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

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IN THE MATTER OF NorthWestern Energy's	)	
Application for Approval to Purchase and Operate	)	REGULATORY DIVISION
PPL Montana's Hydroelectric Facilities, for	)	
Approval of Inclusion of Generation Asset Cost	)	
Of Service in Electricity Supply Rates, for Approval	)	DOCKET NO. D2013.12.85
Of Issuance of Securities to Complete the	)	
Purchase, and for Related Relief	)	

Direct Testimony of

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on behalf of

Human Resource Council, District XI
Natural Resources Defense Council

March 2014

Introduction and Summary

Q. Please state your name and occupation.

A. My name is Thomas Michael Power. I am a Research Professor and Professor Emeritus in the Economics Department at The University of Montana, Missoula, Montana. I am appearing in these proceedings, however, as an independent consulting economist, a principal in Power Consulting, on behalf of Human Resource Council, District XI and the Natural Resources Defense Council.

Q. Have you previously testified before this and other regulatory commissions as an expert witness?

A. Yes. I have testified before this Commission on numerous occasions over the past 40 years. I have also testified before federal and state regulatory commissions throughout the United States and Canada on more than seventy-five occasions. A brief summary of my professional experience and training makes up the third section of this testimony.

Q. What issues will you address in this direct testimony?

A. This testimony with focus on two issues that are important in the evaluation of NorthWestern Energy's (NWE) proposal to purchase the Montana hydroelectric facilities currently owned by PPL Montana (PPLM) and commit them to the service of NWE's customers.

I. The economic implications of the developing regulation of carbon emissions from electric generating facilities.

II. The risks associated with owning and operating coal-fired electric generators.

Q. Can you briefly summarize the conclusions you reach in the testimony that follows?

A. Yes. Let me simply state that conclusions that follow from the analysis contained in the following testimony.

a. NWE appropriately accounted for the risks associated with the developing regulation of carbon emissions from coal-fired electric generating facilities.

b. NWE also appropriately incorporated other risks associated with existing and pending environmental regulation of electric generation.

c. NWE'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.

d. Many other electric utilities in the U.S. incorporate carbon costs into their integrated resource planning analysis. The projected future carbon costs NWE used in its portfolio analysis were near the middle of the range of carbon cost values used by those electric utilities. The carbon cost estimates that NWE included in its electric supply portfolio analysis were not the primary determinant of the favorable conclusion NWE came to about the attractiveness of the proposed hydro purchase to meet NWE's customers' electricity needs as compared to investing in an alternative source of supply such as a natural gas fueled combined cycle combustion turbine (CCCT).

e. Using NWE's portfolio analysis, one would have to take rather extreme and untenable assumptions to make the hydro purchase appear to not be the preferred portfolio: A combination of the following assumptions has to be made: the cost of risk has to be close to zero, a 50 percent reliance on regional electric markets to supply NWE's customers has to be appropriate,

the residual value of the hydroelectric facilities thirty years in the future has to be zero. None of these assumptions are appropriate in electric supply portfolio analysis.

f. NWE appropriately included in its economic comparison of the hydro resource with alternative electric resource portfolios the other risks associated with each portfolio including uncertainty about future electric prices, natural gas prices, weather, customer loads, and coal prices.

g. NWE correctly concluded that it would not be prudent to purchase all of PPLM's electric generation facilities in Montana. In particular, it correctly concluded that it would not be prudent to purchase PPLM's coal-fired electric generators.

h. NWE correctly concluded that the costs associated with the risk of environmental regulation of carbon-based electric generation were significant and should not be treated as insignificant.

i. NWE 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.

j. NWE correctly recognized that PPLM's hydroelectric facilities had very low operating costs, very low environmental regulation risk, avoided the risks associated with variable fuel costs, and substantially reduced its customers' exposure to future fluctuating electric market prices. In addition the geographic dispersion of those hydroelectric resources and small modular character of the individual hydroelectric generators also reduced the risk associated with relying on them.

k. NWE appropriately and in compliance with the Electric Supply Procurement Guidelines took a long-term view of the costs and benefits associated with the hydro purchase.

I. Modeling the Supply Alternatives: Deterministic DCF and Stochastic Analysis

1. Accounting for the Risk Associated with Future Regulation of Carbon Emissions

Q. In NWE's evaluation of the purchase of PPLM's hydroelectric units (hydro purchase) does NWE explicitly attempt to incorporate the costs that may be associated with future regulation of carbon emissions?

A. Yes. NWE estimates the likely level of the costs that would be incurred due to future regulation of carbon emissions into the atmosphere by electric utilities. NWE bases those projected carbon costs on the U.S. Department of Energy's Energy Information Administration's (EIA) 2013 Annual Energy Outlook GHG15 case. In that case, the carbon cost is $15 per metric ton in 2014 and then escalates at 5 percent in years thereafter. NWE, however, does not have carbon costs actually impacting electric utilities until 2021. By then the projected carbon cost would have escalated to $21.11 per metric ton of carbon. That cost then continues to escalate at 5 percent. (2013 Electricity Supply Resource Procurement Plan p.5-6 and 5-7). Inflation is built into these projections. That is, they are cost projections in nominal dollars.

Q. Is this inclusion of a carbon cost in NWE's resource planning a change from the past?

A. No. NWE began formally exploring the risk associated with carbon regulation in its 2005 Electric Supply Resource Plan and has included carbon cost considerations in all of its Electric Supply Plans since 2005. As pointed out in the

testimony of NWE's witness Joseph Stimatz, the Montana Public Service Commission (MPSC) has recognized the appropriateness of considering the risks to NWE and its customers of future regulation of carbon emissions.(Stimatz Direct, pp. JMS-24-25)

In its comments on NWE's 2011 Electric Supply Procurement Plan, the MPSC stated:

> "NWE's base case assumes that, sometime in the future, carbon dioxide emissions will be priced under federal law or rules promulgated by the Environmental Protection Agency. This is a possibility over which the Commission and the utility have little or no power, and *it is correct practice to analyze the planning impacts of carbon regulation.* The base case's 2015 carbon price implementation date is increasingly unrealistic in light of the delays associated with such regulations as the Mercury and Air Toxics Standard and the various state Regional Haze Rules. NWE should revisit the timing of potential future carbon prices in its 2013 Plan." (Emphasis added.) N2011.12.96, MPSC Written Comments at 7 ¶ 18.

This was "correct utility planning practice" in 2011 and continues to be so today.

Q. Do other regulated electric utilities regularly include projected carbon costs associated with future carbon regulation in their resource acquisition planning activities?

A. Yes. As pointed out in the NWE 2013 Electric Supply Plan, Western electric utilities incorporate future carbon costs in their evaluation of and planning for resource acquisition. At least one utility operating in Arizona, California, Colorado, Idaho, Montana, Nebraska, New Mexico, Nevada, Oregon, Utah,

Washington, and Wyoming incorporate future carbon costs into their resource acquisition planning activities. (NWE 2013 Plan p. 6-27.)

Other electric utilities around the nation use carbon cost projections in their resource acquisition planning. A recent review of electric utility integrated resource plans across the nation indicated that Western electric utilities were using such carbon cost projections in their planning. In addition, that study also indicated that at least one electric utility in Alaska, Arkansas, Hawaii, Indiana, Louisiana, Michigan, Mississippi, North Carolina, Oklahoma, South Carolina, and Tennessee included carbon costs in electric utility resource acquisition planning activities. ("2013 Carbon Dioxide Price Forecast," Patrick Luckow et al., Synapse Energy Economics, Inc., February 2014 (revised), Figure 2, p. 17)

Q. Do businesses and government organization other than electric utilities make use of projected costs associated with carbon regulation in their planning?

A. Yes. I am not aware of any extensive surveys of American businesses that would document this, but one recent study by CDP North America[1] focused on the "Use of internal carbon price by companies as [an] incentive and strategic planning tool." That study lists 29 businesses based or operating in the U.S. who use carbon prices in their business planning. These businesses included eight electric utilities but also some of the largest energy, technology, and retail companies in the U.S. See the table below.

[1] Carbon Disclosure Project-North America, December 2013. https://www.cdp.net/CDPResults/companies-carbon-pricing-2013.pdf

Private Companies Using an Internal Proce on Carbon*

Consumer Discretionary		**Industrials**	
Delphi Automotive Plc	$10-$20	Cummins Inc.	*
Walt Disney Company,	$10-$21	Delta Air Lines	*
Consumer Staples		General Electric Company	*
ConAgra Foods, Inc.	*	**Information Technology**	
Wal-Mart Stores, Inc.	*	Google Inc.	$14
Energy		Jabil Circuit, Inc.	*
Apache Corporation	*	Microsoft Corporation,	$6-$7
BP	$40	**Materials**	
Chevron Corporation	*	E.I. du Pont de Nemours and Company	*
ConocoPhillips	$8-$46	**Utilities**	
Devon Energy Corporation	$15	Ameren Corporation	$30
Exxon Mobil Corporation,	$60	American Electric Power Company, Inc.	*
Hess Corporation	*	CMS Energy Corporation	*
Royal Dutch Shell	$40	Duke Energy Corporation	*
Total	$34	Entergy Corporation	*
Financials		Integrys Energy Group	*
Wells Fargo & Company	*	PG&E Corporation	*
		Xcel Energy Inc.	$20

* Carbon Disclosure Project-North America, December 2013.Where no price is shown, companies have stated that the specific price used is confidential business information. However, in responding to pertinent questions in the annual CDP disclosure questionnaire all cited an "internal carbon price" as a planning tool.

U.S. EPA has already begun the process of regulating carbon emissions from electric generators. The Montana Commission has also recognized the risks associated with carbon regulation. The MPSC's Electric Supply Procurement Guidelines require NWE to "develop methods for weighting resource attributes…include[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… (Rule 38.5:8213 (e)(i).

In addition, the Montana Legislature when it passed HB 25, the "electric utility reintegration law, required an electric utility that is proposing to add an "electricity supply resource fueled primarily by coal" to "demonstrate the capture and sequestration of 50% of the carbon dioxide produced" by that coal-fired facility. It is important to note that this legislative requirement only applies to a coal-fired generator that was "constructed after January 1, 2007." That is, it does not apply

NWE's purchase of PPLM's existing coal-fired generators. It does, however, clearly indicate that the Montana Legislature recognized the reality of the risk to customers of impending regulation of carbon emissions from coal-fired generators. The Montana Commission implemented this part of the law in its procurement rules (38.5.8228 (2)(f)) .

Because carbon regulation in one form or another seems certain, businesses have to look forward to both the costs that carbon regulation may impose on them and/or the business opportunities that managing those costs will create for them. The uncertain financial impacts associated with the regulation of carbon cannot be ignored by prudent business managers any more than the many other uncertainties that make up the business environment in which they have to operate.

The same can be said about public decision makers who are analyzing the economic impact or rationality of various public policies that might increase or decrease greenhouse gas emissions. A federal task force consisting of representatives of 11 federal agencies has developed estimates of the public costs associated with greenhouse gas emissions. These costs are intended for use in federal calculations of the benefits, costs, and cost effectiveness of federal activities impacting greenhouse gas emissions. The economic logic behind incorporating these carbon costs into public decision making is that these cost are not yet reflected in market prices and therefore public decisions that do not account for them may be overstating public benefits or understating public costs. In the May 2013 update of this "social cost of carbon for regulatory impact analysis," the carbon cost per short ton of carbon equivalent for 2013 ranged from about $12 to $57 depending on the discount rate used.[2] The value in 2021

[2] Technical Support Document: Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866, May 2013 http://www.whitehouse.gov/sites/default/files/omb/inforeg/social_cost_of_carbon_for_ria_2013_update.pdf , p.3. Adjusted to short tons and 2013 dollars and interpolated between 2010 and 2015.

would be approximately $15 to $74 depending on the inflation rate used.[3] NWE's 2021 carbon price expressed in nominal dollars and short tons would be $15.88, at the lower end of this range.

