Estimated Rate Impacts

Coal Transition Plan Proposal

February (rev) 2016

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About Flink Energy Consulting

Flink Energy was founded by Ken Dragoon in October 2014 to serve clients addressing issues relating to the transition away from fossil energy. Ken has more than thirty years of experience in the electric utility industry, working for the Bonneville Power Administration (15 years), PacifiCorp (9 years), Renewable Northwest (4 years), Northwest Power and Conservation Council (2 years), and Ecofys (2 years). Since its founding, Flink Energy's clients have included Ecofys, Oregon Wave Energy Trust, Utah Clean Energy, Energy Trust of Oregon, Renewable Northwest, Climate Solutions, and Idaho Conservation League. More about Flink Energy's work and publications can be found on the Flink Energy Consulting web site (www.flinkenergy.com).

Revision note: This report was originally released in January 2016. This revision corrects some errata in the original analysis with respect to PGE's calculations. Load growth for PGE was not picked up in the January analysis and the carbon value used in the low carbon case (PGE only) was also incorrect. One other significant change was the labeling on carbon dioxide reductions was originally "tons," but revised in the revision to "million tons." The most apparent difference in the revised version is that the added renewable (assumed to be wind) resource increased by 600 MW over the original version.

Summary

This report summarizes results, methods, and assumptions relating to the Coal Transition Plan Proposal (CTP) for the State of Oregon. The analysis assesses how the increased renewable energy requirements affect Portland General Electric (PGE) and PacifiCorp (Pacific Power in Oregon) revenue requirements and rates. Proposed legislation is not expected to affect other Oregon utilities. CTP calls for ending Oregon ratepayers' responsibility for coal generation by 2030 and doubling renewable energy requirements from 25% to 50% by 2040 (see Figure 1).

The analytical approach broadly adopted the most current utility resource planning assumptions. Wind generation was used as a proxy for all eligible renewable generation to meet the proposed renewable standards. If the standards were met by wind, it would result in approximately 3,950 MW of acquisitions above currently mandated levels by 2040. The proposal also calls for Oregon ratepayer responsibility to pay for coal plants to cease by the end of 2030.

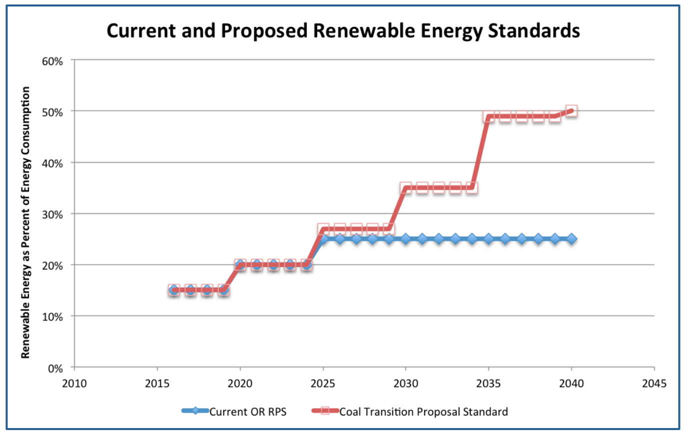

Figure 1 Current and proposed renewable energy standards for Oregon, expressed as a percentage of utility demand.

The net revenue requirement for the additional renewable generation was determined by taking the difference between the cost of constructing and integrating the new resources, and the value of the power produced. The net resource cost also depends on whether current federal tax credits remain in place, and whether a market value is assessed to decreased carbon emissions (a carbon value[1]). Different results were calculated for scenarios with and without the tax credits, and with and without carbon values.

Net costs were expressed as a fraction of current utility revenue requirements as a proxy for rate impacts. For PGE and Pacific Power, over all the scenarios, the cost effects through 2040 ranged from an average increase of 0.9% (no tax credits, no value on carbon) to a decrease of 2.8% (renewable energy tax credits, with high value on carbon). The calculated net costs include the effects of early depreciation of existing coal plants by the end of 2030. Methodology, assumptions, and results are explained in more detail below and tabulated in more detail by year and utility in Appendix 1 – Result Tables.

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[1] The carbon value used was based on PacifiCorp's 2015 IRP and is roughly $20/ton beginning in 2020.

