Basin Creek Dispatch Study

Analyzing the Benefits of a Co-Optimized Dispatch Procedure

March 3, 2016

Energy+Environmental Economics

Basin Creek Dispatch Study

Analyzing the Benefits of a Co-Optimized Dispatch Procedure

March 3, 2016

Energy and Environmental Economics, Inc.
101 Montgomery Street, Suite 1600
San Francisco, CA 94104
415.391.5100
www.ethree.com

Table of Contents

Executive Summary

The following report presents the results of an analysis conducted by Energy and Environmental Economics, Inc., at the request of NorthWestern Energy that examines whether NorthWestern Energy has been efficiently dispatching the Basin Creek power plant and whether NorthWestern Energy could lower customer costs through a jointly optimized dispatch of the Basin Creek and Dave Gates Generating Station resources to satisfy energy, regulation, and reserve requirements for the NorthWestern system.

Using data from operations during 2013, Energy and Environmental Economics, Inc. concludes that:

+ **Existing dispatch of the Basin Creek units is consistent with the Energy Supply Function's directive to minimize customer costs**
+ **Relaxing restrictions on the products that Basin Creek and the Dave Gates Generating Station can provide will change the overall dispatch but has little effect on the total cost**
+ **Lack of perfect information and barriers to communication may limit NWE's ability to realize cost savings resulting from relaxed dispatch procedures**

1 Background

1.1 Study Motivation and Approach

NorthWestern Energy ("NWE") has asked Energy and Environmental Economics, Inc. ("E3") to evaluate the current and potential future dispatch procedures for the Basin Creek power plant. Basin Creek is a 52 MW gas-fired plant dispatched by NWE's Energy Supply unit, under a power supply agreement with Basin Creek Equity Partners approved by the Public Service Commission of Montana ("MPSC") in Docket D2004.3.45, Order No. 6557c. The Basin Creek plant, consisting of nine reciprocating engines, currently provides 17 megawatts ("MW") of non-spinning reserves from three turbines in all operating hours, while the remaining six engines are available to displace market energy purchases during periods when wholesale energy prices exceed the variable cost of dispatching the Basin Creek units.

Along with Basin Creek (and other resources not relevant to the current analysis), NWE owns and operates the Dave Gates Generating Station ("DGGS") at Mill Creek. DGGS is a 150-MW facility consisting of three 50 MW combustion turbines that provides within-hour regulation service required by NWE to fulfill its role as the transmission system balancing authority.

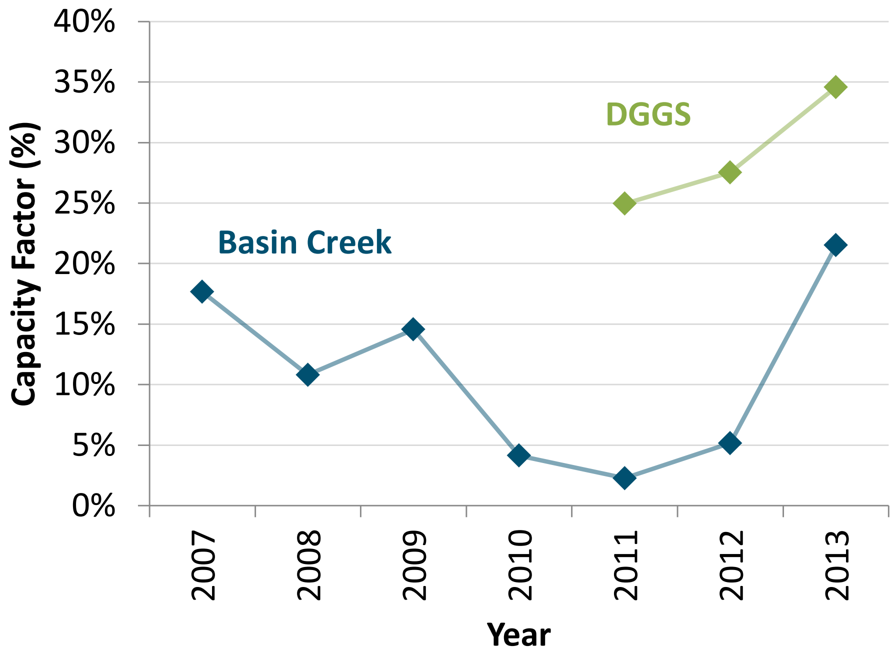
While DGGS is scheduled and dispatched by NWE's Transmission Function, dispatch decisions for the Basin Creek facility are made by the Energy Supply

Function in the interests of keeping these two entities “functionally separate” in accordance with FERC Order 889 (p. 53). Thus, decisions regarding the manner in which DGGS is dispatched to meet within-hour balancing needs have historically been made independent of decisions regarding the Basin Creek units. Conversely, decisions regarding Basin Creek’s ability to provide energy and other ancillary services have been made independent of the DGGS dispatch.

In 2011, NWE filed an “Electricity Supply Resource Procurement Plan” with the MPSC under Docket N2011.12.96, describing the resources which NWE would use to meet its obligations as the default electricity supplier over the 2012-2014 timeframe. This document indicated that the Basin Creek units were providing, on average, 2 MW of generation to NWE’s system out of their 52 MW capacity, a capacity factor of roughly 4%. Though the capacity factor has increased in recent years (shown in Figure 1 below), the plant is still operating at a capacity factor of less than 25%.

This low capacity factor, along with Basin Creek’s relatively low heat rate compared to DGGS, prompted concerns from the MPSC that NWE was not efficiently dispatching its generating resources. As a result, the MPSC called for NWE to conduct additional analysis in order to determine the potential benefits of allowing DGGS to operate as a “flexible retail supply resource” capable of providing both energy and ancillary services (see Docket N2011.12.96, *Written Comments Identifying Concerns Regarding NorthWestern Energy’s Compliance with ARM 38.5.8201-8229,* ¶26). This request was formalized in Docket D2012.5.49 Order 7219h, which directed NWE to verify that it was fully utilizing Basin Creek’s capabilities and determine whether allowing Basin Creek to provide transmission or intra-hour regulation services and DGGS to provide reserves could reduce the cost of meeting NWE's energy, regulation, and reserve needs.

Figure 1. Annual Capacity Factor



In 2014, NWE retained Energy and Environmental Economics, Inc. ("E3") to conduct the requested analysis. The analysis, results of which are presented in this report, consisted of two phases: (1) establish a working model for the existing dispatch procedures that accurately reflects Basin Creek operations in a historical test year to review the Energy Supply Function's past dispatch of the plant, and (2) assess the impact of dispatch procedures focused on using both Basin Creek *and* DGGS to meet NWE's energy supply, reliability, and reserve needs on NWE's overall generator dispatch and the total cost of providing electrical service.

1.2 Current Operations

As mentioned above, the plants being analyzed here (Basin Creek and DGGS) are operated by separate and independent departments of NWE. The "functional separation" of operations between the Transmission and Energy Supply Functions is NWE's attempt to comply with FERC Order 889, which calls for public utilities "to implement standards of conduct to functionally separate transmission and wholesale power merchant functions" (p. 1). For the DGGS and Basin Creek plants, the functional separation of these departments means that Basin Creek is scheduled hourly and the Energy Supply Function does not attempt any mid-hour dispatches to correct imbalances in their scheduled generation, while the Transmission Function does not control Basin Creek as a resource available to help them integrate intermittent generation from wind resources (Docket D2012.5.49, Order 7219h, *Concurring Opinion of Commissioner Travis Kavulla,* p. 36).

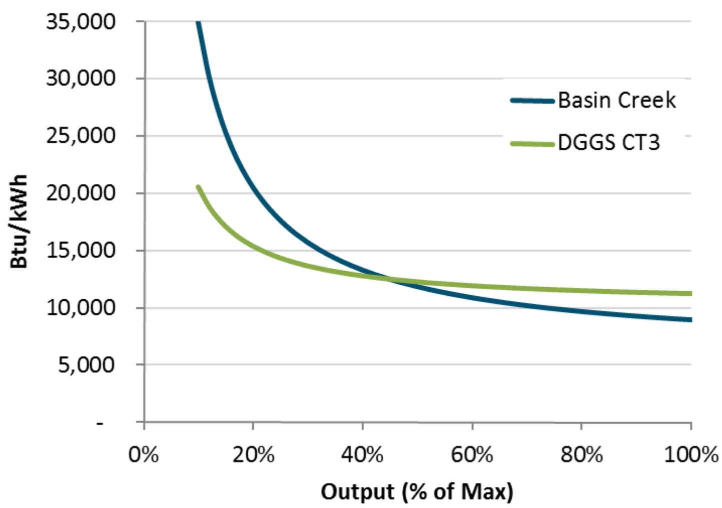
Kevin Markovich, in his testimony in docket D2012.5.49, describes how this functional separation between the Transmission and Energy Supply arms prevents Basin Creek (controlled by the Energy Supply Function) from being dispatched as a regulation resource: "[a]ny efforts by NWE Energy Supply to help in balancing the control area must be done with complete knowledge of NWE transmission and not done independently so that actions being taken are helping rather than hindering the cause" (KJM-5).

