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LEGEND:

Taxpayer =

Partnership =
Parent =
Business A =
Company A =
Company B =
Company C =
Company D =
Company E =
Company F =
Company G =
Individual A =
Individual B =
Individual C =
Individual D =
Utility =
Licensor =
Country A =
State A =
State B =
State C =
State D =
State E =
Plant =
Date 1 =
Date 2 =

Date 3 =
Date 4 =
Date 5 =
Date 6 =
Date 7 =
Date 8 =
Date 9 =
Additive 1 =
Additive 2 =
Center =

Test Rep 1 =

Source Region A =

Dear :

This is in response to your request for rulings, submitted by your authorized representative, concerning the federal income tax consequences of the transaction described below.

Background

Partnership, a State A limited liability company, is a calendar year taxpayer and employs the accrual method of accounting for both book and tax purposes. The members of Partnership are Taxpayer and Company A, a State A limited liability company. The ultimate principal owners of Company A are Individual A, Individual B, Individual C and Individual D. Those individuals have worked and invested together in various projects since at least Date 1. Some of their prior projects included the development, construction and operation of synthetic fuel production facilities and waste coal processing facilities. Commencing in Date 2, the principals agreed to develop a new refined coal business, including that conducted by Company B, a State A limited liability company.

Taxpayer is a State A corporation and wholly owned, indirect subsidiary of Parent, a publicly traded Country A corporation that is primarily engaged, both directly and through its subsidiaries, including Taxpayer and other companies, in Business A. Investor holds its interest in Partnership through Company C, a State A limited liability company that is disregarded as a separate entity from Taxpayer, which in turns holds the interest in Partnership through Company D, a State A limited liability company that is disregarded as a separate entity from Company C.

Partnership was organized on Date 3 to acquire and engage in the refined coal business of Company B, which was organized on Date 4 and proceeded to construct a facility for the production of refined coal that was placed in service at a mine site in State B on or about Date 5 and produced and sold refined coal with the expectation that it would be burned to produce steam. However, due to unforeseen difficulties in identifying customers willing to enter into long-term contracts to purchase refined coal, Partnership did not continue producing refined coal after Date 6.

Subsequently, on Date 7, Company B entered into contracts with Utility, as described below, to locate a refined coal production facility on a site adjacent to the Plant in State C, and to sell refined coal produced in that facility to Utility. Because its existing facility did not meet the functional requirements for producing refined coal at this new location, Company B arranged for the construction of a new facility and assigned the original facility to Company E. The new facility consists of two independent production lines designed to produce refined coal.

On Date 8, Partnership acquired all of the membership interests in Company B from Company E and Company F in a transaction treated as a taxable sale of all of the interests in Company B by Company E and Company F, and as a deemed purchase by Partnership of all of the assets of Company B. Immediately thereafter, Company B merged with and into Partnership pursuant to State A law, such that Partnership became the owner of Company B’s refined coal business and succeeded to the various agreements with Utility described below.

Pursuant to its agreements with Utility, Partnership purchases coal feedstock from Utility. The coal supply agreement does not prohibit Taxpayer from purchasing coal feedstock from third parties, and does not prohibit Partnership from purchasing more feedstock coal than the Utility would expect to buy from Partnership in the form of refined coal.

The feedstock coal purchased by Partnership typically is coal that the Utility itself purchased from third party vendors, consistent with its coal specifications. Partnership uses the Process (as described below) to produce refined coal that it sells to the Utility pursuant to a refined coal sales agreement. All of the refined coal produced in the facility is expected to be used as a fuel at the Plant to produce steam for the generation of electricity. However, any refined coal not purchased by Utility can be sold to one or more third parties.

Partnership has no employees. Rather, it entered into an agreement with Company G, a State A limited liability company and affiliate of Company A. Pursuant to that agreement, Company G will operate, repair and maintain the facility in accordance with an agreed operating plan, will make arrangements to coordinate delivery of spare parts and supplies, will coordinate deliveries of coal feedstock purchases and sales of refined coal, and will perform certain administrative functions in support thereof. In addition, Company G will arrange for testing of refined coal as described below.

