission accept Mr. Clark's proposed adjustment related to the presumed sale of the Kerr facility in 2015?

A. No. Mr. Clark incorrectly characterizes the $89.3 million as an anticipated loss on the presumed sale of the Kerr facility. NorthWestern will not have a loss on the presumed sale. Simply put, NorthWestern is offering PPL Montana, LLC $870 million for the Hydros without Kerr Dam. The difference between $870 million and the calculated $523.1 million original cost of the remaining Hydros is $346.9 million, which is the total acquisition adjustment. It is important to note that at the time of closing, we would anticipate that the original cost of the remaining Hydros will be greater due to additional plant activity. The $870 million price will not change; therefore, because the electric plant will likely increase, the acquisition adjustment will decrease. These changes to plant and the acquisition adjustment will also be reflected in NorthWestern's final compliance filing that will be made in 2015, as discussed in the Prefiled Direct Testimony of Brian Bird.

While NorthWestern was required to calculate the original cost of all facilities, the original cost of Kerr Dam does not impact the acquisition adjustment. Since we will only own the Kerr facility for approximately one year, the $30 million transfer price is the only relevant amount to the purchase and expected sale of the Kerr facility.

Q. Is the Kerr adjustment suggested by Mr. Clark acceptable to NorthWestern?

A. No. Reducing the acquisition adjustment, and therefore rate base, by $89.3 million would significantly impact our financial results to the point where we would not close the transaction.

Q. Has NorthWestern made any further adjustments to the recovery of Kerr costs that would mitigate the rate impact to customers?

A. Yes. NorthWestern is willing to forego any return on or return of its investment in Kerr. Recovery of the Kerr Dam depreciation expense was excluded from our original filing, and in this rebuttal filing, NorthWestern has also removed Kerr from rate base. Up until the transfer of ownership to the Confederated Salish and Kootenai Tribes in 2015, any power from the facility used to serve our customers will be provided at the cost of operating the dam with no return to our shareholders. Under this structure, the beginning plant balance for determining rate base would be $870 million and Kerr would not be included in rate base at all. This adjustment reduces the first year revenue requirement by $3,036,610 (refer to the DiFronzo Rebuttal Testimony).

Q. Does this complete your testimony?

A. Yes, it does.

PREFILED REBUTTAL TESTIMONY

OF PATRICK J. DIFRONZO

ON BEHALF OF NORTHWESTERN ENERGY

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Witness Information

Q. Please state your name and occupation.

A. My name is Patrick J. DiFronzo. I am the Manager of Regulatory Affairs.

Q. Are you the same Patrick DiFronzo who submitted prefiled direct testimony in this proceeding?

A. Yes, I am.

Purpose of Testimony

Q. What is the purpose of your rebuttal testimony in this proceeding?

A. My rebuttal testimony:

1. Presents the updated Test Period Revenue Requirement ("Updated Revenue Requirement") and the adjustments made associated with NorthWestern Energy's ("NorthWestern") purchase of the 11 hydroelectric generating facilities and related assets (the "Hydros") from PPL Montana, LLC ("PPLM"); and
2. Discusses the Hydros derivation of rates and presents the customer bill impact based on the Updated Revenue Requirement.

Rebuttal Hydros Revenue Requirement

Q. What adjustments have you made to the Hydros Revenue Requirement, Exhibit__(PJD-1)?

A. Exhibit__(PJD-5) sets forth the Updated Revenue Requirement for the test period. This exhibit starts with the original revenue requirement amount of $128,402,190, as shown in Column C, line 36. The rebuttal adjustments made to the original filing are shown in Columns D and E to derive the Updated Revenue Requirement amount. The rate base adjustments are based on a 13-month average.

Q. Please explain the book depreciation adjustment in Column D on Exhibit__(PJD-5).

A. Column D reflects changing the Hydros book depreciation life from 40 to 50 years. This change results in a revenue requirement reduction of $4,401,890 as shown on line 36. The Prefiled Rebuttal Testimony of Kendall Kliewer provides further explanation of this change.

Q. Please explain the Kerr Plant adjustment in Column E on Exhibit__(PJD-5).

A. Column E reflects eliminating $30 million from rate base relating to the Kerr plant. This change results in a revenue requirement reduction of $3,036,610 as shown on line 36. The Prefiled Rebuttal Testimony of Brian Bird provides further explanation of this change.

Q. What is the Updated Revenue Requirement requested in this rebuttal filing?

A. Accounting for these adjustments, NorthWestern requests a decrease of $7,438,499 from the original revenue requirement amount of $128,402,190. The Updated Revenue Requirement amount is $120,963,690 as shown in Column G, line 36.

The Hydros Derivation of Rates

Q. Has NorthWestern computed an updated illustration of rates as part of this rebuttal filing?

A. Yes. Refer to Exhibit__(PJD-6). Page 1 of this exhibit summarizes the estimated total electricity supply rates that include the Hydros. The fixed rates for the Hydros are based on the Updated Revenue Requirement as reflected on Exhibit__(PJD-5) page 1, Column G, line 36. The forecasted loads are based on NorthWestern's monthly electricity supply tracker filing with rates effective May 2014 (see Docket No. D2013.7.53). The derivation of the estimated Hydros' fixed rates is shown on page 2. The rates for Colstrip Unit 4, Dave Gates Generating Station, and Spion Kop Wind Generation Facility shown on page 1 are from the May 2014 monthly electric supply tracker filing. The electric supply tracker component rates shown in Column D of page 1 have been adjusted to reflect the impact of the Hydros on spot purchases as well as the associated termination of certain PPLM supply contracts as shown on page 3. The electricity supply costs shown on page 3 reflect the estimated costs for the period October 2014 through September 2015. These base rates are then further adjusted on page 8 so that the percentage rate increase for each customer class is no greater than the residential customer rate class increase. This last step to adjust base rates was not reflected in the original filing but is consistent with past practice and Commission orders relating to the determination of supply rates.

Q. Has NorthWestern computed illustrative customer bill impacts associated with the Updated Revenue Requirement as part of this rebuttal filing?

A. Yes. Refer to Exhibit__(PJD-7). This exhibit illustrates the bill impact to residential electric customers based on NorthWestern's monthly electricity supply tracker filing for rates effective May 1, 2014. This bill impact analysis is based on using the Updated Revenue Requirement as reflected in Exhibit__(PJD-5) page 1, column G, line 36.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

NorthWestern Energy
PPLM Hydro Assets Purchase
Docket D2013.12.85
Rebuttal - Revenue Requirement Analysis