1.2.1 BASIN CREEK PLANT

The Basin Creek plant, approved by the Commission in 2004, is currently utilized by the Energy Supply function of NWE to provide non-spinning reserves in all hours (three generating units totaling 17 MW) while the remaining generation units are dispatched against the wholesale energy market during periods when the price is high enough to justify the production cost of these units.

This dispatch procedure has led to a relatively low capacity factor for the Basin Creek plants. In its 2011 Procurement Plan, NWE calculated the amount of energy that Basin Creek can reliably provide to the portfolio at 2 aMW, representing a capacity factor of 3.8% (5.8% if the units held as non-spinning reserves are excluded). Though the usage of Basin Creek has increased in recent years (see Figure 1 above), the Basin Creek capacity factor remains lower than that for DGGS, despite Basin Creek's higher fuel efficiency (lower heat rate) when its reciprocating engines are dispatched at or near their full capacity. Figure 2 compares the efficiencies of the two plants across their operating ranges.

Figure 2. Average Heat Rates by Output Level, Basin Creek and DGGS CT3



1.2.2 DAVE GATES GENERATING STATION

The Dave Gates Generating Station is a 150 MW station consisting of three generating units, each containing two combustion turbines ("CTs") connected to a single generators. DGGS is owned by NWE and dispatched by the Transmission Function to provide within-hour balancing service to meet NWE's obligations as a balancing authority. It operates with a minimum turndown capacity of 7 aMW (average megawatts), which qualifies as a firm resource eligible to help NWE meet its capacity reserve requirements.

DGGS was approved by the MPSC in 2009 (Docket D2008.8.95, Order 6943a) in order to reduce NWE's reliance on contracts with other utilities to provide regulation services to its transmission system. As part of this approval, however, the MPSC indicated that they would "hold NWE to high standards with regard to prudently using the resource as a part of a comprehensive strategy for providing high quality, reliable service at the lowest possible long-term total cost" (Order 6943a, pp. 48-49).

As Casey Johnston explains in his testimony in Docket D2012.5.49, "[o]ne of the NERC requirements with which NWE is obligated to comply is to balance load and supply" (CEJ-4) in its balancing area, which the Transmission Function of NWE achieves by dispatching DGGS against the BA Area Control Error.

2 Methodology

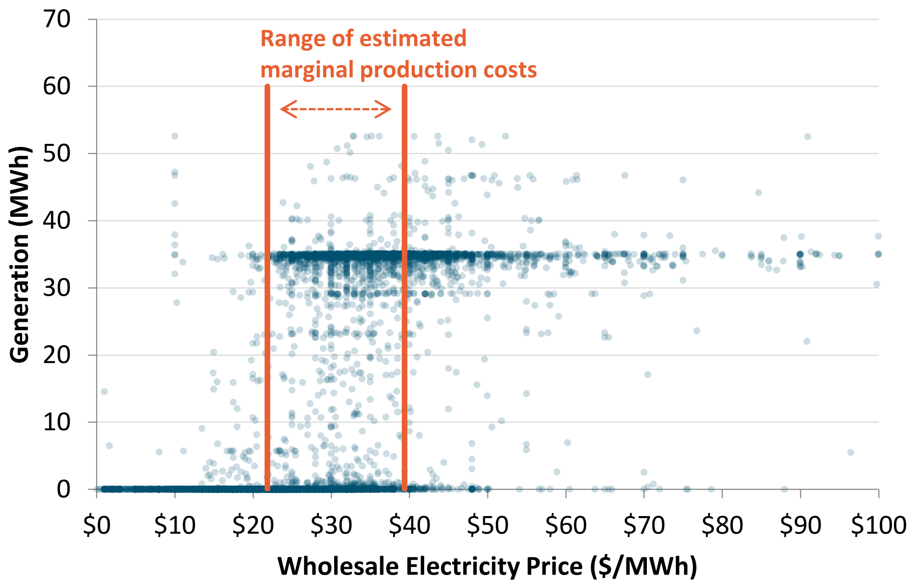
In order to analyze NWE's utilization of the Basin Creek units, E3 conducted an analysis in two parts: (1) an evaluation of the current dispatch to establish relevant decision parameters and assess existing dispatch procedures and (2) modeling an optimized dispatch for Basin Creek and DGGS under the assumption that each of these plants is capable of providing energy, regulation, and reserve services to NWE's system.

Information for these analyses was provided by NWE and collected from other publically available sources where necessary (i.e. EIA, EPA data on Basin Creek emissions and heat rates). All data is taken from 2013.

2.1 Phase 1 – Evaluating Basin Creek's Current Dispatch

To evaluate the current dispatch of Basin Creek, we first examine the relationship between hourly wholesale electricity prices and Basin Creek generation in 2013. Basin Creek generally did not operate when wholesale electricity prices were lower than its marginal production cost, and generation levels increased as prices rose above marginal cost, as shown in Figure 3 below.

Figure 3. 2013 Basin Creek Generation and Wholesale Electricity Price Patterns

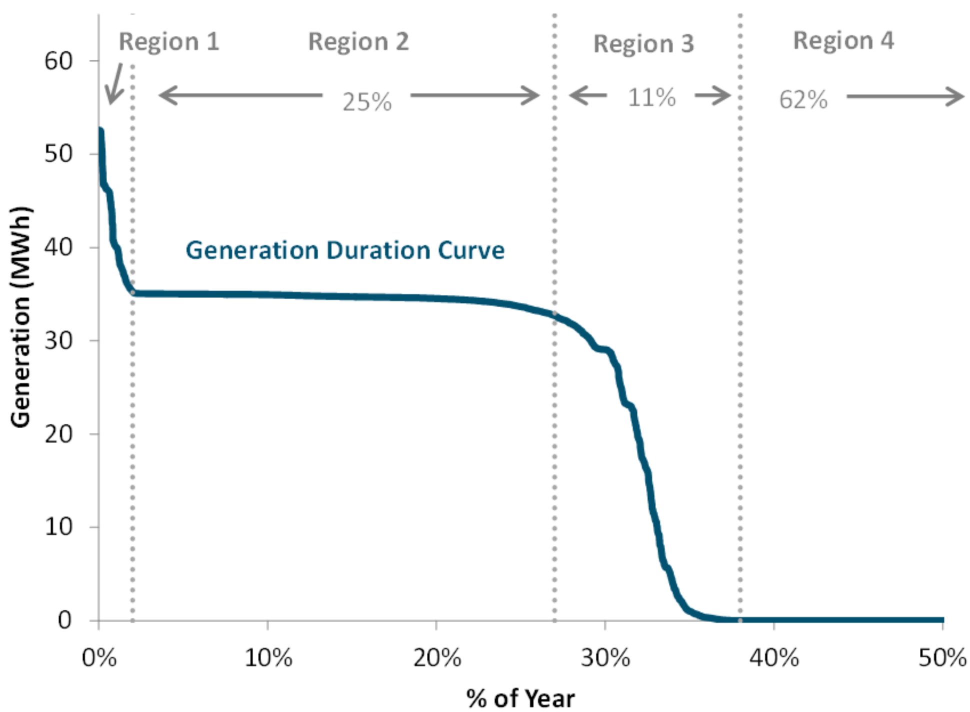


Note: hourly wholesale electricity price is the quantity-weighted average of transactions for that hour.

While Basin Creek has a nameplate capacity of 52 MW, the 2013 operations shown above indicate that the plant will generally be idle (i.e. generating 0 MW) during periods of low prices and outputting about 35 MW during periods when prices are high enough to justify the variable costs of the dispatch. This reflects NWE's current deployment of the Basin Creek plant, in which three of the plant's nine engines (totaling 17 MW) are held as contingency reserves. This chart indicates that Basin Creek was generally shut down when prices fell below the lower end of the marginal production cost range, and all units not held in reserve were generating when the average hourly price climbed above $40 / MWh.