Q. You previously mentioned the carbon prices used by other Western electric utilities in their planning processes to which NWE compared its projected carbon prices in its 2013 Electric Supply Plan. Where in that array of projected carbon prices were NWE's projections?

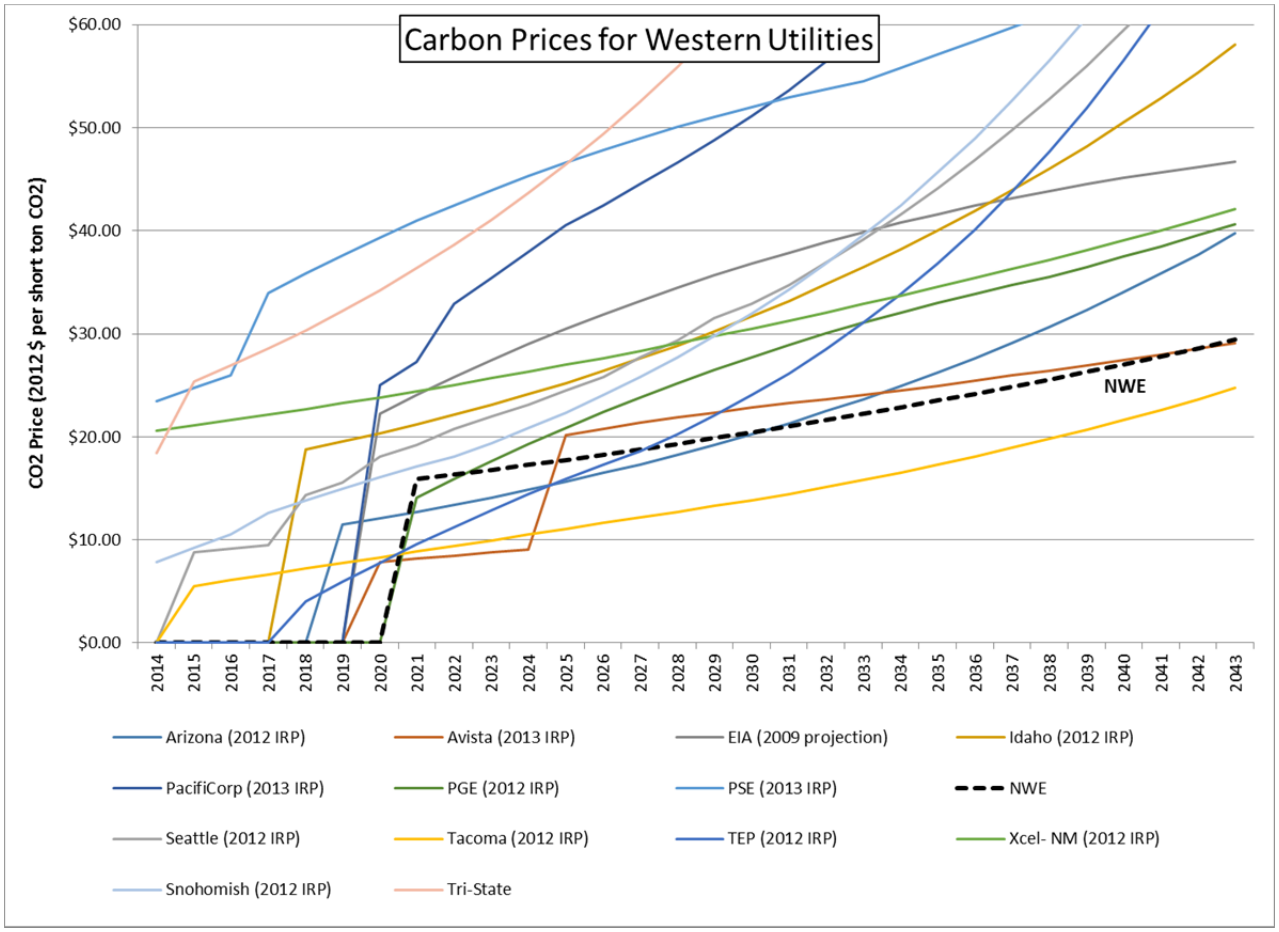
A. As NWE pointed out in its 2013 Plan and emphasized in its direct testimony in this case, NWE's projected average carbon prices were towards the lower end of the average of the other utilities' carbon price projections. The range of values between NWE's maximum carbon values and its mean value includes most of the other Western utility projections. The figure below compares NWE's mean carbon value with those of other Western electric utilities (and includes as a point of reference a 2009 EIA projection).

Of the 13 Western electric utilities used by NWE for comparison purposes, only Tacoma Power projected lower mean carbon prices. The projected mean carbon prices shown for Avista were very close to the mean carbon prices used by NWE. It should be noted that we have expressed the carbon prices in the figure above in terms of dollars per short ton (2,000 pounds per ton) of carbon released rather than in terms of metric tons (2205 pounds per tonne) so that they can be compared with another set of utility carbon prices we will discuss below.

Also, it should be pointed out that the carbon prices shown in the figure above are expressed in inflation-adjusted or real terms. That is, general price inflation has been removed. In NWE's 2013 Electric Supply Plan, the carbon prices were stated in nominal terms, meaning that a general inflation rate was included. The inflation rate used by NWE in its 2013 Plan was 2.1 percent per year. We expressed the carbon cost in these adjusted terms so that these projected

[3] Inflated to 2021 dollars using an assumed inflation rate of 2.1 percent per year.

carbon prices could be more easily judged in terms of the current purchasing power of the dollar and so that they can be more easily compared to another set of utility carbon prices that will be discussed below.



Source: NWE response to Data Request PSC-73a. Data was converted to real 2012 $s using the NWE inflation rate of 2.1 percent per year and converted to short tons from metric tons.

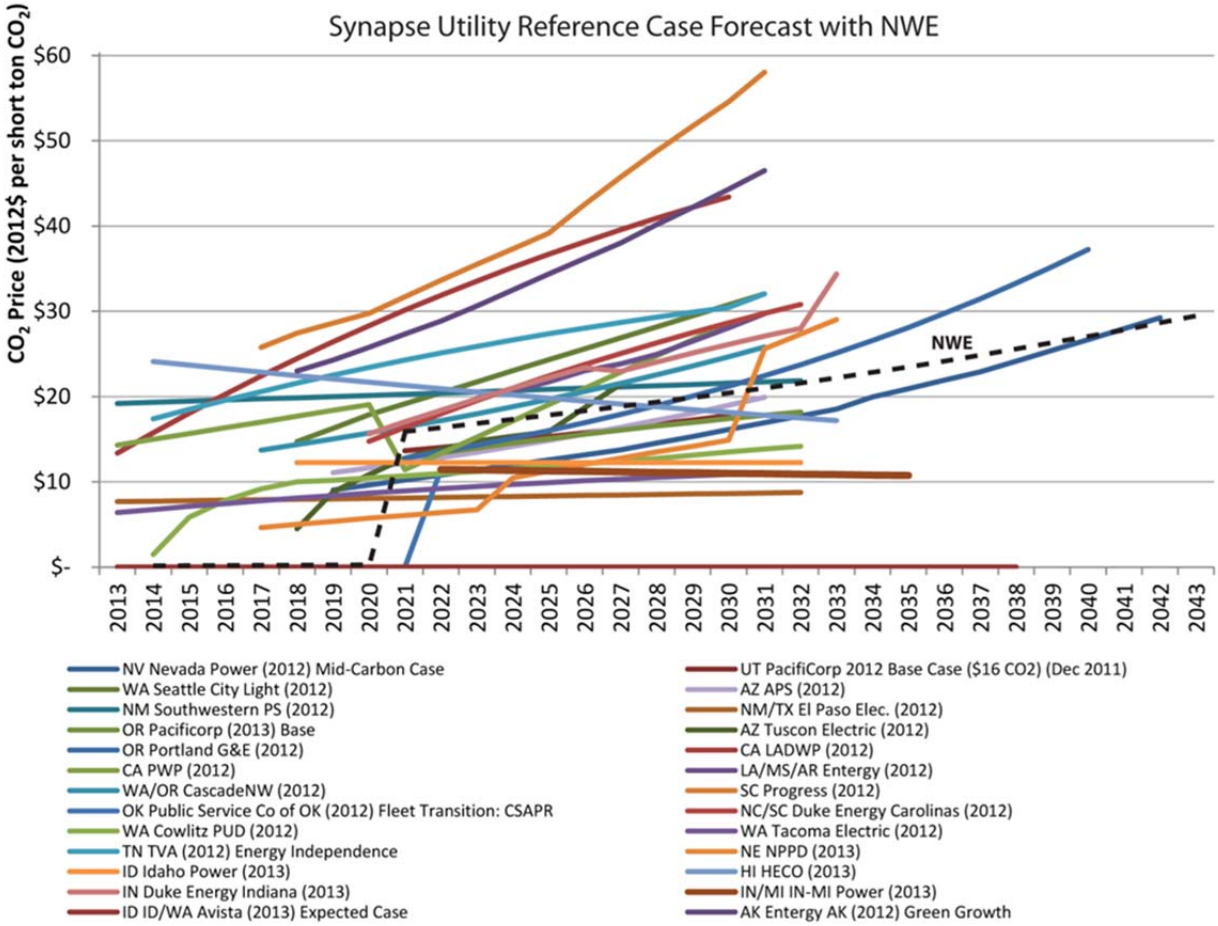
Q. Is there another source of electric utility carbon price assumptions available?

A. Yes. As pointed out above, in November 2013 Synapse Energy Economics released its "2013 Carbon Dioxide Price Forecast."[4] That report provided information on electric utilities operating in another eleven states as well as

[4] Patrick Luckow et al. In February 2014 a revised version was released with "minor corrections" included.

information on most of the Western electric utilities for which NWE had also provided carbon pricing information. This information is shown in the figure below along with NWE's mean carbon price.

As can be seen in the figure below, NWE's projected mean carbon prices are "in the middle of the pack" but towards the lower end of the 28 other utilities on which the Synapse report focused. About 10 utilities had carbon prices clearly higher than NWE's and about 10 had carbon prices that were lower. The eight others were close to NWE's or both above and below NWE's carbon price projection at different times.



Source: "2013 Carbon Dioxide Price Forecast." November 2013 (with 2014 corrections), Patrick Luckow et al., Synapse Energy Economics.

Q. Are NWE's carbon price projections calculated the same way these other utilities' carbon prices were calculated?

A. Not exactly. NWE's carbon price projections were based on the EIA's projected $15 per metric ton carbon price in 2014. NWE delayed the application of that price until 2021. During that time period the carbon cost was assumed to increase at 5 percent per year in nominal terms until it took effect and then continue to increase at that rate. NWE made this projected carbon price the mean of a triangular probability distribution of stochastic carbon prices each year. It set the maximum stochastic price at twice the 2021 $21.11 per ton level and the minimum carbon price at zero.

NWE summarized the other electric utilities' carbon prices by averaging the high, middle, and low estimates for each year unless the low estimate was zero, in which case the zero price was not used in the calculated average carbon price for that utility.

The Synapse tabulation of electric utility carbon prices were expressed in dollars per short ton while NWE, following EIA, expressed the carbon price in metric tons (We converted the NWE presentation of other utilities' carbon costs in the figure above, to short tons for ease of comparison.)

