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July 3, 2014

***Via Electronic Mail and Federal Express***

Public Utility Commission of Oregon
Attn: Filing Center
3930 Fairview Industrial Drive SE
Salem OR 97302

Re: In the Matter of PORTLAND GENERAL ELECTRIC
Net Variable Power Costs (NVPC) and
Annual Power Cost Update (APCU)
**Docket No. UE 286**

Dear Filing Center:

Enclosed for filing in the above-referenced docket, please find the original and five (5) copies of the redacted Rebuttal Testimony and Exhibit of Bradley G. Mullins on behalf of the Industrial Customers of Northwest Utilities. Also enclosed are the original and five (5) copies of the confidential material of same, which is being filed under seal pursuant to Protective Order No. 14-043.

Thank you for your assistance. If you have any questions, please do not hesitate to contact our office.

Sincerely,

Jesse O. Gorsuch

Enclosures
cc: Service List

## CERTIFICATE OF SERVICE

I HEREBY CERTIFY that I have this day served the attached **Rebuttal Testimony of Bradley G. Mullins** upon all parties in this proceeding, as shown below, by sending a copy via electronic mail, and by sending the confidential material of same via U.S. Mail, postage pre-paid, to the parties that have signed the protective order in this docket.

Dated at Portland, Oregon, this 3rd day of July, 2014

Sincerely,

Jesse O. Gorsuch

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**BEFORE THE PUBLIC UTILITY COMMISSION**

**OF OREGON**

**UE 286**

| | |
|---|---|
| In the Matter of | ) |
| | ) |
| PORTLAND GENERAL ELECTRIC COMPANY | ) |
| | ) |
| | ) |
| Net Variable Power Costs (NVPC) and Annual Power Cost Update (APCU) | ) |
| | ) |
| | ) |

**<u>REDACTED REBUTTAL TESTIMONY OF BRADLEY G. MULLINS</u>**

**<u>ON BEHALF OF THE INDUSTRIAL CUSTOMERS OF NORTHWEST UTILITIES</u>**

**July 3, 2014**

## I. INTRODUCTION AND SUMMARY

**Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

A. My name is Bradley G. Mullins, and my business address is 333 SW Taylor Street, Suite 400, Portland, Oregon 97204.

**Q. ARE YOU THE SAME BRADLEY G. MULLINS WHO PREVIOUSLY FILED TESTIMONY IN THIS PROCEEDING?**

A. Yes. I filed opening testimony on behalf of the Industrial Customers of Northwest Utilities ("ICNU") in this proceeding on May 27, 2014.

**Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?**

A. The purpose of my testimony is to respond to the rebuttal testimony of Mike Niman, Teri Peschka, and Patrick G. Hagar submitted on behalf of Portland General Electric (the "Company") in this proceeding, the Company's Net Variable Power Costs ("NVPC") and Annual Power Cost Update ("APCU") filing for 2015. As discussed in that testimony, parties have reached a partial settlement, in principle, and are currently in the process of drafting a stipulation to resolve all issues in this proceeding, with the exception of one related to Port Westward II and wind integration and one related to the Company's Beaver point-to-point ("PTP") transmission contract with the Bonneville Power Administration ("BPA"). My rebuttal testimony will address these two remaining issues.

**Q. PLEASE SUMMARIZE YOUR REBUTTAL TESTIMONY.**

A. The Company has not demonstrated that its management of wind integration costs has been prudent. The information presented in the Company's rebuttal filing reinforces that it should have been capable of achieving a more cost-effective method of integrating wind by the time it planned to place Port Westward II into rates. In addition, while the Company does present new information about the transmission requirements from the Trojan substation, it has not demonstrated how its management of transmission for its plants located near Clatskanie—Beaver, Port Westward I, and Port Westward II—has been in the best interest of customers, and, consequently, prudent. I have modified my recommendation related to the Beaver PTP contract to reflect the savings that should have been achieved had the Company pursued a more economic method to deliver power from its resources located in Clatskanie, Oregon.

**Q. HAVE YOU PREPARED A TABLE TO SUMMARIZE YOUR UPDATED RECOMMENDATION RELATED TO THESE ITEMS?**

A. Yes. Table 1, below, details my updated recommendation.

**TABLE 1**
**NVPC IMPACT OF UPDATED RECOMMENDATION**
***($000)***

| Adjustment | Original | Updated |
|---|---|---|
| Wind Integration | (5,076) | (5,076) |
| Beaver PTP Contract | (6,716) | (1,563) |
| **Total** | **(11,792)** | **(6,639)** |

## II. WIND INTEGRATION

**Q. PLEASE SUMMARIZE THE ISSUE RELATED TO WIND INTEGRATION RAISED IN YOUR OPENING TESTIMONY.**

A. In my opening testimony, I demonstrated that, by not electing to self-integrate, the Company has not selected the most cost-effective method of integrating the Biglow

Canyon and Tucannon River wind resources.[1/] My testimony also presented information to support a conclusion that the Company's failure to do so is imprudent. Accordingly, I recommended that $5.1 million in wind integration costs be disallowed in the test period to reflect the savings that would have resulted had the Company elected to self-integrate Biglow Canyon and Tucannon River for the entire test period.

**Q. HOW DO YOU RESPOND TO THE COMPANY'S REBUTTAL TESTIMONY?**

A. The Company's rebuttal testimony reinforces the fundamental conclusions that I reached in my opening testimony in this case, as well as my opening testimony in the Company's general rate proceeding.[2/] Specifically, the Company is constructing the Port Westward II facility without ensuring that the self-integration benefits associated with this resource—which were used to justify selection of the facility in the 2012 Request for Proposals for Capacity and Baseload Energy Resources ("2012 RFP")[3/]—are achieved. In addition, because the Company did not follow through with its plans to use Port Westward II to integrate wind, my direct testimony in the general rate proceeding indicates that Port Westward II will not be used and useful, nor a prudent investment in rate base, in the test period.

**Q. HOW DID THE COMPANY ATTEMPT TO JUSTIFY ITS DECISION NOT TO SELF-INTEGRATE WIND RESOURCES BY THE TIME PORT WESTWARD II IS PUT INTO RATES?**

A. The Company did not dispute the fact that self-integration is the most cost-effective method of integrating Biglow Canyon and Tucannon River on its system. Instead, the Company claimed that it did not have enough time to implement the systems necessary to

1/ ICNU/100 at 4-11.

2/ Docket No. UE 283, ICNU/100 at 11:1-14:11.

3/ Docket No. UM 1535, PGE Final Draft Request for Proposal for Power Supply Resources (Jan. 25, 2012).

pursue a self-integration option in test period.[4/] The Company also included a discussion of how "[i]ntegration of wind must be accomplished at the portfolio level."[5/] Finally, the Company claimed, focusing on sub-hourly scheduling options, that the uncertainty surrounding the various balancing service elections with BPA prevented it from adopting a more cost-effective wind integration methodology.[6/]

**Q. WHY IS THE COMPANY'S ARGUMENT THAT IT HAS NOT HAD SUFFICIENT TIME TO INSTALL THE NECESSARY INFRASTRUCTURE FOR SELF-INTEGRATION UNCONVINCING?**

A. The Company has been aware of the self-integration option at least since 2007. This is evident from a statement in its 2007 Integrated Resource Plan ("IRP"): "With the completion of Biglow Canyon Phase I later this year, we will operate *and self-integrate* our first wind project …. [W]e believe that our existing system capability is sufficient to integrate the first phase of the Biglow Canyon project …."[7/] Additionally, in Phase 4 of its Wind Integration Study, included with the 2013 IRP, the Company stated: "In 2007, given projections for a significant increase in wind generating resources, [the Company] began efforts to forecast costs associated with self-integration of wind generation."[8/] These statements indicate that the Company has, to some degree, been evaluating the automatic generation control ("AGC") and other equipment necessary for self-integration for at least seven years.

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4/ PGE/200 at 8:20-21.

5/ Id. at 8:22.

6/ Id. at 9:1-2.

7/ In re Portland General Electric Company 2007 Integrated Resource Plan, LC 43, 2007 IRP at 106 (Jun. 29, 2007) (emphasis added).

8/ In re Portland General Electric Company 2013 Integrated Resource Plan, LC 56, 2013 IRP, App. D at D-1 (Mar. 27, 2014).

**Q. ARE THERE OTHER REASONS WHY THE COMPANY'S ARGUMENT REGARDING THE TIMING OF SELF-INTEGRATION IS NOT ACCEPTABLE?**

A. Yes. As I discussed in my opening testimony, the Company largely justified the selection of Port Westward II in the 2012 RFP based on its ability to enable the Company to self-integrate wind.[9/] In the 2012 RFP, the Company required that "[c]apacity resources … must be available no later than 2015."[10/] Thus, the Company set a deadline for the completion of a resource that predates the time that the same resource will be able to be used for its intended purpose. This is imprudent management. Port Westward II and Tucannon River will collectively add over three-quarters of a billion dollars into rate base. If the Company is capable of completing these rate base projects by the test period, it should also have been capable of ensuring that the necessary AGC systems were tested and in place to implement a cost-effective wind integration methodology in the test period.

**Q. HAVE OTHER UTILITIES BEEN CAPABLE OF SELF-INTEGRATING RESOURCES LOCATED IN BPA'S BALANCING AREA IN A TIMELY MANNER?**

A. Yes. As discussed in my opening testimony, the Company is not the first entity to pursue self-integration.[11/] In addition to Iberdrola, PacifiCorp also has been actively managing its integration costs by pursuing self-integration of resources previously located in BPA's balancing area. In April 2013, PacifiCorp completed the necessary system upgrades to dynamically transfer both the Goodnoe Hills and Leaning Juniper wind resources into its

9/ ICNU/100 at 8:17-10:3.

10/ 2012 RFP at 1.

11/ ICNU/100 at 8:9-13. Iberdrola Renewables, LLC ("Iberdrola") has successfully self-integrated its wind resources since 2010.

balancing area, effectively self-integrating those resources.[12/] If Iberdrola and PacifiCorp have had enough time to pursue a self-integration option, then the Company, too, should have had enough time to do so.

**Q. DO YOU AGREE WITH THE COMPANY THAT IT CANNOT SELF-INTEGRATE WIND WITH PORT WESTWARD II ALONE AND THAT INTEGRATION MUST BE ACCOMPLISHED AT THE PORTFOLIO LEVEL?**

A. Yes. This, however, is not relevant to whether it was prudent for the Company to select Port Westward II and put it into rate base before it could be used for its intended purpose. In its 2013 IRP, the Company specifically identifies owned resources other than Port Westward II that will be capable of helping to achieve self-integration. These include: (1) the Company's Mid-Columbia hydro resources; (2) Pelton; (3) Round Butte; (4) Port Westward I's duct burner; (5) Coyote; and (6) Beaver.[13/] It is clear, therefore, that Port Westward II is not the only resource the Company has for self-integration. Thus, the issue is not whether integration can and must be accomplished at the portfolio level. The issue is whether the Company should continue to ask customers to pay to use BPA's resource portfolio to integrate wind on its behalf while simultaneously paying for a flexible capacity resource that was designed specifically to accomplish what the Company is paying BPA to do.

**Q. DOES THE COMPANY'S EXPERIENCE WITH BPA'S COMMITTED INTRA-HOUR ("CIH") PILOT HAVE ANY BEARING ON ITS OPTION TO SELF-INTEGRATE?**

A. No. The Company notes that, beginning on October 1, 2011, it participated in the 30/30 CIH pilot program, which required it to schedule wind generation with BPA on a 30-

12/ In re Rocky Mountain Power's Intent to File a General Rate Case on or about January 3, 2014, Ut.PSC Docket No. 13-035-184, Direct Testimony of Gregory N. Duvall, Redacted at 9:191-10:198 (Jan. 3, 2014).

13/ PGE 2013 IRP, App. D at D-16.

minute basis.[14/] As such, the CIH pilot was nothing more than a preliminary trial of sub-hourly markets. The Company's experience with the pilot CIH may inform its decision to join an energy imbalance, or other similar sub-hourly market, or it may be relevant if the Company were evaluating a sub-hourly, 30/30 or 30/15, scheduling paradigm election with BPA. Participation in the CIH is not, however, a prerequisite for pursuing a self-integration option. The problems and uncertainties encountered as a result of the CIH pilot program are, therefore, not relevant to, and have little bearing on, self-integration.