Examining the output of the Basin Creek units over the course of the year (shown in Figure 4 below), operations can generally be characterized as falling into one of four regions: (1) all engines (including those earmarked for non-spinning reserves) are generating and producing energy, comprising about 2% of the year; (2) six engines are fully loaded, outputting roughly 35 MW, while three engines are held as non-spinning contingency reserves; (3) transient ramping or partial load operations, in which up to six of the generators are operational but not at their fully loaded capacity; and (4) shutdown conditions, where none of the generators are active (though three continue to act as non-spinning reserves).

Figure 4. Generation duration curve for Basin Creek



The operations shown above for Basin Creek include the hours in which units were down for planned (216 hours) or forced (682 hours) outages. Overall, the Basin Creek units operated during 21.8% of all hours and had a combined 21.5% capacity factor during 2013.

To generate a model able to accurately reflect Basin Creek's 2013 operating profile, E3 started with 2013 data on NWE's natural gas and wholesale electricity prices and developed a simple dispatch model based on the comparison between the marginal production cost at Basin Creek and the market price that NWE would receive selling Basin Creek's output into the wholesale electricity market.

2.1.1 NATURAL GAS PRICES – SOURCE AND DATA ISSUES

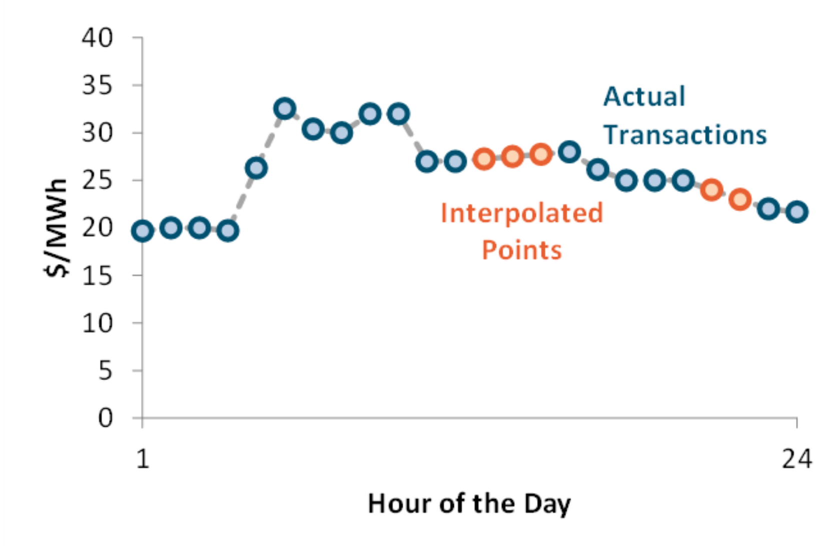
NWE provided natural gas price data for operations at the Basin Creek plant for the months of March to December. The Basin Creek generators were assumed to be price-taking gas consumers with access to as much natural gas as needed to achieve the dispatch dictated by the economic model. If NWE natural gas purchase data was unavailable, E3 used daily natural gas prices from the AECO price hub (in Alberta, Canada) for this period.

2.1.2 WHOLESALE ELECTRICITY PRICES – SOURCES AND DATA ISSUES

Like the natural gas data described above, price data for wholesale electricity sales was taken from actual transactions performed by NWE over the period of interest when possible. NWE provided an hourly accounting of their wholesale electricity transactions over the course of the year, including the quantities purchased or sold in each hour and the prices paid or received in each transaction. For those hours in which multiple transactions were conducted at varying prices, E3 calculated the hourly price as the quantity-weighted average price in that hour.

This methodology provided pricing data for 85% (7,482) of hours throughout the year, but NWE did not engage in any market transactions in the remaining 15% of hours (1,278). For these hours, prices were calculated by interpolation between the nearest data points with available data, as shown in Figure 5 below.

Figure 5. Accounting for Missing Electricity Price Data (Jan. 4, 2013)



2.1.3 NORTHWESTERN ENERGY RESERVE REQUIREMENTS

Based on NWE's directions, E3 assumed that NWE required 15 MW of Non-Spinning and Spinning contingency reserves in each hour of the year. While the spinning reserves were always purchased from the market, non-spinning reserves could either be provided by the Basin Creek generators or purchased through contracts with other nearby electricity agencies, depending on the relative cost. The cost of purchasing these reserves is based on existing contracts for non-spinning reserves between NWE and other wholesale electricity sellers or traders in the area (Powerex and Avista).

2.1.4 BASIN CREEK OPERATING ASSUMPTIONS

NWE also provided E3 with the details of Basin Creek's operational constraints and performance characteristics for use in calculating the production cost to be compared against the wholesale market price. The following parameters were used in the analysis:

- **Heat Rate**: A net heat rate of 9,071 Btu / kWh (HHV) was used to calculate required gas burn in all hours
- **Variable Operations & Maintenance ("VO&M")**: VO&M costs were fixed at $4.63 / MWh based on a cost of $26.31 per engine-hour over 17,188 hours, allocated across 97,748 MWh
- **No minimum load or inter-hour ramping constraints**
- **Air Quality Permit Limitations:** Basin Creek is allowed a total of 34,200 engine run-hours per year, equivalent to running all 9 of its reciprocating engines for 3,800 hours per year
- **Outages:** Actual 2013 available capacity at Basin Creek (provided by NWE) was used in each hour
- **Hourly Energy / Reserves Requirement** - In each hour, the Basin Creek facility and market purchases were assumed to provide 52 MW of wholesale energy, 15 MW of spinning reserves (purchased from the market), and 15 MW of non-spinning reserves (provided by Basin Creek unless the Basin Creek units were unavailable)

2.1.5 MODELING HOURLY DISPATCH

The dispatch of the Basin Creek units was modeled by comparing the production cost in each hour (consisting of fuel and variable O&M costs) to the revenue the generators could realize in that hour by selling electricity in the wholesale market. In hours where generators were available (i.e. not undergoing any maintenance) and the wholesale market price exceeded the variable cost of production, the Basin Creek units not tagged as non-spinning reserves generate at their full capacity and sell this power into the market.

2.2 Phase 2 – Modeling a jointly optimized dispatch of Basin Creek and DGGS

The second component of the analysis performed by E3 was an analysis of the potential cost savings that NWE could realize by relaxing the functional separation between the Transmission and Energy Services Functions of NWE and allowing them to jointly dispatch Basin Creek and DGGS, as well as purchase energy and reserves on the wholesale market, to meet their energy, regulation, and reserve needs.

As mentioned above, the ability to provide balancing services with Basin Creek instead of DGGS could lead to cost savings through Basin Creek's relatively low heat rate, though this efficiency advantage relies on the Basin Creek units being dispatched at or near their full capacity. Freeing up the relatively efficient Basin Creek units to provide these services while letting the less efficient DGGS units act as non-spinning reserves could lower the natural gas consumption required to meet NWE's supply needs and / or displace some additional market purchases.

The following sections describe the assumptions made for this part of the analysis, with a particular focus on those areas where these assumptions differed from the analysis in Phase 1.

2.2.1 NATURAL GAS AND WHOLESALE ENERGY PRICES

In Phase 2, E3 used the same assumptions for natural gas and energy prices, including the same methods for filling in gaps in the data, as used in Phase 1.

2.2.2 GENERATOR AVAILABILITY IN THE BASE AND ALTERNATIVE CASES

As the goal of the Phase 2 analysis is to determine whether allowing NWE to coordinate the dispatch of the Basin Creek and DGGS plants to jointly meet the hourly energy, regulation, and reserve needs of the system could result in cost savings relative to the status quo, E3 modeled two separate dispatch procedures: (1) a “Base Case” dispatch procedure, in which Basin Creek can dispatch six engines (35 MW) for sale into the energy market while three engines (17 MW) are held as non-spinning reserves, while DGGS provides energy and regulation services only, and (2) an “Alternative Case” dispatch procedure, in which three units of Basin Creek (17 MW) and all three DGGS units (150 MW) can provide energy, regulation, or non-spinning reserves, while the remaining six Basin Creek engines can provide either energy or non-spinning reserves (but not regulation). In both of these cases, market purchases can only be used to meet energy requirements; there is no modeled ability for market purchases to provide non-spinning reserves.