Description of the Process

The process at issue for production of refined coal currently employed at the facility involves the mixing of proprietary chemicals (additives) with feedstock coal prior to combustion (the Process). The patent for the Process is owned by Licensor and is licensed to Partnership. Licensor is entitled to certain per ton royalties based on production for the use of its technology. Test results have shown that when mixed with coal, the proprietary additives result in reduced NO_x, SO_2 and mercury emissions during combustion. Different chemicals are targeted at specific pollutants. Based on the characteristics of the feedstock coal burned at the Plant, Partnership has chosen a combination of additives that target the reduction of NO_x and mercury. In the case of NO_x, Partnership understands that Additive 1 is believed to cause a portion of the NO_x to adhere to, or react with, the additive so that it can be captured and is not emitted. In the case of mercury, Partnership understands that Additive 2 is believed to react with the elemental mercury in the feedstock coal so that it is converted into a chemical species of mercury (mercury oxide) that can be effectively captured by particulate control devices. A by-product of the Process is a valuable fly ash that can be used in a diverse array of applications in the steel, mining and cement industries.

Emissions Reduction Testing

For purposes of determining emissions reductions under § 45, Taxpayer will arrange for pilot-scale combustion testing (and laboratory analysis for redetermination purposes), and will not rely on any continuous emissions monitoring system or other field testing. Partnership engaged the research center of a prominent university (the Center) to conduct tests on behalf of Partnership at its pilot-scale combustion test facility (CTF) to determine the emission reductions associated with burning the refined coal compared to the feedstock coal. Center reports described below state:

> The CTF has been extensively used to research and investigate SO_x and NO_x emissions and the transformation of toxic trace metals (Hg [mercury], As, and Pb) during the combustion of coal and other fuels or waste materials. The CTF is capable of producing gas and particulate samples that are representative of those produced in industrial- and full-scale pulverized coal (pc)-fired boilers.

For purposes of qualifying the refined coal produced at the facility, Center conducted pilot-scale combustion tests at its CTF on Date 9 on the blend of feedstock coal of the type typically burned at the Plant.

Test Rep 1 explains that combustion gas analysis is provided by continuous emissions monitors (CEMs) at two locations: the furnace exit, which is used to monitor and maintain a specified excess air level for all test periods, and the outlet of the particulate control device, which is used to assess any air inleakage that may have occurred so that emissions of interest sampled at the back end of the system can be corrected for the dilution caused by the inleakage. Flue gas analyses were obtained from the duct at the outlet of the electrostatic precipitator (ESP). Flue gas mercury measurements were obtained separately by a continuous mercury monitor located at the flue gas ducting at the exit of the particulate control device. Center conducted a series of tests on the feedstock and refined coal blend, measuring the emissions with these devices.

Test Rep 1 states that the test results indicate that the blend of coal and additives achieved the required reductions in both NO_x and total mercury emissions (both determined on a lb/Btu basis) to satisfy the requirements of at least 20% NO_x reduction and at least 40% mercury reduction. Test Rep 1 states that it is expected the emissions reduction reported would be achieved at full scale using the additive levels tested.

<u>Tested Coal</u>

Plant currently burns a blend of subbituminous coal from a number of mines located in State D and State E, within source region A. Partnership produces refined coal using a blend of these coals and sells that refined coal to Plant which burns it to generate electricity from steam. The rank of the source region A coal burned at the Plant is classified by the American Society of Testing Materials (ASTM) as subbituminous coal with a gross calorific value of 8,500 to 9,500 btu/lb. Variations in the coal blend result from the supply and availability of the coals and the needs of the Plant.