In addition, the Synapse report on electric utility carbon cost estimates was based on each utility's "reference" or "base" projected carbon price, ignoring any high and/or low estimates the utility may have also presented. The general idea was to provide an indication of what the utility thought was the "middle" or most likely estimate. Thus Synapse reported the carbon price used by Avista to be zero because that, in fact, was Avista's "base" carbon price. For Avista's analysis of risk, however, Avista used a low (zero), mid, high, and very high carbon price to bracket the possibilities. NWE in reporting on Avista's carbon price assumptions reported the average of the three non-zero carbon prices Avista had

used. As a result, in the Synapse display of different utilities' carbon prices, Avista is represented by a flat line at zero. In NWE's presentation of this data, it represented Avista by a line that relatively closely tracks NWE's carbon price assumptions. If Synapse had reported on Puget Sound Energy's base case carbon price, it would also have shown a flat line at zero while NWE shows a line that is the average of the mid, high, and very high carbon prices that Puget used in developing its analysis of carbon regulation risk.

NWE's exclusion of zero low-case carbon values from the set of other utility carbon prices on which NWE reports had the effect of increasing the average of some of the reported utility carbon prices relative to the Synapse values.

Q. Why did NWE exclude zero carbon costs from its presentation of other utilities' carbon prices?

A. NWE dropped the projections that assumed carbon costs over the next 30 years would be zero on the grounds that NWE "believes a zero price for carbon over the planning horizon is not realistic." (Response to DR PSC-132)

Q. Has that view of projections of zero carbon costs also been expressed by regulatory commissions in the Pacific Northwest region?

A. Yes. As pointed out above, the Montana Commission in commenting on the 2011 NWE Electric Supply Plan indicated that including such carbon costs in the analysis of alternative sources of supply was "correct practice" for regulated utilities. In addition, as quoted above, the Montana Commission's Electric Supply Procurement Rules require the utility to include the risk of carbon regulation in its analysis of any new supply resources. Also, as shown above, regulated utilities across the United States have been incorporating carbon costs into their economic analysis of alternative sources of generation as they plan to meet

future loads. Almost all Western utilities do that too. In that sense incorporating carbon costs in electric utility planning is the standard practice.

More recently, the Washington Utilities and Transportation Commission (WUTC) that has jurisdiction over both Puget Sound Energy and Avista's operations in Washington stated: "The Commission considers a zero cost for $C0_2$ over the 20-year planning horizon unrealistic and unreasonable."[5]

At the same time, the WUTC made the following comment on Puget Sound Energy's 2013 Integrated Resource Plan:

> "However, PSE assumed in its Base Scenario that there would be a zero cost of $C0_2$. The Commission finds this inappropriate for a number of reasons. Although PSE is not currently paying for $C0_2$ emissions, there is growing evidence that society and PSE ratepayers are bearing the costs of those emissions and that those costs are not zero." [6]

The WUTC made these comments in the context of a docket that was both reviewing Puget's most recent integrated resource plan as well as Puget's study of whether to continue to invest in the four Colstrip coal-fired electric generators in which Puget owns a significant interest. Puget's analysis had concluded that investing in these coal-fired electric generators so that they could meet EPA's stricter emission standards was cost effective compared to the alternatives. The Commission expressed its doubts citing, in particular, Puget's assumption of zero future carbon costs associated with these coal-fired generators: "The future

[5]Utilities and Transportation Commission Comments on Puget Sound Energy's Colstrip Study, Docket UE-120767, page 13. February 6, 2014. Appendix B to a letter from the WUTC to Ken Johnson, Director of State Regulatory Affairs, Puget Sound Energy.
[6] Ibid. Appendix A to a letter from the WUTC to Ken Johnson, Director of State Regulatory Affairs, Puget Sound Energy dated February 6, 2014.

risk of $C0_2$ costs is a significant factor in the Commission's view of the economics of Colstrip." [7]

Q. What is your conclusion as to the rationality of explicitly including the potential costs associated with future regulation of carbon emissions into the analysis of alternative ways of meeting customers' electric needs?

A. Accounting for the uncertainties associated with the future operation of electric generators, including uncertainties like fuel costs, electric market prices, operation and maintenance costs, and future regulatory costs is standard practice. The regulatory risks associated with carbon-intensive electric generators in not zero. Ignoring a potentially significant future cost while making electric supply resource decisions would be imprudent.

2. The Relative Importance of Projected Carbon Costs in NWE's Analysis of the Proposed Hydro Purchase

Q. How do NWE's assumptions about future carbon costs impact the economic analysis of the comparison of purchasing the hydro resources as opposed to meeting customer loads with alternative electric supply resources?

A. The projected carbon costs impact several important economic parameters used in the analysis of the cost of alternative electric supply portfolios.

First, given that all carbon-based fuels when burned to generate electricity will emit carbon, the operation of those facilities will be more costly because of the carbon penalty. The more carbon intensive the fuel (e.g. coal as opposed to natural gas), the higher will be the cost of generating electricity with that fuel. Because the hydro resources (and other renewable resources) do not emit carbon, their cost will not be affected by carbon regulation. But, of course, the hydro resources' *relative* attractiveness will rise as carbon costs rise.

[7] Op.cit. WUTC letter to Puget Sound Energy, Appendix B, p. 13

In addition, in a competitive electric market, the market price of electricity will be determined by the variable cost of production from the highest cost generator that has to be deployed to meet demand at any particular point in time. Since the hydro and other renewable generators have very low operating costs, they will always be deployed first and then increasingly costly resources will be deployed based on their operating costs. That means that it is likely that the marginal electric generating units that set the market price of electricity will be generators burning a carbon-based fuel. Carbon prices will therefore increase the market price of electricity too. The less efficient and more costly the thermal electric generators that have to be deployed to meet load are, the higher will be the market price of electricity.

Thus, the projected future carbon prices will impact both the cost of operating any generator that combusts a fuel and it will also impact the cost of buying electricity on the market and the value of selling electricity into the market.

Q. How did NWE evaluate the economic performance of adding the hydro resources to its existing portfolio of resources versus investing in an alternative source of additional generation?

A. NWE carried out discounted cash flow (DCF) analyses in which very specific assumptions were made about the economic environment in which those resources would be used. In a DCF analysis we assume we know the future price of gas, the future level of carbon regulation, future electric market prices, etc. This type of analysis is deterministic in the sense that it is assumed that there is no uncertainly about those economic parameters. It is possible, however, to do a sensitivity analysis by changing the assumed economic parameters one at a time to see how sensitive the results are to those economic assumptions.

The other approach employed by NWE has used to evaluate the economic attractiveness of the hydro resources compared to investment in alternative

resources was to explicitly recognize the range of uncertainty the utility faces and evaluate not only the expected costs of each portfolio of resources but also the uncertainty associated with those costs. The method used to evaluate uncertainty will be discussed below.

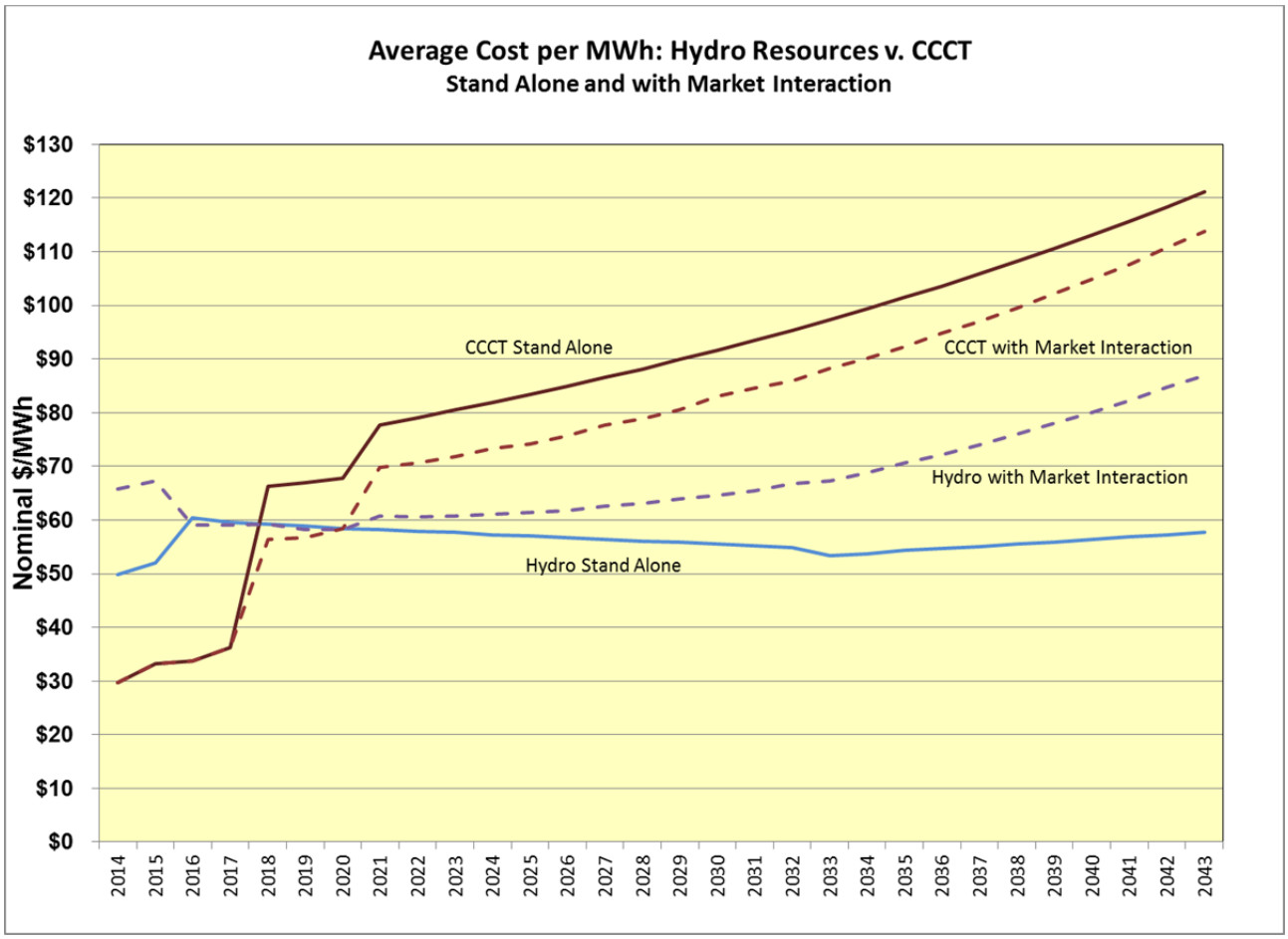
The second approach employed stochastic modeling, which allows analysts to better consider the consequences of uncertainty in evaluating outcomes. That stochastic modeling was carried out by Ascend Analytics for NWE using its PowerSimm model. The difference between deterministic modeling and stochastic modeling will be discussed further below.

Q. What do NWE's deterministic DCF models indicate about the economic attractiveness of the hydro resources in NWE's electric supply portfolio compared to adding a thermoelectric generator?

A. This was shown in NWE witness John Hines Graphs 3 and 4 on pages JDH-19 and JDH-33 in his direct testimony. Those two graphs have been combined and reproduced in the figure below. That figure compares the hydro resources to a natural gas-fired combined cycle combustion turbine (CCCT).

The figure below shows the costs associated with the hydro resources and the CCCT as a "stand alone" generators that are operated as merchant generators selling into the regional electric market. As stand-alone resources, they are not treated as part of NWE's electric supply portfolio where they interact with NWE's customers' demand for electricity and the alternative ways the utility can meet that demand. The figure above also shows the hydro resources and the CCCT as resources within NWE's existing portfolio of resources where the utility dispatches its resources to meet demand in a way that minimizes the total cost and maximizes revenues from off-system sales. That scenario also has the utility going into the electric market to purchase additional supply when its other

resources cannot meet customer demand. The results of that scenario are shown in the figure above as the “with market interaction” curves.