Notwithstanding, even if the CIH pilot was relevant to the Company moving toward self-integration, the Company participated in the pilot program before it selected Port Westward II as its capacity resource in the 2012 RFP, and certainly before it is intending to put this resource into service at the beginning of 2015. If the Company knew, based on its participation in the CIH pilot, that it would not be ready to self-integrate its wind resources by the start of the test period, then it is not sensible for the Company to put a resource specifically designed for that purpose into service at the start of the test period.

**Q. WOULD THE COMPANY'S DECISION WITH RESPECT TO PORT WESTWARD II BE CONSIDERED A PRUDENT BUSINESS PRACTICE IN OTHER INDUSTRIES?**

A. No. If competitive businesses do not follow through with their plans, shareholders bear the loss. Consider, for example, a semiconductor manufacturer who has built a plant to fabricate a new type of chip technology. If it failed to complete the research and development to design the new chip technology before the fabrication plant was constructed, the semiconductor manufacturer, and its shareholders, would incur a loss as

14/ PGE/200 at 9:5-8.

a result. Consider, as another example, a steel manufacturer who has built a new furnace to refine a particular type of steel. If it failed to have the infrastructure in place to deliver raw materials to the facility by the time construction was completed, the steel manufacturer, and its shareholders, would incur losses. There are many examples, but the result is the same. Businesses that fail to follow through with their planning assumptions suffer losses. The Company's decision to build Port Westward II without having in place the necessary infrastructure to ensure this resource would be used for its intended purpose is no different from these examples. Accordingly, this decision was imprudent.

**Q. ARE THERE OTHER REASONS TO REJECT THE COMPANY'S ARGUMENT THAT IT COULD NOT SELF-INTEGRATE IN THE TEST PERIOD?**

A. Yes. The Company's position is internally inconsistent. In its 2013 IRP, the Company analyzed the need for flexible capacity resources assuming that its own resource portfolio, including Port Westward II, would be used to manage the minute-to-minute variations in wind beginning in the first quarter of 2015.[15] In other words, the Company, in assessing its need for flexible resources in the 2013 IRP, assumed that both Biglow Canyon and Tucannon River *would be self-integrated for the entire 2015 test period* even though the Company is not proposing to do so in this case. The 2013 IRP acknowledged that the Company "needs flexible resources to follow the output of variable energy resources (VERs), which are currently primarily wind generation."[16] When evaluating these resources, the Company analyzed the "'load net of wind' for every one-minute

[15] PGE 2013 IRP at 70-71.
[16] Id. at 70.

interval in the three-year data set."[17/] Rather than assume that it would continue to purchase integration service from BPA, the Company made the assumption that "within any one-hour period it must be able to offset variances between forecast and actual VER production with its own flexible resources."[18/] This is yet another example of how the Company has been planning to use Port Westward II, at the portfolio level, to self-integrate wind for the entire test period, despite not having developed the proper systems in time to do so.

**Q. PLEASE SUMMARIZE YOUR RESPONSE TO THE COMPANY REGARDING WIND INTEGRATION.**

A. The Company justified its decision to acquire Port Westward II in its 2012 RFP and its 2013 IRP based on using Port Westward II to integrate its wind resources. The Company does not present a compelling argument that it has prudently managed its wind integration costs in the test period, and also provides further evidence that it has not prudently managed the acquisition of Port Westward II, which will not be used and useful for its intended purpose of integrating wind in the test period. Accordingly, I continue to recommend that the Commission disallow $5.1 million in power costs related to wind integration not prudently incurred or, in the alternative, to disallow Port Westward II in base rates until it can be used for wind integration.

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17/ Id. at 71.

18/ Id. at 70.

## III. BEAVER POINT-TO-POINT CONTRACT

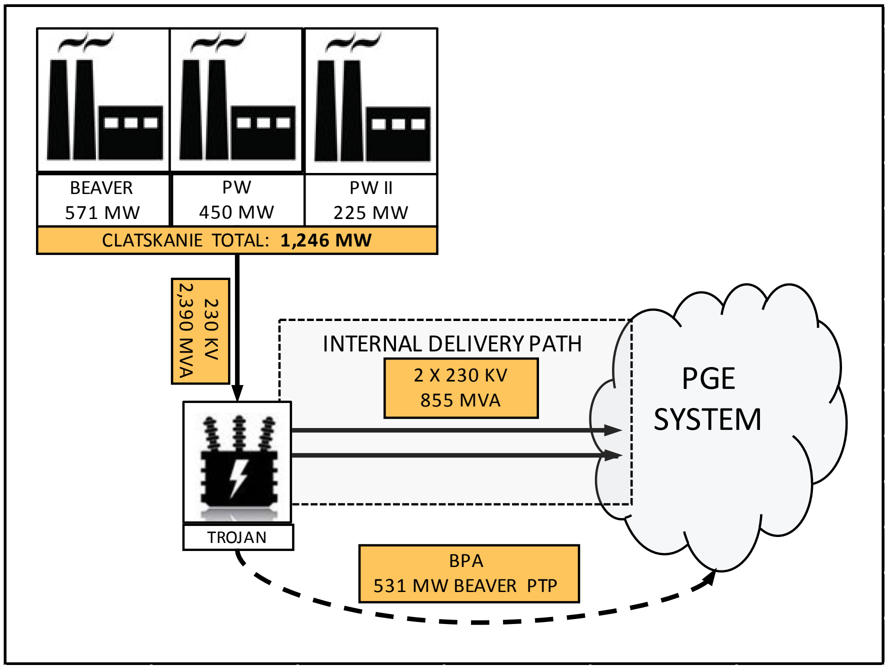
**Q. PLEASE RESTATE THE ISSUE RELATED TO THE BEAVER PTP CONTRACT.**

A. My direct testimony presented information suggesting that a portion of the Beaver PTP contract with BPA was not used and useful and that its five-year renewal was imprudent. The Company has an internal delivery path consisting of two 230 kV transmission lines originating from the Trojan substation and terminating at the Rivergate and St. Mary's substations. My understanding was that this internal delivery path was sufficient to deliver all of the power requirements of both the Port Westward and Beaver power facilities, leaving a portion of the Beaver PTP contract, which also delivers power from the Trojan Substation, unused.

**Q. HOW DID THE COMPANY RESPOND?**

A. The Company claims that its internal delivery path from the Trojan substation is insufficient to deliver power from all of its resources located near Clatskanie, Oregon. This is represented in Figure 1, below.

**FIGURE 1**
**CURRENT TRANSMISSION CAPABILITY FROM CLATSKANIE**




**Q. DOES THE COMPANY'S RESPONSE RESOLVE YOUR CONCERNS WITH THE BEAVER PTP CONTRACT?**

A. No. The Company's explanation of its transmission capabilities from the Trojan substation still calls into question whether the Company is prudently managing its internal transmission assets.

**Q. WHAT IS YOUR CONCERN ABOUT THE INTERNAL DELIVERY PATH?**

A. As detailed in Figure 1, a single transmission path between Clatskanie and Trojan is capable of transferring nearly three times the amount of power as the two transmission lines on the internal delivery path from Trojan into the Company's system. If a single 230 kV path is capable of transferring that amount of power, it follows that the two-line internal 230 kV delivery path from Trojan could be configured to transfer at least this much power. Based on the cost of the Beaver PTP contract, it likely would have been more economic for the Company to upgrade one, or both, of the internal transmission lines from Trojan in order to eliminate the approximate $11.1 million annual cost of the Beaver PTP contract.[19/]

**Q. TO WHAT EXTENT COULD CUSTOMERS HAVE BENEFITED IF THE COMPANY HAD UPGRADED THE INTERNAL DELIVERY PATH?**

A. It depends on the cost. Attached as Exhibit ICNU/201 is a report commissioned by the Western Electricity Coordinating Council performed by Black & Veatch, which details the capital costs for transmission and substations in the West.[20/] Based on this study, a rough estimate of the cost to upgrade one of the two internal transmission lines from Trojan is detailed in Table 2, below.

**TABLE 2**
**ESTIMATED CAPITAL COST OF UPGRADING 230 KV INTERNAL TRANSMISSION LINE FROM TROJAN**

| | | Ref. | **230 KV** |
|---|---|---|---|
| | **Transmission Line:** | | |
| (a) | Base Transmission Cost per Mile | ICNU/201 at 4-2 | $ 927,000 |
| (b) | ACSS Factor (Note 1) | \| | 1.08 |
| (c) | Reconductor Factor | \ | 0.35 |
| (d) | Total Capital per Mile | (a) * (b) * (c) | $ 350,406 |
| (e) | Line Miles | | 50 |
| (f) | Total Trasmission Capital ($000) | (d) * (e) / 1000 | $ 17,520 |
| | **Substation:** | | |
| (g) | Illustrative Substation Upgrades ($000) | Note 2 | $ 15,000 |
| (h) | **Total Capital ($000)** | (f) + (g) | **$ 32,520** |

Note 1: Aluminum Conductor Steel Supported (Results in increased thermal rating of line).
Note 2: The substation upgrade costs depend on the configuration of the individual substations, which has not been analyzed here. Accordingly, an illustrative value has been used.

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19/ Calculated using a $1.479/kW-mo PTP rate and $0.257/kW-mo ancillary service rate.

20/ Capital Costs for Transmission and Substations, Recommendations for WECC Transmission Expansion Planning, Black & Veatch (Oct. 2012).

**Q. HOW DO THESE COSTS COMPARE TO COMPANY ESTIMATES?**

A. They are similar. The Company recently reconductored the approximate 10-mile 230 kV path from Clatskanie to Trojan in order to accommodate the addition of Port Westward II. Based on Company workpapers from the 2012 RFP, the estimated cost per line-mile of this upgrade was approximately $[redacted], which is comparable to the amount shown in row (d) of Table 2, above. Additionally, in its 2009 IRP, the Company proposed an entirely new transmission line from the Trojan substation to South of Allston.[21/] The Company estimated a cost of approximately $45 million in 2009$.[22/] This included costs to acquire land and other contingency costs that would likely not be necessary with a path upgrade.[23/]

**Q. HOW MUCH WOULD CUSTOMERS SAVE IF THE LEVEL OF INVESTMENT SHOWN IN TABLE 2 WERE TO ELIMINATE THE NEED TO ACQUIRE BEAVER PTP CONTRACT CAPACITY?**

A. The amount of savings that would result in the first year after such an upgrade is detailed in Table 3, below.

21/ Docket No. LC 48, PGE 2009 IRP at 182-84 (Nov. 5, 2009).
22/ Id. at 184.
23/ Id.

**TABLE 3**
**FIRST YEAR REVENUE REQUIREMENT OF**
**UPGRADING INTERNAL DELIVERY PATH**
***(Dollars in Thousands)***

| | | |
|---|---|---|
| (a) | Cost of Capital | 7.45% |
| (b) | Tax Rate | 38.5% |
| (c) | Useful Life | 40 yrs |

| | | Ref. | Scenario 1 Low Cost | Scenario 2 Med. Cost | Scenario 3 High Cost |
|---|---|---|---|---|---|
| (d) | **Total Capital Cost** | | **$ 25,000** | **$ 32,520** | **$ 65,000** |
| (e) | Return on Rate Base | (a) * (d) | $ 1,863 | $ 2,423 | $ 4,843 |
| (f) | Amount to Cover Tax | (e) / (1- (b)) - (e) | $1,166 | $1,517 | $3,031 |
| (g) | Depreciation | (d) / (c) | $ 625 | $ 813 | $ 1,625 |
| (h) | **First Year Rev. Req.** | ∑ (e):(g) | **$ 3,653** | **$ 4,752** | **$ 9,499** |
| (i) | Beaver PTP Cost | | $ 11,062 | $ 11,062 | $ 11,062 |
| (j) | **First Year Savings** | (i) - (h) | **$ 7,408** | **$ 6,309** | **$ 1,563** |

Q. **PLEASE SUMMARIZE TABLE 3.**

A. Table 3 demonstrates the savings resulting from an upgrade to the internal delivery path from Trojan in the first year after the upgrade is placed in service, based on three capital cost scenarios. Scenario 2 details the first-year customer savings that would result based on the capital costs detailed in Table 2, above. Scenario 1 is a low-cost scenario, detailing the first-year customer savings that would result based on capital costs of 75 percent of the amount estimated in Table 2, above. Scenario 3 is a high-cost scenario, detailing the first-year savings that would result if capital costs are twice the amount estimated in Table 2. This table demonstrates that even if the cost to upgrade the internal delivery path is $65.0 million, customers would be better off by $1.6 million in the first year after the project is completed. This amount is comparable to the Company's own estimate from the 2009 IRP of the cost to build an entirely new transmission line in this area.[24]

**Q. HOW WOULD THE LEVELIZED REVENUE REQUIREMENT, CALCULATED OVER THE ENTIRE INVESTMENT LIFE, COMPARE TO THE FIRST-YEAR REVENUE REQUIREMENT DETAILED IN TABLE 3?**

A. Comparing the cost of the Beaver PTP contract with the nominal levelized revenue requirement of upgrading the internal delivery path results in the customer benefits detailed in Table 4, below.

