



COALCAST

FUELCAST

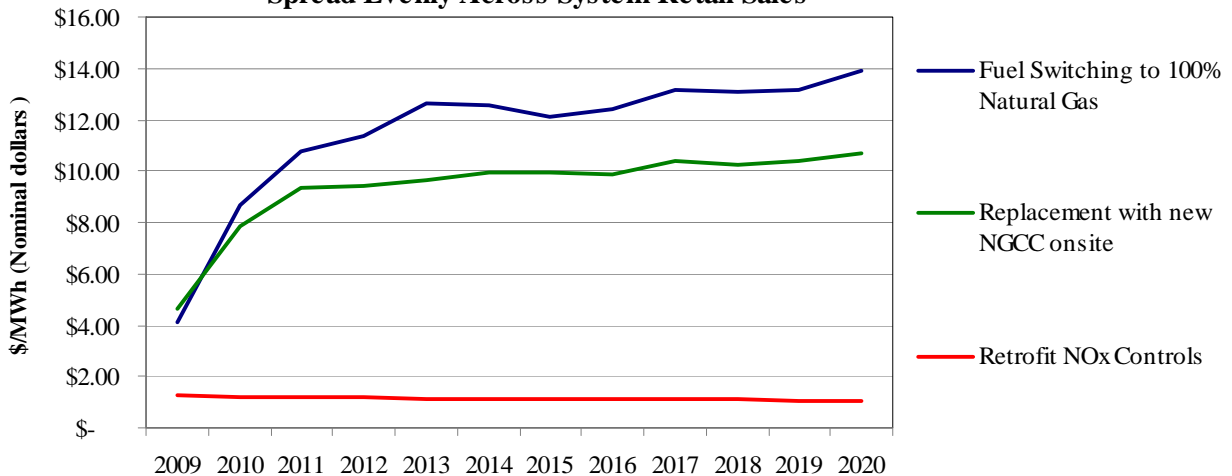
March 25, 2010

### Evaluation of Colorado Clean Air-Clean Jobs Act (HB 10-1365)

The proposed Clean Air Act-Clean Jobs Act (Colorado HB 1365) states its purpose is to develop “A coordinated plan of emission reductions from coal-fired powerplants will enable Colorado utilities to meet the requirements of the federal act and protect public health and the environment at a lower cost than a piecemeal approach. A coordinated plan of emissions will also result in reductions of CO2 and promote the use of natural gas and other emitting resources to meet Colorado’s electricity needs, which in turn promote development of Colorado’s economy and industry.”

HB 1365, as currently drafted, would not meet its primary objective of providing emissions reductions for reasonable rate impacts compared with placing emissions controls on coal-fired generating units, but instead promotes a higher cost solution that will increase electricity rates and lower employment. HB 1365 would lower CO2 emissions and but would do so by promoting consumption of more expensive natural gas. As shown in Figure 1, the analysis concludes that Public Service Company of Colorado’s (PSCo) retail power costs are expected to increase by more than \$10.70/MWh by 2020 if HB 1365 is adopted.

**Figure 1**  
**Projected PSCo Power Costs Increases from HB 1365**  
**Spread Evenly Across System Retail Sales**



Assuming a 2015 implementation date, PSCo would pass their higher power production costs from the implementation of HB1365 to their ratepayers. These cumulative costs over a 6 year period are dependent upon what reduction plan option is selected by PSCo, and can range from \$133,909,717 for retrofitting existing plants with NOx controls, to \$2,370,067,970 to switch boiler fuels from coal to natural gas. Should PSCo elect to expand its plan beyond the 900 MW minimum coal generation to include their other coal fired generation, these costs will escalate far more than shown below. (Note that the costs in this analysis are expressed in nominal dollars. Expressing the costs in constant year dollars (for example, in 2010 dollars) would make a slight difference, but would not affect the overall magnitude of the costs.)