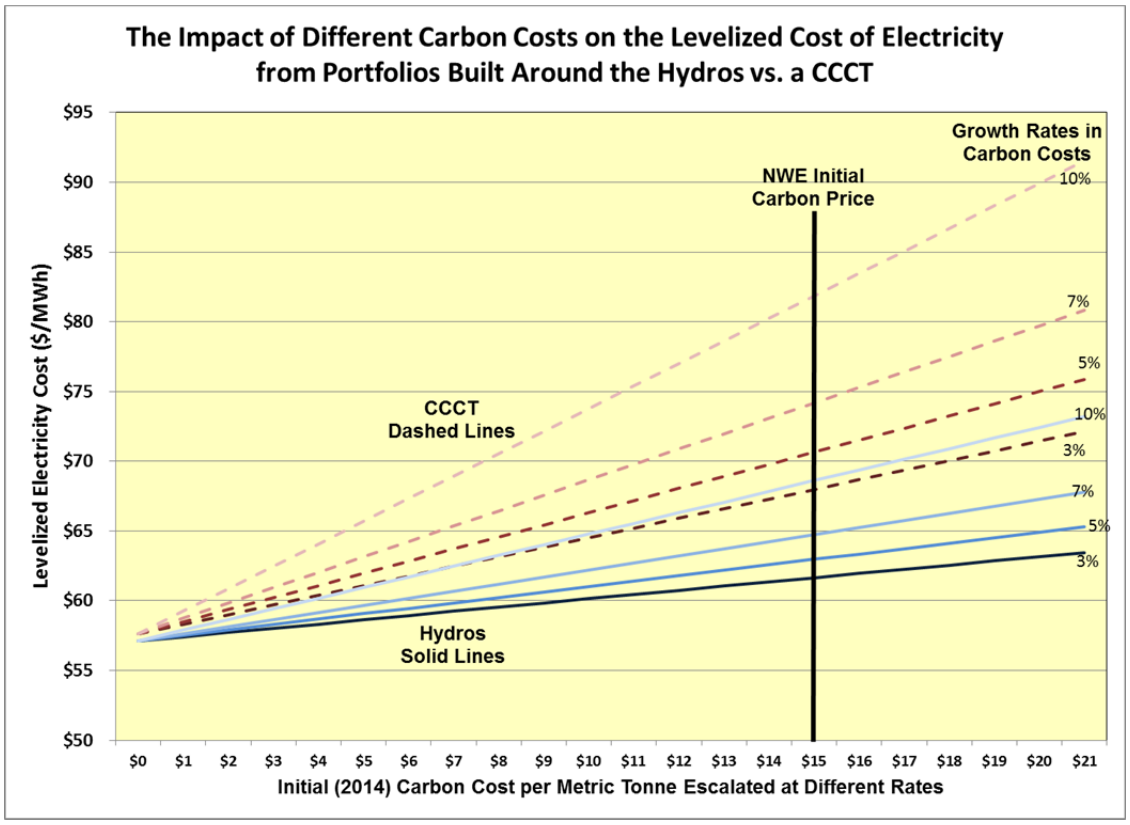


In both the stand-alone and market interaction comparison of the hydro and CCCT resources, the hydro resources are less costly after the year 2021 at which time the carbon cost is assumed to be imposed on carbon-fueled electric generators. For the 3-year period before the CCCT is added, the CCCT curves represent market purchases. In 2018 the capital costs of the CCCT are included in the cost and in 2021 the carbon costs are included. For the hydro resources, the capital costs associated with those resources are added in 2014. As a result, for a brief period, the hydro resources are more costly but after 2020 the hydro resources have lower costs associated with them.

The cost associated with the hydro resources with market interaction rises while the cost of the hydro resources as stand-alone generators declines slightly. This is because conventional capital cost recovery or depreciation front-loads the capital costs of a facility which then decline as that capital investment is amortized. The market interaction hydro resource cost curve rises because the utility sells less "excess" hydroelectric energy into the market and has to buy more electricity in the market as customers' loads increase.

Q. Is the lower cost of electricity from the hydro resources compared to the CCCT entirely due to the assumed carbon cost that is assumed to take effect in 2021?

A. No. Even with very low or zero carbon costs, the DCF modeling indicates that the hydro resources are the lower cost resource. This can be seen in the figure below.



Source: NWE DCF Workbook, NWE response to Data Request PSC-160c that referred to "Exhibit_(JMS-1) and (JMS_2) & p. JMS-20.xls" that was associated with the Direct Testimony of Joe Stimatz. It also referred to the "Curve Calculator 6-7-13.xls" which was provided in response to Data Request MCC-154.

As can be seen in the figure above, even if the assumed carbon cost was zero, the levelized cost of electricity from the CCCT would be slightly higher, $0.50 per MWh higher, $57.62 v. $57.12 per MWh. Each increase of a dollar in the initial level of the carbon cost results in an increase in the advantage of the hydro resources by about 50 cents per MWh. At NWE's assumed initial carbon costs of $15 per metric ton of carbon in 2014 (but not applied until 2021), the advantage of the hydro purchase over the CCCT would increase to $7.68 per MWh from the $0.50 per MWh advantage at a zero carbon cost. (NWE's rate of annual increase in the carbon costs of 5 percent was used in these calculations.)

Q. You have compared the hydro purchase to investing in a natural-gas fired combined cycle combustion turbine rather than to reliance on the regional electric market to provide all of the electricity NWE customers demand over and above what NWE's current electric supply portfolio can cover. Why did you not use market purchases as your reference point?

A. Adding no additional generating resources to NWE's current portfolio would require NWE to go into the regional electric market for about half of the electric energy needed to serve customers' loads. (Page JMS-33 of Joe Stimatz's direct testimony.) That would expose customers to potentially volatile market electric rates for almost half of all the electricity that NWE provides to its customers. We know from the disruptive instability in regional electric prices in the 2000-2001 period and repeated spikes in electric prices since then how costly such volatility in market electricity rates can be to businesses, customers, and the utility.

The Montana Legislature recognized the need for regulated electric utilities to own their own generating resources when it passed in 2007 the "Electric Utility Industry Generation Reintegration Act," HB 25. That act authorized NWE to bring utility-owned electric generating facilities to this Commission for inclusion in NWE's rate base and its customers' rates. The word "reintegration" in the title of the law referred to allowing NWE to move beyond being just a "pipes and wires"

utility that bought all of the electric energy its customers needed from the regional electric market. That legislation provided a framework within which, supervised by this Commission, NWE could reintegrate generating facilities into the electric utility just as the Montana Power Company had done during its history. NWE's Electric Supply Resource Procurement Plans and the analysis supporting them have consistently concluded that adding natural gas fueled electric generators was superior to continuing to rely on market purchases when both cost and risk are taken into account. That is the reason that a CCCT was chosen as the alternative to compare with the hydro purchases. That is also the type of electric generating facility that other American utilities have chosen to help them meet future loads. This will be discussed more in the following section of this testimony.

Although it is easy when market electric prices are low to be complacent about the potential for electric price shocks, most regulated utilities seek to stabilize the costs their customers face by owning a substantial part of the supply needed to serve those customers. At the same time, a balanced portfolio would certainly include some amount of electricity purchased at market prices. Purposely maintaining a 50 percent exposure to the market, however, is not part of a balanced portfolio. For that reason, comparing the hydro purchase to continued over-reliance on the regional electric market is not a comparison with a reasonable alternative.

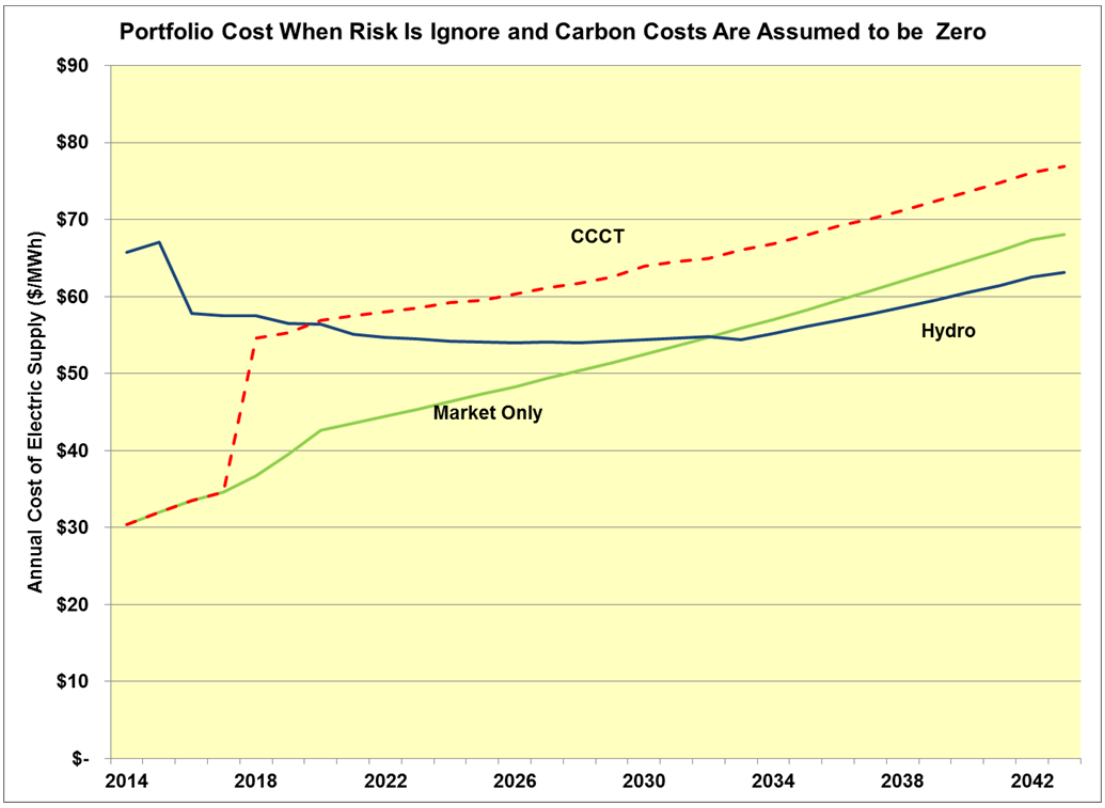
Q. If, however, that comparison of the hydro purchase with NWE's existing portfolio and only additional market purchases were to be made, how would the hydro purchase compare to continued reliance on regional markets for almost half of customers electric needs?

A. In the Discounted Cash Flow deterministic (no risk considered) analysis that NWE carried out, the comparison of the "market only" alternative to the hydro purchase showed that the levelized cost per MWh from those two alternatives

would be about the same when the two were considered in the context of NWE's total portfolio: The levelized cost of electricity would be about $63 per MWh for both the hydro purchase and the "Market Only" alternative. On a stand-alone basis, the hydro purchase alternative was cheaper compared to the "Market Only" alternative: About $56 per MWh for the hydro purchase and $64 per MWh for the market only alternative. (Stimatz Direct Testimony, p. JMS-38) It is important to keep in mind that these analyses did not seek to incorporate the different costs of risk associated with different supply portfolios.

Q. If the carbon cost that NWE included in its analysis is removed, how does the hydro purchase compare to the "market only" alternative?

A. That is shown in the figure below.



Source: NWE DCF Workbook, NWE response to Data Request PSC-160c that referred to "Exhibit_(JMS-1) and (JMS_2) & p. JMS-20.xls" that was associated with the Direct Testimony of Joe Stimatz. It also referred to the "Curve Calculator 6-7-13.xls" which was provided in response to Data Request MCC-154.