Partnership requested that Center test a blend of coal that represents the range of coal blends to be used at the Plant (the “Tested Coal”). The report issued by Center states that the emission reduction requirements outlined in § 45 for NO_x and mercury were satisfied when comparing the results of burning the endpoint fuel to the results of burning the feedstock coal.

Center further reports that it analyzed the variability of fuel N_2 and fuel Hg contents of the Tested Coal because NOx and Hg emissions are of primary concern. Center states that it is expected that higher fuel N_2 and fuel Hg contents will lead to higher emissions of both NOx and Hg, respectively. Center concluded that the N_2 level from the samples tested appear typical for the coal used at the Plant and would not be expected to change dramatically from one shipment to another. The fuel Hg content in the samples tested was higher than average for source region A coals, and Center stated that it is expected that the majority of coal shipments to the Plant would contain similar or lower Hg contents. Therefore, Center concluded that any source region A coal containing similar fuel N_2 and fuel Hg contents would be expected to achieve the required emissions reductions.

Partnership expects to continue to operate with the blend and additive levels discussed in the Center reports, which would be consistent with long-term patterns for coal consumed at the Plant. If so, samples will be taken for redetermination testing within six months after the last emissions test satisfying the qualified emission reduction requirement. Thereafter, within six months after such date, another set of samples will be taken for redetermination testing. In each case, samples will be collected and prepared in accordance with sampling and testing procedures set forth in Partnership's operating protocols. Although testing and preliminary reporting is done timely, occasionally, the Center is not able to issue the final report until after the six-month period.

Although Partnership does not currently anticipate making changes to its coal feedstock or additive levels, or using other coal sources or ranks, additional testing will be conducted prior to acquiring coal feedstock from a different coal source region or of a different rank than reflected in the Tested Coal. In the case of a change in the additive levels, tests will also be run at the new minimum levels of additive as the qualified expert advises is necessary to conclude that a qualified emissions reduction will be expected for the new levels of additive.

RULINGS REQUESTED

Based on the foregoing, you have requested that we rule as follows:

1. The refined coal produced by using the Process constitutes "refined coal" within the meaning of §45(c)(7) of the Code, provided that such refined coal is produced from feedstock coal that is the same source or rank as the "Tested Coal" and provided further that the refined coal satisfies the qualified emission reduction test stated in §45(c)(7)(B) of the Code.

2. Provided that the feedstock coals used to produce refined coal during any determination period are from the same coal source region and of the same rank as the Tested Coal, all feedstock coal that satisfies that criteria shall be treated as feedstock coal of the same source and rank for purposes of section 6.04 of Notice 2010-54, regardless of the mine from which such feedstock coal is purchased.

3. Testing by Center for qualified emissions reduction as set forth in its test reports satisfies the requirements of Notice 2010-54. The pilot scale testing conducted at Center (and subsequent permitted laboratory testing as required for a redetermination described in section 6.04(2)(a) or (b) of Notice 2010-54) to satisfy the qualified emission reduction test of §45(c)(7)(B) of the Code may be relied upon regardless of subsequent normal fluctuations in operating conditions and emissions at the Plant.

4. The results set forth by the Center in a redetermination test report for production may be relied upon after the date of testing even if the report is not received until after the six-month period specified in section 6.04(l)(i) of Notice 2010-54.

LAW AND RATIONALE

Section 45(a) of the Code generally provides a credit against federal income tax for the use of renewable or alternative resources to produce electricity or fuel for the generation of steam. Section 45(e)(8) of the Code provides that, in the case of a producer of "refined coal", the credit available under §45(a) of the Code for any taxable year shall be increased by an amount equal to $4.375 per ton of qualified "refined coal" (i) produced by the taxpayer at a "refined coal production facility" during the 10-year period beginning on the date that the facility was originally placed in service, and which is (ii) sold by the taxpayer to an unrelated person during such 10-year period and such taxable year.