	(A)		(B)	(C)	(D)	(E)	(F)	(G)
			NWE - Original Filing		Rebuttal Adjustments			
			2014				Total Rebuttal	Rebuttal
	Description		Year End	13-Month Ave	Book Depr.	Kerr Plant	Adjustments	Revenue Req.
1	**Electric Utility Plant in Service**							
2	Electric Plant		$ 553,078,225	$ 553,078,225	$ -	$ (30,000,000)	$ (30,000,000)	$ 523,078,225
3	Acquisition Adjustment		346,921,775	346,921,775			-	346,921,775
4	Total Electric Plant		$ 900,000,000	$ 900,000,000	$ -	$ (30,000,000)	$ (30,000,000)	$ 870,000,000
5								
6	Less:							
7	Accumulated Depreciation		21,618,148	10,809,074	(2,149,725)	-	(2,149,725)	8,659,349
8	Total Net Plant		$ 878,381,852	$ 889,190,926	$ 2,149,725	$ (30,000,000)	$ (27,850,275)	$ 861,340,651
9								
10	Less: Customer Contributed Capital							
11	Deferred Income Taxes							
12	Accelerated Tax Depreciation Deferred Tax Liability		$ 3,791,369	$ 1,895,684	$ 752,404	$ -	$ 752,404	$ 2,648,088
13	NOL Deferred Tax Liablity		$ 21,943,007	$ 10,971,503	$ (872,729)	$ (459,173)	$ (1,331,902)	$ 9,639,601
14	Total Customer Contributed Capital		$ 25,734,375	$ 12,867,188	$ (120,325)	$ (459,173)	$ (579,499)	$ 12,287,689
15								
16	Plus: Working Capital							
17	Gross Cash Requirements		$ (10,339,304)	$ (10,339,304)	$ (7,584)	$ 98,689	$ 91,105	$ (10,248,199)
18								
19	Total Year End Rate Base		$ 842,308,172	$ 865,984,434	$ 2,262,466	$ (29,442,138)	$ (27,179,672)	$ 838,804,762
20								
21	**Rate of Return**			7.14%	7.14%	7.14%	7.14%	7.14%
22								
23	***Authorized Return (Avg. Rate Base * Rate of Return)***			$ 61,831,289	$ 161,540	$ (2,102,169)	$ (1,940,629)	$ 59,890,660
24								
25	***Cost of Service:***							
26	Operation & Maintenance Expense		$ 41,816,411		$ -	$ -	$ -	$ 41,816,411
27	Administrative and General Expense		5,807,975		-	-	-	5,807,975
28	Depreciation		21,618,148		(4,299,450)	-	(4,299,450)	17,318,699
29	Property & Other Taxes		14,983,335		-	-	-	14,983,335
30	MPSC & MCC Revenue Tax	0.53%	680,532		(23,330)	(16,094)	(39,424)	641,108
31	Revenue Credits		(43,311,313)		-	-	-	(43,311,313)
32	Deferred Income Taxes		25,734,375		(240,650)	(918,347)	(1,158,997)	24,575,378
33	Current Income Taxes		(758,561)		-	-	-	(758,561)
34	***Total Cost of Service***			$ 66,570,901	$ (4,563,430)	$ (934,441)	$ (5,497,871)	$ 61,073,030
35								
36	**Total Revenue Requirement**			$ 128,402,190	$ (4,401,890)	$ (3,036,610)	$ (7,438,499)	$ 120,963,690

			NWE - Original Filing		Rebuttal Adjustments			
			2014				Total Rebuttal	Rebuttal
	Description		Year End	13-Month Ave	Book Depr.	Kerr Plant	Adjustments	Revenue Req.
	Statement - J							
1	***Income Tax Computation:***	Rate						
2	Revenues		$ 128,402,190		$ (4,401,890)	$ (3,036,610)	$ (7,438,499)	$ 120,963,690
3	Operation & Maintenance Expense		41,816,411		-	-	-	41,816,411
4	Administrative and General Expense		5,807,975		-	-	-	5,807,975
5	Property & Other Taxes		14,983,335		-	-	-	14,983,335
6	MPSC & MCC Revenue Tax		680,532		(23,330)	(16,094)	(39,424)	641,108
7	Revenue Credits		(43,311,313)		-	-	-	(43,311,313)
8	Tax Depreciation (Ref. Exhibit__(PJD-1), Page 10)		32,450,630		-	-	-	32,450,630
9	Montana Corporate Income Tax		3,760,464		(299,126)	(157,381)	(456,507)	3,303,957
10	Interest Expense (Based on Avg. Rate Base)	2.34%	20,264,036		52,942	(688,946)	(636,004)	19,628,031
11	Federal Taxable Income		$ 51,950,120		$ (4,132,375)	$ (2,174,189)	$ (6,306,564)	$ 45,643,557
12								
13	Federal Income Tax @ 35%	35.00%	18,182,542		(1,446,331)	(760,966)	(2,207,297)	15,975,245
14	Federal NOL Dfd for Credit Against Current Tax Expense		(18,182,542)		1,446,331	760,966	2,207,297	(15,975,245)
15	Federal Current Tax Expense before Tax Credits		$ -		$ -	$ -	$ -	$ -
16	Production Tax Credit (Ref. Exhibit__(PJD-1), Page 11)		(758,561)		-	-	-	(758,561)
17	Federal Current Tax Expense With Production Tax Credit		$ (758,561)		$ -	$ -	$ -	$ (758,561)
18								
19	Federal Taxable Income		$ 51,950,120		$ (4,132,375)	$ (2,174,189)	$ (6,306,564)	$ 45,643,557
20	Montana Corporate Income Tax		3,760,464		(299,126)	(157,381)	(456,507)	3,303,957
21	Montana Corporate Taxable		$ 55,710,585		$ (4,431,501)	$ (2,331,570)	$ (6,763,071)	$ 48,947,514
22								
23	Montana Corporate Income Tax @ 6.75%	6.75%	3,760,464		(299,126)	(157,381)	(456,507)	3,303,957
24	Montana NOL Dfd for Credit Against Current Tax Expense		(3,760,464)		299,126	157,381	456,507	(3,303,957)
25	Montana Current Tax Expense		$ -		$ -	$ -	$ -	$ -
26								
27	Total Current Income Tax Expense		$ (758,561)		$ -	$ -	$ -	$ (758,561)
28								
29	***Deferred Income Tax Computation:***	Rate						
30	***Accelerated Tax Depreciation***							
31	Tax Depreciation		$ 32,450,630		$ -	$ -	$ -	$ 32,450,630
32	Less Book Depreciation		(21,618,148)		4,299,450	-	4,299,450	(17,318,699)
33	Net Deferred Taxable Income		$ 10,832,482		$ 4,299,450	$ -	$ 4,299,450	$ 15,131,931
34	Federal Income Tax Rate		35%		35%	35%	35%	35%
35	Federal Deferred Income Tax Expense-Accelerated Tx Deprec		$ 3,791,369		$ 1,504,807	$ -	$ 1,504,807	$ 5,296,176
36								
37	***Net Operating Loss ("NOL")***							
38	Federal Taxable Income offset by NOL		$ 51,950,120		$ (4,132,375)	$ (2,174,189)	$ (6,306,564)	$ 45,643,557
39	Federal Income Tax Rate		35%		35%	35%	35%	35%
40	Federal Deferred Income Tax Expense-NOL		$ 18,182,542		$ (1,446,331)	$ (760,966)	$ (2,207,297)	$ 15,975,245
41								
42	Montana Taxable Income offset by NOL		$ 55,710,585		$ (4,431,501)	$ (2,331,570)	$ (6,763,071)	$ 48,947,514
43	Montana Income Tax Rate		6.75%		6.75%	6.75%	6.75%	6.75%
44	Montana Deferred Income Tax Expense-NOL		$ 3,760,464		$ (299,126)	$ (157,381)	$ (456,507)	$ 3,303,957
45								
46	Total Deferred Income Tax Expense - NOL		$ 21,943,007		$ (1,745,458)	$ (918,347)	$ (2,663,805)	$ 19,279,202
47	Total Deferred Income Tax Expense-Accel Deprec & NOL		$ 25,734,375		$ (240,650)	$ (918,347)	$ (1,158,997)	$ 24,575,378