If the cost of risk is ignored, relying entirely on the market to serve loads beyond NWE's current generating capacity is projected to be cheaper than purchasing the hydro facilities or adding a CCCT to NWE's portfolio until about 2032. After that, the hydro purchase is cheaper. The hydro purchase is cheaper than the CCCT after the year 2020. The levelized cost per MWh associated with the "market only" alternative is projected to be about $10 per MWh cheaper than the hydro purchase <u>if</u> carbon costs are assumed to be zero and other sources of risk are ignored. With that zero carbon cost and zero risk assumptions, the levelized cost per MWh for the hydro purchase and CCCT alternatives are quite similar with the hydro purchase having a 50 cent per MWh advantage.

It is important to note that a scenario of "market only" going forward and zero carbon cost involves serious future risks: Regional electric and natural gas prices are assumed to stay relatively low and no significant costs are projected to be associated with carbon emissions, and natural gas prices are assumed to remain relatively low. Those assumptions leave customers exposed to three significant sources of risk while assigning no cost to that risk.

Given that one of the primary advantages of the hydro purchase is that it will reduce the exposure NWE customers have to electric market price and natural gas fuel price increases and reduce the exposure to cost associated with the future regulation of carbon, ignoring these types of risks in the economic analysis of alternative future electric supply scenarios would be a serious error. One of the primary reasons for electric supply planning is to study the *long-term* implications of alternative electric supply strategies. The Electric Utility Industry Generation Reintegration Act specifies that electric utilities "shall …provide adequate and reliable electricity supply service at the lowest **long-term** total cost" and "identify and cost-effectively manage and mitigate risks related to its obligation to provide electricity supply service…" (69-8-419 MCA, emphasis added.")

That focus on the long-term and risk management is central to the evaluation of alternative electric supply proposals.

3. NWE's Stochastic Analysis of Alternative Supply Scenarios

Q. Did NWE use the deterministic DCF analysis to evaluate the proposed purchase of PPLM's hydroelectric facilities in its 2013 Electric Supply Plan?

A. No. NWE has used a more sophisticated model that allows the uncertain nature of future economic conditions to be directly taken into account in its analysis of alternative electric supply portfolios. Before the start of the development of NWE's 2013 Electric Supply Plan, NWE used the GenTrader model to evaluate alternative resources in the context of NWE's overall portfolio. That model allowed some evaluation of the risk associated with alternative portfolios too.

However, at the time that the hydro purchase materialized as a real possibility, NWE was in the midst of switching to a new model, Ascend Analytics' PowerSimm model. One of the main reasons for the shift to the new model was NWE's and previous Commission's concerns about the adequacy of the risk analysis that GenTrader allowed and the applicability of the model's outputs in guiding resource selection. As a result, *neither* the GenTrader nor the PowerSimm model was ready to be used to evaluate the potential purchase of PPLM generating resources at the time that PPLM requested bids. (Hines' Direct Testimony, page JDH-29 at 15.) That was the reason NWE evaluated the purchase of the PPLM hydro facilities and alternative supply scenarios using the DCF models.

Later in 2013 the NWE system data had been organized for use in Ascend's PowerSimm model and that model had been tested to confirm that it was accurately projecting the operation of the NWE system. At that point, NWE and Ascend could begin modeling alternative portfolios to meet NWE's customers'

electrical needs, including NWE's purchase of the hydro resources, in a way that included the risks associated with the uncertain economic environment in which NWE would be operating. NWE's Application to purchase PPLM's hydroelectric facilities and NWE's 2013 Electric Supply Plan, which is an exhibit to NWE's hydro purchase Application, contained that stochastic analysis of the uncertainty and risk associated with the various alternative portfolios.

Q. Can your briefly describe the difference between the deterministic DCF models and the stochastic PowerSimm model?

A. The DCF models are called deterministic because very specific quantitative information about expected future conditions has to be entered into those models. Even if many of the future characteristics of energy markets and the Montana and national economies are uncertain, the person using the model has to enter his or her judgment as to what those future conditions are most likely to be. Very precise quantitative estimates have to be entered into the DCF models.

As mentioned above, the analyst can run sensitivity analyses to see how changes in assumptions about future conditions might change the conclusions that are reached. Of course, even setting those alternative assumptions to reflect unavoidable uncertainty is subjective and based on best judgment.

The stochastic models like PowerSimm recognize the broad range of uncertainty about future conditions and make evaluating that uncertainty a central part of the modeling. The range of uncertain future conditions that can affect the ultimate cost of electric generation and the demand for that electricity is very broad, including weather, electric market prices, natural gas prices, coal prices, customer loads, variable generation from hydro and wind generators, the cost of debt and common equity, the rate of inflation, the rate of growth of the Montana and national economies, technological change affecting electric generation and electric consumption, and the level and character of environmental regulation

including carbon regulation. Besides having to understand the likely level and rates of change of each of these, the analyst also has to consider the relationship between and among these variables. For instance, natural gas and market electric prices are likely to be related as are economic condition, the demand for electricity, and electric and natural gas prices.

Stochastic models try to incorporate all of the most important characteristics of future electric markets into the model not as “best guesses as to the most likely future value” but as a whole set of possible future value along with the likelihood of those different values actually occurring. The variability of these variables in the past tempered by an understanding of changes that have been taking place in the recent past or expected in the near future provides the variable data set that enters into the model. Where there is not information on past variation, an assumed frequency distribution has to be developed.

Q. What then is the outcome of such a stochastic model?

A. As one would expect, it is a projection of the future frequency distribution of the variables of concern such as the cost of electricity. The analyst then has to provide a way of summarizing in a meaningful way the characteristics of that distribution of possible outcomes. For instance, one way to describe a central tendency in the variable outputs is to form a weighted average of the various values where the weights are the frequency with which they occurred in model runs. Such frequency or probability weighed averages are typically called the *expected* value or weighted mean value. Most people are familiar with interpreting average values; so this is useful and applicable information.

Since one of the primary purposes of stochastic modeling is to provide useful information on the uncertainty surrounding any estimate of expected value, the modeling results also have to summarize the risk associated with the measured expected value. That can be done by producing a measure of variability such as

the standard deviation or variance of the estimate. When risk is handled in that manner, it is left to the decision maker to decide how much weight to place on the expected dollar value and how much weight to place on the risk. The decision maker can look at all of the pairs of expected dollar values and the risk associated with each supply scenario and choose a pair that balances the decision makers' preferences for containing costs as opposed to containing risk.

Ascend Analytics in its PowerSimm model has sought to make the measures of expected value of a portfolio and measures of risk more straightforward by stating the measure of risk in dollar terms just as the measure of expected value is expressed. Those two measures can then be added together to give a risk-adjusted value of, say, the cost of each portfolio. The measure of risk chosen by Ascend Analytics is also easy to understand. It is the frequency-weighted or expected value of the potential negative results beyond the mean.

If our concern about risk is the potential for costs being higher than the estimated mean value, then the cost associated with those higher costs can be stated in dollar terms as simply the expected value of the higher costs when they are weighted by the likelihood that they will occur. This is the risk premium that Ascend Analytics calculates.

A "total cost" then can be calculated for each portfolio analyzed by adding together the mean value of the costs and that risk premium expressed in dollar terms. If the decision-maker is hesitant to treat these two measures of cost, namely the mean value of the portfolio and the risk premium, as equivalent, he or she can keep them separate and do their own subjective weighting of average cost and the expected cost of risk of each portfolio in order to make a decision.

This measure of the cost of risk that Ascend Analytics' has developed focuses on the potential future "downside" associated with the uncertainty about the economic environment. This exclusive focus on future negative outcomes is

appropriate for a regulated utility that has an obligation to protect customers. In a more “speculative” industry, business owners might well also focus on the potentially positive outcomes in which, for instance, costs decline and the company is more profitable because of that. In that sense, Ascend Analytics’ measure of the cost of risk is built around the subjective judgment that potential negative outcomes associated with the uncertain economic environment are more important than potential positive outcomes.

Q. What electric supply scenarios to meet customers’ loads did NWE model with PowerSimm?

A. The original NWE 2013 Electric Supply Plan compared three electric supply portfolios. All three included NWE’s existing electric supply resources and access to market purchases and/or sales. In addition, the alternative portfolios met customers’ loads by:

- i Only relying on electric markets to buy additional supply.
- ii Building a 238 MW CCCT in 2018.
- iii Purchasing the 633 MW of PPLM hydroelectric resources in 2014.

Markets were relied on in all three scenarios to purchase electricity and/or sell excess generation into that market.

A Supplement to the 2013 Electric Supply Plan was released in February 2014 as a result of an agreement between the MPSC staff and NWE to analyze three additional portfolios built around different sized gas-fired generators and/or additional wind-electric generation. Besides NWE’s existing electric supply resources and purchases on the market these three other scenarios added:

- iv Build an effective 97 MW simple cycle combustion turbine in 2018.
- v Build an effective 97 MW simple cycle combustion turbine in 2025 plus 100 MW of wind in 2025.

vi Build an effective 239 MW combined cycle combustion turbine in 2025 as well as 100 MW of wind electric generation in 2025.

Q. What were the results of that stochastic modeling of these alternative supply scenarios?

A. The overall cost, including the risk premium, of each portfolio is shown in the table below.

Comparison of Supply Alternatives: Total Costs

	Current + Market ($millions)	Current+ CCCT ($millions)	Current+ Hydro ($millions)	Current+ LMS SSCT 2018 ($millions)	Current+ LMS+Wind 2025 ($millions)	Current+ CCCT+Wind 2025 ($millions)
Total Cost with Risk Premium	$6,227	$6,246	$6,063	$6,297	$6,243	$6,200
Advantage of Hydro	$376	$387	$0	$443	$384	$332

The hydro purchase alternative is $332 to $443 million dollars less expensive that the alternatives

Q. Part of this cost advantage of the hydro purchase alternative is tied to the higher risk associated with the non-hydro alternatives. How did those cost of risk compare among the alternative supply portfolios?

A. That is shown in the table below.

Comparison of the Cost of Risk Associated with the Supply Alternatives

	Current + Market ($millions)	Current+ CCCT ($millions)	Current+ Hydro ($millions)	Current+ LMS SSCT 2018 ($millions)	Current+ LMS+Wind 2025 ($millions)	Current+ CCCT+Wind 2025 ($millions)
Cost of Risk	$457	$384	$249	$442	$429	$393
Advantage of Hydro	$208	$134	$0	$192	$180	$144

The advantage that the hydro purchase alternative has in lower cost of risk is $134 to $208 million.

Q. Is this cost of risk simply the risk of future carbon regulation?

A. No. Included in the cost of risk is the variability of customer load, weather, hydroelectric and wind generation, natural gas prices, market electric prices, etc. Carbon regulation is only one of many sources of risk.

Q. How would the alternative portfolios compare to the hydro purchase alternative if there were no difference in the cost of risk among the alternatives?

A. First, that would be an indefensible assumption to make. The whole point of stochastic modeling is to quantify the differences in risk among the alternative portfolios. We *know* that the hydro purchase alternative has advantages in terms of risk and that the "market only" alternative has disadvantages associated with risk. However, if we made that indefensible assumption, the hydro purchase still has an advantage over all of the other portfolios. That is shown in the table below. The hydro purchase alternative has an advantage ranging from $168 million to $252 million.