For purposes of §45 of the Code, section 3.01 of Notice 2010-54 provides that the term "refined coal" means a fuel which – (i) is a liquid, gaseous, or solid fuel (including feedstock coal mixed with an additive or additives) produced from coal (including lignite) or high carbon fly ash, including such fuel used as a feedstock, (ii) is sold by the taxpayer with the reasonable expectation that it will be used for the purpose of producing steam, and (iii) is certified by the taxpayer as resulting (when used in the production of steam) in a qualified emission reduction. Section 3.04 of the Notice provides that the term "qualified emission reduction" means, in the case of refined coal produced at a facility placed in service after December 31, 2008, a reduction of at least twenty percent (20%) of the emissions of nitrogen oxide and at least forty percent (40%) of the emissions of either sulfur dioxide or mercury released when burning the refined coal (excluding any dilution caused by materials combined or added during the production process), as compared to the emissions released when burning the feedstock coal or comparable coal predominantly available in the marketplace as of January 1, 2003.

Section 45(d)(8) of the Code generally provides that the term "refined coal production facility" means a facility which is placed in service after October 22, 2004 and before January 1, 2012.

Section 6.01 of Notice 2010-54 generally provides that a qualified emissions reduction does not include any reduction attributable to mining processes or processes that would be treated as mining (as defined in §613(c)(2), (3), (4)(A), (4)(C), or (4)(I)) if performed by the mine owner or operator. Accordingly, in determining whether a qualified emission reduction has been achieved, the emissions released when burning the refined coal must be compared to the emissions that would be released when burning the feedstock coal. Feedstock coal is the product resulting from processes that are treated as mining and are actually applied by a taxpayer in any part of the taxpayer's process of producing refined coal from coal.

Section 613(c)(5) of the Code describes treatment processes that are not considered as mining unless they are provided for in §613(c)(4) or are necessary or incidental to a process provided for in §613(c)(4). Any cleaning process, such as a process that uses ash separation, dewatering, scrubbing through a centrifugal pump, spiral concentration, gravity concentration, flotation, application of liquid hydrocarbons or alcohol to the surface of the fuel particles or to the feed slurry provided such cleaning does not change the physical or chemical structure of the coal, and drying to remove free water, provided such drying does not change the physical or chemical identity of the coal, will be considered as mining.

Section 6.03(1) of the Notice provides, in part, that emissions reduction may be determined using continuous emission monitoring system (CEMS) field testing. Section 6.03(a)(1) provides, in part, that CEMS field testing is testing that meets all the following requirements: (i) the boiler used to conduct the test is coal-fired and steam-producing and is of a size and type commonly used in commercial operations; (ii) emissions are measured using a CEMS; (iii) if EPA has promulgated a performance standard that applies at the time of the test to the pollutant emission being measured, the CEMS must conform to that standard; (iv) emissions for both the feedstock coal and the refined coal are measured at the same operating conditions and over a period of at least 3 hours during which the boiler is operating at a steady state at least 90 percent of full load; and (v) a qualified individual verifies the test results in a manner that satisfies the requirement of section 6.03(1)(b).

Section 6.03(2) of the Notice provides that methods other than CEMS field testing may be used to determine the emission reduction. The permissible methods include (a) testing using a demonstration pilot-scale combustion furnace if it establishes that the method accurately measures the emission reduction that would be achieved in a boiler described in section 6.03(1)(a)(i) and a qualified individual verifies the test results in a manner that satisfies the requirements of section 6.03(1)(c)(i), (ii), (v) and (vi) of the Notice; and (b) a laboratory analysis of the feedstock coal and the refined coal that complies with a currently applicable EPA or ASTM standard and is permitted under section 6.03(2)(b)(i) or (ii).