**TABLE 4**
**NOMINAL LEVELIZED REVENUE REQUIREMENT**
**SAVINGS FROM INTERNAL DELIVERY PATH UPGRADE**
***($000)***

| **Upgrade Cost** | **$ 25,000** | **$ 32,520** | **$ 65,000** | **$ 100,000** |
|---|---|---|---|---|
| Nom. Levelized Rev. Requirement | 2,818 | 3,666 | 7,328 | 11,274 |
| Nom. Levelized Beaver PTP* | 13,769 | 13,769 | 13,769 | 13,769 |
| **Nom. Levelized Ratepayer Benefit** | **$ 10,951** | **$ 10,103** | **$ 6,441** | **$ 2,495** |

*Assumes inflationary, 2 percent annual rate increases

**Q. PLEASE SUMMARIZE TABLE 4.**

A. Table 4 demonstrates that, depending on the cost of upgrading the internal delivery path, ratepayers would have saved $2.5 - $11.0 million per year on a nominal levelized basis over the term of the investment. It also demonstrates that, even if the capital costs of upgrading the internal path exceeds $100 million, customers would still be better off on a nominal levelized basis, in comparison to the cost of the Beaver PTP capacity.

[24] Id.

**Q. WHY DO YOU BELIEVE THAT THESE POTENTIAL SAVINGS ARE EVIDENCE OF IMPRUDENT MANAGEMENT?**

A. The Company recently renewed the Beaver PTP contract for an additional five-year term, which expires in 2020. The Company did not present evidence of any analysis of the costs of the Beaver PTP contract compared to the costs associated with upgrading the internal delivery path from Trojan. In addition, the Company also had an opportunity in 2010 to reevaluate the economics of the Beaver PTP Contract; however, I have not identified any instance where the Company evaluated upgrading the internal path at that time. Because the potential benefits are material, I do not believe that the Company is prudently managing its transmission rights from the resources located near Clatskanie.

**Q. PLEASE SUMMARIZE YOUR UPDATED RECOMMENDATION RELATED TO THE BEAVER PTP CONTRACT.**

A. Because the Company has had two opportunities to reevaluate the economics of the Beaver PTP contract capacity in comparison to internal delivery path upgrades, my updated recommendation is that the Beaver PTP contract costs exceeding the first year revenue requirement associated with the high cost, Scenario 3 from Table 3 above, should be removed from NVPC in this proceeding on the basis of imprudence. This results in a $1.6 million reduction to NVPC.

**Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?**

A. Yes.

**BEFORE THE PUBLIC UTILITY COMMISSION**

**OF OREGON**

**UE 286**

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| In the Matter of | ) |
| | ) |
| PORTLAND GENERAL ELECTRIC COMPANY | ) |
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| Net Variable Power Costs (NVPC) and Annual Power Cost Update (APCU) | ) |
| | ) |
| | ) |

# EXHIBIT ICNU/201

# BLACK & VEATCH REPORT ON CAPITAL COSTS FOR TRANSMISSION AND SUBSTATIONS

**July 3, 2014**

ICNU/201
Mullins/1

# CAPITAL COSTS FOR TRANSMISSION AND SUBSTATIONS

## Recommendations for WECC Transmission Expansion Planning

**B&V PROJECT NO. 176322**



**PREPARED FOR**

Western Electricity Coordinating Council

OCTOBER 2012

**Principal Investigators:**

Tim Mason, Project Manager

Trevor Curry

Dan Wilson

BLACK & VEATCH
Building a world of difference.

# Assumptions and Limitations Disclaimer

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# Table of Contents

## LIST OF TABLES



## LIST OF FIGURES

# 1.0 Introduction

As part of the Western Electricity Coordinating Council (WECC) transmission planning process, Black & Veatch assisted WECC to develop updated assumptions on transmission line and substation costs, as well as to develop a process to ensure that these costs can be readily updated in the future. The effort was completed under the auspices of a peer review workgroup composed of regional transmission experts to ensure that the resulting costs and cost development methodology is robust and appropriate for WECC's current and future requirements.

This report details the transmission and substation costs and development efforts, including the assumptions, methodology, and results. Additionally, it describes the tool developed by Black & Veatch for WECC to be used to estimate transmission and substation costs that will be integrated into WECC's planning process. Finally, the report discusses the benchmarking of this methodology to several recent transmission project examples. This was completed to ensure that the theoretical costs reasonably reflect actual transmission development costs in the WECC region.

## 1.1 APPROACH

Black & Veatch developed capital costs for transmission lines and substations for high-voltage transmission facilities in the WECC using a "bottom-up" approach, detailing the component and land costs and then adjusting these to take into consideration potential cost variations such as location and terrain. "High-voltage" is defined as transmission facilities operating at 230 kilovolts (kV) or higher. The transmission line voltage classes and substation types included in this study are listed in Table 1-1.

**Table 1-1 Transmission and Substation Facilities Included in This Study**

| TRANSMISSION LINE VOLTAGE CLASSES | SUBSTATION TYPES |
|---|---|
| 230 kV Single Circuit | 230 kV |
| 230 kV Double Circuit | 345 kV |
| 345 kV Single Circuit | 500 kV (ac) |
| 345 kV Double Circuit | 500 kV (dc) |
| 500 kV Single Circuit | |
| 500 kV Double Circuit | |
| 500 kV HVDC Bi-pole | |

In addition to developing a set of costs to be used by WECC for the instant planning effort, this effort also resulted in the development of a methodology for developing transmission costs in the future and a tool to develop estimates for the cost of individual lines under consideration. These are detailed in the report.

## 1.2 PEER REVIEW PROCESS

To ensure that the costs and cost methodology were appropriate for its purposes, WECC convened a peer review group composed of regional transmission experts to review and provide recommendations on the costs and methodology. The group provided valuable information about specific transmission line costs to assist in the validation of the methodology, and ensure the costs proposed are reasonable. The group also provided written input and discussion of assumptions during several conference calls between June and September of 2012. The peer review group members are listed in Table 1-2.

**Table 1-2 Transmission Cost Peer Review Group Participants**

| | |
|---|---|
| Bill Pascoe | TransWest Express |
| Bill Hosie | TransCanada |
| Carl Zichella | Natural Resources Defense Council |
| Grace Anderson | California Energy Commission |
| James Cauchois | Western Electricity Coordinating Council |
| Jeff Billinton | California Independent System Operator |
| James Feider | City of Redding, CA |
| Keith White | California Public Utilities Commission |
| Marv Landauer | Columbia Grid |
| Nick Schlag | Energy & Environmental Economics (E3) |
| Ric Campbell | Utah Public Service Commission |
| Stan Holland | Western Electric Coordinating Council |
| Steve Ellerbecker | Western Governors Association |
| Brad Nickell | Western Electric Coordinating Council |
| Keegan Moyer | Western Electric Coordinating Council |
| Byron Woertz | Western Electric Coordinating Council |
| Arne Olson | Energy & Environmental Economics (E3) |

In addition to the input from the peer review group, the draft methodology and tools were presented to the WECC Technical Advisory Subcommittee (TAS) group for review and comments in September 2012. Several comments were received on the costs, which have been incorporated into this report, as appropriate. A summary of the Stakeholder Comments is included in Section 7.0.

## 1.3 VARIABILITY OF COSTS

The costs included in this report are believed to reasonably represent the cost to develop transmission and substation facilities in the WECC region. It is imperative to note, however, that transmission lines and substations are all unique, and the cost of a specific line or substation may be significantly different than the costs provided here due to a variety of factors. Most new transmission and substation facilities interconnect to the existing grid, and a "typical" transmission project will include some level of new equipment and some upgrades to existing equipment.

Furthermore, transmission facilities are developed not only to transmit incremental power generation, but also to provide additional system reliability and serve load. It is often impossible to segregate "capacity costs" from the cost to provide reliability and serve load. The costs here should be used as a guide to develop approximate costs for new transmission, but should not be used to measure the cost or cost-effectiveness of any specific transmission facility.

# 2.0 Transmission Capital Costs

Black & Veatch developed a methodology and tool to calculate indicative capital costs for transmission infrastructure projects throughout the WECC region. This methodology begins with using the current cost of specified transmission equipment and the expected cost of land. The costs are then adjusted to identify the differential cost of developing on different land with different terrain factor adjustments. Black & Veatch identified the following categories and sub-categories to consider from a capital cost perspective:

- Voltage Class
  - Alternating Current (AC) - 230 kV, 345 kV, and 500 kV (single and double circuit)
  - High Voltage Direct Current (HVDC) 500 kV Bi-Pole
- Line Characteristics
  - Conductor Type
  - Pole Structure
  - Length of line
- New Construction or Re-conductor
- Terrain Type
- Location

Black & Veatch utilized its internal knowledge of transmission equipment component costs as a starting point for the cost assumptions. The sections below key in on each of the specific costs identified while gaining a more granular understanding of the capital costs for transmission.

## 2.1 NEW TRANSMISSION

Black & Veatch only considered voltages 230 kV and above, as these were indicative of the majority of transmission infrastructure projects being proposed on the bulk electric transmission network in the WECC region. In addition to AC transmission, 500 kV Bi-Pole HVDC transmission was also considered, which would be more appropriate for long, high capacity transmission projects.

For AC transmission lines, there are many components that make up the entire line cost. First, Black & Veatch identified the initial physical considerations. Without engineering a detailed design, there were many components that could be broken apart into individual cost multipliers. Three key components were determined to be the most important cost considerations for transmission line designs:

- Conductor type
- Structure
- Length of line

Starting from the transmission capital costs developed in the Western Renewable Energy Zones (WREZ) project for the Western Governors Association, Black & Veatch identified a baseline assumption for capital costs per mile based on these three key components. The initial costs per mile for transmission from the WREZ, escalated from the original 2008 values, are shown in Table 2-1.

**Table 2-1 Baseline Transmission Costs**

| LINE DESCRIPTION | NEW LINE COST ($/MILE) |
| --- | --- |
| 230 kV Single Circuit | $927,000 |
| 230 kV Double Circuit | $1,484,000 |
| 345 kV Single Circuit | $1,298,000 |
| 345 kV Double Circuit | $2,077,000 |
| 500 kV Single Circuit | $1,854,000 |
| 500 kV Double Circuit | $2,967,000 |
| 500 kV HVDC Bi-pole | $1,484,000 |

These costs were based on the following assumptions:

- Aluminum Conductor Steel Reinforced (ACSR) conductor
- Tubular (230 kV) / Lattice (345 KV and 500 kV) pole structure
- Line longer than 10 miles

Starting from these baseline costs, Black & Veatch identified various multipliers when adjusting for specific design considerations. For specific projects, it may be important to have a higher rated conductor, especially for transmission lines that are loaded heavily or may span longer distances. This decreases line power losses, and increases current carrying capability. Black & Veatch identified three common conductor types that could be used in new transmission lines: ACSR, Aluminum Conductor Steel Supported (ACSS), and High Tensile Low Sag (HTLS). Each of these conductor types increases the ampacity of the transmission line due to the relative physical properties. ACSR is used most commonly, and is the basis for most transmission lines in the WECC region.