	A	B	C	D	E	F	G	H	I	J	K	L	M
1						NorthWestern Energy							
2						PPLM Hydro Assets Purchase							
3						Docket D2013.12.85							
4													
5						Rebuttal Adjustments - Rate Base 13-Month Average							
6													
7						Statement C							
8					Book Life 50 Yr								
9					Accumulated Depreciation				Accelerated Tax Depreciation			NOL Deferred Tax Liability	
10					Net Activity	Ending Balance			Net Activity	Ending Balance		Net Activity	Ending Balance
11													
12	1	December	2013		0.00	0.00			0.00	0.00		0.00	0.00
13													
14	2	January	2014		-358,287	-358,287			125,401	125,401		-145,455	-145,455
15													
16	3	February	2014		-358,287	-716,575			125,401	250,801		-145,455	-290,910
17													
18	4	March	2014		-358,287	-1,074,862			125,401	376,202		-145,455	-436,364
19													
20	5	April	2014		-358,287	-1,433,150			125,401	501,602		-145,455	-581,819
21													
22	6	May	2014		-358,287	-1,791,437			125,401	627,003		-145,455	-727,274
23													
24	7	June	2014		-358,287	-2,149,725			125,401	752,404		-145,455	-872,729
25													
26	8	July	2014		-358,287	-2,508,012			125,401	877,804		-145,455	-1,018,184
27													
28	9	August	2014		-358,287	-2,866,300			125,401	1,003,205		-145,455	-1,163,638
29													
30	10	September	2014		-358,287	-3,224,587			125,401	1,128,606		-145,455	-1,309,093
31													
32	11	October	2014		-358,287	-3,582,875			125,401	1,254,006		-145,455	-1,454,548
33													
34	12	November	2014		-358,287	-3,941,162			125,401	1,379,407		-145,455	-1,600,003
35													
36	13	December	2014		-358,287	-4,299,450			125,401	1,504,807		-145,455	-1,745,458
37													
38													
39		13-Month Average				-2,149,725				752,404			-872,729

	A	B	C	D	E	F	G	H	I
1					NorthWestern Energy				
2					PPLM Hydro Assets Purchase				
3					Docket D2013.12.85				
4									
5					Rebuttal Adjustments - Rate Base 13-Month Average				
6									
7					Statement C				
8					Kerr Adjustment				
9					Return on Investment			NOL Deferred Tax Liability	
10					Net Activity	Ending Balance		Net Activity	Ending Balance
11									
12	1	December	2013		0.00	-30,000,000		0.00	0.00
13									
14	2	January	2014		0	-30,000,000		-76,529	-76,529
15									
16	3	February	2014		0	-30,000,000		-76,529	-153,058
17									
18	4	March	2014		0	-30,000,000		-76,529	-229,587
19									
20	5	April	2014		0	-30,000,000		-76,529	-306,116
21									
22	6	May	2014		0	-30,000,000		-76,529	-382,645
23									
24	7	June	2014		0	-30,000,000		-76,529	-459,173
25									
26	8	July	2014		0	-30,000,000		-76,529	-535,702
27									
28	9	August	2014		0	-30,000,000		-76,529	-612,231
29									
30	10	September	2014		0	-30,000,000		-76,529	-688,760
31									
32	11	October	2014		0	-30,000,000		-76,529	-765,289
33									
34	12	November	2014		0	-30,000,000		-76,529	-841,818
35									
36	13	December	2014		0	-30,000,000		-76,529	-918,347
37									
38									
39		13-Month Average				-30,000,000			-459,173

	A	B	C	D	E	F	G	H
1			**NorthWestern Energy**					
2			**PPLM Hydro Assets Purchase**					
3			**Docket D2013.12.85**					
4								
5			**Calculation of Working Capital**					
6			**Rebuttal Depreciation Adjustment**					
7			**Statement - E**					
8								
9								
10				12-Month Ended		[1]Net Lag		Cash
11	Line No.			Expenses		Days		Working Capital
12	1	Operation & Maintenance Expense		$ -				
13	2	Administrative and General Expense		0				
14	3	Property & Other Taxes		0				
15	4	Montana Corporate Income Taxes		0				
16	5	Federal Income Taxes		0				
17	6	Subtotal		$ -		-43.21		$ -
18	7							
19	8							
20	9	13-Month Ave. Rate Base without Working Capital	$ 2,270,050					
21	10							
22	11	[2]Weighted Cost of Debt	2.34%					
23	12							
24	13	Interest Expense in Return		$ 53,119		-52.11		-7,584
25	14							
26	15	Total Cash Working Capital						$ (7,584)
27								
28								
29								
30								
31		[1]Net Lag Days fom Management Application Corp. 2008 Lead/Lag Update						
32		Per MPSC Final Order No. 7046h Docket No. D2009.9.129						
33								
34		[2]Weighted Cost of Debt based on proposed capital structure in this filing.						

	A	B	C	D	E	F	G	H
1			NorthWestern Energy					
2			PPLM Hydro Assets Purchase					
3			Docket D2013.12.85					
4								
5			Calculation of Working Capital					
6			Rebuttal Kerr Adjustment					
7			Statement - E					
8								
9								
10				12-Month Ended		[1]Net Lag		Cash
11	Line No.			Expenses		Days		Working Capital
12	1	Operation & Maintenance Expense		$ -				
13	2	Administrative and General Expense		0				
14	3	Property & Other Taxes		0				
15	4	Montana Corporate Income Taxes		0				
16	5	Federal Income Taxes		0				
17	6	Subtotal		$ -		-43.21		$ -
18	7							
19	8							
20	9	13-Month Ave. Rate Base without Working Capital	$ (29,540,827)					
21	10							
22	11	[2]Weighted Cost of Debt	2.34%					
23	12							
24	13	Interest Expense in Return		$ (691,255)		-52.11		98,689
25	14							
26	15	Total Cash Working Capital						$ 98,689
27								
28								
29								
30								
31		[1]Net Lag Days fom Management Application Corp. 2008 Lead/Lag Update						
32		Per MPSC Final Order No. 7046h Docket No. D2009.9.129						
33								
34		[2]Weighted Cost of Debt based on proposed capital structure in this filing.						

	A	B	C	D	E	F	G	H	I	J	K	L
1		**NorthWestern Energy**										
2		**PPLM Hydro Assets Purchase**										
3		**Docket D2013.12.85**										
4		**Plant Balance and Annual Book Depreciation**										
5		**Rebuttal Adjustment**										
6		**Statement - I**										
7												
8				Plant Balance		Less Kerr		Depreciation Base				Rebuttal
9				12/31/2013		12/31/2013		12/31/2013		Accrual %		2014 Accrual
10	E303	Intangible Plant		$ 63,853,971		$ 63,853,971		$ -		0.0000		$ -
11												
12		Total Intangible		$ 63,853,971		$ 63,853,971		$ -				$ -
13												
14	E330.1	Land		$ 5,938,196		$ 1,301,968		$ 4,636,228		0.0000		$ -
15	E330.2	Land Rights		10,939		0		10,939		0.0000		0
16	E331.1	Structures - Generation		147,361,016		3,222,213		144,138,803		0.0200		2,882,776
17	E331.3	Structures - Recreation		639,650		195,082		444,568		0.0200		8,891
18	E332.1	Dams - Generation		157,879,816		9,775,970		148,103,846		0.0200		2,962,077
19	E332.2	Dams - Recreation		39,987		1,259		38,728		0.0200		775
20	E333	Turbines & Generators		129,895,054		16,199,824		113,695,230		0.0200		2,273,905
21	E334	Accessory Equipment		77,919,494		1,697,700		76,221,794		0.0200		1,524,436
22	E335.1	Misc - Generation		48,696,519		20,773,252		27,923,267		0.0200		558,465
23	E335.3	Misc - Recreation		63,033		10,362		52,671		0.0200		1,053
24	E336	Roads & Trails		3,152,861		803,636		2,349,225		0.0200		46,985
25												
26		Total Hydro Generation		$ 571,596,565		$ 53,981,266		$ 517,615,299				$ 10,259,363
27												
28	E350.1	Land		$ 1,130		$ -		$ 1,130		0.0000		$ -
29	E350.2	Land Rights		512		0		512		0.0171		9
30	E352	Structures		4,765		0		4,765		0.0202		96
31	E353	Substation Equipment		6,409,221		1,487,785		4,921,436		0.0220		108,272
32	E354.1	Towers		1,629		0		1,629		0.0253		41
33	E355	Poles		204,184		0		204,184		0.0455		9,290
34	E355.2	Clearing Land		3,535		0		3,535		0.0216		76
35	E356	Conductor		165,754		0		165,754		0.0188		3,116
36	E362	Substation Equipment		65,849		0		65,849		0.0231		1,521
37	E389.6	Land		1,055		0		1,055		0.0000		0
38	E397.2	Communication		93,077		0		93,077		0.0667		6,208
39												
40		Total Transmission		$ 6,950,711		$ 1,487,785		$ 5,462,926				$ 120,901
41												
42		Total Intangible, Hydro & Transmission		$ 642,401,247		$ 119,323,022		$ 523,078,225				$ 10,380,263
43												
44		Acquisition Adjustment		$ 257,598,753		$ (89,323,022)		$ 346,921,775		50 Years		$ 6,938,436
45												
46		Grand Total		$ 900,000,000		$ 30,000,000		$ 870,000,000				$ 17,318,699
47												
48		Note - Hydro accounts depreciated over 40 years = 2.5 % rate - Transmission accrual rates are from the 2012 Montana Depreciation Study										