Methodology

Overview

The analysis was performed in an Excel workbook based on utility load forecasts for the period 2015 through 2040. Renewable energy requirements are expressed as a fraction of the load, with specific energy quantities determined by applying the percentages to utility loads. The base case consisted of expected load growth and current renewable energy requirements, and the alternative case represents the higher proposed renewable energy requirements. Separate analyses were performed for PGE and PacifiCorp using data derived from utility sources wherever practicable. Renewable resource acquisitions were assumed to be in the form of wind resources, using costs and financial assumptions from PacifiCorp's 2015 Integrated Resource Plan (IRP). Costs were independently calculated for scenarios where the current tax credits continue to be available and where they are not available.

Mark-to-Market Valuation

The net revenue requirement for the additional renewable generation was determined by taking the difference between the cost of constructing and integrating the new resources, and the value of the power produced. The cost of renewable resource additions are based on PacifiCorp's 2015 IRP levelized cost of wind (approximately $80/MWh in 2015 dollars). The value of the power produced was taken to be the market value of that power. Net revenue requirement is the difference between this cost of the resource and the value of the power.

This method of assessing net value is known as "mark-to-market" that is a common method for resource valuation purposes. It does however contrast with the more complex utility integrated resource planning approach in which resource additions are evaluated based on the effects on each utility's existing portfolio of resources and market access. The mark-to-market approach was adopted due to the scope of analysis (two utilities, one spanning multiple state jurisdictions) and available time and resources for the analysis. One of the limitations of the approach is its inability to assess changes in dispatch (and emissions) of utilities' existing resources.

In mark-to-market analyses, the net value of non-fossil resources is extremely sensitive to electric market and natural gas prices. Historically gas and electric prices are closely associated with one another, primarily because the electric market price tends to be set by the highest marginal cost resource needed to meet load, and those resources are predominantly power plants burning natural gas. Figure 2 shows the historical relationship between natural gas prices and Northwest wholesale electric power prices. It should be noted that the close relationship can be broken during periods of shortage, causing electric prices to spike and periods of excess when high renewable resource output causes all natural gas plants to be idled. It should also be noted that the relationship could also be broken in a future heavily dominated by non-fossil resources.