Figure 6 below shows a visual comparison of the products each individual unit can provide in the two cases, where green indicates that the unit is eligible to provide that service while red indicates that it is not.

As a modeling assumption, E3 limited the number of Basin Creek engines eligible to provide regulation to three due to the air quality permit issues that limit Basin Creek's total runtime over the year. If E3 had assumed that all nine Basin Creek turbines were available to produce regulation services in every hour of the year, the model would always select Basin Creek to provide regulation down services over DGGS due to the lower heat rate and VO&M costs at Basin Creek. This regulation dispatch would then either crowd out economic dispatch for energy service in hours with high wholesale energy prices (increasing the total cost) or need to be screened out in post-processing.

Figure 6. Unit Eligibility by Case and Category

Resource		Base Dispatch			Alternative Dispatch		
Plant	**Unit**	**Energy**	**Regulation**	**Non-Spin**	**Energy**	**Regulation**	**Non-Spin**
Basin Creek	Engine 1						
	Engine 2						
	Engine 3						
	Engine 4						
	Engine 5						
	Engine 6						
	Engine 7						
	Engine 8						
	Engine 9						
Dave Gates Generating Station	Unit 1						
	Unit 2						
	Unit 3						
Wholesale Market	Energy						

2.2.3 NORTHWEST ENERGY RESERVE REQUIREMENTS

In the Phase 2 analysis, E3 modified the hourly reserve requirements to reflect (1) the total energy, regulation, and reserves to be provided by the combination of DGGS, Basin Creek, and wholesale market purchases (as opposed to just Basin Creek and wholesale market purchases, as modeled in Phase 1); and (2) the fact that neither Basin Creek nor DGGS typically provide spinning reserves, as NWE opts to procure these from wholesale market purchases. As a result, the

Phase 2 analysis optimizes to provide the following products and amounts in each hour from the available resources:

- **Energy:** 200 MW in each hour
- **Regulation Up:** at least 40 MW in each hour
- **Regulation Down:** at least 40 MW in each hour
- **Spinning Reserves:** None[1]
- **Non-Spinning Reserves:** at least 15 MW in each hour

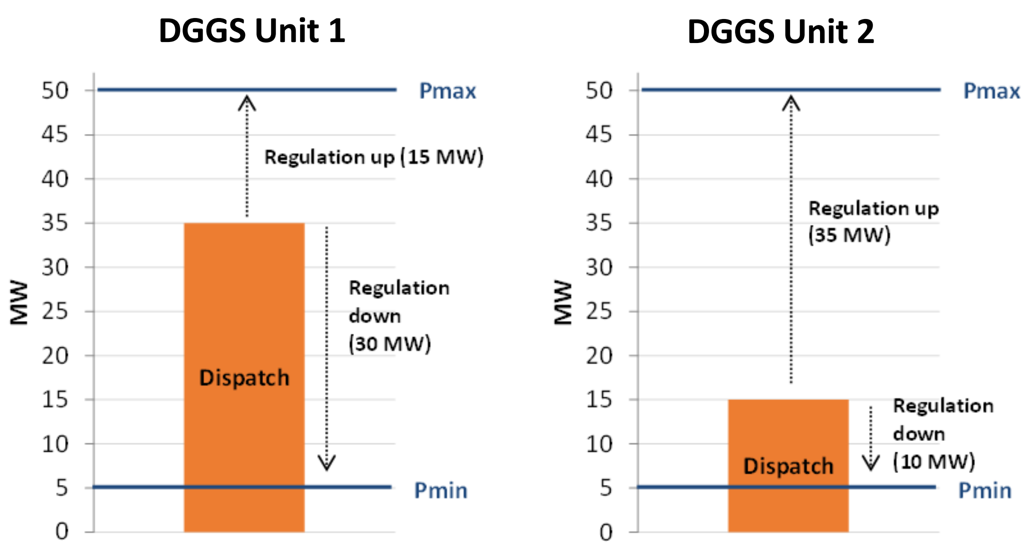
It is important to note that while the quantities of Regulation Up/Down and Non-Spinning Reserves can exceed their minimum level, the optimized dispatch generated by the model is post-processed to ensure that the total energy delivered by the combination of Basin Creek, DGGS, and market purchases is equal to 200 MWh in every hour. This post-processing ensures that the total cost results are comparable between the Base and Alternative Cases.

The need to provide both up and down regulation services is an important addition to the analysis in Phase 2. While Phase 1 modeled the dispatch of Basin Creek's energy-providing units as binary (operating at full capacity in the high price hours, off in the low price hours), the need for regulation up and down in Phase 2 can result in units being optimally dispatched between their minimum and full capacities, allowing them room to increase or decrease their output as needed. Figure 7 below shows an example of how two DGGS units might be dispatched to jointly optimize their provision of energy and regulation up/down

[1] Since neither Basin Creek nor DGGS provide spinning reserves, requiring the dispatch to optimize the purchases of spinning reserves in each hour would simply result in purchasing the full amount from the market in every hour, and would be unaffected by assumptions regarding the method by which DGGS and Basin Creek are dispatched.

services. Since the heat rate each engine can achieve is dependent on the level at which a given turbine is generating (discussed further below), the model must balance the need to leave room for upward regulation against the heat rate penalty that operating below full output entails, as well as ensuring that the generator is not operating below its minimum level.

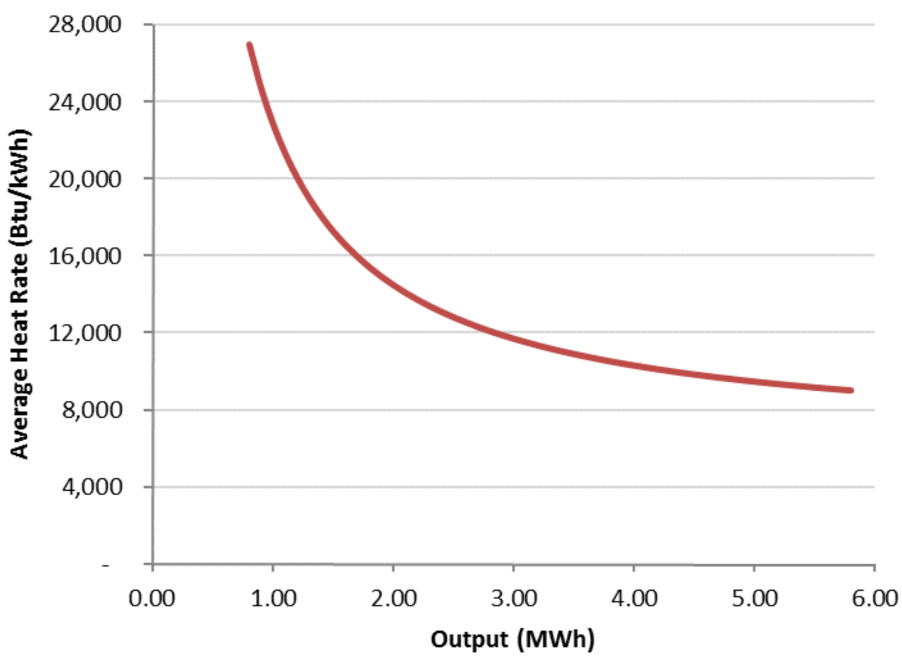
Figure 7. Optimizing Multiple Units for Energy and Regulation Up/Down Provision



2.2.4 BASIN CREEK OPERATING ASSUMPTIONS

While the assumption of a fixed heat rate was a useful simplification in the on/off dispatch modeled in Phase 1, the optimization in Phase 2 must take into account the heat rate penalty associated with operating the Basin Creek units below full capacity. E3 approximated the heat rate curve for the reciprocating engines at Basin Creek by generating a linear input-output curve based on information on the heat rates at the minimum and maximum generation levels[2]. This heat rate curve was then used to approximate the fuel usage (and associated fuel costs) for each of the Basin Creek engines across the range of each unit's possible dispatch levels. The heat rate curve used in the analysis is shown in Figure 8 below.