NorthWestern Energy
Electric Utility
Total Estimated Electric Supply Rate
PPLM Hydro Assets Purchase
Year 2014

	Estimated Electric Supply Rates [1]	Proposed DSM Rebate [2]	Colstrip Unit 4 Current Fixed Rates [3]	Colstrip Unit 4 Current Variable Rates [4]	Colstrip Unit 4 Proposed DSM Rebate [5]	Dave Gates Gen Station Current Fixed Rates [6]	Dave Gates Gen Station Current Variable Rates [7]	Dave Gates Gen Station Proposed DSM Rebate [8]	Spion Kop Current Fixed Rates [9]	Spion Kop Current Variable Rates [10]	PPLM Hydro Assets Estimated Fixed Rates [11]	Estimated Total Supply Rates
Residential												
Residential	0.023512	(0.000824)	0.012734	0.004067	(0.000396)	0.004795	0.002170	(0.000043)	0.001458	(0.000012)	0.020216	0.067677
Residential Employee	0.014107	(0.000494)	0.007640	0.002440	(0.000238)	0.002877	0.001302	(0.000026)	0.000875	(0.000007)	0.012130	0.040606
Total Residential												
General Service 1												
GS-1 Sec Non-Demand	0.021270	(0.000824)	0.012734	0.004067	(0.000396)	0.004795	0.002170	(0.000043)	0.001459	(0.000012)	0.020216	0.065436
GS-1 Sec Demand	0.023512	(0.000824)	0.012734	0.004067	(0.000396)	0.004795	0.002170	(0.000043)	0.001459	(0.000012)	0.020216	0.067678
GS-1 Pri Non-Demand	0.022865	(0.000801)	0.012385	0.003956	(0.000385)	0.004664	0.002111	(0.000042)	0.001420	(0.000012)	0.019663	0.065824
GS-1 Pri Demand	0.020879	(0.000801)	0.012385	0.003956	(0.000385)	0.004664	0.002111	(0.000042)	0.001420	(0.000012)	0.019663	0.063838
Total GS-1												
General Service 2												
GS-2 Substation	0.022669	(0.000794)	0.012278	0.003922	(0.000382)	0.004624	0.002093	(0.000042)	0.001407	(0.000012)	0.019494	0.065257
GS-2 Transmission	0.022534	(0.000789)	0.012204	0.003898	(0.000380)	0.004596	0.002080	(0.000042)	0.001399	(0.000011)	0.019376	0.064865
Total GS-2												
Irrigation												
Irrigation	0.021270	(0.000824)	0.012734	0.004067	(0.000396)	0.004795	0.002170	(0.000043)	0.001459	(0.000012)	0.020216	0.065436
Total Irrigation												
Lighting												
Lighting	0.021270	(0.000824)	0.012734	0.004067	(0.000396)	0.004795	0.002170	(0.000043)	0.001459	(0.000012)	0.020216	0.065436
Total Lighting												
Average Billed Rate	**0.023136**	**(0.000820)**	**0.012680**	**0.004050**	**(0.000394)**	**0.004775**	**0.002161**	**(0.000043)**	**0.001453**	**(0.000012)**	**0.020131**	**0.067116**
Total Supply Rate		**22.316**			**16.336**			**6.893**		**1.441**	**20.131**	**67.117**

[1] Source: Exhibit__(PJD-6), Page 8 of 8. Capped Rate Method.
[2] Source: Docket No. D2012.5.49 Final Order 7219h Updated compliance filing Attachment 4
[3] Source: Fixed rates approved in Docket No. D2010.5.50 Order No. 7093c, effective 04/01/2010.
[4] Source: Appendix H Jan 2014
[5] Source: Docket No. D2012.5.49 Final Order 7219h Updated compliance filing Attachment 5
[6] Source: Fixed rates (based on 2nd yr rev req) approved in Docket No. D2008.8.95 Order No.6943e, effective 01/01/2012.
[7] Source: Appendix J Jan 2014
[8] Source: Docket No. D2012.5.49 Final Order 7219h Updated compliance filing Attachment 6
[9] Source: Fixed rates (based on 2nd yr rev req) approved in Docket No. D2011.5.41 Order No.7159i, effective 1/1/2013.

NorthWestern Energy
PPLM Hydro Assets Purchase

Derivation of Rates
12 Months Ended December 2014

Customer Rate Class	Loss Factor	May14 to Apr15 Supply Retail kWh Sales	Sales Adjusted for Employee Discount	Sales Weighted by Losses	Electric Supply Rate After Losses	Electric Supply Revenue Check
Residential	8.5100%	2,348,215,345	2,348,215,345	2,548,048,471	$ 0.020216	$ 47,471,521
Residential Employee	8.5100%	3,763,166	2,257,900	2,450,047	$ 0.012130	$ 45,647
GS 1 Secondary NonDemand	8.5100%	280,624,257	280,624,257	304,505,381	$ 0.020216	$ 5,673,100
GS 1 Secondary Demand	8.5100%	2,506,111,156	2,506,111,156	2,719,381,215	$ 0.020216	$ 50,663,543
GS 1 Primary NonDemand	5.5400%	572,442	572,442	604,156	$ 0.019663	$ 11,256
GS 1 Primary Demand	5.5400%	357,204,874	357,204,874	376,994,024	$ 0.019663	$ 7,023,719
General Service Substation	4.6300%	232,669,987	232,669,987	243,442,607	$ 0.019494	$ 4,535,669
General Service Transmission	4.0000%	135,701,068	135,701,068	141,129,111	$ 0.019376	$ 2,629,344
Irrigation	8.5100%	86,094,805	86,094,805	93,421,473	$ 0.020216	$ 1,740,493
Lighting	8.5100%	57,613,774	57,613,774	62,516,706	$ 0.020216	$ 1,164,720
		6,008,570,874	6,007,065,608	6,492,493,191	$ 0.020136	$ 120,959,012
YNP Contract		19,233,936			Rounding Adjustment	$ 4,678
Total Electric Supply Load		6,027,804,810				$ 120,963,690