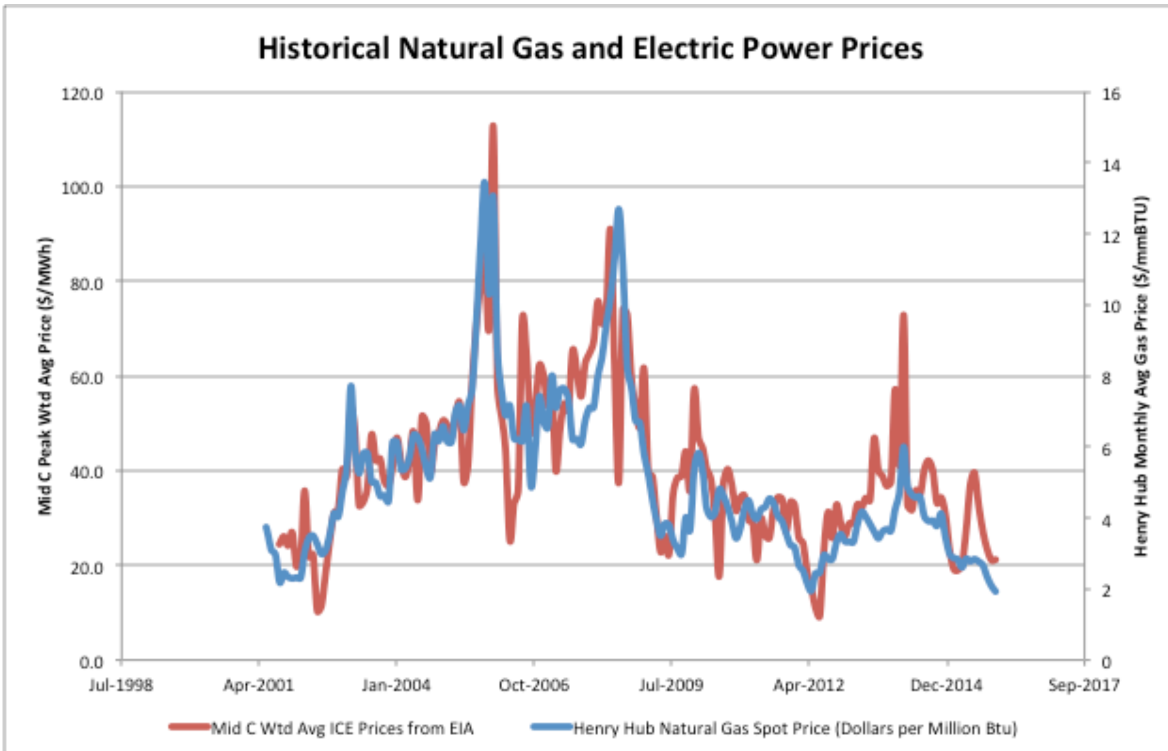

Figure 2 Historical relationship between natural gas and electric market prices. Data from Energy Information Administration for average monthly Henry Hub gas and weighted average Mid Columbia peak power prices.

For consistency with utility power plans, this analysis relied on PacifiCorp's 2015 IRP electric market price forecast, extrapolated to 2040. Figure 3 shows the market price forecast along with the cost of new wind resources. It can be seen from the figure that the cost of new wind resources in the analysis is higher than wholesale market prices through much of the study horizon. The prices depicted in Figure 3 represent the value of "flat" (constant through hours of the day and season of the year) generation at the Mid Columbia market price point. Northwest wind generation has both seasonality and a diurnal pattern. Nevertheless, the wind seasonality is limited and largely complemented by solar[2], while other renewables (e.g., geothermal and biomass) tend to be "flat", so the approximation may be reasonable.

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[2] Northwest wind resources has little diurnal pattern except in the winter when nighttime winds tend to be higher. The higher wintertime winds contribute most of the seasonality of Northwest

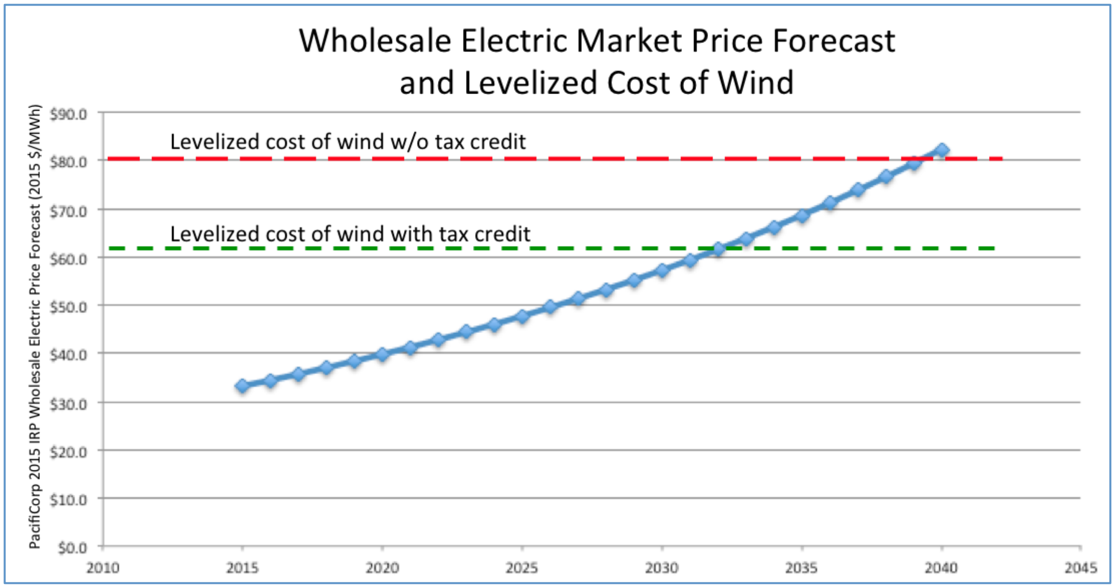

Figure 3 Comparison of wholesale electric market price forecast and cost of new wind resources, expressed in 2015 dollars.