Cumulative Cost 2015-2020

Fuel Switching to 100% Natural Gas	\$ 2,370,067,970
Replacement with new NGCC onsite	\$ 2,051,822,131
Retrofit NOx Controls	\$ 133,909,717

**HB 1365 Requirements**

The proposal applies to only one Colorado electric utility<sup>1</sup> - PSCo - that currently accounts for 61 percent of Colorado retail power sales. Under HB 1365, PSCo would be required to submit an emission control plan to the Colorado Public Utility Commission by August 15, 2010. This plan must cover a minimum 900 MW or 50% of utility coal-fired capacity that has not already announced retirement<sup>2</sup>. Based upon the PSCo system power production costs and statements by Xcel<sup>3</sup>, the targeted coal capacity would, at a minimum, include the Cherokee, Pawnee, and Valmont coal-fired stations. However, PSCo could expand the plan to include its other ongoing coal-fired capacity. The plan can include environmental control retrofits and conversion of coal-fired capacity to natural gas that can achieve at least 70 percent reduction in NOx from 2008 levels<sup>4</sup>. Any new or repowered generating capacity built under the plan must achieve an emission rate of less than 1,100 lbs CO2/MWh—effectively eliminating any competing low cost solid fuel or biomass options. The proposal states that it is in the public interest to replace coal capacity with natural gas generation. Finally, the plan can also include long-term natural gas supply contracts.

The Colorado PUC must approve/disapprove the PSCo emission reduction plan by December 15, 2010. The bill does not require the plan to provide the lowest cost solution to Colorado ratepayers or wait until the federal actions it wants to address are first defined. Once approved, the plan, with its investments outlined and long-term natural gas contracts, would be deemed prudent and eligible for full cost recovery. PSCo would be guaranteed full rate recovery and would have no prudence risk. PSCo has the option to withdraw plan if the Commission modifies plan in any way.

**System Impacts**

**Retrofit NOx Controls:** The lowest cost alternative to reduce NOx emissions by 70 percent or more would be to retrofit post-combustion NOx controls onto the stations. For the two most likely coal stations, Valmont and Cherokee (903 MW), these controls would cost \$174.4 million to install and

---

<sup>1</sup> Section 40-3.2-204 (1) applies to “all rate regulated utilities that own or operate coal-fired electric generating units in Colorado.” Of the two Colorado rate regulated electric utilities, only PSCo has coal-fired units located within Colorado.

<sup>2</sup> Section 40-3.2-204(2)(a)

<sup>3</sup> “Xcel Energy eyes potential coal unit shutdowns in favor of natural gas”,

<http://www.snl.com/InteractiveX/article.aspx?CDID=A-10863397-10800&KPLT=2>

<sup>4</sup> Section 40-3.2-205(a)

\$36 million per year in annual operating costs (including capital recovery)<sup>5</sup>. These costs spread across retail sales would increase power costs by an average of 0.56 \$/MWh by 2020, or \$4.32 for the average residential PSCo customer in 2020. These compliance costs are far less than the competing natural gas based alternatives. However the Commission is under no obligation to select the lowest cost alternative under HB 1365.

The remaining alternatives center on replacing coal generation with natural gas alternatives. PSCo would need to examine three options: 1) switching fuel, 2) repowering and 3) replacement with greenfield gas combined cycle capacity. The focus for this evaluation was on the two highest cost coal units that are at risk—Cherokee and Valmont.

Fuel Switching: The lowest capital cost alternative would be to keep the existing coal boilers, but to switch them to burning 100 percent natural gas<sup>6</sup>. Both Cherokee and Valmont stations were designed to burn either coal or natural gas but would likely experience a loss in energy efficiency of at least 3-5 percent due to the different fuel characteristics<sup>7</sup>. As shown in Table 1, plant fuel costs would increase significantly (\$35-60/MWh) due to the higher natural gas acquisition costs versus its current coal sources. These fuel cost gaps should continue to increase and reach \$67-73/MWh by 2020 or \$466 million per year. If spread across the entire PSCo retail sales, PSCo power rates would need to increase by \$13.90 /MWh or by \$108/year for their average residential customer.