PPLM Hydro Assets Purchase - 2014 Revenue Requirement	$ 120,963,690
less: YNP Contract Revenues	$ -
Supply Excluding Generation Assets Rate Design Revenues	$ 120,963,690
Electric Supply Cost Rate Before Losses	**$ 0.018631**
Electric Supply Cost Rate After Losses	**$ 0.020131**

NorthWestern Energy
Electric Utility Derivation of Rates
Electricity Supply Excluding Generation Assets - Prior to Cap Adjustment
Tracker Period 2014

	B	D	F	H	J	L	N
11			May14 to Apr15	Sales Adjusted		Electricity	Electricity
12		Loss	Supply Retail	for Employee	Sales Weighted	Supply Rate	Supply Revenue
13		Factor	kWh Sales	Discount	by Losses	After Losses	Check
14	**Customer Rate Class**						
15	Residential	8.5100%	2,348,215,345	2,348,215,345	2,548,048,471	$ 0.023234	$ 54,558,435
16	Residential Employee	8.5100%	3,763,166	2,257,900	2,450,047	$ 0.013940	$ 52,459
17	GS 1 Secondary NonDemand	8.5100%	280,624,257	280,624,257	304,505,381	$ 0.023234	$ 6,520,024
18	GS 1 Secondary Demand	8.5100%	2,506,111,156	2,506,111,156	2,719,381,215	$ 0.023234	$ 58,226,987
19	GS 1 Primary NonDemand	5.5400%	572,442	572,442	604,156	$ 0.022598	$ 12,936
20	GS 1 Primary Demand	5.5400%	357,204,874	357,204,874	376,994,024	$ 0.022598	$ 8,072,116
21	General Service Substation	4.6300%	232,669,987	232,669,987	243,442,607	$ 0.022403	$ 5,212,506
22	General Service Transmission	4.0000%	135,701,068	135,701,068	141,129,111	$ 0.022268	$ 3,021,791
23	Irrigation	8.5100%	86,094,805	86,094,805	93,421,473	$ 0.023234	$ 2,000,327
24	Lighting	8.5100%	57,613,774	57,613,774	62,516,706	$ 0.023234	$ 1,338,598
25			6,008,570,874	6,007,065,608	6,492,493,191	$ 0.023142	$ 139,016,178
26	YNP Contract		19,233,936			Rounding Adjustment	$ 217
27	Total Electricity Supply Load		6,027,804,810				$ 139,016,396
30	Electricity Supply Excluding Generation Assets Costs (Ref Line 52)				$ 140,233,904		
31	less: YNP Contract Revenues				$ (1,217,508)		
32	**Electricity Supply Excluding Generation Assets Rate Design Revenues**				**$ 139,016,396**		
34	Electricity Supply Cost Rate Before Losses				$ 0.021412		
35	Electricity Supply Cost Rate After Losses				$ 0.023136		
37	YNP Contract Load		19,233,936				
38	YNP May13-Apr14 Contract Supply Rate		0.063300				
39	YNP Supply Revenue		$ 1,217,508				
42	**Electric Supply Costs for period October 2014 through September 2015**						
43	Net Market Purchase Costs (Reference Page 5 Line 110)				$ 196,023,914		
44	DSM Lost Revenues [1]				$ 5,558,676		
45	DSM Program Costs [1]				$ 9,618,958		
46	Adm & General [1]				$ 2,104,535		
47	Transmission [1]				$ 811,920		
48	**Total Supply Tracker Costs Excluding Generation Cost of Service**				$ 214,118,003		
50	Remove Spot Purchases With Mustang				$ (64,780,583)		
51	Remove Terminated PPL Contract				$ (9,690,240)		
52	Add Spot Purchases With PPLM Hydro Assets Purchase				$ 586,724		
53	**Total Electric Supply Costs**				$ 140,233,904		
56	[1] Based on May 2014 Electric Monthly Supply Tracker Filing						

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
1	**Electric Supply Cost Tracker**														
2	**Electric Tracker Projection**				Note: compiled from Calendar 2014 and 2015										
3															
4	**Volumes in MWh**		Oct-14	Nov-14	Dec-14	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Total
5			Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	
6	Off System Transactions														
7	Fixed Price														
8		**Base Fixed Price Purchases**													
9		Competitive Solicitations	103,800	99,725	103,400	29,000	26,400	28,975	28,400	28,600	28,400	29,000	29,000	28,000	562,700
10		**Base Fixed Price Sales**													
11		Competitive Solicitations	-	-	-	-	-	-	-	-	-	-	-	-	-
12		**Term Fixed Price Purchases**	32,400	28,800	31,200	66,200	60,000	66,125	64,400	65,800	64,400	66,200	66,200	64,000	675,725
13		**Term Fixed Price Sales**	-	-	-	-	-	-	-	-	-	-	-	-	-
14	Index Price														
15		**Base Index Price Purchases**	-	-	-	-	-	-	-	-	-	-	-	-	-
16		**Base Index Price Sales**													
17		Competitive Solicitations	(29,400)	(27,625)	(29,000)	(29,000)	(26,400)	(28,975)	(28,400)	(28,600)	(28,400)	(10,400)	(10,400)	(10,000)	(286,600)
18		**Term Index Price Purchases**	-	-	-	-	-	-	-	-	-	-	-	-	-
19		**Term Index Price Sales**	(74,400)	(72,100)	(74,400)	-	-	-	-	-	-	-	-	-	(220,900)
20		**Spot Purchases**	-	-	-	-	-	-	-	-	-	-	-	-	-
21		**Spot Sales**	(32,400)	(28,800)	(31,200)	(66,200)	(60,000)	(66,125)	(64,400)	(65,800)	(64,400)	(84,800)	(84,800)	(82,000)	(730,925)
22															
23	On System Transactions														
24	Fixed Price														
25		**Rate Based Assets**													
26		Colstrip Unit 4	150,288	145,440	150,288	150,288	135,744	150,288	122,436	126,148	122,436	150,288	150,288	145,440	1,699,372
27		Dave Gates Generating Station	5,208	5,047	5,208	5,208	4,704	5,201	5,040	5,208	5,040	5,208	5,208	5,040	61,320
28		Spion Kop	14,136	14,400	11,904	17,856	10,752	11,888	11,520	8,928	8,640	8,184	8,184	9,360	135,752
29		**Base Fixed Price Purchases**													
30		PPL 7 Year Contract	-	-	-	-	-	-	-	-	-	-	-	-	-
31		Judith Gap	43,440	48,480	51,032	55,912	41,568	43,064	38,912	34,616	25,840	22,672	25,800	28,080	459,416
32		Other Small PPAs	[redacted]												
33		Competitive Solicitations	21,600	19,200	20,800	20,800	19,200	20,800	20,800	20,000	20,800	20,800	20,800	20,000	245,600
34		QF Tier II	69,936	66,960	74,400	67,704	65,856	69,936	71,280	76,632	68,400	61,008	54,312	64,800	811,224
35		QF Tier II Adjustments													
36		QF-1 Tariff	14,969	16,924	17,484	18,972	14,448	15,233	13,429	14,415	12,961	11,861	13,392	12,195	176,282
37		**CREP**	8,272	9,163	12,688	10,579	5,196	10,504	8,181	6,891	7,682	6,511	6,117	6,037	97,820
38		**Term Fixed Price Sales**	-	-	-	-	-	-	-	-	-	-	-	-	-
39	Index Price														
40		**Base Index Price Purchases**													
41		Basin Creek	864	384	832	1,248	384	416	832	400	2,912	2,912	3,328	1,200	15,712
42		Competitive Solicitations	45,000	44,475	45,400	29,000	26,400	28,975	28,400	28,600	28,400	10,400	10,400	10,000	335,450
43		**Term Index Price Purchases**	123,600	112,850	120,400	37,200	33,600	37,150	36,000	37,200	36,000	37,200	37,200	36,000	684,400
44		**Term Index Price Sales**	-	-	-	-	-	-	-	-	-	-	-	-	-
45		**Spot Purchases**	9,517	39,625	90,421	179,038	166,681	132,129	121,174	121,723	162,853	249,622	227,722	150,867	1,651,371
46		**Spot Sales**	-	-	-	-	-	-	-	-	-	-	-	-	-
47		Imbalance, Current Month Estim	-	-	-	-	-	-	-	-	-	-	-	-	-
48		Imbalance, Prior Month True-up	-	-	-	-	-	-	-	-	-	-	-	-	-
49		Imbalance, Accounting & BA Exp	-	-	-	-	-	-	-	-	-	-	-	-	-
50															
51	Ancillary and Other														
52		Basin Creek Fixed Costs	-	-	-	-	-	-	-	-	-	-	-	-	-
53		Basin Creek Variable Costs	-	-	-	-	-	-	-	-	-	-	-	-	-
54		Operating Reserves	-	-	-	-	-	-	-	-	-	-	-	-	-
55	**Total Delivered Supply**		515,014	535,926	614,250	607,197	536,628	538,958	490,964	488,944	509,883	594,850	570,934	496,939	6,500,487