The results of this analysis are especially sensitive to the relative cost of resources and the cost of wholesale electric prices. Wholesale electric prices are, in turn, highly sensitive to natural gas prices. Figure 2 illustrates the volatile history of natural gas prices, and by implication, the difficulty of assessing them into the future. Technological changes have kept prices low in recent years, but the future remains unclear due to potential environmental regulation relating to developing the resource, and carbon emissions. The forecast used in this study is dependent on a specific view of natural gas prices into the future that could be very different.

The sensitivity of results on very uncertain natural gas price forecasts is a basic feature of the valuation problem—not specific to the particular methodology (i.e., mark-to-market) used. If prices remain low, it will appear that the increase in renewable generation is less economic. If prices rise beyond the forecast, the increase in renewable generation will be more cost effective. Since price increases are relatively unbounded, one benefit (not monetized in this analysis) is that the renewable generation provides insurance against potential rises in fossil fuel prices and positions the utilities well in the event that the cost of carbon emissions becomes internalized to the utilities. This effect is partly captured in the scenarios examining three levels of carbon valuation: none, low, and high.

Early Coal Retirement and Accelerated Depreciation

Terminating coal sales to Oregon was modeled by assuming that the remaining Oregon share of the coal plant book value past 2030 is levied on ratepayers over the period 2018 through 2030 in equal (nominal dollars) annual amounts. The only coal plant with residual book value for PGE

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winds as well—except for the increase nighttime winter winds, there would be little seasonality or diurnal pattern to Northwest wind generation.

and PacifiCorp past 2030 is the 2,094 MW Colstrip plant in Montana. Data provided by the client showed approximately $39 million book value to distribute to PGE customers ($3.2 million in annual accelerated rate requirements), and $9.3 million to PacifiCorp's Oregon customers ($0.7 annual rate requirements)[3].

Value of Carbon Savings

An additional credit for carbon emission savings was examined as a separate line item in the workbook. The analysis was not sufficiently detailed to assess changes in specific generators in the region due to the increase in renewable energy production. As a result, it cannot be certainly determined how much carbon emissions are reduced, or the savings that may accrue in the event a specific carbon valuation is adopted. However, the addition of renewable resources has the effect of reducing the output of higher variable cost resources in the market[4]. The amount of carbon reduction can effectively be "book-ended" by assuming either that all the reduced fossil generation occurs at relatively efficient and lower carbon combined cycle gas plants ("CCCT") or the relatively high carbon output of a coal plant. The actual reductions in carbon emissions will likely fall between these extremes[5].

Integration Costs

The cost of wind used in the study included the integration cost assessed by PacifiCorp. These costs were assumed to grow at the rate of inflation. While integration costs have long been expected to rise with increasing penetration levels, the recent history has seen the costs

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[3] The treatment of depreciation was slightly inconsistent with other dollar values used in the analysis—the depreciation values are in nominal dollars, while market prices and wind energy costs are in constant 2015 dollars. This tends to overstate the effect of early retirement of Colstrip on rates.

[4] As many have noted, there are times when generation from wind resources results in reducing generation from the hydro system. However the effect of that is to essentially store the energy until such time as the market prices are more favorable—in effect displacing thermal units at a later date. The net effect remains the reduction of output from fossil units. There are times when the generation exceeds what can be accommodated, resulting in generation being curtailed altogether. The present analysis assumes the amount of curtailed generation is small enough to leave out of the analysis.

[5] Because natural gas fueled power plants generally have higher variable costs than coal plants, they are typically the first units to be displaced by incremental renewable generation. However, the Northwest has a long history of renewable (hydro) energy displacing coal generation, and the author is aware of statements by utility operators in the Northwest and outside the Northwest noting that coal plant generation has at times been displaced by wind generation.

generally fall as utilities adjust operating procedures (e.g., shorter operating periods, and participation in the energy imbalance market), and refine their cost estimates.

Methodology Summary

The analysis described in this report relied on PacifiCorp and PGE IRP load forecast data to determine the amount of incremental acquisition of renewable resources under the proposal. Resource additions were assumed to comprise wind generation priced both with and without the current renewable resource tax credits as separate scenarios. Countering the increase in costs to ratepayers for the acquired generation is a valuation of the energy produced based on PacifiCorp's 2015 IRP wholesale electric market price forecast. Increases and decreases in net costs were expressed as rate impacts by dividing by an approximate revenue requirement for each utility[6].