Section 6.04(1) of the Notice provides that a taxpayer may establish that a qualified emission reduction determined under section 6.03 applies to production from a facility by a determination or redetermination that is valid at the time the production occurs. A determination or redetermination is valid for the period beginning on the date of the determination or redetermination and ending with the occurrence of the earliest of the following events: (i) the lapse of six months from the date of such determination or redetermination; (ii) a change in the source or rank of the feedstock coal that occurs after the date of such determination or redetermination; or (iii) a change in the process of producing refined coal from the feedstock coal that occurs after the date of such determination or redetermination.

Section 6.04(2) of the Notice provides that in the case of a redetermination required because of a change in the process of producing refined coal from the feedstock coal, the redetermination required under section 6.04 must use a method that meets the requirements of section 6.03. In any other case, the redetermination requirement may be satisfied by laboratory analysis establishing that – (a) the sulfur (S) or mercury content of the amount of refined coal necessary to produce an amount of useful energy has been reduced by at least 20 percent (40 percent, in the case of facilities placed in service after December 31, 2008) in comparison to the S or mercury content of the amount of feedstock coal necessary to produce the same amount of useful energy, excluding any dilution caused by materials combined or added during the production process; (b) the S or mercury content of both the feedstock coal and the refined coal do not vary by more than 10 percent from the S and mercury content of the feedstock coal and refined coal used in the most recent determination that meets the requirements of the Notice.

Finally, section 6.05 of the Notice provides that the certification requirement of section 3.01(1)(c) of the Notice is satisfied with respect to fuel for which the refined coal credit is claimed only if the taxpayer attaches to its tax return on which the credit is claimed a certification that contains the following: (1) a statement that the fuel will result in a qualified emissions reduction when used in the production of steam; (2) a statement indicating whether CEMS field testing was used to determine the emissions reduction; (3) if CEMS field testing was not used to determine the emissions reduction, a description of the method used; (4) a statement that the emissions reduction was determined or redetermined within the six months preceding the production of the fuel and that there have been no changes in the source or rank of the feedstock coal used in the process of producing refined coal from feedstock coal since the emissions reduction was most recently determined or redetermined; and (5) a declaration signed by the taxpayer in the following form: "Under penalties of perjury, I declare that I have examined this certification and to the best of my knowledge and belief, it is true, correct, and complete."

With respect to the first issue, the Process starts with several chemical additives being added to the feedstock coal prior to its combustion in a furnace. The additives provide the chemical structure that results in the reduction of emissions of nitrogen oxide and mercury during combustion. Section 6.01 of the Notice provides generally that a qualified emissions reduction does not include any reduction attributable to mining processes or processes that would be treated as mining if performed by the mine owner or operator. In the instant case, the Process is not a mining process. Further, section 3.01 of the Notice clarifies §45(c)(7) of the Code and specifically provides that refined coal includes feedstock coal mixed with additives. Thus, additive processes that mix certain chemicals or other additives with the coal in order to achieve emissions reductions may qualify for the refined coal production tax credit. Additionally, section 3.03 defines comparable coal as coal that is of the same rank as the feedstock coal and that has an emissions profile comparable to the emissions profile of the feedstock coal. Accordingly, we conclude that the coal produced by using the Process constitutes a "refined coal" within the meaning of §45(c)(7) of the Code, provided that the refined coal (i) is produced from feedstock coal that is the same source or rank as the "Tested Coal" and (ii) satisfies the qualified emission reduction test stated in §45(c)(7)(B) of the Code.

With respect to the second issue, the emissions profile of the refined coal product is compared to the emissions profile of either the feedstock coal or a comparable coal predominantly available in the marketplace as of January 1, 2003. Section 3.03 of the Notice provides that a "comparable coal" is defined as coal that is of the same rank as the feedstock coal and that has an emissions profile comparable to the emissions profile of the feedstock coal. Section 6.04 of provides that a determination or redetermination of a qualified emissions reduction is valid until the occurrence of the earliest of the following events: (i) the lapse of six months from the date of such determination or redetermination; (ii) a change in the source or rank of the feedstock coal that occurs after the date of such determination or redetermination; or (iii) a change in the process of producing refined coal from the feedstock coal that occurs after the date of such determination or redetermination. Accordingly, we conclude that provided that the feedstock coals during any determination period are from the same coal source regions and of the same rank as the Tested Coal, all feedstock coal that satisfies that criteria shall be treated as feedstock coal of the same source and rank for purposes of section 6.04 of Notice 2010-54, regardless of the mine from which such feedstock coal is purchased.