Comparison of the Alternative Portfolio Cost if the Costs of Risk Are Zero

	Current + Market ($millions)	Current+ CCCT ($millions)	Current+ Hydro ($millions)	Current+ LMS SSCT 2018 ($millions)	Current+ LMS+Wind 2025 ($millions)	Current+ CCCT+Wind 2025 ($millions)
Total Cost if the Cost of Risk Is Zero	$5,770	$5,854	$5,601	$5,852	$5,806	$5,790
Advantage of Hydro	$168	$252	$0	$251	$204	$188

Q. The costs of the hydro purchase portfolio has an aspect that plays a larger role in the total cost than in the other portfolios, namely the remaining value of the asset at the end of the 30-year planning period. How would the results of the

comparison of the costs of the alternative portfolios change if one assumed that there was no residual value associated with the hydroelectric facilities beyond the 30-year analysis period and no residual value associated with any of the other alternatives either?

A. Because the hydro electric generators have a longer life than the combustion and wind turbines included in the other alternatives, the residual value at the end of the 30-year period of analysis is much higher for the hydro purchase alternative. The residual value is a measure of the discounted value that these generators can continue to produce beyond year 30. For the hydro purchase alternative that was $212 million dollars. For the combustion turbine alternatives, the residual value ranged from about $3 to $17 million depending on how capital intensive the alternative was and when they were assumed to come on line.

These differences in residual value are tied to the expected life of the generators. It would be inappropriate to assume that these residual values were zero or that there were no differences among the alternatives in residual value.

If the measure of electric generator residual value is counterfactually assumed to be zero, the hydro purchase alternative is still superior to all of the other alternatives. That is shown in the table below. The hydro purchase alternative has an advantage over the other alternative portfolios of $137 to $234 million.

Comparison of the Alternative Portfolio Cost if the Generators Have No Residual Value

	Current + Market ($millions)	Current+ CCCT ($millions)	Current+ Hydro ($millions)	Current+ LMS SSCT 2018 ($millions)	Current+ LMS+Wind 2025 ($millions)	Current+ CCCT+Wind 2025 ($millions)
Total Cost if the Residual Value of Generators after 30 Years Is Zero	$6,227	$6,246	$6,063	$6,297	$6,243	$6,200
Advantage of Hydro	$164	$184	$0	$234	$181	$137

Q. If there were no cost associated with risk and there were no residual value after 30 years associated with the hydroelectric generators or any of the other additional generators added in the scenarios, how would the hydro purchase compare to the alternative scenarios?

A. The assumption that all six supply portfolios had zero cost of risk and had zero residual value would be empirically false. Two important characteristics of electric supply alternatives would be ignored. However, if we were to make that double counterfactual assumption, the total costs of all six supply portfolios would appear to be about the same. The differences in total costs would be in the tenths of one percent. All alternatives would be approximately equally costly. In other words, it would be a toss-up. The hydro purchase alternative would be very slightly more expensive compared to 4 of the 5 alternatives.

Comparison of Alternative Portfolios if Both the Cost of Risk and Residual Generator Values Are Zero

	Current + Market ($millions)	Current+ CCCT ($millions)	Current+ Hydro ($millions)	Current+ LMS SSCT 2018 ($millions)	Current+ LMS+Wind 2025 ($millions)	Current+ CCCT+Wind 2025 ($millions)
Total Cost if Both Cost of Risk and Residual Value Are Zero	$6,227	$6,256	$6,275	$6,300	$6,252	$6,217
Advantage of Hydro	-$48	-$19	$0	$25	-$23	-$58

Q. What conclusion do you draw from this review of the PowerSimm stochastic analysis of the various supply alternatives?

A. The conclusion that the hydro purchase alternative is superior to the other alternative sources of electric supply appears to be quite robust even in the face of adopting unrealistic and unsupportable assumptions about the characteristics of the alternative supply portfolios and the inclusions of “alternative” portfolios, e.g. the “market only” portfolio, that are not realistic.

Q. Has NWE's modeling of the hydro purchase compared to other electric supply portfolios incorporated all of the positive characteristics associated with purchasing PPLM's hydroelectric facilities?

A. No. That modeling only considered characteristics of alternative portfolios that can be quantified, typically in dollar terms. But, as in almost any business or public policy decision there are other valuable characteristics that have to be left out of the formal modeling either partially or completely because they are difficult to express in dollar terms.

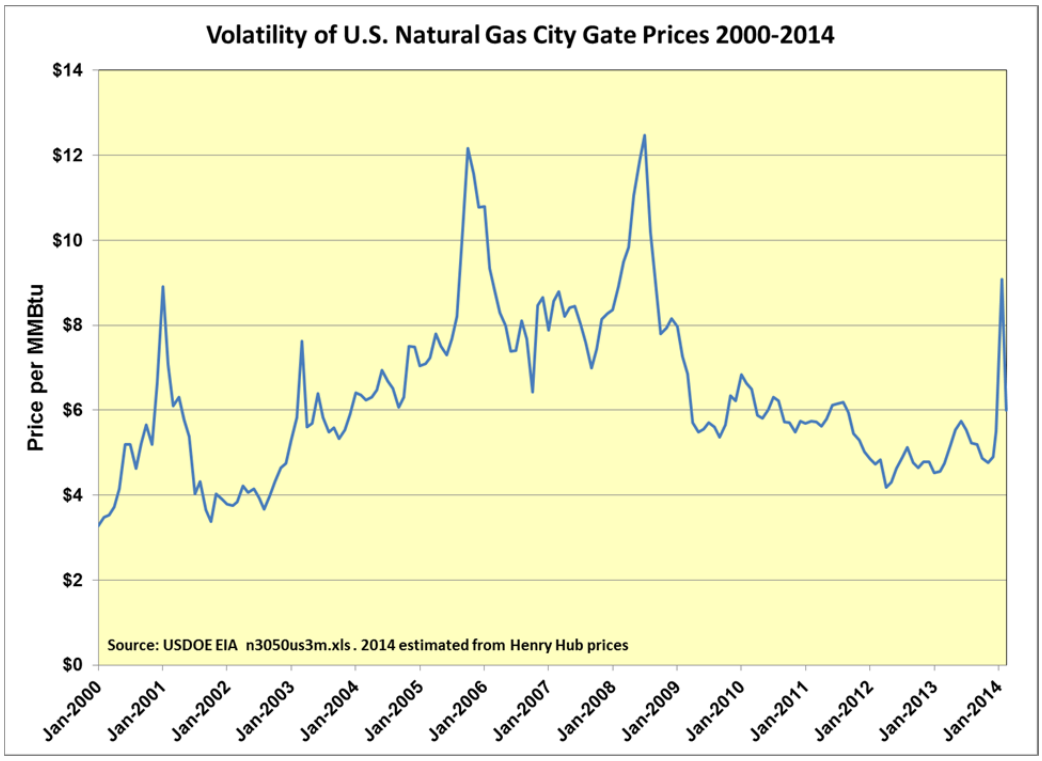
In this particular case, the important non-dollar considerations include the following:

a. The importance of focusing on the long-term rather than focusing only on the past, the present, or the near future. The Commission's Electric Supply Procurement Guidelines emphasize the importance of that, specifying that it is minimizing customer costs and risks in the long-term that is the appropriate target.

b. Focusing on the stability of customers' utility bills. Both residential and business customers have limited ability in the short-term to adjust their electric use without accepting uncomfortable or even unsafe changes in energy use or reducing basic consumption in other areas of their limited budgets. This is especially true of low- and fixed-income customers. Pursuing moderate cost long-lasting resources that shield customers from the volatility of energy markets is important. The figure below reminds us of how natural gas prices have fluctuated widely over the last decade and a half. Market electric prices in the region have also fluctuated widely. The MPSC's Electric Supply Procurement Guidelines also direct NWE to pursue "rate stability" that is defined to mean "minimal price variation, both month-to-month, and year-to-year, and minimal price inflation over time." (38.5.8201 (10))

c. Judging by the electric generating facilities in which electric utilities have been actually investing, the preferred supply resources have been lower-carbon, minimal emission, and geographically distributed resources. These types of resources, as one would expect, reflect the efforts by utilities to reduce regulatory risks, especially the risks of environmental regulation. NWE's proposed hydroelectric purchase reflects that same pattern. It also reflects the direction provided in the Commission's Electric Supply Resource Procurement Guidelines that specify that NWE should "assemble and maintain a balanced, environmentally responsible portfolio of electricity supply resources." (35.5.8204 (1)(d)

d. PPLM's hydroelectric resources were built to serve businesses and residents of Montana and did so for about a century. Those hydroelectric resources make significant use of Montana's rivers and lakes. In that sense they are part of the basic infrastructure serving the state of Montana. "Repatriating" them so that they again are committed to serving Montana customers and are again regulated by the Montana Commission also is an important cultural, political, and economic consideration.



II. The Cost and Risks Associated with Existing Coal-Fired Generators

Q. When PPLM offered to sell its generating facilities in Montana, NWE initially offered a relatively low price for all of those generating facilities, both the coal-fired electric generators and the hydroelectric facilities, but a higher price for the hydroelectric facilities alone. If NWE thought it could buy all of the facilities for a lower price than it would have to pay for just the hydroelectric facilities, why did it ultimately only seek to buy the PPLM hydroelectric facilities?

A. NWE was primarily interested in the hydroelectric facilities, but PPLM asked bidders to bid on the whole set of PPLM's Montana electric generating facilities. NWE made a bid that conformed with PPLM's request for bids but NWE also submitted a bid for only the hydroelectric facilities, a bid that did not conform with PPLM's request for bids. In that sense, NWE's bid for ***all*** of PPLM's generating facilities was not a serious bid, but may have been necessary to get PPLM to look seriously at its bid for the hydroelectric facilities.

NWE's initial judgment was that it was the hydroelectric facilities that NWE wanted to purchase if it could purchase them at a price that did not impose a major increase on customers' bills. As NWE looked in more detail at the benefits and risks associated with also purchasing the PPLM's coal-fired electric generators, NWE confirmed its initial judgment that those coal-fired plants were not a reasonable purchase to make for NWE's customers.

Q. What costs and risks associated with PPLM's coal-fired generators could render their value negative to NWE's customers?

A. There were two primary concerns that NWE had about purchasing all of PPLM's Montana electric generating facilities:[8]

[8] NWE response to PSC-087 and MCC-002.

i Pending and future environmental regulations that would require substantial additional investments in the coal-fired plants to bring them into compliance with federal environmental standards or force the closure of those plants because those compliance costs would render those plants too costly as a source of electricity. NWE also had concerns about environmental cleanup obligations and liability upon plant closure.

ii NWE did not need all of the generating capacity that PPLM wanted to sell. If NWE bought all of those facilities, it would have to sell much of the generation into regional electric markets at unknown and variable prices. NWE's customers' electric bills would be at the mercy of those electric markets because of large volumes of electricity NWE would have to sell on those markets. The revenue NWE received from those off-system sales could fluctuate widely, potentially causing NWE's customers' bills to also fluctuate. Alternatively, NWE's stockholders would be at risk for sales at low prices on thet electric market if the MPSC did not approve putting the full burden of under-recovery of the generators' costs on customers when regional electric prices were low.

In addition to those primary cost and risk concerns, NWE was also worried about the possibility that FERC would conclude that NWE's ownership of all of these sources of electric supply in Montana would give it sufficient market power that FERC would impose additional regulation on NWE's electric energy transactions in Montana.

NWE also saw the fact that it would be just one of the owners of the Colstrip facilities, having to negotiate management decisions with a group of utilities as a negative feature of purchasing just a share of Colstrip 3. Buying all of the hydroelectric facilities, on the other hand, would give NWE full control over the management of those resources.

Q. In your judgment were NWE's concerns about the costs associated with impending and future environmental regulation reasonable?

A. Yes. NWE is not alone is worrying about the viability of older and smaller coal-fired generators such as Colstrip 1 and 2 in the face of the imposition of stricter air quality standards being imposed. That concern that the new federal regulations would force the abandonment of existing coal-fired generators was not based on mere speculation about what might happen. It was based on the reality of the costs associated with meeting those standards at older coal-fired electric generators. PPLM, for instance, had already announced that it would shut down and mothball the Corette coal-fired generator outside of Billings rather than invest in the pollution control equipment that would be necessary to meet EPA's Mercury and Air Toxics Standards (MATS).