Assumptions

Overview

The analysis was based on increasing the renewable energy standard from current levels (15% through 2019, 20% from 2020 to 2024, and 25% from 2025 on) to a higher standard (no change through 2024, 27% from 2025 through 2029, 35% from 2030 through 2034, 45% from 2035 through 2039, and 50% from 2040 on) as illustrated in Figure 1. Assumptions in the PGE and PacifiCorp analysis adhered as closely to utility Integrated Resource Plan assumptions as possible, primarily PacifiCorp's as it is the more recent of the two. The economic effects of incremental renewable energy costs and benefits are most sensitive to two fundamentally important assumptions—the cost of renewable energy and wholesale market prices.

Cost of Renewable Energy and Wholesale Market Prices

Renewable resources were represented as new 29% capacity factor wind resources from PacifiCorp's Integrated Resource Plan (IRP) at a cost of $61.57/MWh (levelized 2015 dollars) with federal tax credits ("PTC/ITC"), and $80.30 without tax credits (both scenarios studied). These costs include integration costs for wind and assume that the cost of wind generation increases at the rate of inflation. Because the analysis was based on constant 2015 level dollars,

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[6] Revenue requirements forecasts were not available. The denominator was based on a single recent year revenue requirement for each utility. This likely overstates the percentage changes somewhat (especially in the later years) as revenue requirements can be expected to grow through time.

the total resource cost figures in PacifiCorp's IRP were used without annual adjustment, except to increase for inflation from 2014 dollars represented the IRP[7].

Wholesale electric market prices were taken from PacifiCorp's 2015 IRP estimate of Mid Columbia market prices and extrapolated at a real 3.7% per year[8]. These two assumptions drive the results of the analysis—if wholesale electric market prices rise faster or slower relative to renewable resource costs, the results could be much more positive (if faster), or negative (if slower).

Carbon Emission Savings

The assumed carbon value was taken from PacifiCorp's 2015 IRP: a constant $20.38 in 2015 dollars beginning in 2020[9], and held constant in real terms (i.e., increases with inflation). As described previously, the range in carbon benefits was based on the assumed carbon emissions of displaced resources: a low of 0.605 tons/MWh (Imperial tons) for combined cycle combustion turbines burning natural gas, and a high of 1.075 tons/MWh for coal displacement (assuming sub bituminous coal). The scenarios adjusting ratepayer impacts for carbon emissions are based on carbon emission cost savings. An alternative approach would be to use a carbon cost adjusted market price curve such as PacifiCorp presents in Figure 7.7 (see Figure

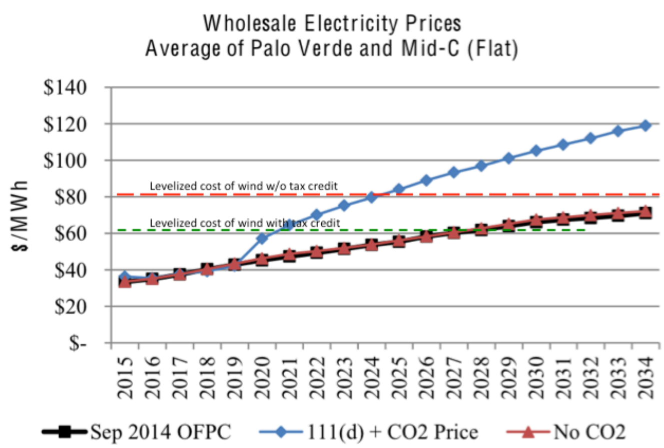

Figure 4 Carbon adjusted forward price curve from PacifiCorp 2015 IRP with levelized wind resource costs superimposed.

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[7] See PacifiCorp 2015 IRP, Table 6.2 page 99—entries for "2.0 MW wind turbine 29% CF WA/OR": 78.80 and 60.43 $/MWh.

