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June 27, 2013

Ms. Mary Jo Kunkle
Michigan Public Service Commission
6545 Mercantile Way
P. O. Box 30221
Lansing, MI 48909

RE: MPSC Case N°. U-17097

Dear Ms. Kunkle:

The following is attached for paperless electronic filing:

Initial Brief of the Michigan Environmental Council and the Natural Resources Defense Council

E-Service List

Sincerely,

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STATE OF MICHIGAN

MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of THE DETROIT EDISON COMPANY for Authority to Implement a Power Supply Cost Recovery Plan in its Rate Schedules For 2013 Metered Jurisdictional Sales of Electricity.	Case N$^{o.}$ U-17097 ALJ Sharon L. Feldman

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INITIAL BRIEF OF THE MICHIGAN ENVIRONMENTAL COUNCIL AND THE NATURAL RESOURCES DEFENSE COUNCIL

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June 27, 2013

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I. INTRODUCTION

The Michigan Environmental Council ("MEC") and the Natural Resources Defense Council ("NRDC") submit this initial brief to address four principal issues relating to the DTE Electric Company's ("DTE Electric" or "Company")[1] 2013 Power Supply Cost Recovery ("PSCR") plan. First, DTE Electric's 2013 PSCR plan and corresponding five-year PSCR forecast are neither reasonable nor prudent because both the plan and the forecast are based on the same flawed modeling approach that has led the Company to make increasingly erroneous projections of system generation, purchases, and revenues over each of the past six years. Second, the Company's PSCR plan and five-year power supply forecast unreasonably follow a business-as-usual approach that is increasingly non-competitive and fails to prudently respond to fundamentally changed market conditions. Third, the Commission should find that it is unlikely to authorize recovery of Detroit Edison's projected PSCR costs related to pollution controls because the Company has neither provided a credible estimate of what those costs would be, nor demonstrated that the costs would be part of a least cost plan for environmental compliance. Finally, the Commission should disapprove of the Company's proposed Reduced Emissions Fuel ("REF") project because it subjects DTE Electric and its customers to unreasonable risks, because the project fails to provide the Company with sufficient benefits in return for its assumption of those risks, and because the project violates the Commission's Code of Conduct.

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[1] The Company formerly known as the Detroit Edison Company recently changed its name to the DTE Electric Company. References in this brief to the "DTE Electric Company" or to "DTE Electric" are therefore references to the former Detroit Edison Company. References to the "DTE Energy Company," on the other hand, are references to the unregulated corporate parent of the DTE Electric Company.

II. SUMMARY OF PROCEEDINGS

A. DTE Electric's 2013 PSCR Plan and 5-Year Forecast

On September 28, 2012, DTE Electric submitted a PSCR application for the 2013 plan year. DTE Electric projects incurring power supply costs of $1,511,833,000 in 2013, to which the Company adds a projected under recovery from 2012 of $81,182,000, for total 2013 power supply costs of $1,593,015,000.[2] DTE Electric seeks to recover these costs through a PSCR factor of 4.74 mills per kilowatt hour above its existing PSCR base of 31.26 mills per kilowatt hour.[3]

Along with its PSCR application, DTE Electric filed a 5-year forecast of its power supply requirements and sources for meeting those requirements. DTE Electric's 5-year forecast envisions retiring only two small and underutilized coal units in 2015, while having almost the exact same proportion of energy production coming from coal versus natural gas in 2013 (78% to 1%) as in 2008 (79% to 1%) and as projected for 2017 (78% to 1%).[4] As a result, the 5-year forecast projects that DTE Electric's generation portfolio will remain dominated by aging coal-fired units, with the Company's natural gas capacity virtually never operating and no additional renewable generation beyond the state mandate.[5] Under this plan, DTE Electric's power supply costs are projected to increase to $1,909,822,000 in

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[2] Exhibit A-3.

[3] *Id*.

[4] Exhibit MEC-2.

[5] Exhibit A-16.

2017,[6] with the Company's PSCR factor more than doubling to 11.68 mills per kilowatt hour.[7]

B. Pollution Control Sorbent Costs.

Consistent with the Company's plan to keep virtually all of its coal-fired generation capacity operating, DTE Electric asks the Commission to indicate whether it is unlikely to approve recovery for two types of pollution control sorbents starting in 2015.[8] The first are activated carbon injection ("ACI") sorbents, such as Powdered Activated Carbon ("PAC") or Brominated Activated Carbon ("BrPAC"), which are intended to reduce mercury emissions as required by the federal Mercury and Air Toxics Standards ("MATS") and the Michigan Mercury Rule. The second are sorbents such as Trona or sodium bicarbonate that are used in dry sorbent injection ("DSI") systems in an effort to reduce acid gases as required by the MATS rule. DTE Electric estimates that it will have total ACI sorbent expenses of approximately $5.3 million per year starting in 2015, and DSI sorbent expenses starting at $13 million in 2015 and increasing to $14.2 million by 2017.[9]

C. Levelized Cost of Electricity Analysis.

While DTE Electric described its DSI and ACI proposal as being part of a "least cost strategy" for achieving compliance with MATS and the Michigan Mercury Rule,[10] the

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[6] DTE Electric's 5-year plan assumes zero under-recoveries for each year after 2013. Exhibit A-4. Such assumption is questionable given that the Company has experienced between $18 million and $95 million in under-recoveries in all but one year since 2005.