**Table 1. Fuel Switching Alternative Costs**

		2009	2010	2011	2012
<b>Cherokee</b>					
Delivered Coal Price	\$/MMBtu	\$ 1.72	\$ 1.25	\$ 1.27	\$ 1.30
Heatrate	MMBtu/MWh	10.56	10.56	10.56	10.56
Delivered Coal Price	\$/MWh	\$ 18.16	\$ 13.20	\$ 13.44	\$ 13.68
Delivered Gas Price Unadjusted	\$/MMBtu	\$ 3.58	\$ 4.93	\$ 5.96	\$ 6.44
Heatrate	MMBtu/MWh	10.56	10.56	10.56	10.56
Gas Heatrate penalty multiplier		1.05	1.05	1.05	1.05
Delivered Gas Price	\$/MWh	\$ 39.70	\$ 54.67	\$ 66.09	\$ 71.41
Increased Delivered Fuel Price Premium for Natural Gas	\$/MWh	\$ 21.53	\$ 41.47	\$ 52.65	\$ 57.73
<b>Valmont</b>					
Delivered Coal Price	\$/MMBtu	\$ 1.78	\$ 1.96	\$ 1.78	\$ 1.96
Heatrate	MMBtu/MWh	9.57	9.57	9.59	9.59
Delivered Coal Price	\$/MWh	\$ 17.07	\$ 18.77	\$ 17.11	\$ 18.82
Delivered Gas Price Unadjusted	\$/MMBtu	\$ 3.58	\$ 4.93	\$ 5.96	\$ 6.44
Heatrate	MMBtu/MWh	9.57	9.57	9.59	9.59
Gas Heatrate penalty multiplier		1.05	1.05	1.05	1.05
Delivered Gas Price	\$/MWh	\$ 35.97	\$ 49.53	\$ 60.02	\$ 64.86
Increased Delivered Fuel Price Premium for Natural Gas	\$/MWh	\$ 18.90	\$ 30.76	\$ 42.91	\$ 46.04

<sup>5</sup> Assumes SCR retrofit controls at Cherokee #4, SNCR controls at Cherokee #1-3 and Valmont #5 with some reduced generation.

<sup>6</sup> Xcel adopted this same fuel switching approach for its Black Dog station in Minnesota.

<sup>7</sup> Natural gas combustion produces primarily radiant heat in a boiler. Coal combustion creates radiant and convective heat in a boiler.

Fuel switching should reduce NOx emission rates by 68 percent<sup>8</sup>, SO2 rates by 100 percent, and CO2 rates by 40 percent. Overall, the CO2 emission reduction costs from fuel switching would escalate from \$147/ton (in 2015) to \$172/ton CO2 removed by 2020. These switching costs are far higher than projected costs from implementing federal GHG regulation (\$15-30/ton)<sup>9</sup>, DOE projected carbon capture and sequestration costs (\$65-75/ton)<sup>10</sup>, and purchasing CO2 credits on the Chicago Climate Exchange (\$0.10/ton as of 3/22/10), RGGI (\$2.07/ton in March 2010 auction) or European carbon trading markets (\$19.15/ton for Dec 2010 allowances as of 3/22/10).

Replace Coal Boilers with New Gas Combined Cycle (NGCC) Onsite Capacity: An alternate approach would be retiring the two coal stations and replacing them with new gas combined cycle capacity. By placing this replacement capacity at the old coal plant site, PSCo should avoid the transmission tie in and some onsite auxiliary service costs (e.g. cooling water, fire protection) while keeping some onsite operational personnel. This alternative requires a new investment of \$810 million in 900 MW replacement generating capacity.

The new NGCC capacity would be more energy efficient than the existing coal units by 26 percent. Despite this efficiency improvement, natural gas will still cost \$36/MWh more in 2015 and \$43/MWh more in 2020 than the coal costs. Overall, the combination of the capital recovery costs and higher fuel costs could cost PSCo ratepayers \$368 million more for replacement power costs by 2020. These costs spread across all PSCo retail power sales would increase power rates by \$10.70/MWh in 2020 (nominal\$). For the average residential customer in 2020, this cost increase translates into \$83/year in higher power costs.