Many other electric utilities around the nation have recently reevaluated the coal-fired electric generators they owned in light of the increasingly strict regulation of the environmental pollution associated with them. That reevaluation has led to the scheduled retirement of a large number of coal-fired electric generators.

In March 2014 EIA reported that between 2010 and 2012 almost 13,000 MW of coal-fired electric generating capacity had been retired. This was the equivalent of about 17 electric generators the size of Colstrip 3 or 4 being retired. At the same time EIA projected that 60,000 MW of coal-fired generating capacity would be retired between 2010 and 2040, but most of it before 2016. That would be the equivalent of 80 coal-fired generators the size of Colstrip 3 or 4 being retired. EIA associated these abandonments of coal-fired generation to the EPA's Mercury and Air Toxics Standards that coal-fired generators had to meet by 2015 or, with an extension, by 2016.[9]

[9] ***Today in Energy,*** EIA, March 10, 2014, http://www.eia.gov/todayinenergy/detail.cfm?id=15031 .

Q. Are EPA's MATS restrictions on electric generators the only impending environmental restrictions that might affect the economic viability of existing coal-fired generators?

A. No. As discussed in the previous section of this testimony, EPA is in the process of limiting the carbon emissions from electric generators burning fossil fuels. EPA has issued regulations limiting the carbon emissions of *new* generators to about the level associated with a new natural-gas fueled CCCT. Those carbon emission limits are likely to block the building of any new coal-fired generators in the foreseeable future. EPA is now working on limits on the carbon emissions from *existing* fossil-fueled generators that could force more coal-fired plant retirements.

In 2012, EPA finalized a regional haze rule for Montana (77 Fed. Reg. 57864, September 18, 2012). That rule will require additional emission control technology at Colstrip 1 and 2.

In addition, the EPA's Cross State Air Pollution Rule (CSAPR), although currently being challenged in court, is likely to also restrict the generation of electricity with coal. Even if the U.S. Supreme Court voids the existing rule, my understanding is that EPA will be required to adopt some rule dealing with cross-state air pollution.

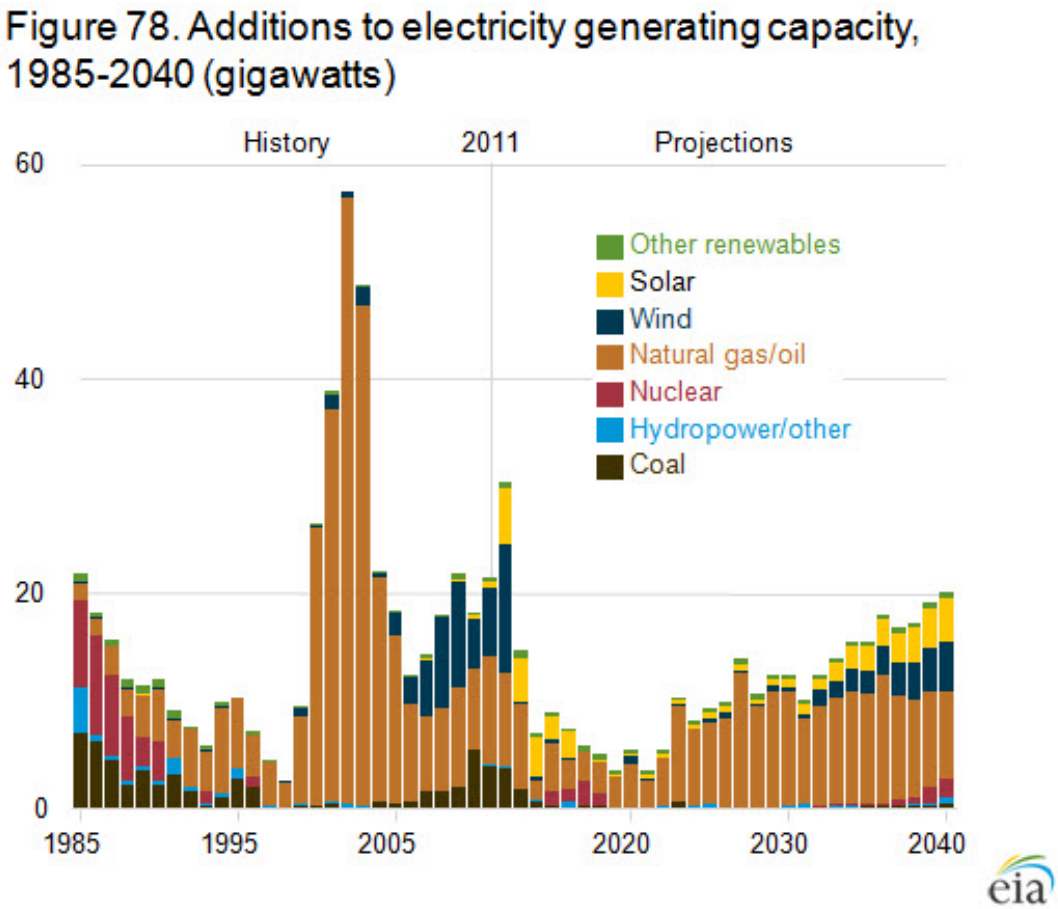
EPA is also working on a Coal Combustion Residuals (CCR) Disposal Rule that will begin to regulate the handling of the waste products associated with the combustion of coal. Those wastes have been in the news since the release of almost a billion gallons of waste sludge from TVA's coal-fired Kingston facility in Tennessee in 2008. That sludge inundated homes and polluted two tributaries of the Tennessee River. In February of this year, one of Duke Energy's coal-fired plants released coal-waste sludge into the Dan River, polluting the water supply of Danville, Virginia. Duke Energy has dozens of coal waste sludge ponds that have been polluting ground and surface waters for many years. That is not a

distant problem. The Colstrip generating stations have also been accumulating coal waste sludge in ponds that are leaking into the ground below them and potentially into the groundwater. That is what EPA's Coal Combustion Residuals Disposal Rule is intended to regulate. Reducing the risk of catastrophic failure of the waste ponds, stopping the pollution of surface and groundwater, and the remediation of existing water pollution are also likely to impose additional costs on coal-fired generators in the near future.

Q. Is NWE the only utility that is hesitant to invest in additional coal-fired generation?

A. Certainly not. Investors and electric utilities have been shifting away from coal-fired generation for almost two decades. In addition almost no new coal-fired generators are projected to be built over the next 30 years. This is shown in the figure below that comes from EIA's 2013 Annual Energy Outlook. Keep in mind that it takes close to a decade between the decision to invest in a coal-fired generator and that generator actually coming on line. That long planning, permitting, and construction period is one of the negative characteristics of coal, as well as nuclear generation.

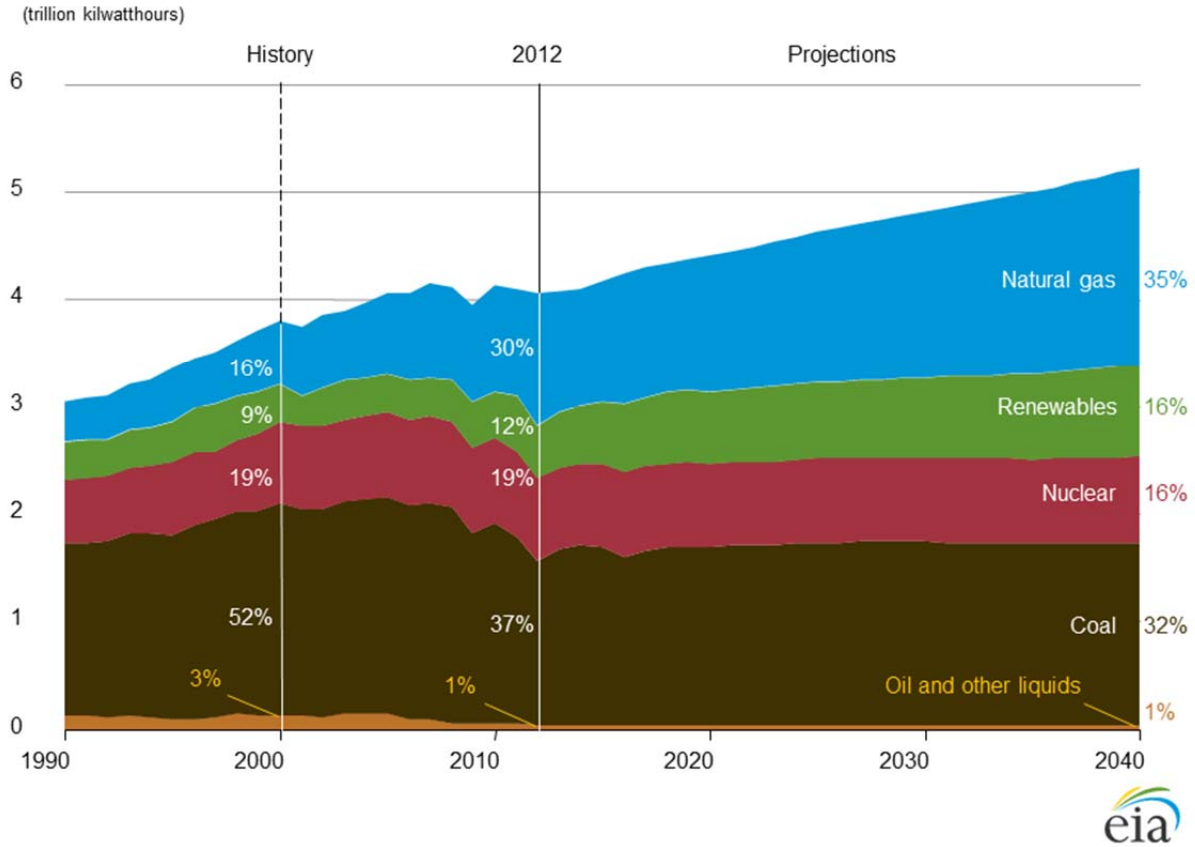
Future *additions* to electric generation capacity will be primarily fueled by natural gas, wind, and solar energy. The capacity of nuclear generating plants will decline as existing nuclear plants are retired. As natural gas prices rise, existing nuclear plants (and for that matter coal plants as I will discuss below) will be used more frequently. Future investment in nuclear plants will rely on significant federal government support.



Source: Figure 78. EIA Annual Energy Outlook 2013.

As a result, the share of U.S. generation that will come from coal-fired generators is project to decline dramatically from where it recently was. In 2000 52 percent of U.S. electricity generation was fueled by coal. In 2012, coal's share of electric generation had fallen to 37 percent. The EIA projections are that coal's share of electric generation will continue to decline, leveling off at about 32 percent by 2040. At the same time the share electricity fueled by natural gas has increased from 16 percent to 30 percent in 2012 and expected to reach 35 percent by 2040, surpassing coal's share of 32 percent. See the EIA Energy Outlook 2014 figure below.