[7] Exhibit A-4.

[8] DTE Electric Company, Application, MPSC Case No. U-16892 (Sept. 28, 2012), 4-5.

[9] Exhibit A-2.

[10] See Direct Testimony of DTE Electric witness William C. Rogers ("Rogers Direct"), 2 Tr 120; Cross Examination of DTE Electric witness William C. Rogers ("Rogers Cross"), 2 Tr 155.

Company's application did not include any evidence supporting that assertion. During the discovery process, however, DTE Electric produced the results of a spreadsheet analysis that purported to compare the levelized cost of energy from many of the Company's coal units with DSI and ACI, from those coal units with flue gas desulfurization (commonly referred to as "scrubbers") and ACI, and from replacing each coal unit with a new natural gas combined cycle ("NGCC") plant. This Levelized Cost of Energy ("LCOE") analysis[11] concluded that, based on DTE Electric's inputs, the NGCC option would be lower cost than adding scrubbers and ACI to most of the coal units, but that if only DSI and ACI were added to the coal units most of them would have a lower levelized cost of electricity than the NGCC plant. The results for the River Rouge plant, however, were extremely close, with the new NGCC being less than 5% more expensive than the River Rouge units with DSI and ACI. In her testimony, MEC/NRDC witness Patricia Richards demonstrated that the LCOE analysis relied on numerous faulty assumptions that skewed the analysis in favor of DTE Electric's coal units, including use of an outdated and inflated natural gas price projection, assuming no costs related to carbon dioxide emissions, and ignoring the likelihood of the need for future PSCR costs to comply with other existing environmental standards.

D. Reduced Emissions Fuel Project.

DTE Electric's application includes extensive testimony and exhibits concerning its REF project, but it does not specifically request any related relief from the Commission. Still, because it states that the Company "continues to evaluate and implement" the REF project, and because it makes an extensive effort to justify that project, DTE Electric's

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[11] See Exhibits MEC-46 and MEC-47.

application in this case appears to include an implicit request that the Commission approve the use of REF as a component of its PSCR plan and 5-year PSCR forecast.

III. LEGAL STANDARD

Under MCL 460.6j, a utility seeking to recover fuel costs from its customers must annually file a PSCR[12] plan with the Commission. The Commission then reviews the PSCR plan in a contested case proceeding, in which the utility carries the burden of proving to the Commission that it took all appropriate steps to minimize the cost of fuel and that its proposed PSCR costs were "incurred under reasonable and prudent policies and practices."[13] Consistent with the general rule that public utilities bear the burden of proof in demonstrating that their proposed rates are lawful and reasonable,[14] a utility seeking an increase in its PSCR cost recovery is required to "place in evidence facts relied upon to support [its] petition or application to increase rates and charges."[15] The Commission has previously stated that ""[t]he utility has the statutory burden of presenting evidence in support of recovering its PSCR costs, and other parties may challenge costs that they believe are excessive due to company decision making."[16] And in yet another case, the Commission explained that "the burden is on the utility to demonstrate that its PSCR costs

[12] PSCR costs are defined by statute as "the booked costs, including transportation costs, reclamation costs, and disposal and reprocessing costs, of fuel burned by the utility for electric generation and the booked costs of purchases and net interchanged power transactions by the utility incurred under reasonable and prudent policies and practices." MCL 460.6j(1)(a).

[13] MCL 460.6j(1)(a); see also MCL 460.6j(3), (6); MCL 460.6a(2).

[14] See 73B C.J.S. Public Utilities § 131.

[15] MCL 460.6a(1).

[16] January 25, 2010 Order in MPSC Case No U-15675, 9.

are attributable to reasonable and prudent management decisions. The Commission has, on many occasions, disallowed costs that were not so attributed."[17] As such, if the utility does not make the requisite showings of prudence, reasonableness, and minimization of costs, the PSCR costs must be amended or disallowed.[18]

A core part of the Commission's reasonableness and prudence determination is an evaluation of "whether the utility has taken all appropriate actions to minimize the cost of fuel."[19] As the Commission has explained, this provision requires DTE Electric to "take all appropriate steps to minimize coal costs charged to its PSCR customers."[20] A utility's failure "to pursue appropriate measures to reduce its PSCR expenses could be deemed unreasonable or imprudent conduct that could lead to the disallowance of costs."[21] Accordingly, the relevant standard is not whether DTE Electric's actions may have some benefit for ratepayers but instead whether the utility has taken "all appropriate actions" to minimize its PSCR costs.