Figure 8. Engine Average Heat Rate Curve (by Output) for the Basin Creek Reciprocating Engines



+ **Minimum Load Requirement:** Each of Basin Creek's nine reciprocating engines, if individually committed, must output at least 0.8 MW

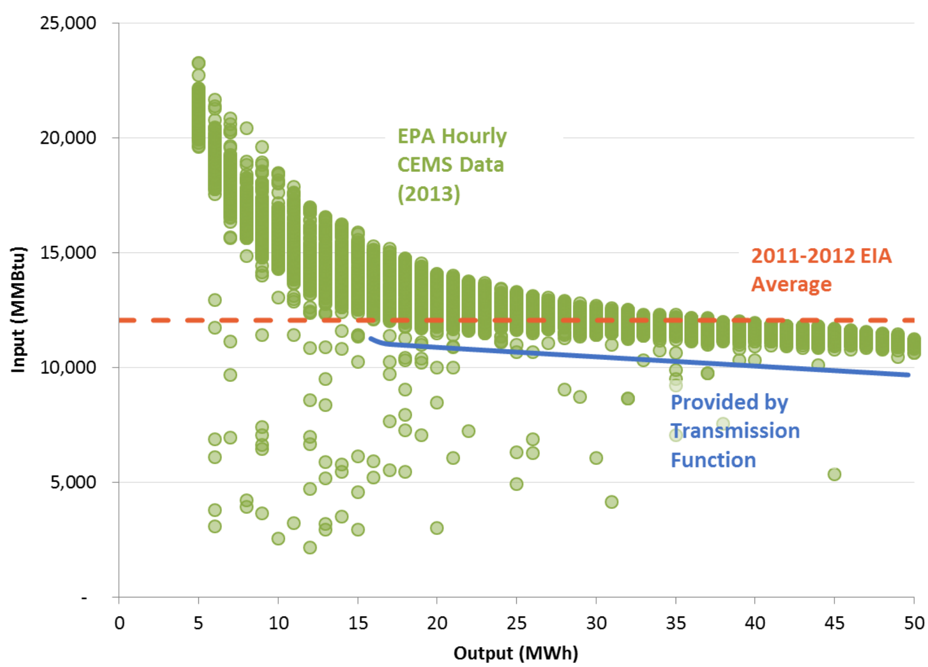
[2] 27,000 Btu/kWh at the minimum output of 0.80 MW and 9,000 Btu/kWh at the maximum output of 5.77 MW

Assumptions regarding the VO&M costs, ramping capabilities, air quality-based operating restrictions, and outages remain the same as in the Phase 1 analysis (described in section 2.1.4 above).

2.2.5 DAVE GATES GENERATING STATION OPERATING ASSUMPTIONS

For the Phase 2 analysis, NWE provided E3 with details about the operations of the combustion turbines ("CTs") at DGGS, which E3 used to calculate hourly production costs for comparison against the costs of procuring energy, regulation, and reserve services from Basin Creek and the wholesale market.

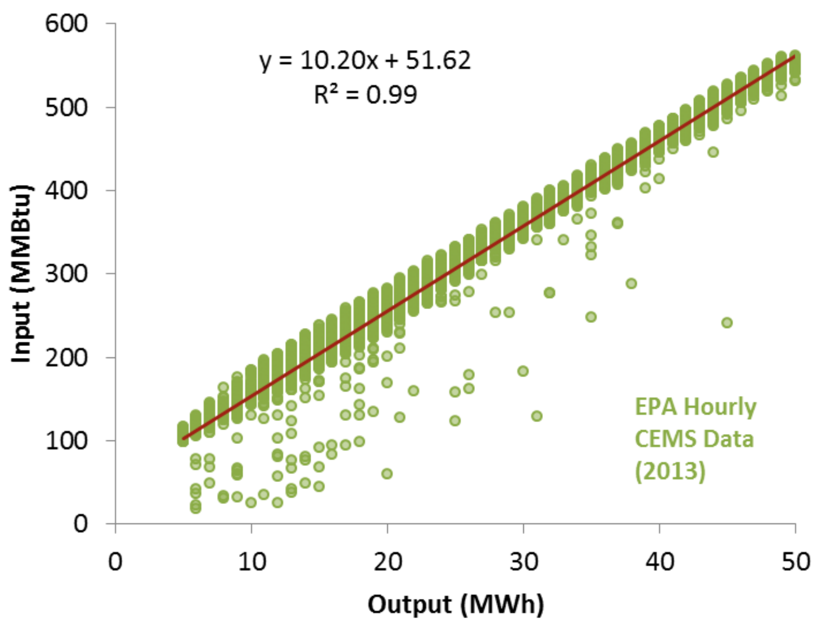
Figure 9. DGGS CT3 Heat Rate Data



- **Heat Rate**: While the data provided by NWE was sufficient to generate a dispatch-based heat rate curve for the Basin Creek reciprocating engines, the data that the Transmission Function provided on the operating characteristics did not match up with the available data from the Energy Information Administration ("EIA") or the Environmental Protection Agency ("EPA"). Figure 9 below compares the data from each of these three sources.

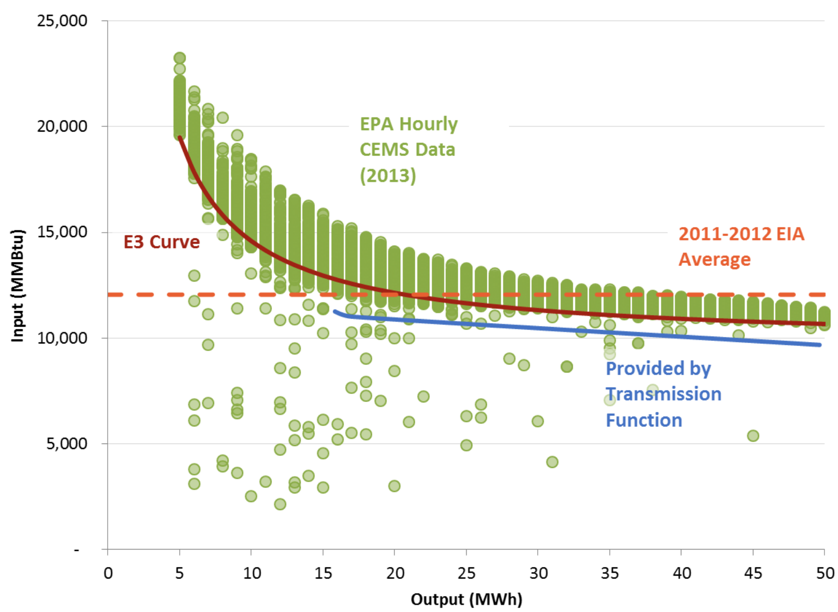
To account for the discrepancies between the different data source, E3 generated a new heat rate curve for the DGGS units based on the 2013 CEMS data, which contained hourly input (MMBtu) / output (MWh) data. The input/output curve for the DGGS can be closely approximated (R^2 = 0.99) by a linear function, shown in Figure 10.

Figure 10. DGGS CT3 Input-Output Curve



Though the linear function shown above exhibits a very good fit with the 2013 CEMS data, E3 decreased both the intercept (51.62) and the slope (10.20) of the trend line shown above by 5% to better align the heat rates used in the analysis with those provided by NWE's Transmission Function while still tracking the available data from 2013. This adjustment also reflects the fact that the CEMS data reports gross generator output rather than output net of any parasitic loads. The resulting curve is shown in Figure 11 below.

Figure 11. E3 Generated DGGS Heat Rate Curve by Unit Output



+ **Variable O&M:** The VO&M cost for DGGS units was set at $11.28 / MWh based on 2013 operations data provided by NWE
+ **Minimum load:** If a DGGS unit is committed, it must output at least 5 MW
+ **No inter-hour ramping restrictions**
+ **No air quality permit limitations**
+ **No planned outages**

2.2.6 MODELING HOURLY DISPATCH

While the Phase 1 analysis employed a relatively straightforward on/off dispatch model for the Basin Creek units, the variety of energy, regulation, and reserve services needed in the Phase 2 model, along with the necessity for partial dispatch and the inclusion of variable heat rates, require a more detailed approach to modeling hourly output from each of the 12 units (nine reciprocating engines at Basin Creek and three CTs at DGGS). To achieve this, E3 utilized an hourly model in which the dispatch in each hour is determined by a non-linear General Reduced Gradient ("GRG") optimization using Excel's built-in Solver package that minimizes the total cost of procuring the required energy, regulation, and reserve resources.

The total cost of production in a given hour is the sum of the marginal costs of production at Basin Creek and DGGS multiplied by the output from each of these plants and the cost of market purchases required to meet the total energy need in that hour (assumed to be 200 MWh in every hour for this analysis). Because of the variable heat rate assumption included in the Phase 2 modeling, these production costs are not simply a function of the natural gas price in a given hour, but also depend on the dispatch of each unit. The GRG algorithm iterates through various combinations of turbines, deciding both which units to dispatch and the level at which to dispatch. Each attempted solution must include a commitment decision (on/off) for each generator, a dispatch level (in MW) for each committed generator that falls between that generator's minimum and maximum outputs, and must satisfy the total requirements listed above for energy, regulation up and down, and non-spinning reserves.