With respect to the third issue, section 6.03(3) of the Notice provides that any permissible testing method provided for in the Notice can be used in emission testing for any pollutant. That is, a taxpayer can use different testing methods for each of nitrogen oxide, sulfur dioxide or mercury, provided the method used for any pollutant is a permissible method. Section 6.04(1) provides that an emission test establishing a "qualified emission reduction" qualifies the refined coal for a six-month period provided there is no change in the process for producing the refined coal or in the source or rank of the feedstock coal. Therefore, a taxpayer must "redetermine" the emission reductions to qualify for the succeeding six-month period using one or more approved methods. In the instant case, Partnership will arrange for pilot-scale combustion testing, and will not rely on any continuous emissions monitoring system or other field testing, which is permitted under section 6.03 of the Notice. Specifically, Partnership will arrange with the Center to conduct testing (including redetermination testing) at its CTF to determine the emissions reductions associated with burning the refined coal product compared to the feedstock. For purposes of qualifying the refined coal produced at the facilities, the Center has conducted pilot-scale combustion tests at its CTF as documented in Test Rep 1. In conducting such tests, the Center conducted tests on the feedstock, and then mixed a separate sample of the feedstock with the additives so that it could conduct tests on the refined coal product. In each of its reports, the Center reported that the test results indicated that the blend of coal and additives achieved the required emissions reductions. Based on the foregoing, we conclude that testing by the Center for qualified emissions reductions as set forth in its test reports (including interim reports) satisfies the requirements of Notice 2010-54. Qualified emissions reduction through testing by the Center at its combustion research facility or similar pilot-scale combustion testing facilities under Notice 2010-54 may be relied upon, regardless of subsequent normal fluctuations in operating conditions and emissions at the power plants where the refined coal is burned.

With respect to the fourth issue, it is intended that the Center will engage in redetermination testing every six months, or more frequently if required pursuant to Notice 2010-54. However, the Center is not always able to issue the written report required by section 6.03(2)(a) of Notice 2010-54 within the six month period. Thus, although the redetermination is completed with the six month period the report may be received after the six month period. Nonetheless, Center informed Partnership of the results of the test on the day of the tests so that it was able to take in account the results of the redetermination with the six month period. Accordingly, we conclude that the results set forth by the Center in a redetermination test report for production may be relied upon after the date of testing even if the report is not received until after the six-month period specified in section 6.04(l)(i) of Notice 2010-54. However, Partnership must, in any event, receive the written report within 90 days from the date of testing.

No opinion is expressed regarding any other issue not specifically addressed in this ruling letter. In particular, no opinion is expressed with respect to (1) whether Taxpayer or any of its affiliates is the Producer of the refined coal for purposes of § 45(e)(8) of the Code; (2) whether there has been a sale of refined coal to an unrelated person; or (3) when the Facility was, in fact, placed in service.

In accordance with the Power of Attorney on file with this office, we are sending a copy of this letter to your authorized representatives. A copy of this ruling must be attached to any income tax return to which it is relevant. Alternatively, taxpayers filing their returns electronically may satisfy this requirement by attaching a statement to their return that provides the date and control number of the letter ruling.

This ruling is directed only to the Taxpayer who requested it. Section 6110(k)(3) of the Code provides it may not be used or cited as precedent. We are sending a copy of this letter ruling to the Industry Director.

Sincerely,

Peter C. Friedman

Peter C. Friedman
Senior Technician Reviewer, Branch 6
Office of Associate Chief Counsel (Passthroughs & Special Industries)