As part of its PSCR filing, DTE Electric was also required to file:

> a 5-year forecast of the power supply requirements of its customers, its anticipated sources of supply, and projections of power supply costs, in light of its existing sources of electrical generation and sources of electrical generation under construction. The forecast shall include a description of all relevant major contracts and power supply arrangements

[17] June 27, 2003 Order in MPSC Case No. U-13562, 3.

[18] MCL 460.6j(6).

[19] *Id.*

[20] February 28, 2005, Order in MPSC Case No. U-13917, 19.

[21] *Id.*

> entered into or contemplated by the utility, and such other information as the commission may require.[22]

In reviewing DTE Electric's filing, the Commission must "evaluate the decisions underlying the 5-year forecast filed by a utility" and "may also indicate any cost items in the 5-year forecast that, on the basis of present evidence, the commission would be unlikely to permit the utility to recover from its customers…."[23] DTE Electric has specifically requested that the Commission indicate whether it would be unlikely to permit recovery of the ACI and DSI pollution control sorbents starting in 2015.

IV. ARGUMENT

The record in this case shows that DTE Electric has proposed a business-as-usual cost recovery plan and five-year power supply forecast that is based on unreliable forecasting methods, that ignores fundamentally changing market conditions, and that is neither just nor reasonable. The Company's application falters right out of the gate because it is based on projections of generation, market sales, and revenue derived from a modeling approach that has been generating increasingly erroneous data over the past six years. The resulting cost recovery plan and power supply forecast double down on a failed strategy that is both increasingly costly for ratepayers and non-competitive in the Midcontinent Independent System Operator ("MISO") marketplace. DTE Electric seeks to perpetuate this costly strategy by requesting that the Commission signal its likely approval of significant PSCR cost increases for pollution control sorbents starting in 2015. But the Company has failed to provide credible estimates of the costs of those sorbents or to

[22] MCL 460.6j(4).

[23] MCL 460.6j(b)(7).

demonstrate that such sorbent usage is part of a least cost plan for complying with state and federal environmental standards.

While this business-as-usual approach leads to power supply costs that are not just and reasonable, it is profitable for DTE Electric's shareholders and unregulated affiliates. In particular, the Company's REF project, by which unregulated affiliates plan to generate at least half-a-billion-dollars in revenue through the use of DTE Electric coal at no net cost, creates an incentive for DTE Electric to remain a utility that is overly-dependent on coal. Because the Commission's Code of Conduct forecloses such subsidization of unregulated affiliates on the backs of DTE Electric's captive ratepayers, however, and because the REF project is itself an unreasonable course of conduct for a regulated public utility, the Commission should reject the REF project and remove any incentive for DTE Electric's parent company to continue its failed, business-as-usual approach to electric generation and fuel supply.

A. DTE Electric Has Based Its PSCR Application on a Methodology That Has Been Increasingly Inaccurate for at Least the past Six Years.

A core portion of any PSCR filing is the utility's projection of energy generation, market sales and purchases, and resulting revenues and expenses, as those are key factors in determining the power supply costs that ratepayers are likely to incur. As part of its application, DTE Electric projected values for each of those factors by using an economic modeling program called PROMOD, in which the Company attempts to forecast how MISO will dispatch its generating units. As DTE Electric's witnesses made clear, the

PROMOD modeling used in this proceeding is a "methodology that is largely the same" as that used by the Company in its past eight PSCR filings.[24]

Unfortunately for the Company's customers, that methodology has led to projections over the past eight years that are increasingly wrong. In almost every one of those years, the Company has over-projected the amount of energy that it would generate and under-estimated the amount of energy that it would need to purchase from the MISO market. Such errors have made DTE Electric's power supply plans and forecasts appear more favorable to ratepayers than they have ended up being, and they have led the Company to seek reimbursement for increasingly large under-recoveries in reconciliation cases each year. Given this track record, DTE Electric's reliance here on "largely the same" methodology makes its projections inherently unreliable. As such, the Commission should reject DTE Electric's PSCR application unless and until the Company develops a methodology that is more likely lead to more accurate projections.

1. DTE Electric's Pattern of Erroneous Projections of Generation and Market Energy Purchases.

A comparison of DTE Electric's past filings, in both PSCR plan and PSCR reconciliation cases, demonstrates just how far off the mark the Company's projections have been. As shown in Table 1, DTE Electric has over-projected its generation in seven of the past eight years, with the 2009 projection off by 6.6% and the 2012 projection off by 9.4%.