[8] This assumption was taken from PacifiCorp's 2015 IRP (Figure 1.4, p. 4), removing a 1.9% fixed inflation rate (ibid, page 131) from the nominal prices in the chart, and extrapolating after 2024 to 2040. Note that PacifiCorp's IRP includes a higher "Official Forward Price Curve (OFPC)" consisting of a melding of Mid Columbia and Palo Verde prices. The Mid Columbia price point was deemed more applicable to resources available to both PGE and PacifiCorp for delivery to Oregon customers.

[9] This value is expressed in 2015 dollars. The value quoted in PacifiCorp's IRP is $22.39/ton in nominal 2020 dollars (p. 146). Converted to $20.39 in 2015 dollars by taking out inflation at 1.9% per year.

4). PacifiCorp's carbon value was used in lieu of a carbon adjusted forward price curve.

Renewable Energy Credit Banking

The analysis assumed that renewable energy credits (RECs) held by the utilities to meet renewable energy requirements are largely expended prior to the first year in which the standards are increased above current levels (2025).

Detailed Results

Overview

Under the proposal, incremental resource acquisitions over current RPS levels were (rounding) 270 MW in 2025, 1430 MW by 2030 (i.e., 1160 MW more than the 2025 acquisition), 3000 MW by 2035, and 3950 MW by 2040. By way of comparison, Oregon's presently installed wind generation totals about 3150 MW[10].

The effect of the increases in RPS requirements on retail rates was also estimated, ranging from an average of 0.9% higher revenue requirements for PGE and PacifiCorp under the most adverse scenario (no production tax credits, no value on carbon reductions), to an average decrease in revenue requirements of 2.8% (with production tax credits, higher carbon value estimate).

The carbon emission reductions were also estimated under the scenarios. Reductions in 2030 emissions from recent values ranged from 11% to 19% depending on the assumed displaced resources (combined cycle gas or coal). Carbon emission reductions in 2040 ranged from 30-53%. Reductions may not necessarily occur entirely on PGE and PacifiCorp owned power plants, but can be expected to occur somewhere in the western electric system.

Tabulated Results

The analysis assessed the effects of incremental renewable energy requirements under four specific scenarios arising from changing assumptions about the presence of federal tax credits, and whether a carbon savings value is assessed. These four scenarios are identified as:

- Scenario 1- No federal tax credit and no value on carbon savings.
- Scenario 2- No federal tax credit with a range of carbon savings (low and high).
- Scenario 3- Federal tax credit continues and no value on carbon savings.
- Scenario 4- Federal tax credit continues with a range of carbon savings (low and high).

[10] Not all of Oregon's wind currently is dedicated to Oregon's customers, and the additional renewables (wind or otherwise) could be located outside Oregon—the figures are presented solely to provide the reader a frame of reference.

Results for each of these scenarios are summarized in Table 1 below. Detailed results by year for the combined and individual utilities are contained in Appendix 1.

Table 1 Summary of detailed results.

Scenario	Average Rate Impact 2015-2040	Biggest Year Increase Over Base Case[11]	Biggest Year Decrease Over Base Case[12]
1 - No tax Credit, No Carbon Value	0.9%	2035 (3%)	2040 (-0.6%)
2 - No tax Credit, low/high Carbon Values	-0.3% to -1.1%	2030 (1.4%)	2040 (-4.6%)
3 - Tax Credit, No Carbon Value	-0.8%	2030 (0.7%)	2040 (-6.7%)
4 - Tax Credit, low/high Carbon Values	-1.9% to -2.8%	2018 (0.2%)	2040 (-13.8%)

Conclusion

The effects on ratepayers from the increased renewable energy standards is likely to result in rate increases to Oregonians averaging about 1% under fairly conservative, utility-based assumptions. With any increases in natural gas prices due to increased environmental regulation on gas exploration and development, or the advent of carbon emission based levies, the analysis suggests a net reduction in rates over the base case scenario. There is a wide range of uncertainty in the results, but investments in fixed cost resources such as renewables continues to represent a good hedge (insurance) against higher future fossil fuel prices as well as reducing environmental regulatory risk.

[11] The figures represent the greater of either PacifiCorp or PGE's revenue requirement above base case percentage.
[12] Similar to previous note, this is the greater of PacifiCorp and PGE's largest decrease. The largest decrease overall was PGE's 23.9% decrease in 2040 for high carbon in Scenario 4.

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