It was important for Black & Veatch to quantify the additional cost to the entire line length if one of these higher ampacity conductors was selected, as it would affect the entire cost of the line. Table 2-2 below indicates the cost multipliers for each of these conductor types, which would be multiplied against the base transmission cost for each voltage level.

**Table 2-2 Conductor Cost Multipliers**

| CONDUCTOR | 230 KV SINGLE | 230 KV DOUBLE | 345 KV SINGLE | 345 KV DOUBLE | 500 KV SINGLE | 500 KV DOUBLE | 500 KV HVDC BI-POLE |
|---|---|---|---|---|---|---|---|
| ACSR | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 |
| ACSS | 1.08 | 1.08 | 1.08 | 1.08 | 1.08 | 1.08 | 1.08 |
| HTLS | 3.60 | 3.60 | 3.60 | 3.60 | 3.60 | 3.60 | 3.60 |

Various structure types can be considered to support transmission lines. Areas that have higher population may use a tubular steel pole, whereas wide-open mountain ranges may use the lattice steel structure. Since this design constraint can have an impact on the capital cost, it was important to capture these costs as well. While most 230 kV transmission lines are typically made of steel poles, 345 kV and above transmission lines typically use lattice steel structures; however, this is not always the case. For instance, in urban areas, some 345 kV transmission lines may use steel poles, as they reduce the amount of required right of way. An example of each type of structure is shown in Figure 2-1.

**Figure 2-1 Pole Structures: Steel Pole (Populus-Terminal 345 kV) vs. Lattice (Path 26)**

Black & Veatch quantified the capital cost multipliers associated with each type of structure, as shown in Table 2-3.

**Table 2-3 Transmission Structure Type Cost Multipliers**

| STRUCTURE | 230 KV SINGLE | 230 KV DOUBLE | 345 KV SINGLE | 345 KV DOUBLE | 500 KV SINGLE | 500 KV DOUBLE | 500 KV HVDC BI-POLE |
|---|---|---|---|---|---|---|---|
| Lattice | 0.90 | 0.90 | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 |
| Tubular Steel | 1.00 | 1.00 | 1.30 | 1.30 | 1.50 | 1.50 | 1.50 |

Finally, it is important to consider the length of the transmission line. In general, the longer the transmission line, the less it costs per mile. The primary reason for this is that design and engineering, costs are non-linear—it takes almost as much to design and approve a short line as it does a long line. The capital cost multipliers associated with various transmission line lengths are indicated in Table 2-4 below.

**Table 2-4 Transmission Length Cost Multipliers**

| LENGTH | 230 KV SINGLE | 230 KV DOUBLE | 345 KV SINGLE | 345 KV DOUBLE | 500 KV SINGLE | 500 KV DOUBLE | 500 KV HVDC BI-POLE |
|---|---|---|---|---|---|---|---|
| > 10 miles | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 |
| 3-10 miles | 1.20 | 1.20 | 1.20 | 1.20 | 1.20 | 1.20 | 1.20 |
| < 3 miles | 1.50 | 1.50 | 1.50 | 1.50 | 1.50 | 1.50 | 1.50 |

## 2.2 RE-CONDUCTORING

In areas where there are existing transmission lines, it may be necessary or more cost-effective to re-conductor an existing transmission rather than to build a new line. Re-conductoring can be defined many different ways, but for simplicity re-conductoring in this effort is defined as replacing an existing conductor to increase ampacity. This assumes that the new conductor would be of similar size and weight, hence no upgrading of poles or insulators is required.

To quantify the capital costs associated with re-conductoring a transmission line, Black & Veatch assumed the following:

- 230 kV Transmission Conductors
  - 2 conductors per phase
  - Conductor assumed to be 35% of total capital cost
- 345 kV Transmission Conductors
  - 3 conductors per phase
  - Conductor assumed to be 45% of total capital cost
- 500 kV Transmission Conductors

  - 4 conductors per phase
  - Conductor assumed to be 55% of total capital cost
- 500 kV Bi-Pole Transmission Conductors
  - 3 conductors per phase
  - Conductor assumed to be 55% of total capital cost

## 2.3 TERRAIN MULTIPLIER

Transmission equipment capital costs are only a portion of the overall transmission line capital costs. A substantial factor in total transmission line costs is the construction cost for developing lines in different types of terrain. Black & Veatch identified nine different terrain types and then developed cost multipliers to compensate for the difficulty of construction in each terrain type. The lowest cost of development was identified as scrub or flat terrain, and the most difficult and expensive type of terrain is forested areas. Table 2-5 identifies the different types of terrain assessed.

Black & Veatch surveyed published information to ascertain terrain cost differences. California Investor-Owned Utilities (IOUs) publish their terrain cost multipliers annually. The only other public source of terrain multipliers for Western U.S. transmission development is the WREZ. Using stakeholder input and validation, the Peer Review Group adopted a set of terrain cost multipliers that represent a mix of these factors, detailed on Table 2-5.

**Table 2-5 Terrain Cost Multipliers**

| TERRAIN | PG&E[1] | SCE[2] | SDG&E[3] | WREZ | WECC |
|---|---|---|---|---|---|
| Desert | 1.00 | 1.10 | 1.00 | - | **1.05** |
| Scrub / Flat | 1.00 | 1.00 | 1.00 | 1.00 | **1.00** |
| Farmland | 1.00 | 1.00 | 1.00 | 1.10 | **1.00** |
| Forested | 1.50 | 3.00 | - | 1.30 | **2.25** |
| Rolling Hill (2-8% slope) | 1.30 | 1.50 | - | - | **1.40** |
| Mountain (>8% slope) | 1.50 | 2.00 | 1.30 | - | **1.75** |
| Wetland | - | - | 1.20 | 1.20 | **1.20** |
| Suburban | 1.20 | 1.33 | 1.20 | - | **1.27** |
| Urban | 1.50 | 1.67 | - | 1.15 | **1.59** |

[1] **2012 PG&E Per Unit Cost Guide - http://www.caiso.com/Documents/PGE_2012FinalPerUnitCostGuide.xls**
[2] **2012 SCE Per Unit Cost Guide - http://www.caiso.com/Documents/SCE_2012FinalPerUnitCostGuide.xls**
[3] **2012 SDG&E Per Unit Cost Guide - http://www.caiso.com/Documents/SDGE_2012FinalPerUnitCostGuide.xls**

## 2.4 RIGHT OF WAY COSTS

In addition to the capital costs for transmission line equipment and difficulty of construction based on terrain, there are costs associated with acquiring land for the transmission line. In some cases, right of way costs can come to 10% of total project costs, although this proportion varies significantly between projects. In order to estimate per-mile right of way costs for generic transmission projects, two pieces of information are needed:

- Right of way widths for each voltage class (from which one can calculate the number of acres required per mile of transmission line)
- Right of way costs per acre

With these pieces of information, one can simply multiply the acres per mile by the cost per acre to calculate the total right of way cost per mile of transmission line. Black & Veatch developed estimates for both right of way widths and right of way costs per acre which can be applied across the WECC region; the methodology and results are discussed separately below.

### 2.4.1 Right of Way Widths

In order to develop generic right of way width estimates for each voltage class considered in this study, Black & Veatch surveyed available information from a variety of industry sources—FERC and NERC documents, individual utility estimates, and actual project right of way widths from existing and proposed projects throughout the WECC region. This survey revealed that transmission project right of way widths vary significantly, even within the same voltage class. Table 2-6 below shows the results of a comprehensive survey that FERC conducted in 2004 to quantify right of way widths by utility (note that this survey included utilities nationwide, not just those in the WECC region).[4]

**Table 2-6 FERC Nationwide Survey of Right of Way Widths (2004)**

| MINIMUM WIDTH | 230 KV (# OF UTILITIES) | 345 KV (# OF UTILITIES) | 500 KV (# OF UTILITIES) |
|---|---|---|---|
| < 125 ft. | 40 | 6 | 4 |
| 126 - 175 ft. | 36 | 36 | 21 |
| > 175 ft. | 30 | 30 | 13 |

**Note: This survey included utilities nationwide, not only those in the WECC region.**

However, the FERC data were only one of the many sources investigated. Table 2-7 below shows the larger set of data sources that Black & Veatch drew from (which focused on utilities and projects in the WECC region), and the right of way widths specified for each voltage class in each data source. In the "WECC Assumption" row, the right of way width assumption for each voltage class is shown; this was based on adopting the most common value from the various data sources for each voltage class, and also ensuring a logical progression so that widths increased at successively higher voltages and double circuit line widths were greater than those for single

[4] http://www.ferc.gov/industries/electric/indus-act/reliability/veg-mgmt-rpt-final.pdf

circuits. The bottom row shows the acres of right of way per mile of transmission. These "acre/mile" values were the values used in all subsequent right of way cost calculations for this study.

**Table 2-7 Right of Way Widths by Voltage Class and Data Source**

| SOURCE | 230-KV SINGLE CIRCUIT | 230-KV DOUBLE CIRCUIT | 345-KV SINGLE CIRCUIT | 345-KV DOUBLE CIRCUIT | 500-KV SINGLE CIRCUIT | 500-KV DOUBLE CIRCUIT | 500-KV DC BI-POLE |
|---|---|---|---|---|---|---|---|
| FERC Nation-wide Utility Survey | 100 ft. | - | 125 ft. | - | 175 ft. | - | - |
| DRECP (SCE/LADWP) | 100 ft. | - | - | - | 200 ft. | - | - |
| SDG&E | - | 300 ft. | - | - | 200 ft. | - | - |
| PG&E | 75 ft. | - | - | - | - | - | - |
| PacifiCorp | 125/150 ft. | - | 150 ft. | - | 250/300 ft. | 300 | - |
| BPA | 125/225 ft. | - | - | - | 150 ft. | - | - |
| Idaho Power | - | - | - | - | 250 ft. | - | - |
| Xcel Energy | - | - | - | 225/250 ft. | - | - | - |
| WREZ | 150 ft. | 150 ft. | 160 ft. | 160 ft. | 175 ft. | 175 ft. | 200 ft. |
| WECC Assumption | 125 ft. | 150 ft. | 175 ft. | 200 ft. | 200 ft. | 250 ft. | 200 ft. |
| **Acres/mile*** | **15.14** | **18.17** | **21.20** | **24.23** | **24.23** | **30.29** | **24.23** |

***Acres/mile values were calculated by multiplying the right of way width by 5,280 feet per mile and dividing by 43,560 sq. ft. per acre.**

## 2.4.2 Right of Way Costs Per Acre

To develop estimates of right of way costs, the Peer Review Group adopted a methodology based on the Bureau of Land Management's (BLM) Linear Right of Way Schedule for Year 2015 (taken from 43 CFR Parts 2800, 2880, 2920).[5] This document provides estimates of land rental costs in each U.S. county, developed specifically for the purpose of linear right of way uses such as transmission lines. Although these rental costs do not differentiate between different land uses (e.g. farmland, pasture land, urban or suburban land, etc.) and may not accurately predict the cost of any particular parcel of land, they do provide the following advantages:

[5] http://www.blm.gov/pgdata/etc/medialib/blm/wo/MINERALS__REALTY__AND_RESOURCE_PROTECTION_/cost_recovery.Par.47392.File.dat/RentLinearRentSchedule2009-2015-NoHighlight.pdf

- Consistent data across all states and counties
- Transparent, public data source
- Costs designed for the purpose of right of way leases
- Capture the relative cost differences between different regions and land uses

Because these costs are given in rental terms (dollars per acre per year) and the WECC transmission costs are expressed in capital costs it is necessary to convert the lease costs to capital costs (dollars per acre). The following formula was used for this conversion:

[6]

Black & Veatch assumed a Capitalization Rate of ten percent and assumed that Land Taxes are equal to one percent of the Land Rental Cost.

In addition to providing per-acre rental costs for each U.S. county, the BLM right of way schedule also categorizes all counties into twelve different cost “zones”. For simplicity, Black & Veatch used the zone data rather than individual county-level cost data. Table 2-8 lists the BLM land rental costs by zone and the equivalent capital cost by zone.