[24] Direct Testimony of DTE Electric witness Robert E. Palmer ("Palmer Direct"), 3 Tr 449-50; Direct Testimony of DTE Electric witness Angela P. Wojtowicz ("Wojtowicz Direct"), 3 Tr 558-59.

Table 1: Actual vs. Projected Generation – 2005 to 2012 – in GWhs[25]

Year	Projected Generation	Actual Generation	Difference in GWhs	% Difference
2005	51,070	50,075	-995	-1.9%
2006	49,843	47,731	-2,112	-4.2%
2007	50,761	51,313	552	1.1%
2008	52,820	51,391	-1,429	-2.7%
2009	49,609	48,535	-1,074	-2.2%
2010	51,192	47,828	-3,364	-6.6%
2011	46,472	44,994	-1,478	-3.2%
2012	42,868	38,841	-4,027	-9.4%

DTE Electric has also had to purchase substantially more energy from the MISO market than the Company projected in seven of the past eight years. While DTE Electric's generation has been declining, its actual market energy purchases have been more than double the projected levels for each of the past three years, as shown in Table 2 below:

Table 2: Projected vs. Actual MISO Market Purchases – 2005 to 2012 – in GWhs[26]

Year	Projected Purchases	Actual Purchases	Difference in GWhs	% Difference
2005	4,724	6,377	1,653	35%
2006	5,503	9,862	4,359	79.2%
2007	3,750	7,048	3,298	87.9%
2008	3,957	6,278	2,321	58.6%
2009	5,524	5,835	311	5.6%
2010	1,657	6,044	4,387	264.8%
2011	3,198	7,275	4,077	127.5%
2012	3,209	8,641	5,432	169.3%

Combined with consistently erroneous projections regarding the price of MISO market purchases, DTE Electric's underestimating of the amount of power it would purchase from

[25] Exhibit MEC-54; DTE Electric Company, Application, MPSC Case No. U-14275-R (March 30, 2006), Exhibit A-1; DTE Electric Company, Application, MPSC Case No. U-14702-R (March 30, 2007), Exhibit A-1.

[26] Exhibit MEC-55; DTE Electric Company, Application, MPSC Case No. U-14275-R (March 30, 2006), Exhibit A-1; DTE Electric Company, Application, MPSC Case No. U-14702-R (March 30, 2007), Exhibit A-1.

MISO has led the Company to significantly underestimate the costs it would incur for MISO market purchases in seven of the past eight years, as shown in Table 3 below:

Table 3: Projected vs. Actual Market Purchase Costs – 2005 to 2012 – in $1,000s[27]

Year	Projected Market Purchase Costs	Actual Market Purchase Costs	Difference	% Difference
2005	216,371	573,841	357,470	165.2%
2006	390,257	529,573	139,316	35.7%
2007	199,869	423,145	223,276	111.7%
2008	263,282	415,212	151,930	57.7%
2009	361,909	201,604	-160,305	-44.3%
2010	89,620	250,087	160,467	179.1%
2011	100,546	289,001	188,455	187.4%
2012	129,007	312,014	183,007	141.9%

These erroneous projections have had a real-world impact on ratepayers: in six out of the past seven years, the total cost of DTE Electric's PSCR plan has turned out to be tens of millions of dollars higher than the Company projected. DTE Electric has worked to recover such extra costs in a series of increasingly large under-recoveries sought through the PSCR reconciliation process, as set forth in Table 4 below:

[27] Exhibit MEC-55; DTE Electric Company, Application, MPSC Case No. U-14275-R (March 30, 2006), Exhibit A-1; DTE Electric Company, Application, MPSC Case No. U-14702-R (March 30, 2007), Exhibit A-1.

Table 4: DTE Electric Under-Recoveries

Year	Under-Recovery Sought in Reconciliation
2006	$50,890,282[28]
2007	$43,625,610[29]
2008	$18,616,159[30]
2009	($15,642,519)[31]
2010	$52,623,012[32]
2011	$95,601.896[33]
2012	$86,934,903[34]

Adding to the unreasonableness of its projections, DTE Electric's 5-year plan assumes zero under-recoveries for each year after 2013.[35] Given the Company's track record over the past eight years, such an assumption is questionable at best.

During his cross examination, DTE Electric witness Robert Palmer demonstrated the Company's lack of knowledge regarding MISO dispatching by describing MISO as a "big black box" that factors in a lot of parameters "that they know when we don't exactly know."[36] What the pattern of erroneous projections over the past eight PSCR plans demonstrates is that the DTE Electric's effort to understand the MISO "black box" has been

[28] DTE Electric Company, Application, MPSC Case No. U-14702-R (March 30, 2007), 3.

[29] DTE Electric Company, Application, MPSC Case No. U-15002-R (March 31, 2008), 3.

