Internal Revenue Service

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Person To Contact:
, ID No.
Telephone Number:

Refer Reply To:
CC:PSI:B6
PLR-120861-12
Date:
March 12, 2013

LEGEND:

Taxpayer =

Company =

Developer =
Member A =
Member B =
Member C =
Member D =
State A =
State B =
State C =
State D =
State E =
State F =
State G =
State H =
State I =
Date 1 =
Date 2 =
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Date 4 =
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Date 9 =
Date 10 =
Date 11 =
Date 12 =
Date 13 =
Date 14 =
Lessor 1 =
Lessor 2 =
Lessor 3 =
Lessor 4 =
Lessor 5 =
Lessor 6 =
Power Plant 1 =
Power Plant 2 =
Power Plant 3 =
Power Plant 4 =
Power Plant 5 =
Power Plant 6 =
Utility A =
Utility B =
Utility C =
Utility D =
Operator 1 =
Operator 2 =
Operator 3 =
Manager =
Licensor =
$xx =
$yy =
Additive 1 =
Additive 2 =
Center =
Test Rep 1 =

Test Rep 2 =

Test Rep 3 =

Test Rep 4 =
Test Rep 5 =

Test Rep 6 =

Test Rep 7 =

x% =
y% =
Source Region A =
Source Region B =
Source Region C =
Source Region D =
Source Region E =

Dear :

This is in response to your request, submitted by your authorized representative, to supplement private letter ruling PLR-135547-11 dated January 12, 2012, concerning the federal income tax consequences of the transaction described below.

Background

Taxpayer, a State A corporation, is a calendar year taxpayer and employs the accrual method of accounting for both book and tax purposes. Taxpayer is publicly traded and conducts a global financial services business.

Company is a State A limited liability company that is wholly owned by Taxpayer. Company is disregarded as a separate entity from Taxpayer for federal tax purposes.

Developer is a State A limited liability company that is classified as a partnership for federal tax purposes. Developer is owned by Member A, Member B, Member C and Member D. The principal owners of these entities 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 principal owners of Developer agreed to develop a new refined coal business, including the facilities described herein.

On Date 3, Company entered into a participation agreement with Developer pursuant to which the Company agreed to enter into facility lease agreements with respect to certain facilities designed to produce refined coal. The participation agreement subsequently was amended on Date 4, Date 11 and Date 12. The facilities covered by the participation agreement are owned by Lessor 1, Lessor 2, Lessor 3, Lessor 4, Lessor 5 and Lessor 6, respectively. Each of the Lessor entities is a State A limited liability company that is owned by an affiliate of Developer. The facility owned by Lessor 1 is located at Power Plant 1, which is owned by Utility A. The facility owned by Lessor 2 is located at Power Plant 2, which is owned by Utility A. The facility owned by

Lessor 3 was constructed at Power Plant 3, which is owned by Utility B. The facility owned by Lessor 4 was constructed at Power Plant 4, which is owned by Utility C. The facility owned by Lessor 5 was constructed at Power Plant 5, which is owned by Utility D. The facility owned by Lessor 6 was constructed at Power Plant 6, which is owned by Utility D.

In connection with each facility lease agreement, the applicable Lessor assigned to the Company the project agreements with the applicable Utility. In addition, the Company entered into operation and maintenance agreements with Operator 1, Operator 2, or Operator 3, each of which is a State A limited liability company and affiliate of Developer. Pursuant to those agreements, the applicable Operator will operate, repair and maintain the facilities 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, the applicable Operator will arrange for testing of refined coal as described below.

With respect to each facility, Company will purchase coal feedstock from the applicable Utility. The coal supply agreements do not prohibit the Company from purchasing feedstock coal from third parties, and do not prohibit the Company from purchasing more feedstock coal than the applicable Utility would expect to buy from the Company in the form of refined coal.

The feedstock coal purchased by the Company typically will be coal that the applicable Utility itself purchased from third party vendors, or in the case of Utility B, acquired from affiliates, consistent with its coal specifications. At each facility, the Company will buy feedstock coal and use the Process (as described below) to produce refined coal that it will sell to the applicable Utility pursuant to a refined coal sales agreement. All of the refined coal produced in the facilities is expected to be used as a fuel at the applicable Power Plant to produce steam for the generation of electricity. However, any refined coal not purchased by the applicable Utility can be sold to one or more third parties.

The Company has no employees. Rather, it entered into a refined coal management services agreement with Manager, a State A limited liability company and affiliate of Developer, with respect to certain management responsibilities relating to the Company's refined coal business. Pursuant to that agreement, subject to the provision of funds by the Company, and subject further to the limitations on its authority as specified in the agreement with respect to certain major decisions that require the Company's approval, the Manager is responsible for the operation of the facilities and the Company's refined coal business.