The accelerated retirement of the coal units would reduce system emissions because of the lower emissions from the replacement capacity. Overall, the NGCC replacement capacity would have 91 percent lower NOx emission rate (per MWh) and 59 percent lower CO2 emission rate (per MWh).<sup>11</sup> Overall, the CO2 emission reduction costs from coal unit replacement would escalate from \$66/ton (in 2015) to \$76/ton CO2 removed by 2020. These switching costs are far higher than projected costs from implementing federal GHG regulation (\$15-30/ton)<sup>12</sup>, DOE projected carbon capture and sequestration costs (\$65-75/ton)<sup>13</sup>, and purchasing CO2 credits on the Chicago Climate Exchange (\$0.10/ton as of 3/22/10), RGGI (\$2.07/ton in March 2010 auction) or European carbon trading markets (\$19.15/ton for Dec 2010 allowances as of 3/22/10).

These findings are consistent with the earlier modeling results for PSCo's 2007 Colorado Resource Plan (November 2007). PSCo modeled carbon penalty scenarios from \$0-40/ton CO2. This utility

---

<sup>8</sup> Estimated that NOx emission rate for the two stations would be reduced from 0.38 #NOx/MMBtu in 2009 to 0.12#NOx/MMBtu. CO2 rate would decrease from 1.06 tons/MWh to 0.64 tons/MWh.

<sup>9</sup>Sources: Energy Market and Economic Impacts of HR2454- the American Clean Energy and Security Act (DOE-EIA Aug 2009) Table 1 projected allowance values of \$31.70/metric ton (\$28.77/short ton) in 2020, EPA Analysis of the American Clean Energy and Security Act of 2009 (EPA-June 2009) estimated CO2 allowance values at \$13/ton CO2e in 2015 and \$16/ton CO2e in 2020.

<sup>10</sup> Source: Exhibit ES-11 Cost and Performance Baseline for Fossil Energy Plants (DOE-NETL May 2007)

<sup>11</sup> Actual 2008 emission rate for the two coal fired stations were 4.17#NOx/MWh and 1.06 tons CO2/MWh. For a new NGCC these emission rates would be reduced to 0.38 lbs NOx/MWh and 0.44 tons CO2/MWh.

<sup>12</sup>Sources: Energy Market and Economic Impacts of HR2454- the American Clean Energy and Security Act (DOE-EIA Aug 2009) Table 1 projected allowance values of \$31.70/metric ton (\$28.77/short ton) in 2020, EPA Analysis of the American Clean Energy and Security Act of 2009 (EPA-June 2009) estimated CO2 allowance values at \$13/ton CO2e in 2015 and \$16/ton CO2e in 2020.

<sup>13</sup> Source: Exhibit ES-11 Cost and Performance Baseline for Fossil Energy Plants (DOE-NETL May 2007)

modeling concluded that continued coal use at Cherokee and Valmont was the lowest cost system resource alternative for all carbon penalty scenarios<sup>14</sup>.

### **Employment Impacts**

While increasing natural gas production and consumption in Colorado would boost drilling and pipeline construction employment, overall employment would decrease as more coal mining, transportation, and power plant operation jobs would be lost than gained in the natural gas sector. Overall, 2.6 million tons of coal demand would be replaced with between 43.2 BCF/year (replacement case) and 58.4 BCF/year (fuel switch) from conversion of Cherokee and Valmont to natural gas.

As is shown in Table 2, an estimated 806 workers are employed in the two power plant operations (310), mining the 2.6 million tons/year of Colorado coal (233), rail transportation to the Cherokee and Valmont's coal units (211), and providing plant supplies (52). These jobs represent direct Colorado jobs and exclude any indirect and induced jobs supported by employee spending and commerce.