[30] DTE Electric Company, Application, MPSC Case No. U-15417-R (March 30, 2009), 3.

[31] DTE Electric Company, Application, MPSC Case No. U-15677-R (March 30, 2010), 3.

[32] DTE Electric Company, Application, MPSC Case No. U-16047-R (March 31, 2011), 3.

[33] DTE Electric Company, Reply Brief, MPSC Case No. U-16434 (June 7, 2013), 43.

[34] DTE Electric Company, Application, MPSC Case No. U-16892-R (March 28, 2013), 3.

[35] Exhibit A-4.

[36] Cross Examination of DTE Electric witness Robert E. Palmer ("Palmer Cross") 3 Tr 471.

unsuccessful. Given such flawed results, it is plainly unreasonable for DTE Electric to continue using "largely the same" methodology in creating the projections upon which its 2013 PSCR plan and five-year forecast are based.

2. DTE Electric's Pattern of Erroneous Projections Call Into Question the Reliability of the Company's Current PSCR Plan and Five-Year Forecast.

The pattern of erroneous projections in DTE Electric's PSCR filings is not merely an academic issue. Instead, it calls into question the reliability and reasonableness of DTE Electric's PSCR plan and five-year power supply forecast. For example, DTE Electric's present filing projects that generation in 2013 will be 2,418 GWhs higher than its actual 2012 generation, but 1,609 GWhs lower than it had projected for 2012. Similarly, DTE Electric is projecting that its generation in 2014 through 2017 will remain higher than the actual 2012 generation, but lower than the level it projected for 2012.[37] So, the question is whether DTE Electric's generation has essentially flat-lined at a level somewhat above the 2012 low, or whether the Company is continuing the downward slide that it has been in since 2008. Given DTE Electric's track record of erroneous projections and decision to use "largely the same" methodology for the projections in this proceeding, there is no basis in the record upon which to conclude which path the Company is on.

A similar disparity is seen regarding DTE Electric's projected market purchases. The 2013 market purchase projection of 6,873 GWhs is 1,768 GWhs lower than the actual level of purchases in 2012, but more than double the amount that DTE Electric projected for 2012. And the projected market purchase levels for 2014 through 2017 are approximately equal to the level of actual purchases in 2012, but are well over double the projected 2012 levels. So, once again, there is no basis to determine whether DTE Electric

[37] Exhibit A-13.

market purchases are likely to remain fairly similar to the 2012 levels, or whether they will end up once again being considerably higher than what the Company has projected.

The same trend is seen with regards to the total cost for market purchases that DTE Electric expects to incur. The Company's 2013 projection of $323 million is approximately equal to the actual 2012 level of $312 million, but it is nearly 150% higher than the level that DTE Electric had projected for 2012. By 2017, DTE Electric projects that its market purchasing costs will increase to $573 million, which is a little short of double the actual 2012 level, but more than four times as high as what the Company had projected for 2012. Once again, the unreliability of DTE Electric's projections has raised significant doubt regarding whether the Company's market purchasing costs are going to remain steady in 2013 and nearly double by 2017, or whether they will quadruple by 2017.

3. The Issue of DTE Electric's Pattern of Erroneous Projections Should Not Simply Be Punted to PSCR Reconciliation Cases.

The Commission should reject any argument that the unreliability of DTE Electric's projections are unimportant because resulting under-recoveries can be addressed in the PSCR reconciliation proceeding. For one thing, DTE Electric's expenditures would be subject to a lower level of scrutiny at the reconciliation stage than they are in a PSCR proceeding. In a PSCR proceeding, the Company bears the burden of demonstrating that its proposed PSCR spending is just and reasonable and that it has "taken all appropriate actions to minimize" costs. By contrast, in a reconciliation proceeding, if the excess costs have been incurred through actions that are consistent with an approved PSCR plan, DTE Electric need show only that the costs resulted from "reasonable and prudent management actions," with no requirement to take all appropriate actions to minimize costs.[38] The Commission should not authorize DTE Electric to continue to punt tens of millions of dollars of its PSCR costs to the less rigorous reconciliation proceeding but, instead, should require the Company to take steps to improve the accuracy of its planning projections or, at a minimum, provide a thorough analysis as to why increased accuracy is not possible and how the impact on ratepayers of such inaccuracies can be minimized.

Any effort to punt issues regarding the accuracy of DTE Electric's PSCR projections to reconciliation should also be rejected because the reconciliation process does not provide for the type of planning that is to occur in the five-year power planning forecast. Such planning can be meaningfully carried out and reviewed only if a utility presents a reasonably reliable projection of future conditions so that there can be an accurate assessment of the costs that ratepayers face and the options for reducing such costs. As explained above, however, DTE Electric's PSCR filings have consistently painted an overly positive picture regarding generation, power purchases, and costs over the past eight years, thereby masking the need (discussed further below) for the Company to take further steps to minimize PSCR costs for its ratepayers. Allowing DTE Electric to punt issues regarding the reliability of its projections to the reconciliation process would undermine the value of the five-year power supply forecasting by enabling the Company to continue to present an overly-rosy view in support of its increasingly costly and decreasingly competitive business-as-usual strategy.