Since the analysis assumes no restrictions based on inter-hour ramping, the optimization in each hour is independent of dispatch decisions in the hours preceding or following it. Instead, the solution in each hour is a function of the unit availability across the two plants and the natural gas and market prices for that hour.

2.2.7 RESULTS POST-PROCESSING

After the model produces an optimized 8760 dispatch of the Basin Creek and DGGS units, E3 applies post-processing calculations to ensure that the Base and Alternative cases are comparable and compliant with air quality run-time restrictions on the Basin Creek units. This post-processing consists of two steps: (1) ensuring that exactly 200 MWh of energy is available in every hour, and (2) limiting the Basin Creek dispatch to a total of 34,200 engine run hours over the course of the year.

The first adjustment, ensuring that no more and no less than 200 MWh are procured in each hour, ensures that the total cost numbers are strictly comparable in terms of the services provided for that total cost. This becomes an issue during hours where either the market price is negative or Basin Creek is unavailable. In hours with a negative wholesale market price, the model optimization purchases the maximum amount of market energy (200 MWh) regardless of the dispatch of the other units, as each additional MWh “purchased” from the market reduces the total cost of that hour’s portfolio.

When the Basin Creek units are down for maintenance, the model cannot solve the optimization because it cannot procure sufficient non-spinning reserves, as none of the DGGS units are eligible to provide non-spinning reserves in the Base Case. Thus, the dispatch in these hours must be determined manually.

The second adjustment ensures that the optimized dispatch is permissible according to Basin Creek's engine run hour restrictions. To ensure compliance, E3 first calculates the total dispatch of Basin Creek over the course of the year. If this number exceeds the number of MWh that can be generated while obeying the air quality limits, the model replaces the alternative dispatch configuration with the base dispatch configuration hour by hour, starting with those hours in which the alternative dispatch saves the least relative to the base dispatch and proceeding in order of increasing value until the total Basin Creek generation is reduced by a sufficient amount to fall within the air quality limits.

3 Results

3.1 Phase 1 Results

The results of Phase 1 confirm that modeling the operations of Basin Creek based on a comparison of marginal production costs and wholesale energy prices produces a reasonable dispatch that resembles the actual dispatch over the course of 2013. Across a variety of metrics, the modeled and actual dispatches are similar.

The analysis also shows that there does not seem to be a consistent failure to dispatch Basin Creek when prices would suggest it should be dispatched, nor is there a consistent pattern of dispatching Basin Creek when the model suggests it should not be dispatched.

3.1.1 BASIN CREEK CAPACITY FACTOR

Figure 12 shows a comparison of the actual capacity factor and the capacity factor associated with E3's modeled dispatch for 2013, a difference of less than 1% over the course of the year. This represents a difference in total generation of 2,500 MWh over the course of the year, out of nearly 100,000 MWh generated in 2013.

Monthly capacity factors exhibit more variation, with the modeled dispatch overestimating the capacity factor by a significant amount in September and

December while underestimating in June and July as shown in Figure 13. Despite this variation, however, the overall pattern of the modeled capacity factors over the course of the year follows a similar pattern as the actual data.

Figure 12. Actual vs. Modeled Annual Capacity Factor

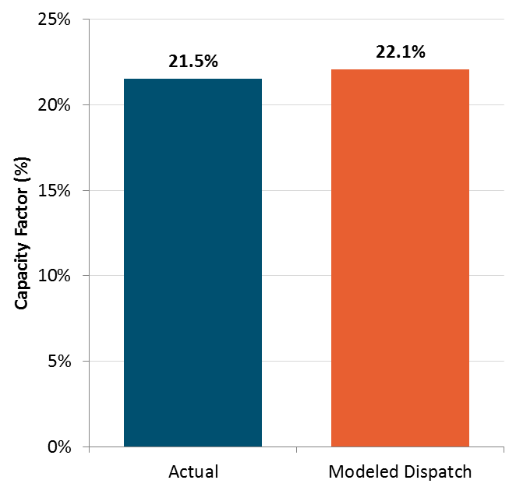
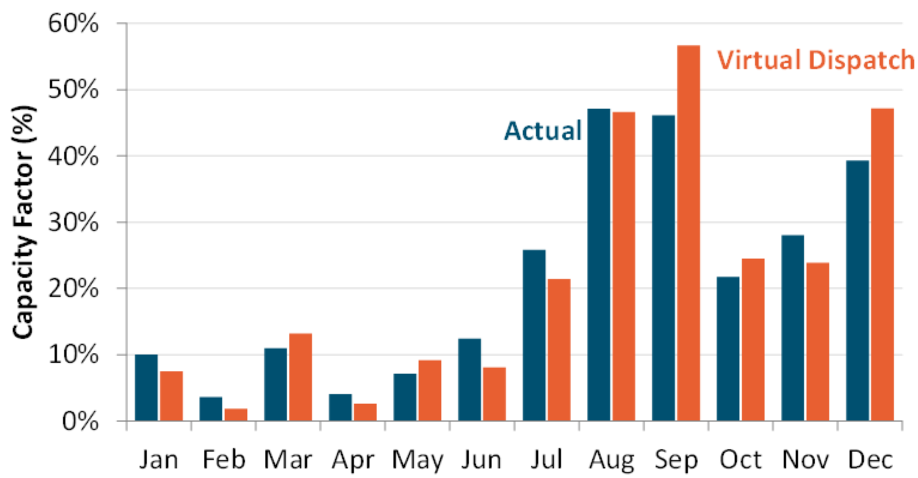


Figure 13. Actual v. Modeled Monthly Capacity Factor



3.1.2 AVERAGE GENERATION BY MONTH-HOUR

Though achieving comparable capacity factors across the course of the year indicates that the model is reasonably approximating the actual dispatch of the

Basin Creek units, comparable within-day results are also necessary given the importance of hourly operations for an electrical system. Figure 14 below compares the average generation in each month-hour between the actual dispatch in 2013 and virtual dispatch modeled by E3.

Figure 14. Average Generation by Month-Hour

Actual Dispatch (2013)

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1	2	1	0	0	1	1	2	4	8	8	8	8	7	5	4	4	4	4	7	13	13	11	8	3
2	2	1	0	0	0	0	0	3	4	5	5	4	1	1	1	0	0	0	0	1	4	4	5	3
3	6	5	2	1	1	2	4	5	7	11	11	8	6	6	6	6	7	7	7	6	7	8	5	5
4	0	0	0	0	0	0	0	2	9	11	9	8	5	3	2	0	0	0	0	0	0	1	1	0
5	3	0	0	0	0	1	1	2	2	6	7	6	5	2	5	3	4	6	6	5	7	5	6	5
6	5	3	1	0	1	0	0	1	0	2	1	3	7	10	11	13	14	17	17	15	9	10	7	8
7	9	6	6	4	3	3	3	4	4	4	9	12	20	23	25	25	27	27	26	22	19	16	13	9
8	28	26	18	15	15	15	16	15	12	15	22	29	31	33	32	32	32	32	30	27	27	29	28	28
9	27	24	15	14	15	15	17	19	20	22	27	28	29	28	29	29	28	26	25	27	29	29	28	28
10	9	4	2	2	1	1	6	15	17	18	19	21	20	15	13	11	10	11	11	12	14	15	13	10
11	11	8	6	4	5	5	7	15	19	21	21	20	20	18	15	14	14	14	17	23	22	18	17	13
12	21	21	14	9	9	10	16	18	20	21	24	26	26	21	20	18	19	21	26	26	28	27	25	23

Virtual Dispatch

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1	0	0	0	0	0	3	4	8	7	7	4	4	3	3	2	2	4	9	9	8	6	4	3	1
2	0	0	0	0	0	1	2	2	2	1	1	1	1	0	0	0	1	0	6	2	0	0	0	0
3	6	6	6	6	7	7	11	12	11	9	6	8	8	7	7	6	7	6	8	7	4	4	4	4
4	0	0	0	0	0	1	7	9	6	6	3	1	0	0	0	0	0	0	0	0	0	0	0	0
5	0	0	1	1	1	3	2	2	6	9	7	7	8	7	7	8	9	8	7	7	7	5	3	2
6	0	0	0	0	0	0	0	1	1	2	5	5	6	9	9	10	10	10	9	9	6	5	2	1
7	0	0	0	0	0	2	1	2	4	10	13	18	21	22	25	23	23	22	21	20	14	10	10	6
8	16	16	11	10	12	17	11	18	24	29	32	31	31	32	32	33	33	32	30	30	28	28	27	21
9	25	24	26	27	28	32	27	28	29	30	30	30	30	31	31	31	31	32	31	31	31	32	31	26
10	1	1	1	1	3	14	15	15	18	19	19	21	17	15	16	16	17	18	18	22	12	10	10	7
11	3	3	3	3	8	10	14	17	18	18	18	16	11	9	10	10	16	22	20	18	17	13	9	9
12	17	17	16	18	19	23	25	26	26	27	27	27	25	25	24	25	30	30	32	31	25	24	24	24

Again, the results shown here indicate that although there are differences between the actual and virtual dispatches, the values produced by the virtual dispatch exhibit the same general patterns as the actual dispatch over the course of the year.