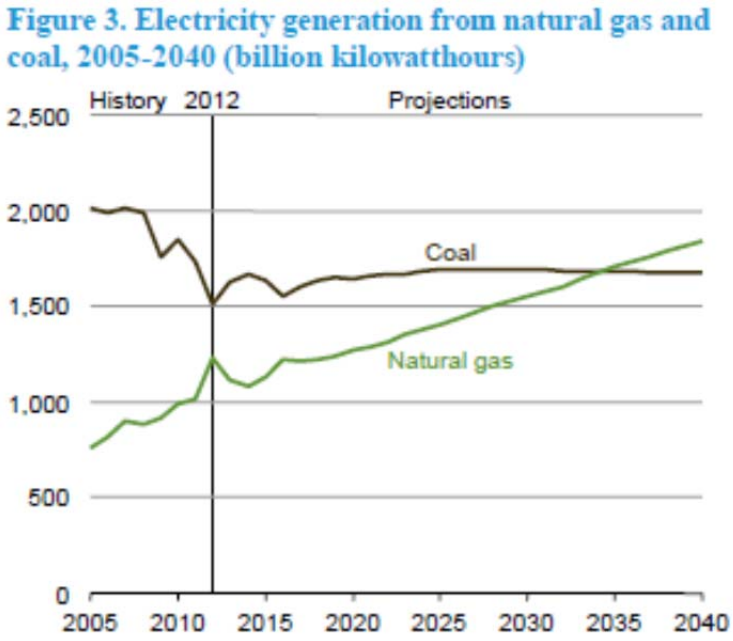
Figure 13. Electricity generation by fuel, 1990-2040



Q. Are you saying that coal will be abandoned in the near future as a fuel for electric generation?

A. Certainly not. As the EIA figures above and below indicate, for the next several decades coal will continue to provide a third of the electricity consumed in the U.S. Actually, despite the fact that it seems likely that no or almost no new coal-fired electric generators will be built, the amount of electricity coming from coal-fired generation will increase modestly between 2012 and 2030 as the existing coal-fired generators are utilized to a greater extent. The very low natural gas prices in recent years have limited the use of existing coal-fired generators. As

natural gas prices are projected to rise, EIA projects that those existing coal-fired plants will be used more and more intensively.[10]



Source: Annual Energy Outlook 2014 Early Release Overview

Q. Did NWE's evaluation of the PPLM's coal-fired plants conclude that coal-fired generators *in general* had a negative value to the utility and its customers?

A. No. NWE's analysis indicated that the older, smaller, and less efficient coal-fired generators, Colstrip 1 and 2 and Corette, could have negative economic values. That same analysis indicated that PPLM's share of Colstrip 3 had a positive economic value. The negative values estimated for Colstrip 1 and 2 and Corette, however, canceled the positive value of PPLM's share of Colstrip 3.[11] NWE has also stated that its share of Colstrip 4 has a positive economic value. [12]

[10] Annual Energy Outlook 2014 Early Release Overview, pp. 11 and 13. http://www.eia.gov/forecasts/aeo/er/pdf/0383er(2014).pdf .
[11] Brian Bird direct testimony, p. BBB-7; NWE Response to PSC-087; NWE response to PSC-066, Valuation tab, H4 to H6.
[12]NWE response to MCC-004.

Q. Has the regulation of emissions from coal-fired generators threatened the viability of Montana and Wyoming coal mining operations in the past?

A. No. In fact it has been that environmental regulation of emissions from coal-fired generators that largely created the market for Montana and Wyoming Powder River Basin coal in the eastern United States. One of the primary early objectives of the Clean Air Act and the amendments to it has been the reduction of sulfur emissions. Those sulfur emissions not only threatened the health of those breathing polluted air but also contributed to acid rain and damage to crops, forests, and lakes.

Because Powder River Basin is very low in sulfur, it offered a lower cost way for electric generators to reduce their sulfur emissions than installing costly additional pollution control devices. The regulation of sulfur emissions not only created potentially higher costs for electric generators but also created economic opportunity for those businesses that could help reduce sulfur emissions in a relatively low cost way. That included the coal mines in Montana and Wyoming.

Q. Are you suggesting that the regulation of carbon emissions will not have negative impacts on Montana coal production and the Montana economy?

A. We do not know what the net impact on the Montana economy will be. The most important cause of the weaker demand for Powder River Basin coal in recent years has been the Great Recession and the slow recovery that has reduced the rate of growth of the national economy. In addition natural gas prices have been at very low levels. Finally, the capital cost of coal-fired generators and the long time period from planning to operation have made natural-gas fired electric generators more attractive to serve base loads.

The regulation of carbon and other emissions from coal-fired electric generators will favor less carbon intensive sources of energy: renewable sources such as

the Montana hydroelectric units at issue in this case but also wind-electric generation and other renewable energy sources will be favored. Natural gas will also be favored if the methane leaks associated with its development, transportation, and use can be controlled and the uncertainty about the environmental safety of “fracking” tight shale formations can be eliminated. In any case, economic opportunities will be created in Montana as a result of carbon regulation just as they were by sulfur regulation. As the EIA projections make clear, coal, including Powder River Basin coal, will continue to play an important role in the nation’s and Montana’s energy portfolio for several decades into the future.

Q. If NWE had purchased all of the PPLM electric generating facilities in Montana, namely, both the hydroelectric and coal-fired generators, would that have reduced the cost and risk in serving its customers?

A. That seems very unlikely. The likely impacts would have included all of the following:

i NWE would have a much larger electricity supply that its customers needed. That very large excess supply would have to be sold into the regional market for an uncertain and fluctuating value. NWE would be put in the position of a merchant generator as well as a regulated utility. Either customers or shareholders or both would have to shoulder that increased risk. Neither the MPSC nor FERC is likely to have looked upon this situation favorably. In addition, electricity from the PPLM coal-fired generators may be rejected by the coastal states of the West that are trying to reduce their dependence on carbon-intensive fuels.

ii NWE would have inherited the environmental problems associated with coal-fired generation and would have had to invest large amounts of capital in Colstrip 1 and 2 and Corette to meet federal emission standards. Alternatively, NWE would have had to simply abandon three of the coal-fired plants NWE had just purchased.

iii NWE would have also inherited other looming environmental problems, including those associated with the disposal of coal combustion waste that has become an increasing environmental concern. NWE would also have inherited the cost of remediation of the generation sites after the coal-fired plants were shut down.

iv NWE would have had to deal with EPA's planned regulation of the carbon emitted from existing coal-fired generators and the costs associated with that. It is likely that at some point in the future this direct regulation of carbon emission will be replaced with carbon pricing because that is a more efficient, flexible, and reliable way of managing carbon emissions.

It seems unlikely that NWE purposely taking on these additional costs and risks associated by purchasing PPLM coal-fired generators would be considered a prudent business decision for a regulated utility.

III. Qualifications of Thomas Michael Power

Q. What is your current professional association?

A. I am a Research Professor and Professor Emeritus in the Economics Department at The University of Montana in Missoula, Montana. I am also a Principal in Power Consulting, Inc., an independent economic consulting firm.

Q. Please describe your formal education and training.

A. I received my Bachelor's Degree in Physics from Lehigh University in Bethlehem, Pennsylvania. I graduated with honors and Phi Beta Kappa. I was elected a Woodrow Wilson Fellow in national competition and attended Princeton University where I received my Masters and Doctoral Degrees in Economics.

I taught math and physics at Lehigh University and have taught economics at Princeton University, Lehigh University, and the University of Montana. I have

been on the faculty of the University of Montana since 1968. I served as Chairman of the Economics Department from 1978 to 2007. In August 2007 I retired from University teaching and administration. My specialties are regional economics and resource economics.

Q. Have you testified as an expert witness before utility regulatory commissions before?

A. Yes. Since 1974 I have appeared many times before numerous federal, state, and municipal regulatory commissions.

I have testified before the Federal Energy Regulatory Commission, the Northwest Regional Power Planning Council, and the Bonneville Power Administration as well as before various congressional committees.

I have also testified before the utility regulatory commissions in the following states: Arizona, Colorado, Florida, Georgia, Idaho, Indiana, Illinois, Kansas, Montana, Nebraska, Nevada, Oklahoma, Oregon, Texas, Utah, and Washington.

In addition, I have testified in utility cases before the City Councils of Seattle, Austin, and Spokane. I have also testified before the Snohomish County, Washington, Public Utility Board and the Springfield, Oregon, Public Utility Board. I have testified in State District Courts in Idaho, North Dakota, Oregon, and Montana and in Federal Court in Montana.

I have testified before the Montana Board of Natural Resources and the Washington Department of Ecology, and the Washington Energy Facility Site Evaluation Council on the siting of energy facilities.

I have served as lecturer at National Association of Utility Regulatory Commissioners' Technical Conferences and at annual conferences of the Mid-

America Regulatory Commissioners and the Western Utility Regulatory Commissioners.

Since 1988 I served on the Montana Power Company Conservation and Least Cost Planning Advisory and Universal Benefits Advisory Committee until the Montana Power Company left the utility business. Since NorthWestern Energy Company took over the Montana Power distribution system, I have served on its Technical Advisory Committee and Universal Benefits Advisory Committee as well as its Natural Gas Technical Advisory Committee. For several years I also served on the Montana Regulatory Reform Working Group. In the past I have served on the Montana Governor's Citizens Advisory Council on Energy. More recently I served on the Governor’s Energy Security Task Force.

Q. Have you done other studies dealing with energy economics?

A. Yes. In 1975, I received an NSF/RANN grant to assemble a team of economists, geologists, and energy technologists to study coal development in the Northern Great Plains. That study led to a series of almost a dozen reports, the final summary being published as ***Projections of Northern Great Plains Coal Mining and Energy Conversion Development 1975-2000 A.D.*** Several of the other papers dealing with defining coal markets and energy projection techniques have also been published.

Between 1976 and 1985 I conducted studies of the economics of alternative energy systems, transmission reliability, the applicability of the PURPA rate making standards to hydroelectric system "going thermal", utility avoided costs, optimal operation of storage hydroelectric facilities, development of electric utilities on Indian reservations, and the impact of energy facility development on local economic development. In 1995 ***Public Utilities Fortnightly*** published my article on “Making Sense of Peak Load Cost Allocations.”

Q. Can you give examples of other studies have you done in the field of resource economics?

A. In 2007 Stanford University Press published a book I edited and to which I contributed entitled ***Accounting for Mother Nature: Changing Demands for Her Bounty*** (with Terry Anderson and Laura Huggins). In 2001 Island Press published ***Post-Cowboy Economics: Pay and Prosperity in the New American West****,* which I co-authored with Richard Barrett. In 1996 two other books of mine were published. Island Press published ***Lost Landscapes and Failed Economies: The Search for a Value of Place*****.** M.E. Sharpe published ***Environmental Protection and Economic Well-Being: The Economic Pursuit of Quality.*** The latter book is the rewritten and updated Second Edition of ***The Economic Pursuit of Quality***, which was published by M.E. Sharpe, New York in 1988. In 1980 Westview Press published my first book, ***The Economic Value of the Quality of Life.***

I have also contributed two dozen chapters to various other books. Among the many articles and reports I have published are: "Public Timber Supply, Market Adjustments, and Local Economies: Economic Assumptions of the Northwest Forest Plan," (***Conservation Biology***, 20(2):341-350, 2006), "The Economics of River and Wetland Restoration in the Vermillion River Basin," ***Great Plains Natural Resources Journal,***4(2), Spring, 1999, "The Wealth of Nature," ***Issues in Science and Technology***, National Academy of Sciences, Spring, 1996, "Economic Well-being and Environmental Protection in the Pacific Northwest," ***Illahee: Journal for the Northwest Environment*****,** 11(3 & 4), Fall-Winter, 1995, and "Urban Disamenities" ***Journal of Urban Economics***, June, 1981.

I have published papers on almost a dozen federal irrigation projects in the western states in addition to papers dealing with the value of in-stream flows for wildlife and recreational uses. I have testified before the State Board of Minerals and the Environment and the Oahe Conservancy Board in South Dakota as well

as the Alberta Energy Resources Conservation Board and Natural Resource Conservation Board on topics related to resource development. I have also testified several times before various Canadian Federal Environmental Review Boards.

Q. Does that conclude your testimony?

A. Yes, it does.