[38] MCL 460.6j(15).

B. DTE Electric's Five-Year PSCR Forecast Sets Forth a Business-as-Usual Approach That Ignores Fundamental Changes in Energy Markets.

DTE Electric's five-year PSCR forecast is largely defined by one critical factor - the Company's decision to continue its overreliance on aging coal-fired generating units as its predominant source of power. That decision ties DTE Electric and its ratepayers to an increasingly costly fuel, and will also lead to a significant increase in PSCR costs due to the need to use DSI and ACI sorbents to reduce hazardous air pollution emissions from those plants. What that decision does not do is minimize PSCR costs or lead to rates that are just and reasonable. Instead, ratepayers face increasing PSCR costs as DTE Electric continues to ignore fundamentally changed market conditions that have made the Company's aging generating fleet less competitive. As MEC/NRDC witness Richards explained, DTE Electric's overreliance on aging coal units is unreasonable because those units face:

> increasing coal costs, a significant decline in current and projected natural gas prices, lower market energy and capacity prices, the need to use expensive sorbents and other pollution controls for coal units, future carbon policy risk, and the availability of cost-effective resource alternatives.[39]

Rather than take prudent steps to adjust to such changing conditions by, for example, retiring some of its coal units, DTE Electric's PSCR filing represents a doubling down on a failing strategy. As such, the Commission should indicate that based on present evidence it is unlikely to permit full recovery of the PSCR costs for continued operation of DTE Electric's aging coal units.

[39] Direct Testimony of MEC and NRDC witness Patricia H. Richards ("Richards Direct"), 2 Tr 348-49.

1. DTE Electric's Increasingly Costly Business-As-Usual Approach During a Time of Falling and Low Natural Gas and Market Energy Prices.

DTE Electric's PSCR filing portrays a utility that would look virtually the same in 2017 as it does today and as it did in 2008. In particular, outside of the addition of some renewable energy resources required by Michigan law, DTE Electric's generation mix would be virtually unchanged, with nearly the exact same proportion of energy production coming from coal versus natural gas in 2013 (78% to 1%) as in 2008 (79% to 1%) and as projected for 2017 (78% to 1%).[40] Faced with significant environmental compliance requirements over the next few years, DTE Electric proposes to retire only two small and underutilized coal units, while seeking increased PSCR costs related to the pollution control sorbents that would be needed to reduce emissions from most of the rest of the coal units.

DTE Electric's inertial power supply approach has and will continue to lead to significantly increasing PSCR costs for its ratepayers. In particular, DTE Electric's PSCR unit costs rose 116% from 2004 through 2011. The Company is requesting PSCR costs for 2013 that are 16% higher than the 2011 costs. By 2017, those costs would be 37% over 2011 levels and 197% over 2004 levels.[41] According to the Commission's 2012 Summer Energy Appraisal, monthly bills for DTE Electric's residential electric customers were 13.5% higher in 2012 than in 2011, in part because of increasing PSCR costs.[42]

Much of the increase in PSCR costs is due to the fact that DTE Electric's actual per-unit cost of coal rose from $1.35/MBtu in 2004 to $2.70/MBtu in 2012. Such costs are

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[40] Exhibit MEC-2.

[41] Exhibit MEC-4.

[42] Richards Direct at 2 Tr 352; Exhibit MEC-7.

projected to increase to $2.80/MBtu in 2013, and to $3.20/MBtu by 2017, for a total price increase of 137% from 2004 to 2017.[43] And starting in 2015, DTE Electric is projecting to have at least $20 million per year in additional PSCR costs stemming from the use of DSI and ACI sorbents that are necessary to bring the coal units into compliance with the Michigan Mercury Rule and the federal Mercury and Air Toxics Standard.

In contrast to rising PSCR costs for DTE Electric's ratepayers, other energy sources have declined in price significantly and are projected to stay at low levels for the foreseeable future. For example, DTE Electric reports that its cost of natural gas declined from $5.98/mmBtu in 2009 to $3.48/mmBtu in 2012.[44] Such lower prices are not just a brief aberration.[45] Instead, EIA projects the natural gas price to be $4.07/mmBtu in 2017 and to not return to the 2008 price until 2034.[46] Such low natural gas prices have also led to significantly lower MISO market energy prices, which are expected to stay at low levels.[47] With no base or intermediate load natural gas capacity, however, DTE Electric has been unable to take advantage of such lower natural gas prices.