3.1.3 EVALUATING NWE ENERGY SUPPLY'S DISPATCH OF THE BASIN CREEK UNITS

In the *Notice of Commission Action and Limited Intervention Deadline* issued by the MPSC on November 15, 2012 under Docket D2012.5.49, the Commission directed NWE to provide evidence of their efforts to "efficiently dispatch NorthWestern's portfolio of electricity supply resources" (p. 2). In the context of the Energy Supply Function of NWE, an efficient dispatch of the Basin Creek units is one in which the Basin Creek units are appropriately dispatched to minimize the cost of energy supply to NWE's customers, displacing market purchases when the marginal production cost at Basin Creek is lower than the cost of purchasing energy on the wholesale market.

The analysis conducted by E3 shows that in the majority of hours, Energy Supply is dispatching the Basin Creek exactly as the model would predict, with no difference between modeled and actual dispatch in over 56% of hours. Of the hours in which there are differences, 50% show a difference of less than 5 MW.

The analysis also shows that there does not seem to be a consistent failure to dispatch Basin Creek when prices would suggest it should be dispatched, nor is there a consistent pattern of dispatching Basin Creek when the model suggests it should not be dispatched. Of the hours in which actual generation deviated from the modeled dispatch by 1 MW or more, the model dispatched more than was actually generated in 47% of hours and less than actual in 53%.

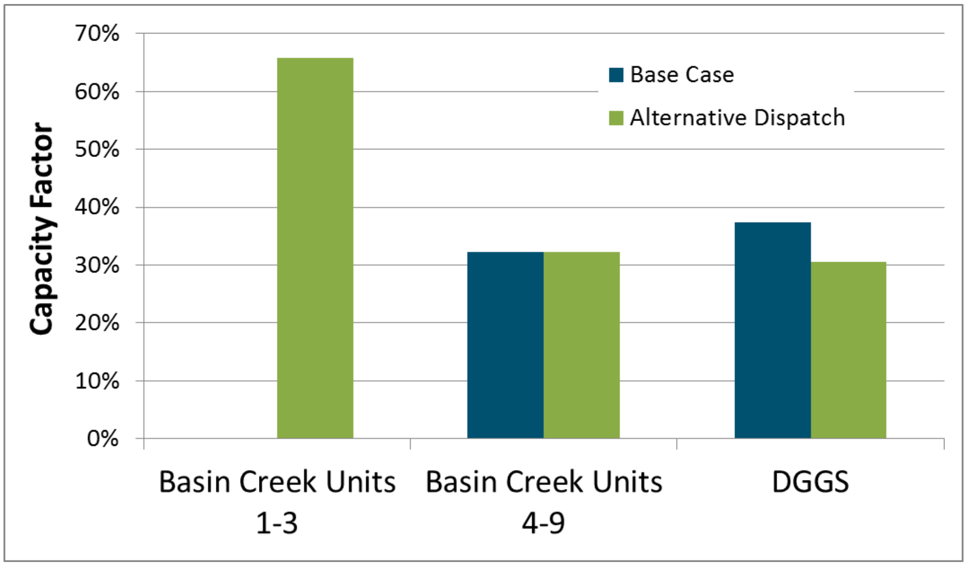
3.2 Phase 2 Results

In Phase 2, E3 explored whether allowing the Basin Creek units the option to provide regulation services while allowing DGGS the option to provide non-spinning reserves could lower the total cost of meeting NWE's energy, regulation, and reserve needs over the course of the year.

3.2.1 CHANGES IN GENERATION AND MARKET PURCHASES

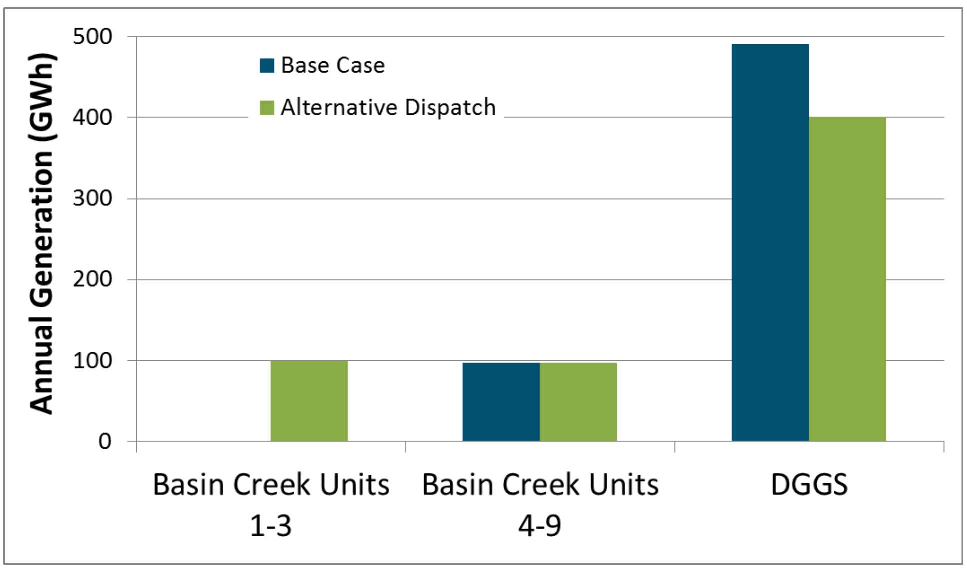
Allowing Basin Creek to provide regulation increases the output from Basin Creek units 1-3 (previously held as spinning reserves) while decreasing the output from DGGS. The effect on the capacity factors at these plants is shown in Figure 15.

Figure 15. Capacity Factors in the Base and Alternative Dispatch Cases



Though there is a large change in capacity factors for the units previously used as non-spinning reserves, the overall change in generation is less significant on an absolute basis. Allowing the Basin Creek units to provide regulation services displaces generation from the DGGS. Because of the relatively high heat rate for the Basin Creek units when they are operating at less than full capacity, using one of the DGGS units to provide non-spinning reserves while the Basin Creek units provide regulation down service represents a cost-effective substitution, while they can also displace some regulation up service if gas prices are low enough (mitigating the cost penalty of their reduced efficiency).

Figure 16. Annual Generation in the Base and Alternative Cases



The total amount of regulation down service that they can displace, however, is limited by both their size (52 MW total, compared to 150 MW available from DGGS) and the air quality permit restrictions in place for the Basin Creek generators. Without the restrictions imposed by the air quality permit, the Basin

Creek turbines could displace over 42 additional GWh from DGGS and market purchases.

The total quantity of market purchases made in order to ensure delivery of 200 MWh in each hour decreases slightly when the restrictions on DGGS and Basin Creek are relaxed, decreasing by just over 10 GWh (roughly 0.8% of the total market purchases in the base case).