**Table 2-8 BLM Land Rental and Land Capital Costs by Zone**

| BLM ZONE NUMBER | LAND RENTAL COST ($/ACRE-YEAR) | LAND CAPITAL COST ($/ACRE) |
|---|---|---|
| 1 | $ 9 | $ 85 |
| 2 | $ 17 | $ 171 |
| 3 | $ 34 | $ 341 |
| 4 | $ 52 | $ 512 |
| 5 | $ 69 | $ 683 |
| 6 | $ 103 | $ 1,024 |
| 7 | $ 172 | $ 1,707 |
| 8 | $ 345 | $ 3,414 |
| 9 | $ 690 | $ 6,828 |
| 10 | $ 1,035 | $ 10,242 |
| 11 | $ 1,724 | $ 17,071 |
| **12** | **$ 3,449** | **$ 34,141** |

[6] **Land Rental Value** is the annual fee individuals are willing to pay for the exclusive right to use a land site for a period of time. **Land Taxes** is the portion of the land rental value that is claimed for the community. **Capitalization Rate** is a market determined rate of return that would attract individuals to invest in the use of land, considering all of the risks and benefits which could be realized.

## 2.5 TRANSMISSION CALCULATION METHODOLOGY

Multiplying the right of way acres per mile by the land cost per acre yields the total right of way cost per mile of transmission line. This value was then added to the base transmission costs discussed in Sections 2.1, 2.2, and 2.3 to develop the total transmission line capital cost. The exact equation used to calculate the total transmission cost is explained in Section 2.5.

**Total Transmission Line Cost =**

[(Base Transmission Cost) x (Conductor Multiplier) x (Structure Multiplier) x (Re-conductor Multiplier) x (Terrain Multiplier) + (ROW Acres/Mile) x (Land Cost/Acre)] x (# of Miles)

# 3.0 Substation Capital Costs

Transmission cost estimates often only consider the conductor cost, without consideration of the requirements for new substation facilities needed to connect the transmission to the existing grid. This section quantifies the substation costs associated with transmission infrastructure development.

There are numerous considerations that go into the design of a substation that will significantly impact the cost of the facility. For the purpose of this effort, however, the Peer Review Group adopted a methodology that was simple enough to be repeatable, but granular enough to estimate a capital cost for various sized substations with different line and transformer positions, additional reactive equipment, or new transformers. Since HVDC lines were also identified in the transmission capital costs, HVDC converter station equipment and costs were also estimated. The following cost components were identified to calculate the substation cost:

- Base Substation Cost
- Line/Transformer Positions
- Transformer
- HVDC Converter Station
- Static VAR Compensator, Shunt Reactors and Series Capacitors

## 3.1 NEW SUBSTATION BASE COST

Black & Veatch first identified a set of base substation costs, which excludes all major equipment. Since substations can be built in very remote areas, it was important to note that the substation costs in this methodology assume flat, barren land with relatively easy site access. The new substation costs, which include land, substation fence, control building, etc are identified in Table 3-1 below.

**Table 3-1 New Base Substation Capital Costs**

| EQUIPMENT | 230 KV SUBSTATION | 345 KV SUBSTATION | 500 KV SUBSTATION |
|---|---|---|---|
| Base Cost (New Substation) | $1,648,000 | $2,060,000 | $2,472,000 |

## 3.2 LINE AND TRANSFORMER POSITIONS

In addition to the substation base cost Black & Veatch considered the cost of breaker postions necessary to interconnect lines and transformers for new and existing substations. All of these require circuit breakers and switches for isolation of equipment. This isolation can be designed in multiple configurations; however, two are most common: ring bus and breaker-and-a-half (BAAH).

A ring bus configuration assumes one breaker for each line or transformer position; whereas, a BAAH configuration assumes one and a half breakers for every line or transformer configuration (e.g. 4 lines equates to 6 breakers); see Figure 3-1 for a diagram of each configuration.

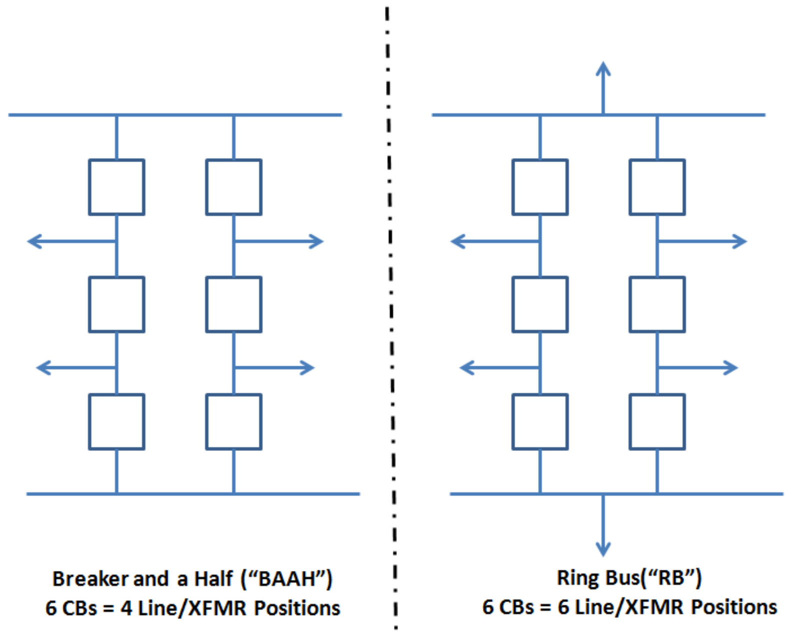


**Figure 3-1 Substation Configurations**

A line position is defined as a transmission line entering or exiting and terminating at the substation. For one transmission line looping into a substation, it would require two line positions. A transformer position is equal to the number of transformers added. Each of these types of configurations is used at different voltages and number of lines in and out of the substation. Smaller substations typically assume a ring bus configuration, while larger substations use a BAAH configuration. Table 3-2 identifies the basic cost per line or transformer position and the associated multipliers. These costs include the breaker, switches, structures, and protection schemes associated with these configurations.

**Table 3-2 Line/Transformer Position Cost and Multipliers**

| EQUIPMENT | 230 KV SUBSTATION | 345 KV SUBSTATION | 500 KV SUBSTATION |
|---|---|---|---|
| Cost Per Line/XFMR Position | $1,442,000 | $2,163,000 | $2,884,000 |
| Ring Bus Multiplier | 1 | 1 | 1 |
| Breaker and a Half Multiplier | 1.5 | 1.5 | 1.5 |

If an existing substation is expanded, in the case of connecting two existing substations with a new transmission line, no incremental base substation costs are incurred.

## 3.3 TRANSFORMERS

Many transmission lines connect to substations that serve load areas, typically at a lower voltage level than the bulk transmission system. To do so, transformers are needed to decrease the voltage and deliver electricity to load centers. Transformers vary by voltage, as well as by current carrying capability. Transformers can vary in cost substantially based on variables such as copper commodity prices, as well as cost of freight; however, the costs considered and vetted by the WECC stakeholders are typical in the industry. The costs considered include foundation and oil containment for the transformer.

Table 3-3 below identifies the capital costs associated with each voltage class in a cost per mega-volt ampere (MVA), which is dependent on the amount of current carrying capability necessary to deliver from the high voltage side to the low voltage side of the transformer.

**Table 3-3 Transformer Capital Costs**

| TRANSFORMER COST ($/MVA) | 230 KV SUBSTATION | 345 KV SUBSTATION | 500 KV SUBSTATION |
|---|---|---|---|
| 115/230 kV XFMR | $7,000 | - | - |
| 115/345 kV XFMR | - | $10,000 | - |
| 115/500 kV XFMR | - | - | $10,000 |
| 138/230 kV XFMR | $7,000 | - | - |
| 138/345 kV XFMR | - | $10,000 | - |
| 138/500 kV XFMR | - | - | $10,000 |
| 230/345 kV XFMR | | $10,000 | - |
| 230/500 kV XFMR | $11,000 | - | $11,000 |
| 345/500 kV XFMR | - | $13,000 | $13,000 |

## 3.4 REACTIVE COMPONENTS

An ideal transmission system does not require any reactive support; however, this is rarely the case. Many transmission networks are integrated in a manner that supports voltage dips across the network; however, some weaker systems may require additional reactive power support to maintain grid reliability. The amount of reactive support, and the speed with which the support needs to be transferred to the grid, will determine what type of reactive component is required at the substation.

Black & Veatch identified three key reactive components commonly used for transmission level grid support. Each piece of equipment has its own level of complexity, size, and cost.

- Shunt Reactor
- Series Capacitor
- Static VAr Compensator (SVC)

Shunt reactors are commonly used to reduce voltages due to high line charging on lightly loaded transmission networks. Series capacitors do the exact opposite – they increase voltages by providing additional reactive charging to the transmission network to maintain system voltages.

Black & Veatch worked with stakeholders to assume a "turnkey" installation, which includes with engineering, design, and construction support for a site that "has been rough-graded and has access to a source of medium voltage auxiliary power"[7]. Table 3-4 identifies the typical costs for shunt reactors and series capacitors.

**Table 3-4 Shunt Reactor and Series Capacitor Capital Costs**

| EQUIPMENT | 230 KV SUBSTATION | 345 KV SUBSTATION | 500 KV SUBSTATION |
|---|---|---|---|
| Shunt Reactor ($/MVAR) | $20,000 | $20,000 | $20,000 |
| Series Capacitor ($/MVAR) | $30,000 | $10,000 | $10,000 |

Static VAr Compensators (SVCs) combine both technologies, while adding speed of support. SVCs are constantly connected to the grid, whereas capacitors and reactors typically have to be switched. SVCs are more expensive than their static counterparts; however, they offer more flexibility in resources. The costs for SVCs vary based on size and the assumptions made about the ease of installation. Table 3-5 below shows SVC costs identified by HydroOne, Arizona Public Service Company (APS), and the Peer Review Group adopted costs. Like Shunt Reactor and Series Capacitor capital costs, SVC costs assume a "turnkey" installation.

**Table 3-5 SVC Capital Costs**

| VOLTAGE CLASS | HYDRO ONE[8] | APS[9] | WECC |
|---|---|---|---|
| 500 kV | - | - | $85,000 |
| 345 kV | - | - | $85,000 |
| 230 kV | $94,500 | $75,000 | $85,000 |
| 115 kV | $141,000 | - | - |
| Medium Voltage | $142,000 | - | - |
| Low Voltage | $250,000 | - | - |

[7] Stakeholder comment from Eric John of ABB, regarding turnkey SC turnkey installation.
[8] http://www.appro.org/docs/HONIconnectionsJan2009/Naren_Pattani_%20-_Tx_presentation_at_%20APPrO-CanWEA-OWA_workshop,_Jan_22_2009.pdf
[9] http://www.wecc.biz/committees/BOD/TEPPC/020209/Lists/Agendas/1/Reactors%20%20Capacitors%20%20SVC%20%20PSS.pdf

## 3.5 HIGH VOLTAGE DIRECT CURRENT CONVERTER STATION

HVDC converter stations are required at both ends of a HVDC transmission line. The converter stations change the HVDC power to AC power and then interconnect it to the AC transmission network. There are benefits to using HVDC transmission lines for very long transmission segments, as line losses are substantially lower due to the lack of reactive losses, which make up the majority of AC transmission line losses. For shorter distances, HVDC lines are generally not cost-effective, as the converter substation costs are substantially higher than the cost of an AC substation.

There are various costs associated with a HVDC converter station, and the most variable cost is the reactive component. The costs on Table 3-6 are indicative of a typical transmission system, and what is needed to provide reliable power to the AC transmission network.