2. DTE Electric Is Overly Relying on Coal Units That Are Increasingly Non-Competitive in the MISO Market to the Detriment of its PSCR Ratepayers.

Given that DTE Electric is facing rising generation costs in a MISO market that has low natural gas and energy prices, it is not surprising that the record demonstrates that the Company's coal units are increasingly non-competitive. In particular, total generation from

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[43] Exhibit MEC-3.

[44] Exhibit MEC-52.

[45] Richards Direct at 2 Tr 353; Exhibit MEC-7.

[46] Exhibit MEC-7.

[47] Richards Direct at 2 Tr 353.

the DTE Electric fleet, which is dispatched by MISO, fell from 51,391GWhs in 2008 to 38,841GWhs in 2012, which is a decline of 24.3%. In its five-year forecast, DTE Electric projects that its total generation will recover slightly, to between 39,840GWhs and 41,644GWhs in the 2013 to 2017 timeframe, though such levels are still approximately 20% lower than 2008 generation.[48] And, as explained in Section IV(A), above, it is questionable whether any increase is actually likely, as DTE Electric has over estimated its generation in seven out of the last eight years, and its projected generation in each of years 2013 through 2017 is still below the generation that the Company projected for 2012.

The declining competitiveness of DTE Electric's generating units is also shown by the fact that the capacity factors of most of the Company's coal units have declined significantly since 2008 and are expected to remain flat or decline through 2017. For example:

- River Rouge Units 2 and 3 had capacity factors of 72 and 73% in 2008, and are projected to have capacity factors of 43% and 47% in 2013 and 49% and 55% in 2017.
- The capacity factors for the six units at St. Clair ranged from 59% to 67% in 2008, and are projected to range from 42% to 55% in 2013 and 41% to 52% in 2017.
- The capacity factors for the four Monroe units ranged from 65% to 77% in 2008, and are projected to range from 48% to 56% in 2013 and from 50% to 57% in 2017.
- The capacity factor for Belle River Unit 2 is expected to decline from 86% in 2008 to 80% in 2013 and 78% in 2017, while Belle River Unit 1's capacity

[48] Exhibit A-13.

factor is expected to hold relatively steady at 61% in 2008, and 59% in both 2013 and 2017.[49]

In short, in a competitive market with relatively low natural gas and market energy prices, DTE Electric's coal generating units are not being economically dispatched by MISO nearly as much as they used to.

The non-competitiveness of DTE Electric's generating units is also shown by the increasing levels of power that the Company is purchasing from the MISO market. In 2008, DTE Electric purchased 6,278GWhs of energy from the MISO market, while in 2012 the Company purchased 8,641GWhs, for an increase of 37.6%. While the Company projects that such purchases will decline to 6,873GWhs in 2013, it expects the purchases to escalate to between 7,665GWhs and 8,764GWhs for 2014 through 2017.[50] And, as explained in Section IV(A), above, DTE Electric has ended up purchasing between two and more than four times as much power from the MISO market in 2010 through 2012 as the Company projected it would, so it is likely that actual MISO purchases for 2013 to 2017 will be higher than assumed in this application.

DTE Electric's overreliance on increasingly noncompetitive generating units impact PSCR customers in at least three ways. First, declining capacity factors mean that all of the costs of the plant, including PSCR costs, are spread over fewer MWhs of energy production, which means that cost of operating the plants will be higher on a per-unit basis.[51] Second, DTE Electric's ratepayers will be paying to purchase more market energy while also still incurring the expenses related to maintaining the Company's aging coal

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[49] Exhibit MEC-5.

[50] Exhibit A-13.

[51] Richards Direct at 2 Tr 352.

units. Third, and perhaps most significantly, DTE Electric's plan to continue relying on its aging coal units limits the opportunity to pursue other, likely lower cost energy options, such as natural gas, renewable energy, and wholesale market energy and capacity in lieu of the continued operation of some of the coal units.[52] Yet such increased fuel diversity could help DTE Electric lower its PSCR costs.[53]

3. A Five-Year PSCR Forecast Is Not Restricted to an Evaluation of the Utility's Existing Generating Resources.

In its rebuttal testimony, DTE Electric attempts to dismiss concerns regarding the Company's failure to adjust to fundamentally changed market conditions as not within the ambit of the PSCR statute.[54] In particular, DTE Electric witness Kevin O'Neill offers an interpretation of MCL 460.6j that, he contends, shows that only the costs of operating a utility's existing generation resources may be considered in a PSCR proceeding.[55] Witness testimony is, of course, not the place for such legal argument but, regardless, Mr. O'Neill has ignored portions of MCL 460.6j that reject his restrictive interpretation. In particular, Mr. O'Neill relies solely on language from MCL 460.6j(3), regarding the requirements for a 12-month PSCR plan, apparently overlooking the fact that DTE Electric also submitted a five-year forecast under MCL 460.6j(4). Pursuant to MCL 460.6j(4), the five-year forecast is supposed to consider "existing sources of electrical generation," but also requires consideration of "anticipated sources of supply" and "all relevant major contracts and power supply arrangements entered into or contemplated by the utility." Such

[52] *Id.* at 2 Tr 355-56.