Description of the Process

The process at issue for production of refined coal currently employed at the facilities involves the adding of proprietary chemicals (additives) to feedstock coal prior to combustion (the Process). The patent for the Process is owned by Licensor and is licensed to the Lessors and sublicensed to the Company. Licensor is entitled to certain per ton royalties based on production for the use of its technology. Specifically, Company will make royalty payments to Licensor equal to $xx per ton of coal feedstock subjected to the Process, which royalties will increase to $yy per ton of coal feedstock subjected to the Process on the date specified in each license agreement.

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 Power Plants, Company has chosen a combination of additives that target the reduction of NO_x and mercury. In the case of NO_x, Company 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, Company 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.

<u>Emissions Reduction Testing</u>

For purposes of determining emissions reductions under § 45, Company will arrange for pilot-scale combustion testing, and will not rely on any continuous emissions monitoring system or other field testing. Developer engaged the research center of a prominent university (the Center) to conduct tests on behalf of the Lessors 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 located at Power Plant 1, Center conducted pilot-scale combustion tests at its CTF on Date 5 on the blend of feedstock coals of the type typically burned at Power Plant 1. Similar tests were conducted by Center at its CTF on Date 6 on the blend of feedstock coals of the type typically burned at Power Plant 2, on Date 7 on the blend of feedstock coals of the type typically burned at Power Plant 3, on Date 8 on the blend of feedstock coals of the type typically burned at Power Plant 4, on Date 9 on the blend of feedstock coals of the type typically burned at Power Plant 5, and on Date 13 and Date 14 on the blend of feedstock coals of the type typically burned at Power Plant 6.

The Center reports explain 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 blends, 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. Similar conclusions are reached by Center in Test Rep 2, Test Rep 3, Test Rep 4, Test Rep 5, Test Rep 6 and Test Rep 7.

Tested Coal

Power Plant 1 currently burns bituminous coals from a number of mines in source region A located in State B, State C and State D. The coal rank of all of the source region A coal burned at Power Plant 1 is classified by the American Society of Testing Materials (ASTM) as bituminous coal with a gross calorific value of 10,500 to 12,000 btu/lb.

Power Plant 2 currently burns bituminous coals from a number of mines in source region B located in State C, State D and State E. The coal rank of all of the source region B coal burned at Power Plant 2 is classified by the ASTM as bituminous coal with a gross calorific value of 12,000 to 13,000 btu/lb.

Power Plant 3 currently burns lignite from two mines in source region C located in State F. The coal rank of all of the source region C coal burned at Power Plant 3 is classified by the ASTM as lignite with a gross calorific value of 6,500 to 7,500 btu/lb.

Power Plant 4 currently burns coals from several mines in source region D located in State G. The coal rank of approximately x% of the blend of the source region D coal burned at Power Plant 4 is classified by the ASTM at bituminous coal with a gross calorific value of 10,500 to 12,200 btu/lb, and the coal rank of approximately y%

of the blend of the source region D coal burned at Power Plant 4 is classified by the ASTM as subbituminous coal with a gross calorific value of 8,500 to 9,000 btu/lb.

Power Plant 5 currently burns coals from several mines in source region E located in State I and lignite from several mines in source region C located in State H. The coal rank of all of the source region C coal burned at Power Plant 5 is classified by the ASTM as lignite with a gross calorific value of 6,500 to 7,500 btu/lob, and the coal rank of all of the source region E coal burned at Power Plant 5 is classified by the ASTM as subbituminous coal with a gross calorific value of 8,500 to 9,500 btu/lb.

Power Plant 6 currently burns coals from several mines in source region E in State I and lignite from a mine adjacent to Power Plant 6 in State H, within Source Region C. The coal rank of all of the source region C coal burned at Power Plant 6 is classified by the ASTM as lignite with a gross calorific value of 6,500 to 7,500 btu/lob, and the coal rank of all of the source region E coal burned at Power Plant 6 is classified by the ASTM as subbituminous coal with a gross calorific value of 8,000 to 9,000 btu/lb.

For each of its tests, Center tested blends of coal that represent the range of coal blends to be used at the respective Power Plant (the “Tested Coal”). The reports issued by Center state that the emission reduction requirements outlined in § 45 for NO_x and mercury were satisfied when comparing the results of burning the endpoint fuels to the results of burning the feedstock coal.