	A / B	C	D	E	F	G	H	I	J	K	L	M	N	O
56	**Electric Tracker Projection Excluding Generation Assets Cost of Service**													
57	**Total Supply Expense**													
58														
59		Oct-14	Nov-14	Dec-14	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Total
60		Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	
61	Off System Transactions													
62	Fixed Price													
63	Base Fixed Price Purchases													
64	Competitive Solicitations	$ 4,398,960	$ 4,183,460	$ 4,362,240	$ 1,671,800	$ 1,520,160	$ 1,670,240	$ 1,634,360	$ 1,652,140	$ 1,634,360	$ 1,671,800	$ 1,671,800	$ 1,614,700	$ 27,686,020
65	Base Fixed Price Sales													
66	Competitive Solicitations	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
67	Term Fixed Price Purchases	$ 1,311,660	$ 1,165,920	$ 1,263,080	$ 2,390,810	$ 2,173,800	$ 2,388,565	$ 2,337,020	$ 2,362,990	$ 2,337,020	$ 2,390,810	$ 2,390,810	$ 2,309,200	$ 24,821,689
68	Term Fixed Price Sales	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
69	Index Price													
70	Base Index Price Purchases	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
71	Base Index Price Sales													
72	Competitive Solicitations	$ (1,171,590)	$ (1,105,000)	$ (1,248,450)	$ (1,241,612)	$ (1,075,770)	$ (1,107,915)	$ (857,410)	$ (863,448)	$ (845,439)	$ (450,840)	$ (450,840)	$ (433,500)	$ (10,851,815)
73	Term Index Price Purchases	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
74	Term Index Price Sales	$ (2,964,840)	$ (2,884,000)	$ (3,202,920)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (9,051,760)
75	Spot Purchases	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
76	Spot Sales	$ (1,291,140)	$ (1,152,000)	$ (1,343,160)	$ (2,834,301)	$ (2,444,931)	$ (2,528,418)	$ (1,944,268)	$ (1,986,535)	$ (1,917,123)	$ (3,676,080)	$ (3,676,080)	$ (3,554,700)	$ (28,348,736)
77														
78	On System Transactions													
79	Fixed Price													
80	Rate Based Assets													
81	Colstrip Unit 4													$ -
82	Dave Gates Generating Station													$ -
83	Spion Kop													$ -
84	Base Fixed Price Purchases													
85	PPL 7 Year Contract	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
86	Judith Gap	$ 1,379,220	$ 1,539,240	$ 1,620,266	$ 1,775,206	$ 1,319,784	$ 1,367,282	$ 1,235,456	$ 1,099,058	$ 820,420	$ 719,836	$ 819,150	$ 891,540	$ 14,586,458
87	Other Small PPAs	$ 503,562	$ 758,312	$ 782,502	$ 799,428	$ 722,064	$ 798,854	$ 773,640	$ 589,285	$ 441,605	$ 456,325	$ 513,509	$ 496,944	$ 7,635,529
88	Competitive Solicitations	$ 1,166,940	$ 1,037,280	$ 1,123,720	$ 1,123,720	$ 1,037,280	$ 1,123,720	$ 1,123,720	$ 1,080,500	$ 1,123,720	$ 1,123,720	$ 1,123,720	$ 1,080,500	$ 13,268,540
89	QF Tier II	$ 2,564,553	$ 2,455,423	$ 2,728,248	$ 2,482,706	$ 2,414,940	$ 2,564,553	$ 2,613,838	$ 2,810,095	$ 2,508,228	$ 2,237,163	$ 1,991,621	$ 2,376,216	$ 29,747,584
90	QF Tier II Adjustments													
91	QF-1 Tariff	$ 997,543	$ 1,127,815	$ 1,165,134	$ 1,264,294	$ 962,815	$ 1,015,094	$ 894,905	$ 960,586	$ 863,712	$ 790,397	$ 892,443	$ 812,665	$ 11,747,402
92	CREP	$ 322,600	$ 357,370	$ 494,850	$ 412,573	$ 202,630	$ 409,654	$ 319,067	$ 268,735	$ 299,591	$ 253,936	$ 238,546	$ 235,434	$ 3,814,986
93	Term Fixed Price Sales	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
94	Index Price													
95	Base Index Price Purchases													
96	Basin Creek	na	na	na	na	na	na	na	na	na	na	na	na	na
97	Competitive Solicitations	$ 1,697,550	$ 1,679,763	$ 1,855,770	$ 1,220,812	$ 1,056,570	$ 1,087,115	$ 836,610	$ 843,448	$ 824,639	$ 430,040	$ 430,040	$ 413,500	$ 12,375,858
98	Term Index Price Purchases	$ 4,685,100	$ 4,289,905	$ 4,946,940	$ 1,493,689	$ 1,280,362	$ 1,321,677	$ 992,058	$ 1,022,887	$ 976,884	$ 1,513,620	$ 1,513,620	$ 1,464,600	$ 25,501,341
99	Term Index Price Sales	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
100	Spot Purchases	$ 379,255	$ 1,584,989	$ 3,892,634	$ 7,665,373	$ 6,792,052	$ 5,052,221	$ 3,658,299	$ 3,674,874	$ 4,847,956	$ 10,821,118	$ 9,871,729	$ 6,540,083	$ 64,780,583
101	Spot Sales	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
102	Imbalance, Current Month Estim	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
103	Imbalance, Prior Month True-up	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
104	Imbalance, Accounting & BA Exp	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
105														
106	Ancillary and Other													
107	Basin Creek Fixed Costs	$ 351,048	$ 929,397	$ 351,048	$ 351,048	$ 361,128	$ 351,048	$ 354,408	$ 926,037	$ 354,408	$ 351,048	$ 351,048	$ 354,408	$ 5,386,076
108	Basin Creek Variable Costs	$ 25,920	$ 11,520	$ 24,960	$ 37,440	$ 11,520	$ 12,480	$ 24,960	$ 12,000	$ 87,360	$ 87,360	$ 99,840	$ 36,000	$ 471,360
109	Operating Reserves	$ 208,320	$ 201,600	$ 208,320	$ 208,320	$ 188,160	$ 208,320	$ 201,600	$ 208,320	$ 201,600	$ 208,320	$ 208,320	$ 201,600	$ 2,452,800
110	**Total Delivered Supply**	$ 14,564,661	$ 16,180,993	$ 19,025,182	$ 18,821,306	$ 16,522,563	$ 15,733,994	$ 14,198,263	$ 14,660,971	$ 14,558,940	$ 18,928,574	$ 17,989,277	$ 14,839,191	$ 196,023,914