**Table 3-6 HVDC Converter Station Costs**

| HVDC 500 KV CONVERTER STATION | |
|---|---|
| MW Rating | 3000 MW |
| **Cost Components** | |
| Converter Terminal (including DC switching station equipment) | $275,000,000 |
| Reactive Support (synchronous condensers, SVCs, etc.) | $150,000,000 |
| AC Switchyard | $20,000,000 |
| **Total Cost** | **$445,000,000** |

## 3.6 SUBSTATION CALCULATION METHODOLOGY

Using the substation components detailed above, the total substation cost is calculated using the following equation:

**Total Individual Substation Cost =**

[(Substation Base Cost) + (Line/XFMR Position Base Cost) x (# of Line/XFMR Positions) x (RB or BAAH Multiplier) + (XFMR Cost/MVA) x (XFMR MVA Rating) x (# of XFMRs) + (SVC Cost/MVAR) (# MVARs) + (Series Cap. Cost/MVAR) x (# MVARs) + (Shunt Reactor Cost/MVAR) x (# MVARs) + (HVDC Converter Station Cost)]

If the substation has a high side and a low side voltage, both Line/XFMR Position costs have to be calculated; however, the Substation Base Cost does not have to be added again. The highest voltage of the substation will be the basis for the Substation Base Cost.

# 4.0 Summary of Capital Costs

The methodology in Sections 2.0 and 3.0 above considers multiple components to compute a complete capital cost for a transmission infrastructure project. The capital costs above are summarized in the sections below.

## 4.1 TRANSMISSION CAPITAL COSTS

Using the methodology discussed in Section 2.0, Black & Veatch surveyed various transmission costs as well as used internal industry knowledge to determine a typical value for transmission costs. While industry costs can vary substantially, the Peer Review Group determined that these values are reasonable for projects installed in the WECC region.

Using the numbers from tables above and the equation below, the total capital cost for a transmission line can be calculated.

**Total Transmission Line Cost =**

[(Base Transmission Cost) x (Conductor Multiplier) x (Structure Multiplier) x (Re-conductor Multiplier) x (Terrain Multiplier) + (ROW Acres/Mile) x (Land Cost/Acre)] x (# of Miles)

**Table 4-1 Transmission Capital Cost Summary**

| EQUIPMENT | 230 KV SINGLE CIRCUIT | 230 KV DOUBLE CIRCUIT | 345 KV SINGLE CIRCUIT | 345 KV DOUBLE CIRCUIT | 500 KV SINGLE CIRCUIT | 500 KV DOUBLE CIRCUIT | 500 KV HVDC BI-POLE |
|---|---|---|---|---|---|---|---|
| Base Cost | $927,000 | $1,484,000 | $1,298,000 | $2,077,000 | $1,854,000 | $2,967,000 | $1,484,000 |
| **Multipliers** | | | | | | | |
| Conductor | | | | | | | |
| ACSR | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 |
| ACSS | 1.08 | 1.08 | 1.08 | 1.08 | 1.08 | 1.08 | 1.08 |
| HTLS | 3.60 | 3.60 | 3.60 | 3.60 | 3.60 | 3.60 | 3.60 |
| Structure | | | | | | | |
| Lattice | 0.90 | 0.90 | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 |
| Tubular Steel | 1.00 | 1.00 | 1.30 | 1.30 | 1.50 | 1.50 | 1.50 |
| Length | | | | | | | |
| > 10 miles | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 |
| 3-10 miles | 1.20 | 1.20 | 1.20 | 1.20 | 1.20 | 1.20 | 1.20 |
| < 3 miles | 1.50 | 1.50 | 1.50 | 1.50 | 1.50 | 1.50 | 1.50 |
| Age | | | | | | | |
| New | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 |
| Re-conductor | 0.35 | 0.45 | 0.45 | 0.55 | 0.55 | 0.65 | 0.55 |
| Terrain | | | | | | | |
| Desert | 1.05 | 1.05 | 1.05 | 1.05 | 1.05 | 1.05 | 1.05 |
| Scrub / Flat | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 |
| Farmland | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 |
| Forested | 2.25 | 2.25 | 2.25 | 2.25 | 2.25 | 2.25 | 2.25 |
| Rolling Hill (2-8% slope) | 1.40 | 1.40 | 1.40 | 1.40 | 1.40 | 1.40 | 1.40 |
| Mountain (>8% slope) | 1.75 | 1.75 | 1.75 | 1.75 | 1.75 | 1.75 | 1.75 |
| Wetland | 1.20 | 1.20 | 1.20 | 1.20 | 1.20 | 1.20 | 1.20 |
| Suburban | 1.27 | 1.27 | 1.27 | 1.27 | 1.27 | 1.27 | 1.27 |
| Urban | 1.59 | 1.59 | 1.59 | 1.59 | 1.59 | 1.59 | 1.59 |

In addition to the capital cost of equipment for transmission lines, the acquisition of land for ROW was determined based on BLM land values. The land costs are detailed on Table 2-8.

## 4.2 SUBSTATION CAPITAL COSTS

Using the methodology discussed in Section 3.0, Black & Veatch surveyed various substation costs as well as used internal industry knowledge to determine a typical value for substation costs. While industry costs can vary substantially, the Peer Review Group determined that these values are reasonable for projects installed in the WECC region, with the key assumption that the substation would be constructed on flat, barren land.

**Table 4-2 Substation Capital Cost Summary**

| EQUIPMENT | 230 KV SUBSTATION | 345 KV SUBSTATION | 500 KV SUBSTATION |
|---|---|---|---|
| Base Cost (New Substation) | $1,648,000 | $2,060,000 | $2,472,000 |
| Cost Per Line/XFMR Position | $1,442,000 | $2,163,000 | $2,884,000 |
| Ring Bus Multiplier | 1 | 1 | 1 |
| Breaker and a Half Multiplier | 1.5 | 1.5 | 1.5 |
| 500 kV HVDC Converter Station | - | - | $445,000,000 |
| Shunt Reactor ($/MVAR) | $20,000 | $20,000 | $20,000 |
| Series Capacitor ($/MVAR) | $30,000 | $10,000 | $10,000 |
| SVC Cost ($/MVAR) | $85,000 | $85,000 | $85,000 |
| Transformer Cost ($/MVA) | | | |
| 115/230 kV XFMR | $7,000 | - | - |
| 115/345 kV XFMR | - | $10,000 | - |
| 115/500 kV XFMR | - | - | $10,000 |
| 138/230 kV XFMR | $7,000 | - | - |
| 138/345 kV XFMR | - | $10,000 | - |
| 138/500 kV XFMR | - | - | $10,000 |
| 230/345 kV XFMR | | $10,000 | - |
| 230/500 kV XFMR | $11,000 | - | $11,000 |
| 345/500 kV XFMR | - | $13,000 | $13,000 |

Using the above table and the equation below, the capital cost for the substation can be calculated.

**Total Individual Substation Cost =**

[(Substation Base Cost) + (Line/XFMR Position Base Cost) x (# of Line/XFMR Positions) x (RB or BAAH Multiplier) + (XFMR Cost/MVA) x (XFMR MVA Rating) x (# of XFMRs) + (SVC Cost/MVAR) (# MVARs) + (Series Cap. Cost/MVAR) x (# MVARs) + (Shunt Reactor Cost/MVAR) x (# MVARs) + (HVDC Converter Station Cost)]

## 4.3 ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION AND OVERHEAD COSTS

The transmission and substation costs described in Sections 2.0 and 3.0 above are given as "overnight" costs, i.e. the cost if the project could be engineered, procured and constructed overnight without financing or overhead costs. To address this, Black & Veatch developed estimates of Allowance for Funds Used During Construction (AFUDC) and overhead, which could be added to the transmission and substation costs to produce realistic total project cost estimates.

In general, AFUDC is defined as the cost of debt and equity funds used to finance construction projects; overhead is defined as the miscellaneous costs required to maintain an organization but are not directly tied to a specific project, e.g. administrative costs, legal costs, internal management costs, etc. AFUDC and overhead costs are usually estimated as a percentage of transmission and substation costs. It is important to note that different entities (investor-owned utilities, public utilities, independent project developers) use very different definitions of what is included in AFUDC and Overhead costs, and also have widely differing estimates of these costs. Black & Veatch surveyed a number of sources to understand the range of these estimates, and to develop a recommended value which could be used by WECC to reasonably represent all types of project ownership structures. A sampling of AFUDC and overhead costs are shown in Table 4-3 below.

**Table 4-3 Survey of AFUDC and Overhead Costs and Recommended Values**

| | INDEPENDENT DEVELOPER | IOU | PUBLIC UTILITY |
|---|---|---|---|
| Source | B&V Estimate | NV Energy/PacifiCorp | BPA |
| AFUDC Cost | 10.0% | 8.6% | 4.1% |
| Overhead Cost | 10.0% | 6.2% | 23.0% |
| **Recommended Values** | 7.5% (AFUDC) + 10.0% (Overhead) = 17.5% | | |

Based on the collected data, Black & Veatch recommended and the Peer Review Group adopted a value of 7.5% for AFUDC costs and 10.0% for overhead costs, for a total of 17.5%. This 17.5% adder for AFUDC and overhead costs was used in all calculations for this study.

Adding the cost of the transmission calculated in Section 4.1 and the substation costs calculated in Section 4.2 together will result in the total project capital costs prior to AFUDC and overhead. Using the above information, the entire cost of a project can be calculated.

**Total Project Cost =**

[(Total Transmission Capital Cost) + (Total Substation Capital Cost)] x [(AFUDC – 7.5%) + (Overhead – 10%)]

# 5.0 Cost Calculator

After developing the capital cost estimates for transmission and substations described in Section 4.0, Black & Veatch created a cost calculator which incorporated all of the cost estimates for transmission and substations cost components into a single, user-friendly Excel-based tool. The cost calculator is simple but flexible, and can be used to estimate the costs of any hypothetical transmission project and associated substations within the WECC region. The calculator employs the cost formulas for transmission and substations to calculate total project costs (for the entire line length and on a per-mile basis), and is automated to the extent possible to allow for quick estimates. The cost calculator workbook is split into three different sheets, each of which is described below:

- Transmission Cost Calculator
- Substation Cost Calculator
- Cost Totals

## 5.1 TRANSMISSION COST CALCULATOR

A screenshot of the Transmission Cost Calculator sheet of the cost calculator workbook is shown in Figure 5-1 below.

**Black & Veatch Transmission Line Capital Cost Calculator**

| Legend |
|---|
| User Selection |
| Auto-calculated |
| Adjustable Parameter |

| | Selection | Multiplier | Cumulative Cost/Mile |
|---|---|---|---|
| Voltage Class | 500 kV Single Circuit | 1 | $ 1,854,000.00 |
| Conductor Type | | 1 | $ 1,854,000.00 |
| Structure | | 1 | $ 1,854,000.00 |
| Length Category | | 1 | $ 1,854,000.00 |
| New or Re-conductor? | | 1 | $ 1,854,000.00 |
| Terrain Multiplier | | 1.08 | $ 1,998,533.77 |

230 kV Single Circuit
230 kV Double Circuit
345 kV Single Circuit
345 kV Double Circuit
500 kV Single Circuit
500 kV Double Circuit
500 kV HVDC Circuit

| Terrain Type | Miles of Terrain Type | Multiplier | Weighted Miles |
|---|---|---|---|
| Forested | 0.9 | 2.25 | 1.9 |
| Scrubbed/Flat | 189.0 | 1 | 189.0 |
| Wetland | 0.0 | 1.2 | 0.0 |
| Farmland | 0.0 | 1 | 0.0 |
| Desert/Barren Land | 0.9 | 1.05 | 1.0 |
| Urban | 0.0 | 1.59 | 0.0 |
| Rolling Hills (2-8% Slope) | 40.1 | 1.4 | 56.2 |
| Mountain (>8% Slope) | 1.2 | 1.75 | 2.2 |
| Total Miles | 232.1 | | |

| BLM Cost Zone Number | ROW Miles in BLM Zone | $/Acre | $/Mile of ROW | Zone ROW Costs |
|---|---|---|---|---|
| 1 | 20.0 | $ 85.34 | $ 2,068.80 | $ 41,376.00 |
| 2 | 50.0 | $ 170.68 | $ 4,137.60 | $ 206,880.00 |
| 3 | 23.0 | $ 341.45 | $ 8,277.60 | $ 190,384.80 |
| 4 | 10.0 | $ 512.13 | $ 12,415.20 | $ 124,152.00 |
| 5 | 5.0 | $ 682.80 | $ 16,552.80 | $ 82,764.00 |
| 6 | 5.0 | $ 1,024.25 | $ 24,830.40 | $ 124,152.00 |
| 7 | 5.0 | $ 1,707.06 | $ 41,383.20 | $ 206,916.00 |
| 8 | 5.0 | $ 3,414.11 | $ 82,766.40 | $ 413,832.00 |
| 9 | 5.0 | $ 6,828.23 | $ 165,532.80 | $ 827,664.00 |
| 10 | 5.0 | $ 10,242.34 | $ 248,299.20 | $ 1,241,496.00 |
| 11 | 5.0 | $ 17,070.57 | $ 413,832.00 | $ 2,069,160.00 |
| 12 | 5.0 | $ 34,141.14 | $ 827,664.00 | $ 4,138,320.00 |

| AFUDC/Overhead Cost | 17.5% |
|---|---|

| Project Cost Results | Per Mile | Total |
|---|---|---|
| Line Cost | $ 1,998,533.77 | $ 463,873,675.03 |
| ROW Cost | $ 41,649.31 | $ 9,667,096.80 |
| AFUDC Cost | $ 357,032.04 | $ 82,869,635.07 |
| All Costs | $ 2,397,215.12 | $ 556,410,406.90 |

**Figure 5-1 Transmission Cost Calculator Sheet of Cost Calculator Workbook**

On this sheet, the user first selects the basic transmission line characteristics from a series of drop-down menus. The options for each follow the different equipment types and specifications described in Section 2.1. After that, the user must enter information about the line routing. This information consists of the number of miles of line which pass through each terrain type described in Section 2.3, and the number of miles of line which pass through each BLM cost zone described in Section 2.4. These line routing values are not calculated within this sheet—rather, the user must obtain these values by performing a separate Geographic Information System (GIS) analysis.