Switching both plants from coal to natural gas would likely result in the net displacement of several hundred jobs. Overall, the full cycle from gas drilling, pipeline transportation, and powerplant operation would employ an estimated 518 employees—representing a net loss of 290 jobs versus the current coal operations. These direct jobs associated with natural gas would also likely be in Colorado. However, of the 518 direct jobs created from conversion, 104 jobs are associated with well drilling that are shorter-term period jobs. As these wells deplete, the crews will again be hired to drill replacement wells. The remaining 414 direct jobs are permanent jobs in gas extraction (178), pipeline operation (36), and powerplant operation (200).

The coal retirement and building new gas combined cycle capacity would create 283 direct, full-time jobs—a net employment loss of 523 people versus the current coal alternative. As with the gas switching option, these jobs would likely be direct Colorado jobs. Of the employment, 62 jobs would be well drilling jobs that occur over shorter periods. The remaining 221 jobs created from new NGCC capacity would be ongoing jobs.

For both the coal and new gas combined cycle options, new construction would be needed to install the needed environmental controls (NOx control retrofit) or new generating capacity. The \$174 million in environmental controls or the \$810 million in NGCC capacity would also create temporary construction jobs. In addition, the increased gas consumption at the existing coal sites may also require additional investments to expand pipeline delivery capacity to the station that was not part of this study.

###

---

<sup>14</sup> Colorado Resource Plan (Nov. 2007) pg 2-69.

**Overview Of Jobs Associated With Converting Cherokee and Valmont to Natural Gas**

	Current Cherokee and Valmont Jobs for Coal Steam Electric			Conversion to Natural Gas Steam Electric			Replace Cherokee and Valmont Jobs if New Combined Cycles Are Built		
	Cherokee (710 MW)	Valmont (186 MW)	Total <sup>(1)</sup>	Cherokee (710 MW)	Valmont (186 MW)	Total <sup>(2)</sup>	Cherokee <sup>(3)</sup> (710 MW)	Valmont (186 MW)	Total
<b>On-Site Jobs</b>									
On-Site Operational Jobs	146	57	203	93	41	134	39	25	64
Add'l Plant Maintenance Jobs	24	83	107	53	13	66	20	5	25
			<b>310</b>			<b>200</b>			<b>89</b>
<b>Fuel Supply Jobs</b>									
Coal Mining <sup>(4)</sup>	186	47	233	-	-	- <sup>(9)</sup>	-	-	- <sup>(9)</sup>
Well Drilling Est <sup>(5)</sup>	-	-	-	83	21	104	50	12	62
Gas Extraction Est <sup>(6)</sup>	-	-	-	143	35	178	85	21	106
			<b>233</b>			<b>282</b>			<b>168</b>
<b>Fuel Transportation</b>									
Coal Rail/Truck <sup>(7)</sup>	169	42	211	-	-	-	-	-	-
Natural Gas Pipeline <sup>(8)</sup>	-	-	-	29	7	36	21	5	26
			<b>211</b>			<b>36</b>			<b>26</b>
<b>Chemical Supplies<sup>(7)</sup></b>	42	10	52	-	-	0	-	-	0
<b>Total</b>			<b>806</b>			<b>518</b>			<b>283</b>

(1) FERC Form 1 and maintenance at \$106,000/job for 50% of maintenance cost 2008 for on-site jobs.  
(2) Mid range between coal steam electric and combined cycle natural gas for on-site jobs.  
(3) FERC Form 1 for Fort St. Vrain combined cycle plant @ 744 MW for on-site jobs.  
(4) EVA ratio of MSHA data for coal mining.  
(5) 50% of wells in Colorado are for natural gas and ratioed to Cherokee and Valmont proposed usage adapted from Colorado Energy Research Institute (Report 2007-1).  
(6) 75% of extraction in Colorado is for natural gas and ratioed to Cherokee and Valmont proposed usage adapted from Colorado Energy Research Institute (Report 2007-1).  
(7) EVA report.  
(8) BLS statistics ratioed to fuel usage.  
(9) Short term jobs.

Prepared by Energy Ventures Analysis  
On behalf of the  
American Coalition for Clean Coal Electricity