	A / B	C	D	E	F	G	H	I	J	K	L	M	N	O
111	**Electric Tracker Projection Excluding Generation Assets Cost of Service**													
112	**Unit Costs**													
113														
114		Oct-14	Nov-14	Dec-14	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Total
115		Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	
116	<u>Off System Transactions</u>													
117	Fixed Price													
118	**Base Fixed Price Purchases**													
119	Competitive Solicitations	$ 42.38	$ 41.95	$ 42.19	$ 57.65	$ 57.58	$ 57.64	$ 57.55	$ 57.77	$ 57.55	$ 57.65	$ 57.65	$ 57.67	$ 49.20
120	**Base Fixed Price Sales**													
121	Competitive Solicitations	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
122	**Term Fixed Price Purchases**	$ 40.48	$ 40.48	$ 40.48	$ 36.11	$ 36.23	$ 36.12	$ 36.29	$ 35.91	$ 36.29	$ 36.11	$ 36.11	$ 36.08	$ 36.73
123	**Term Fixed Price Sales**	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
124	Index Price													
125	**Base Index Price Purchases**	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
126	**Base Index Price Sales**													
127	Competitive Solicitations	$ 39.85	$ 40.00	$ 43.05	$ 42.81	$ 40.75	$ 38.24	$ 30.19	$ 30.19	$ 29.77	$ 43.35	$ 43.35	$ 43.35	$ 37.86
128	**Term Index Price Purchases**	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
129	**Term Index Price Sales**	$ 39.85	$ 40.00	$ 43.05	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	$ 40.98
130	**Spot Purchases**	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
131	**Spot Sales**	$ 39.85	$ 40.00	$ 43.05	$ 42.81	$ 40.75	$ 38.24	$ 30.19	$ 30.19	$ 29.77	$ 43.35	$ 43.35	$ 43.35	$ 38.78
132														
133	<u>On System Transactions</u>													
134	Fixed Price													
135	**Rate Based Assets**													
136	Colstrip Unit 4													$ -
137	Dave Gates Generating Station													$ -
138	Spion Kop													$ -
139	**Base Fixed Price Purchases**													
140	PPL 7 Year Contract	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
141	Judith Gap	$ 31.75	$ 31.75	$ 31.75	$ 31.75	$ 31.75	$ 31.75	$ 31.75	$ 31.75	$ 31.75	$ 31.75	$ 31.75	$ 31.75	$ 31.75
142	Other Small PPAs	$ 61.53	$ 58.43	$ 58.43	$ 59.69	$ 59.69	$ 59.69	$ 59.69	$ 72.00	$ 55.76	$ 55.76	$ 62.75	$ 62.75	$ 60.23
143	Competitive Solicitations	$ 54.03	$ 54.03	$ 54.03	$ 54.03	$ 54.03	$ 54.03	$ 54.03	$ 54.03	$ 54.03	$ 54.03	$ 54.03	$ 54.03	$ 54.03
144	QF Tier II	$ 36.67	$ 36.67	$ 36.67	$ 36.67	$ 36.67	$ 36.67	$ 36.67	$ 36.67	$ 36.67	$ 36.67	$ 36.67	$ 36.67	$ 36.67
145	QF Tier II Adjustments	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
146	QF-1 Tariff	$ 66.64	$ 66.64	$ 66.64	$ 66.64	$ 66.64	$ 66.64	$ 66.64	$ 66.64	$ 66.64	$ 66.64	$ 66.64	$ 66.64	$ 66.64
147	**Spot Purchases**	$ 39.00	$ 39.00	$ 39.00	$ 39.00	$ 39.00	$ 39.00	$ 39.00	$ 39.00	$ 39.00	$ 39.00	$ 39.00	$ 39.00	$ 39.00
148	**Spot Sales**	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
149	Index Price													
150	**Base Index Price Purchases**													
151	Basin Creek	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
152	Competitive Solicitations	$ 37.72	$ 37.77	$ 40.88	$ 42.10	$ 40.02	$ 37.52	$ 29.46	$ 29.49	$ 29.04	$ 41.35	$ 41.35	$ 41.35	$ 36.89
153	**Term Index Price Purchases**	$ 37.91	$ 38.01	$ 41.09	$ 40.15	$ 38.11	$ 35.58	$ 27.56	$ 27.50	$ 27.14	$ 40.69	$ 40.69	$ 40.68	$ 37.26
154	**Term Index Price Sales**	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
155	**Spot Purchases**	$ 39.85	$ 40.00	$ 43.05	$ 42.81	$ 40.75	$ 38.24	$ 30.19	$ 30.19	$ 29.77	$ 43.35	$ 43.35	$ 43.35	$ 39.23
156	**Spot Sales**	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
157	Imbalance, Current Month Estim	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
158	Imbalance, Prior Month True-up	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
159	Imbalance, Accounting & BA Expense													
160														
161	<u>**Ancillary and Other**</u>													
162	Basin Creek Fixed Costs	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
163	Basin Creek Variable Costs	$ 30.00	$ 30.00	$ 30.00	$ 30.00	$ 30.00	$ 30.00	$ 30.00	$ 30.00	$ 30.00	$ 30.00	$ 30.00	$ 30.00	$ 30.00
164	Operating Reserves	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
165	**Total Delivered Supply**	$ 28.28	$ 30.19	$ 30.97	$ 31.00	$ 30.79	$ 29.19	$ 28.92	$ 29.98	$ 28.55	$ 31.82	$ 31.51	$ 29.86	$ 30.16