Once all selections are made and all values are entered, the transmission line, right of way, and AFUDC/overhead costs for the project are automatically calculated at the bottom of the sheet in the "Project Cost Results" section, for the entire line length and on a per-mile basis.

The calculator is also flexible. In addition to the cells highlighted in yellow, which indicate places where the user must select from a drop-down menu or enter a value, a number of cells are highlighted green, to indicate that the values in those cells are parameters that can be adjusted by the user. Adjusting these values allows the user to test the sensitivity of the project cost results to certain parameters. The following are parameters which can be adjusted on this sheet:

- Terrain type multipliers
- AFUDC/overhead cost adder
- Transmission base costs
- Conductor type multipliers
- Structure type multipliers
- Length category multipliers
- New vs. re-conductor multipliers
- Right of way width assumptions
- BLM Zone Land Rental Costs
- Land Tax Rate
- Capitalization Rate

## 5.2 SUBSTATION COST CALCULATOR

A screenshot of the Substation Cost Calculator sheet of the cost calculator workbook is shown in Figure 5-2 below.

| Black & Veatch Substation Capital Cost Calculator | | | | User Selection |
|---|---|---|---|---|
| | | | | Auto-calculated |
| | Selection | Cost Component | Cost | Adjustable Parameter |
| Voltage | 500 kV Substation | Base Cost | $ 2,472,000 | |
| New or Existing Site? | New | Circuit Breakers | $ 17,304,000 | |
| Circuit Breaker Type | Breaker and a Half | 500 kV HVDC Converter | N/A | |
| # of Line/XFMR Positions | 4 | Transformer(s) | $ 11,000,000 | |
| 500-kV HVDC Converter? | No | SVC(s) | $ 10,000,000 | |
| Transformer Type | 230/500 kV XFMR | Shunt Reactor(s) | $ 10,000,000 | |
| MVA Rating Per Transformer | 115/345 kV XFMR<br>115/500 kV XFMR | Series Capacitor(s) | $ 20,000,000 | |
| # of Transformers | 138/230 kV XFMR | AFUDC/Overhead Cost | $ 12,385,800.000 | |
| SVC MVAR Rating | 138/345 kV XFMR<br>138/500 kV XFMR | | | |
| Shunt Reactor MVAR Rating | 230/345 kV XFMR | Total Substation Cost | $ 83,161,800 | |
| Series Capacitor MVAR Rating | 230/500 kV XFMR<br>345/500 kV XFMR | | | |
| AFUDC/Overhead Cost | 17.5% | | | |

**Figure 5-2 Substation Cost Calculator Sheet of Cost Calculator Workbook**

On this sheet, the user selects the basic substation characteristics from a series of drop-down menus, and also enters appropriate values for certain characteristics (e.g. "# of Transformers"), according to the options described in Section 2.1. The cost for each substation component is shown on the right side, the AFUDC/overhead cost is automatically calculated, and the total substation cost is automatically summed at the bottom.

It is important to note that this sheet can be used to calculate costs for only one individual substation at a time. If a particular transmission project involves more than one substation, then information about each substation will need to be entered separately, and the total cost of each individual substation will need to be entered in the empty cells in the Cost Totals sheet of the workbook.

There are also a number of adjustable parameters in this sheet, which are:

- AFUDC/overhead cost adder
- Base substation costs
- Cost per line position
- Line position type multipliers
- HVDC converter station cost
- Shunt reactor cost
- Series capacitor cost
- SVC cost
- Transformer costs

## 5.3 COST TOTALS

A screenshot of the Cost Totals sheet of the cost calculator workbook is shown in Figure 5-3 below.

**Black & Veatch Transmission and Substation Cost Totals**

| Project Cost Results | Per Mile | Total |
|---|---|---|
| Line Cost | $ 1,998,533.77 | $ 463,873,675.03 |
| ROW Cost | $ 41,649.31 | $ 9,667,096.80 |
| Substation #1 | N/A | $ 83,161,800.00 |
| Substation #2 | N/A | $ 50,000,000.00 |
| Substation #3 | N/A | |
| Substation #4 | N/A | |
| Substation #5 | N/A | |
| AFUDC Cost | $ 357,032.04 | $ 106,172,950.07 |
| **All Costs** | **$ 2,397,215.12** | **$ 712,875,521.90** |

| |
|---|
| User Selection |
| Auto-calculated |

**Figure 5-3 Cost Totals Sheet of Cost Calculator Workbook**

On this sheet, the transmission and substation costs calculated on the other two sheets are summed to find the total project cost, for the entire line length and on a per-mile basis. The transmission line and right of way cost data are automatically transferred from the Transmission Cost Calculator sheet. Since it is anticipated that most projects will have multiple associated substations and each individual substation cost must be calculated separately, there are five empty cells in which the user can enter the cost of individual substations from the Substation Cost Calculator sheet. Once the substation costs are entered, the AFUDC and overhead cost is automatically calculated and the total project cost is automatically summed at the bottom.

# 6.0 Scenario Analysis

After creating the cost calculator, Black & Veatch tested it to ensure that it was user-friendly, and more importantly to ensure that the transmission and substation cost assumptions incorporated into the calculator were reasonable when compared to existing and proposed transmission projects. An initial list of over 20 projects was narrowed down to four representative projects which were used to validate Black & Veatch's cost assumptions. To perform this scenario analysis, Black & Veatch obtained the most detailed information possible within the time available about the four real transmission projects, with significant help from WECC staff and other stakeholders; sources included internal utility documents, regulatory filings, and information filed with WECC. The four projects are:

- PacifiCorp: Gateway Central Line (Populus - Terminal Segment)
- NV Energy: One Nevada Line
- Bonneville Power Administration (BPA): McNary – John Day Line
- Xcel Energy: Comanche – Daniels Park Line

The map in Figure 6-1 below shows the location of each of the four selected projects. They are spread throughout the WECC region, each in a different utility territory, and they cover the full range of terrain types as well as both the 345-kV and 500-kV voltage classes.

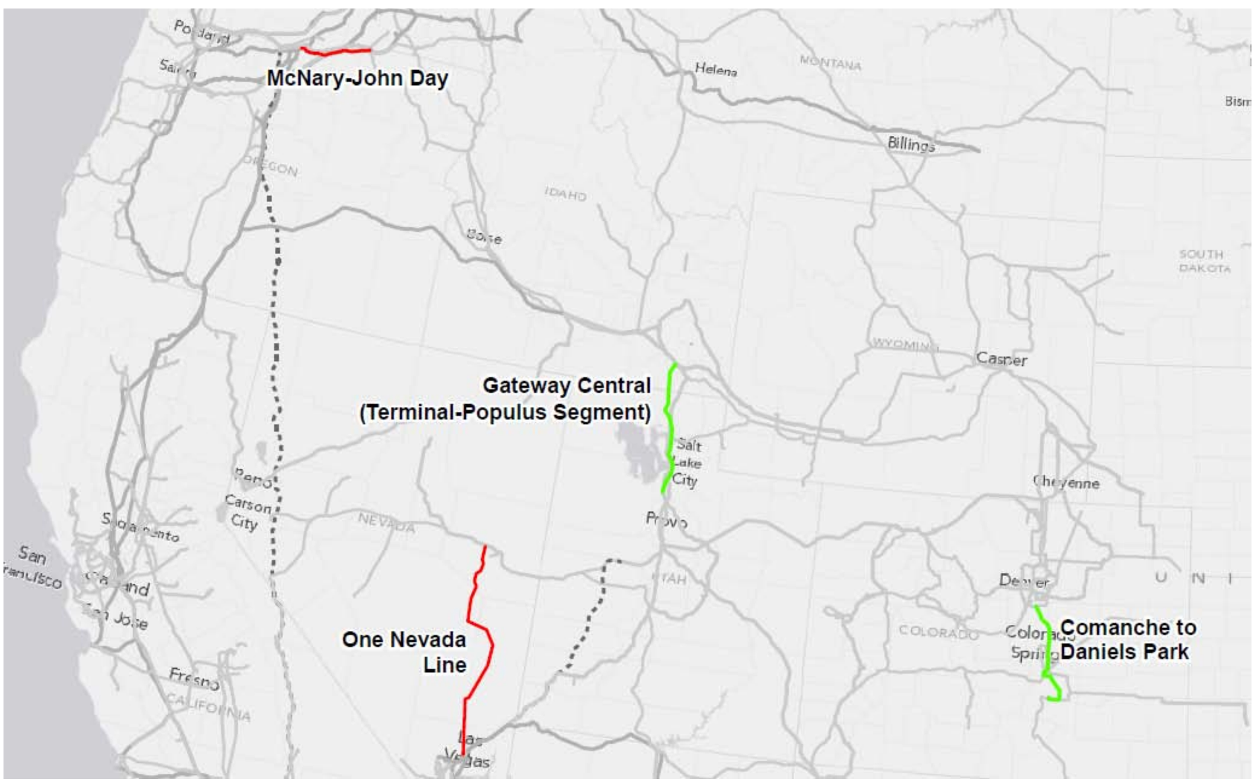


**Figure 6-1 Map of the Four Transmission Projects Selected for Scenario Analysis**

For each project, once detailed information had been obtained about project characteristics and project costs, Black & Veatch entered information in the cost calculator to simulate the real transmission project as closely as possible. Values were also entered for the number of miles of each terrain type, and the number of miles in each BLM cost zone, based on a separate GIS analysis performed outside of the cost calculator. Table 6-1 below shows the project characteristics used to simulate each project, and Table 6-2 shows the number of miles in each terrain type for each project.