Center further reports that it analyzed the variability of fuel N2 and fuel Hg contents between coals of the rank and from the source regions used at each of the Power Plants because NOx and Hg emissions are of primary concern. In each case, Center states that it is expected that higher fuel N2 and Hg contents will lead to higher emissions of both NOx and Hg, respectively. Center concluded that the N2 and Hg levels from the many samples tested appear typical for many of the Tested Coals and would not be expected to change dramatically from one shipment to another. After reviewing the average levels of N2 and Hg against the combustion test results, Center concluded that any fuel blend tested would represent the range of fuels commonly fired by the respective Power Plant and could be expected to achieve the required reductions.

The Company expects to continue to operate with the blends and additive levels discussed in the Center reports, which would be consistent with long-term patterns for coal consumed at the Power Plants. 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 the Taxpayer’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 Company does not currently anticipate making changes to its coal feedstock or additive levels, 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.

In addition, the Company may decide to collect and test composite samples of feedstock and refined coal at one or more of its facility sites to determine the sulfur and mercury content of the samples. If such samples are collected, a rolling six-month average of the laboratory analyses would be computed to determine whether there has been a change of the sulfur and mercury content by more than ten percent.

RULINGS REQUESTED

Based on the foregoing, Taxpayer has requested that we rule as follows:

1. The refined coal produced 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 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.

3. Testing by Center for qualified emissions reduction as set forth in its test reports satisfies the requirements of Notice 2010-54. Taxpayer may rely on the pilot scale testing conducted at Center to satisfy the qualified emission reduction test of §45(c)(7)(B) of the Code regardless of subsequent normal fluctuations in operating conditions and emissions at the Power Plants.

4. Pursuant to section 6.04(2)(b) of Notice 2010-54, the Taxpayer may satisfy the redetermination requirement of section 6.04 of Notice 2010-54 by laboratory analysis establishing that the sulfur and mercury content of both the feedstock coal and the refined coal, on average, do not vary by more than ten percent from the sulfur and mercury content of the feedstock coal and refined coal used in the most recent determination that meets the requirements of section 6.03 of Notice 2010-54.

5. The results set forth by the Center in a redetermination test report for production may be relied upon after the date of the testing even if the report is not received until after the six month period specified in section 6.04(1)(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 achieve, 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, the Company 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, the Company 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, Test Rep 2, Test Rep 3, Test Rep 4, Test Rep 5, Test Rep 6 and Test Rep 7. 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. If a redetermination test is conducted before the six month anniversary date but a final report is not received before such date, Center provides interim results that are certified as required by Notice 2010-54, and agrees to deliver a final report upon completion. 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. The Taxpayer may establish a qualified emissions reduction through testing by the Center at its combustion research facility or similar pilot-scale combustion testing facilities under Notice 2010-54.

With respect to the fourth issue, section 6.04(2) of Notice 2010-54 provides, in part, 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 the sulfur and mercury content of both the feedstock coal and the refined coal do not vary by more than 10 percent from the sulfur and mercury content of the feedstock coal and refined coal used in the most recent redetermination that meets the requirements of the Notice. Accordingly, we conclude that Taxpayer may satisfy the redetermination requirement of section 6.04 of Notice 2010-54, by laboratory analysis establishing that the sulfur and mercury content of both the feedstock coal and the refined coal, on average, do not vary by more than 10 percent from the sulfur and mercury content of the feedstock coal and refined coal used in the most recent determination that meets the requirements of section 6.03 of Notice 2010-54.

With respect to the fifth issue, it is intended that the Taxpayer 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 redetermination testing is completed within the six month period, the report may be received after the six month period. Nonetheless, the Center informed the Taxpayer of the results of the test on the day of the tests so that it was able to take into account the results of the redetermination within the six month period. Nevertheless, the delay by the Center in issuing its report cannot be indefinite. 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(1)(i) of Notice 2010-54, so long as the Taxpayer receives the written report within 90 days from the date of testing. However, the redetermination of qualified emissions reduction must occur during the earliest of the events described in section 6.04 of the Notice 2010-54 regardless of the time of the actual receipt of Center’s test report.

This ruling expresses no opinion about any issue not specifically addressed in this ruling letter, including (1) whether any person has sold refined coal to an unrelated person, or (2) when the facility was "placed in service." In particular, we express or imply no opinion that the Taxpayer has sufficient risks and rewards of the production activity to qualify as the producer of the refined coal. The Service may challenge an attempt to transfer the credit to a taxpayer who does not qualify as a producer, including transfers structured as partnerships, sales or leases that do not also transfer sufficient risks and rewards of the production activity.

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