NorthWestern Energy
Electric Utility
Total Proposed Supply Rate
May 1, 2014

	Proposed Electric Supply Rates [1]	Proposed DSM Rebate [2]	Colstrip Unit 4 Current Fixed Rates [3]	Colstrip Unit 4 Proposed Variable Rates [4]	Colstrip Unit 4 Proposed DSM Rebate [5]	Dave Gates Gen Station Current Fixed Rates [6]	Dave Gates Gen Station Proposed Variable Rates [7]	Dave Gates Gen Station Proposed DSM Rebate [8]	Spion Kop Proposed Fixed Rates [9]	Spion Kop Proposed Variable Rates [10]	Proposed Total Supply Rates
Residential											
Residential	0.038634	(0.000824)	0.012734	0.004067	(0.000396)	0.004795	0.002170	(0.000043)	0.001458	(0.000012)	0.062583
Residential Employee	0.023181	(0.000494)	0.007640	0.002440	(0.000238)	0.002877	0.001302	(0.000026)	0.000875	(0.000007)	0.037550
Total Residential											
General Service 1											
GS-1 Sec Non-Demand	0.034951	(0.000824)	0.012734	0.004067	(0.000396)	0.004795	0.002170	(0.000043)	0.001459	(0.000012)	0.058901
GS-1 Sec Demand	0.038634	(0.000824)	0.012734	0.004067	(0.000396)	0.004795	0.002170	(0.000043)	0.001459	(0.000012)	0.062584
GS-1 Pri Non-Demand	0.037572	(0.000801)	0.012385	0.003956	(0.000385)	0.004664	0.002111	(0.000042)	0.001420	(0.000012)	0.060868
GS-1 Pri Demand	0.034309	(0.000801)	0.012385	0.003956	(0.000385)	0.004664	0.002111	(0.000042)	0.001420	(0.000012)	0.057605
Total GS-1											
General Service 2											
GS-2 Substation	0.037250	(0.000794)	0.012278	0.003922	(0.000382)	0.004624	0.002093	(0.000042)	0.001407	(0.000012)	0.060344
GS-2 Transmission	0.037028	(0.000789)	0.012204	0.003898	(0.000380)	0.004596	0.002080	(0.000042)	0.001399	(0.000011)	0.059983
Total GS-2											
Irrigation											
Irrigation	0.034951	(0.000824)	0.012734	0.004067	(0.000396)	0.004795	0.002170	(0.000043)	0.001459	(0.000012)	0.058901
Total Irrigation											
Lighting											
Lighting	0.034951	(0.000824)	0.012734	0.004067	(0.000396)	0.004795	0.002170	(0.000043)	0.001459	(0.000012)	0.058901
Total Lighting											
Average Billed Rate	**0.038017**	**(0.000820)**	**0.012680**	**0.004050**	**(0.000394)**	**0.004775**	**0.002161**	**(0.000043)**	**0.001453**	**(0.000012)**	0.061866
Total Supply Rate		**37.197**			**16.336**			**6.893**		**1.441**	**61.867**

[1] Source: Appendix E May 2014.
[2] Source: Docket No. D2012.5.49 Final Order 7219h Updated compliance filing Attachment 4
[3] Source: Fixed rates approved in Docket No. D2010.5.50 Order No. 7093c, effective 04/01/2010.
[4] Source: Appendix H Jan 2014
[5] Source: Docket No. D2012.5.49 Final Order 7219h Updated compliance filing Attachment 5
[6] Source: Fixed rates (based on 2nd yr rev req) approved in Docket No. D2008.8.95 Order No.6943e, effective 01/01/2012.
[7] Source: Appendix J Jan 2014
[8] Source: Docket No. D2012.5.49 Final Order 7219h Updated compliance filing Attachment 6
[9] Source: Fixed rates (based on 2nd yr rev req) approved in Docket No. D2011.5.41 Order No.7159i, effective 1/1/2013.
[10] Source: Appendix L Jan 2014

NorthWestern Energy
Electric Utility Derivation of Rates
Electricity Supply Excluding Generation Assets Capped at Residential Increase
Revenues ($000)
Tracker Period 2014

CAPPED RATES	May14 to Apr15 Supply Retail kWh Sales	Current Revenue	Proposed Rates	Proposed Revenue	$ Change	% Change	$ at Res Cap -39.86%	Capped $ Change	Capped % Change	Capped kWh Rates
Residential										
Residential	2,348,215	$ 90,722	$0.023234	$ 54,558	$ (36,164)	-39.86%	$ 54,558	$ 55,211	-39.14%	$0.023512
Res Employee	3,763	$ 87	$0.013940	$ 52	$ (35)	-39.86%	$ 52	$ 53	-39.15%	$0.014107
Total Residential	2,351,979	$ 90,809		$ 54,611	$ (36,198)	-39.86%	$ 54,611	$ 55,264	-39.14%	
General Service 1										
GS1 Sec NonDmd	280,624	$ 9,808	$0.023234	$ 6,520	$ (3,288)	-33.52%	$ 5,898	$ 5,969	-39.14%	$0.021270
GS1 Sec Dmd	2,506,111	$ 96,822	$0.023234	$ 58,227	$ (38,595)	-39.86%	$ 58,227	$ 58,923	-39.14%	$0.023512
GS1 Prim NonDmd	572	$ 22	$0.022598	$ 13	$ (9)	-39.85%	$ 13	$ 13	-39.14%	$0.022865
GS1 Prim Dmd	357,205	$ 12,255	$0.022598	$ 8,072	$ (4,183)	-34.13%	$ 7,370	$ 7,458	-39.14%	$0.020879
Total GS-1	3,144,513	$ 118,907		$ 72,832	$ (46,075)	-38.75%	$ 71,508	$ 72,363	-39.14%	
General Service 2										
GS2 Substation	232,670	$ 8,667	$0.022403	$ 5,213	$ (3,455)	-39.86%	$ 5,212	$ 5,275	-39.14%	$0.022669
GS2 Transmission	135,701	$ 5,025	$0.022268	$ 3,022	$ (2,003)	-39.86%	$ 3,022	$ 3,058	-39.14%	$0.022534
Total GS-2	368,371	$ 13,692		$ 8,234	$ (5,457)	-39.86%	$ 8,234	$ 8,332	-39.14%	
Irrigation										
Irrigation	86,095	$ 3,009	$0.023234	$ 2,000	$ (1,009)	-33.52%	$ 1,810	$ 1,831	-39.14%	$0.021270
Total Irrigation	86,095	$ 3,009		$ 2,000	$ (1,009)	-33.52%	$ 1,810	$ 1,831	-39.14%	
Lighting										
Lighting	57,614	$ 2,014	$0.023234	$ 1,339	$ (675)	-33.52%	$ 1,211	$ 1,225	-39.14%	$0.021270
Total Lighting	57,614	$ 2,014		$ 1,339	$ (675)	-33.52%	$ 1,211	$ 1,225	-39.14%	
Total Rate Schedule	6,008,571	$ 228,431		$ 139,016	$ (89,415)	-39.14%	$ 137,374	$ 139,016		
	-							(0)		
Capped Rate Adjustment Factor							0.011955			

	A	B	C	D	E	F	G	H	I
1									
2	NorthWestern Energy								
3									
4									
5									
6									
7								***Settlement Adjustments***	
8	**Typical Bill Calculation**							**1) No Return on $30 M Kerr Plant**	
9								**2) Book Depr Change to 50 Yrs**	
10	**Electric Residential Service**								
11								***With PPLM Hydro Assets***	
12	**kWh per month**		**750**						
13									
14					**Current Rates**	Total Bill		**Projected Rates**	Total Bill
15					**5/1/2014**	Amount		**10/1/2014**	Amount
16	Res. Dist.-Service Charge				$ 5.25	$ 5.25		$ 5.25	$ 5.25
17									
18	Plus:								
19	Res. Supply-Energy				**$ 0.062583**	$ 46.94		**$ 0.067677**	$ 50.76
20	Res. Deferred Supply Costs				$ (0.000365)	$ (0.27)		$ (0.000365)	$ (0.27)
21	Res. CTC-QF				$ 0.003350	$ 2.51		$ 0.003350	$ 2.51
22	Res. Transmission-Energy				$ 0.009165	$ 6.87		$ 0.009165	$ 6.87
23	Res. Distribution-Energy				$ 0.028529	$ 21.40		$ 0.028529	$ 21.40
24	Res. USBC				$ 0.001334	$ 1.00		$ 0.001334	$ 1.00
25	Res. BPA-Credit				$ (0.006810)	$ (5.11)		$ (0.006810)	$ (5.11)
26	Total Kwh Charge				$ 0.097786	$ 73.34		$ 0.102880	$ 77.16
27									
28	**Total Bill**				**$ 0.104786**	**$ 78.59**		**$ 0.109880**	**$ 82.41**
29									
30	Monthly Increase (Decrease)								$ 3.82
31	Annual Increase (Decrease)								$ 45.84
32	**Percent Change**								**4.86%**