### Table 6-1 Transmission Project Characteristics Used in Scenario Analysis

| PROJECT | VOLTAGE | LENGTH (MILES) | CONDUCTOR TYPE | STRUCTURE | NEW OR RE-CONDUCTOR |
|---|---|---|---|---|---|
| PacifiCorp - Gateway Central (Populus-Terminal) | 345-kV Double Circuit | 135 | ACSR | Tubular Steel | New |
| NV Energy - One Nevada | 500-kV Single Circuit | 235 | ACSR | Lattice | New |
| BPA – McNary-John Day | 500-kV Single Circuit | 79 | ACSR | Lattice | New |
| Xcel Energy – Comanche-Daniels Park | 345-kV Double Circuit | 125 | ACSR | Tubular Steel | Re-conductor |

**Note: This is based on the information available to Black & Veatch at the time of this analysis, and may not reflect actual project characteristics in all cases.**

### Table 6-2 Miles in Each Terrain Type for Transmission Projects in Scenario Analysis

| PROJECT | FORESTED | SCRUB/ FLAT | WETLAND | FARMLAND | DESERT/ BARREN LAND | URBAN | ROLLING HILL (2-8% SLOPE) | MOUNTAIN (>8% SLOPE) |
|---|---|---|---|---|---|---|---|---|
| PacifiCorp - Gateway Central (Populus-Terminal) | 0.3 | 49.3 | 0.6 | 29.8 | 0.5 | 23.7 | 17.7 | 11.7 |
| NV Energy - One Nevada | 0.9 | 189.0 | 0.0 | 0.0 | 0.9 | 0.0 | 40.1 | 1.2 |
| BPA – McNary-John Day | 0.0 | 31.5 | 0.0 | 28.1 | 0.0 | 2.4 | 9.1 | 0.7 |
| Xcel Energy – Comanche-Daniels Park | 6.1 | 111.6 | 0.0 | 3.1 | 0.0 | 0.2 | 0.0 | 0.0 |

**Note: These values are based on Black & Veatch GIS analysis, and may not reflect the actual number of miles in each terrain type for each project.**

For each project scenario, the analysis output from the calculator was the project transmission line costs, ROW costs, substation costs, and AFUDC/overhead costs. These costs were then summed to find the total project cost, and this estimated project cost was compared to the total cost of the actual project. Black & Veatch did not attempt to match the actual project costs component-by-component (e.g. estimated right of way costs were not intended or expected to closely match actual right of way costs)—rather, Black & Veatch attempted to match the estimated total project cost to the actual total project cost. This was because for some projects cost data was not available at this detailed level, and also because projects often differ in what is included in each cost component. Thus, the total project cost was considered the key metric for testing the cost calculator.

## 6.1 PACIFICORP: GATEWAY CENTRAL LINE (POPULUS – TERMINAL SEGMENT)

This 345-kV double circuit line segment is part of PacifiCorp's Gateway Central project, centered in Utah, and extends from the new Populus substation in southeastern Idaho to the existing Terminal substation in the Salt Lake City area. It was completed in 2010. The most notable characteristic of this line is that it crosses a significant amount of mountainous terrain and urban and suburban terrain around Salt Lake City, which the other three lines do not. Table 6-3 shows the results of the scenario analysis.

**Table 6-3 Scenario Analysis Results for PacifiCorp: Gateway Central Line**

| COST COMPONENT | ACTUAL COST | B&V ESTIMATED COST | DIFFERENCE (ACTUAL – ESTIMATED COST) |
|---|---|---|---|
| Line Cost (including wires, poles, etc.) | $ 498,439,614 | $ 443,071,335 | 11% |
| ROW Cost | $ 70,183,253 | $ 2,774,370 | 96% |
| Substation Cost | $ 126,054,613 | $ 187,689,000 | - 49% |
| AFUDC/Overhead Cost | $ 122,152,660 | $ 110,868,573 | 9% |
| **Total Cost** | **$ 816,830,140** | **$ 744,403,278** | **9%** |

**Note: These results are not meant as a comment on the actual project costs listed; they are simply meant to provide a test of the cost calculator developed by Black & Veatch.**

The estimated and actual project costs match within 9%, which indicates that the cost calculator provides a relatively close approximation of actual project costs in this case. Black & Veatch was able to obtain detailed cost information for this project, which provides more confidence in the accuracy of the estimate.

## 6.2 NV ENERGY: ONE NEVADA LINE

This 500-kV single circuit project extends from the Robinson Summit substation in northern Nevada to the Harry Allen substation near Las Vegas in southern Nevada; its purpose is to connect the two different grids operated by NV Energy's subsidiaries Sierra Pacific Power Company and Nevada Power Company. It is currently under construction and is expected to be completed in 2013. The most notable characteristic of this line is that it crosses land that is almost entirely uninhabited and either flat or rolling hill terrain, while the other three lines cross land that is mostly inhabited. Table 6-4 shows the results of the scenario analysis.

**Table 6-4 Scenario Analysis Results for NV Energy: One Nevada Line**

| COST COMPONENT | ACTUAL COST | B&V ESTIMATED COST | DIFFERENCE (ACTUAL – ESTIMATED COST) |
|---|---|---|---|
| Line Cost (including wires, poles, etc.) | Unknown | $ 463,873,675 | N/A |
| ROW Cost | Unknown | $ 2,226,191 | N/A |
| Substation Cost | Unknown | $ 131,404,000 | N/A |
| AFUDC/Overhead Cost | Unknown | $ 104,563,176 | N/A |
| **Total Cost** | **$ 509,710,592** | **$ 702,067,042** | **-38%** |
| **Note: These results are not meant as a comment on the actual project costs listed; they are simply meant to provide a test of the cost calculator developed by Black & Veatch.** | | | |

The estimated and actual project costs match within 38%. The larger difference between estimated and actual costs for this project is likely the result of the fact that Black & Veatch was not able to obtain either detailed cost data or complete information about the technical characteristics of the line. However, it was discovered that a novel type of tower structure was used, which does not match the generic type of lattice tower that was assumed in this analysis.

## 6.3 BONNEVILLE POWER ADMINISTRATION (BPA): MCNARY – JOHN DAY LINE

This 500-kV single circuit project is part of a series of upgrades and new lines throughout BPA's territory, and extends from the existing McNary substation to the existing John Day substation along the southern side of the Columbia River in northern Oregon. It was completed in early 2012. The most notable characteristic of this line is that it crosses a significant amount of farmland—the terrain is mostly flat. Table 6-5 shows the results of the scenario analysis.

**Table 6-5 Scenario Analysis Results for BPA: McNary – John Day Line**

| COST COMPONENT | ACTUAL COST | B&V ESTIMATED COST | DIFFERENCE (ACTUAL – ESTIMATED COST) |
|---|---|---|---|
| Line Cost (including wires, poles, etc.) | $126,814,842 | $ 143,288,287 | -13% |
| ROW Cost | Unknown | $ 265,993 | N/A |
| Substation Cost | $17,484,816 | $ 14,420,000 | 18% |
| AFUDC/Overhead Cost | $39,105,207 | $ 27,645,499 | 29% |
| **Total Cost** | **$183,404,865** | **$ 185,619,780** | **-1%** |

**Note: These results are not meant as a comment on the actual project costs listed; they are simply meant to provide a test of the cost calculator developed by Black & Veatch.**

The estimated and actual project costs match within 1%, which indicates that the cost calculator provides a very close approximation of actual project costs in this case. Black & Veatch was able to obtain detailed cost and technical information about the project, which provides confidence about the accuracy of the estimate.

## 6.4 XCEL ENERGY: COMANCHE – DANIELS PARK LINE

This 345-kV double circuit project extends from the substation at the Comanche coal plant near Pueblo, CO to the Daniels Park substation in the southern part of the Denver metro area. It was completed in 2009. The most notable characteristic of this project is that it mostly consisted of re-conductoring existing lines, re-energizing them at a higher voltage, and constructing some new line parallel to existing lines on existing right of way. Table 6-6 shows the results of the scenario analysis.

**Table 6-6 Scenario Analysis Results for Xcel Energy: Comanche – Daniels Park Line**

| COST COMPONENT | ACTUAL COST | B&V ESTIMATED COST | DIFFERENCE (ACTUAL – ESTIMATED COST) |
|---|---|---|---|
| Line Cost (including wires, poles, etc.) | Unknown | $ 191,146,222 | N/A |
| ROW Cost | Unknown | $ 1,188,954 | N/A |
| Substation Cost | Unknown | $ 12,978,000 | N/A |
| AFUDC/Overhead Cost | Unknown | $ 35,929,805 | N/A |
| **Total Cost** | **$ 151,950,000** | **$ 241,242,982** | **-59%** |

**Note: These results are not meant as a comment on the actual project costs listed; they are simply meant to provide a test of the cost calculator developed by Black & Veatch.**

The estimated and actual project costs match within 59%. The larger difference between estimated and actual costs for this project is likely the result of the fact that Black & Veatch was not able to obtain either detailed cost data or complete information about the technical characteristics of the line. Specifically, the estimated cost may be higher than the actual cost because the project involved less line construction or substation construction than Black & Veatch assumed.

## 6.5 SUMMARY

The results of the scenario analysis for all four transmission projects are summarized in Table 6-7 below.

**Table 6-7 Summary of Scenario Analysis Results for All Four Projects**

| COST COMPONENT | ACTUAL COST | B&V ESTIMATED COST | DIFFERENCE (ACTUAL – ESTIMATED COST) |
|---|---|---|---|
| PacifiCorp - Gateway Central (Populus-Terminal) | $ 816,830,140 | $ 744,403,278 | 9% |
| NV Energy - One Nevada | $ 509,710,592 | $ 702,067,042 | -38% |
| BPA – McNary-John Day | $183,404,865 | $ 185,619,780 | -1% |
| Xcel Energy – Comanche-Daniels Park | $ 151,950,000 | $ 241,242,982 | -59% |

**Note: These results are not meant as a comment on the actual project costs listed; they are simply meant to provide a test of the cost calculator developed by Black & Veatch.**

These results show that the cost calculator provided very good estimates for the PacifiCorp and BPA projects (within 9% and 1%, respectively), and reasonable, though not perfect, estimates for the NV Energy and Xcel Energy projects (within 38% and 59%, respectively). The two projects for which Black & Veatch obtained the most detailed cost and technical information—PacifiCorp and BPA—were the ones for which the estimates most closely matched the actual costs. This increases confidence that with a sufficient level of information, the cost calculator provides a good approximation of the costs of a real transmission project. Thus, the capital cost validation exercise described in this section shows that Black & Veatch's transmission and substation cost assumptions are appropriate when compared to actual projects.

In addition, it should be noted that the cost calculator will be used by WECC to assess the relative costs of different possible transmission projects in the Western Interconnection, i.e. it will be used to compare potential projects rather than to estimate exactly how much a single actual project will cost. Given the high degree of variability in these costs, the cost calculator provides a good estimate of the relative costs of developing transmission projects throughout the WECC region, and will serve the purpose for which it was intended.

# 7.0 Discussion of Stakeholder Comments

Black & Veatch received a number of formal comments from stakeholders after the final presentation of its recommendations on capital costs for WECC. All comments were considered and addressed to the extent possible. The comments and responses are summarized in Table 7-1 below, and the name and affiliation of each commenter is provided.

**Table 7-1 Summary of Stakeholder Comments and Responses**

| COMMENTER NAME AND AFFILIATION | COMMENT | BLACK & VEATCH RESPONSE |
|---|---|---|
| Eric John, ABB Inc. | The costs stated for series capacitors (SC) far exceed the market levels that ABB has seen as the market leader for this product. Firm prices for EPC SC banks range from $10,000/MVAr to $30,000/MVAr. The higher range applies to banks 300 MVAr and less. The lower part of the range applies in cases where for banks larger than 300 MVAr or in cases where multiple banks are to be supplied as part of a reactive compensation program. | Black & Veatch discussed this in detail with ABB, and $50,000/MVAr was found to be too high. ABB indicated that there are significant fixed costs involved in sizing a Series Capacitor, and based on their experience, the typical range indicated that the smaller SC's were around $30,000/MVAr, and larger SC's were around $10,000/MVAr, assuming turnkey installation with rough-grading complete. Black & Veatch has updated the costs to reflect this: $30,000/MVAr (230 kV), $10,000/MVAr (345 kV and 500 kV). |
| Eric John, ABB Inc. | Suggest an additional comment about the scope for a "Turnkey" SC installation. The above $/MVAr figures assume a site has been rough-graded and access to a source of medium voltage auxiliary power. | Black & Veatch has documented this assumption in the report. |
| Eric John, ABB Inc. | The costs stated for series capacitors (SVC) are reasonable. However, ABB recommends that the values be stated as a range from $60,000/MVAr to $85,000/MVAr. | Black & Veatch appreciates that there are ranges for these costs; however, for the purpose of this methodology, it was decided to use one value. As the SVC sizes are arbitrary in this methodology, Black & Veatch assumed the more conservative value of $85,000/MVAr. |