3.2.2 CHANGE IN TOTAL COST

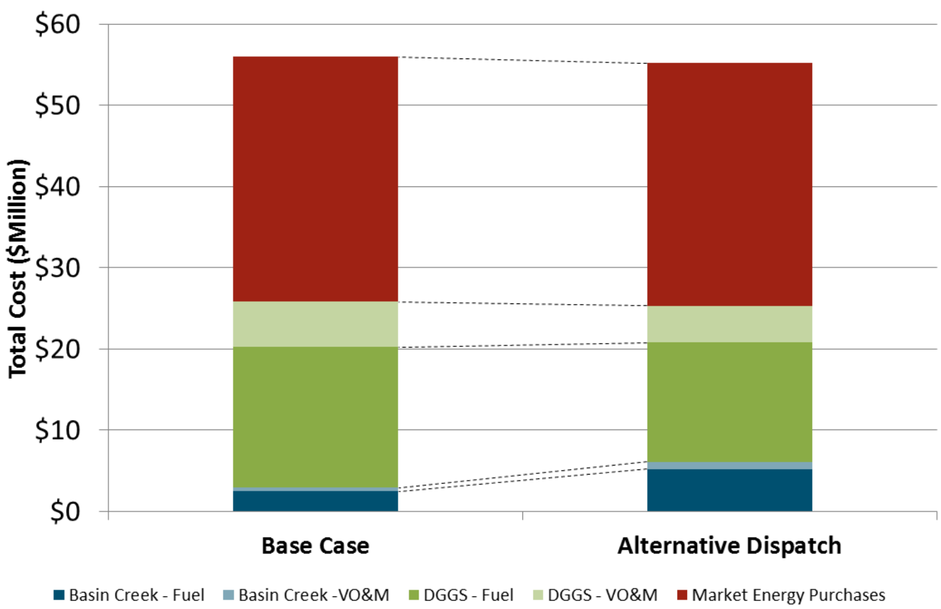


Figure 17. Total Costs by Case

The total cost of meeting NWE’s energy, regulation, and reserve needs is lower under the alternative dispatch than the base dispatch. The total cost in the base case is $55.95M, while the total cost in the alternative case is $55.2M, a total change of $742K. Costs associated with the generation at Basin Creek more than double, increasing from $2.93M to $6.11M (a change of $3.18M) in the alternative case. This increase at Basin Creek is offset by the reduction in costs associated with generation at DGGS, which go from $22.87M to $19.21M (a reduction of $3.65M). The total amount spent on market purchases decreases by $267K, from $30.14M to $29.88M.

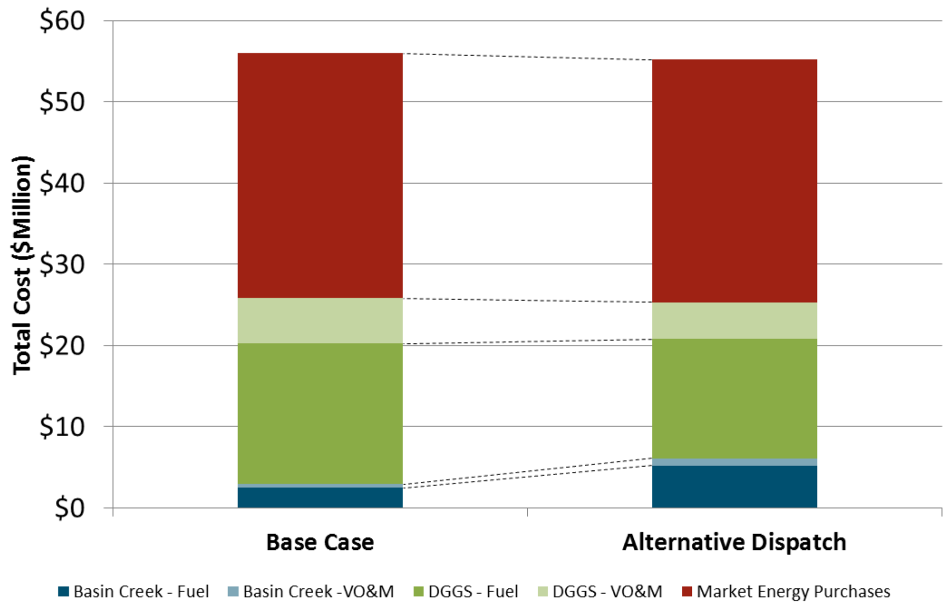


Figure 17 charts the composition of the total cost in the two cases, while.

Table 1. Total Costs in the Base and Alternative Dispatch Cases

	Base Case	Alternative Dispatch Case	Change (%)
Basin Creek			
- Fuel Purchases	$2,484,887	$5,202,108	$2,717,221 (+109%)
- VO&M	$450,943	$911,978	$461,035 (+102%)
DGGS			
- Fuel Purchases	$17,328,824	$14,684,575	-$2,644,249 (-15%)
- VO&M	$5,538,076	$4,528,522	-$1,009,554 (-18%)
Market Purchases	$30,142,407	$29,875,402	-$267,005 (-1%)
Total Cost	$55,945,137	$55,202,585	-$742,552 (-1.3%)

In percentage terms, the total cost decreases by 1.3% as a result of allowing Basin Creek and DGGS to provide regulation and reserve services (respectively) to the NWE system.

4 Summary and Conclusions

The analysis presented in this paper has two components: the first phase of the analysis looked at the existing operations at Basin Creek, examining whether they have been conducted in a manner that minimized the cost of serve the energy needs of NorthWestern customers; the second phase examined the potential cost savings that could be achieved by relaxing the operating restrictions at both the Basin Creek and DGGS plants, allowing the two to jointly optimize the provision of energy, regulation, and reserves rather than relying solely on DGGS for regulation and Basin Creek for non-spinning reserves.

- **Findings**
  - **Existing dispatch of the Basin Creek units is consistent with the Energy Supply Function's directive to minimize customer costs:** The results of Phase 1 indicate that a backward-looking optimization of Basin Creek's operations based on historical natural gas and wholesale energy prices yields a dispatch pattern over the course of the year that is not an exact replica of the actual dispatch, but follows the same general patterns on both the hourly and monthly time scales. Overall, the dispatch of Basin Creek modeled here achieved a capacity factor nearly identical to its actual 2013 capacity factor.

    Looking forward, these results indicate that the possibility of significantly lower energy costs through a more efficient dispatch of the Basin Creek plant against the wholesale energy market is unlikely. Even with perfect hindsight, the dispatch of the Basin Creek units looked very similar to the actual dispatch over the course of 2013.

- **Relaxing restrictions on the products that Basin Creek and DGGS can provide will change the overall dispatch but has little effect on the total cost:** The Phase 2 analysis indicates that allowing Basin Creek to provide regulation services to the Transmission Function of NWE while allowing DGGS to provide to act as non-spinning reserves results in a significant reduction in generation at DGGS. Providing non-spinning reserves with one of the DGGS CTs allows the relatively efficient Basin Creek reciprocating engines to provide regulation down services. However, the impact is limited by the size of the Basin Creek plant (52 MW, or roughly the size of a single DGGS CT) and restrictions on the amount of time that the Basin Creek turbines can run due to air quality concerns. Overall, the generation of Basin Creek nearly doubles and the output of DGGS goes down by almost 20%, but the impact on the total cost of providing the full menu of products required by the NorthWestern system is modest: total costs decreased by roughly 1.3%.

+ Caveats

- **Lack of perfect information and barriers to communication may limit NWE's ability to realize cost savings resulting from relaxed dispatch procedures:** The Phase 2 analysis indicates that co-optimizing the dispatch of Basin Creek and DGGS could result in a small reduction in the total cost of meeting NWE's obligations, assuming the dispatch can take advantage of the highest value hours for Basin Creek to run while still remaining under its air quality runtime restrictions. Realizing these reductions may be difficult, as the backwards looking model was able to choose the highest value hours with full information, while actual day-to-day operations would have to rely on projections of future wholesale electricity and natural gas prices to make decisions about the allocation of Basin Creek operating hours.

Achieving the cost savings found here would also require communication between the Transmission and Energy Supply Functions of NorthWestern Energy This would require the development of communication protocols to ensure that NWE continues to abide by the functional separation requirements of FERC Order 889.

5 References

Docket D2012.5.49, *Notice of Commission Action and Limited Intervention Deadline*. Issued November 15, 2012.

Docket D2012.5.49, *Prefiled Supplemental Testimony of Casey E. Johnston on Behalf of NorthWestern Energy*. Filed February 1, 2013.

Docket D2012.5.49, *Prefiled Supplemental Testimony of Kevin J. Markovich on Behalf of NorthWestern Energy*. Filed February 1, 2013.

Docket D2012.5.49, Final Order 7219h. Issued October 28, 2013.

Docket N2011.12.96, *Written Comments Identifying Concerns Regarding NorthWestern Energy's Compliance with ARM 38.5.8201-8229.*

FERC Order No. 889, *Open Access Same-Time Information System (formerly Real-Time Information Networks) and Standards of Conduct.* Issued April 24, 1996.