[53] *Id.* at 2 Tr 348-49.

[54] Rebuttal Testimony of DTE Electric witness Kevin L. O'Neill ("O'Neill Rebuttal"), 2 Tr 263-64.

[55] *Id.*

provisions make clear that the five-year forecast is not limited to only DTE Electric's existing generating resources. In addition, MCL 460.6j(4) allows for consideration of "such other information as the commission may require." As such, the Commission is plainly not limited to consideration of only DTE Electric's existing generating units in assessing the reasonableness and prudence of the Company's five-year forecast.

4. DTE Electric's Claims Regarding Fuel Diversity Are Unavailing.

In its rebuttal testimony, DTE Electric also contended that it had the kind of fuel diversity that MEC/NRDC witness Richards offered testimony in support of. In particular, witness Palmer contends that DTE Electric has 2,000MW of natural gas capacity, which is equal to 16% of the utility's total capacity.[56] Upon closer inspection, however, 1,800 of those megawatts are peaking units that are expected to run only very rarely and, therefore, do not meaningfully contribute to fuel diversity.[57] In fact, over the past five years, many of the units never operated more than 1% of the time, and the most that any of the units operated was one unit that operated 6.46% of the time in a single year.[58] Over the next five years, DTE Electric projects that these units will continue their very limited operation, with capacity factors ranging from 0.4% to 4.7%.[59] The remaining 200MW of natural gas capacity identified by Mr. Palmer consists of nothing more than the ability of a few of DTE

[56] Rebuttal Testimony of DTE Electric witness Robert E. Palmer ("Palmer Rebuttal"), 3 Tr 457; Exhibit A-27.

[57] Palmer Cross at 3 Tr 475-82.

[58] Exhibit MEC-48, 2-3. Note that all references to the page numbers of exhibits in this brief are to the page number contained in the relevant exhibit's header, where available or applicable.

[59] *Id.* at 4.

Electric's coal units to startup on natural gas.[60] In response to discovery, the Company acknowledged that "these are basically coal fired units," not natural gas units.[61]

It is perhaps not surprising that DTE Electric would cite to peaking units given that it does not have any base-load or intermediate load natural gas facilities. But peaking units that are expected to run only very rarely do not provide any meaningful contribution to fuel diversity. The fact that DTE Electric is citing to peaking units that operate only rarely or that serve merely as startup capacity for coal units conclusively demonstrates how little fuel diversity DTE Electric has and how the Company has not taken any meaningful steps to adjust to fundamentally changed market conditions.

When asked in discovery what changes DTE Electric had made to its PSCR plan in response to lower current and projected natural gas prices, the only substantive change the Company could identify was work that increased the gas capacity of the Greenwood plant from 550MW to 785MW.[62] But the Greenwood plant is part of the 1,800MW of peaking capacity discussed above that is not expected to operate very frequently. Over the past five years, the annual capacity factor at Greenwood ranged from 2% to 7%, and over the next five years, the plant is projected to have only a 3% capacity factor[63] and to generate only between 193GWhs and 215GWhs per year of energy.[64] The fact that the work at Greenwood is the only specific example that DTE Electric was able to identify as a response to the substantial drop in current and projected natural gas prices

[60] Palmer Cross at 3 Tr 484-87.

[61] Exhibit MEC-49.

[62] Exhibit MEC-1.

[63] Exhibit MEC-50.

[64] Exhibit A-24; Palmer Cross at 3 Tr 489-90, 506-08.

demonstrates just how little the Company has done to seize the opportunity presented by that decline in prices.

DTE Electric witness Palmer attempts to justify his company's failure to adjust to significantly lower natural gas prices by noting that natural gas prices are projected to increase in price over future years.[65] Mr. Palmer's credibility regarding natural gas price projections, however, is questionable given that he acknowledged under cross examination that he had discovered that the EIA's 2013 natural gas price projections were lower than what he reported they were in Exhibit A-28 but that he did not bother to correct his exhibit to provide the lower numbers.[66] Regardless, simply noting that natural gas prices will increase again in the future misses the point, which is that current and projected natural gas prices have dropped approximately 70% since 2008 and are not expected to return to their 2008 value until 2034, yet DTE Electric's coal versus gas energy mix is unchanged from the time when current and projected natural gas prices were significantly higher. Both coal and natural gas prices are projected to increase in the coming years. The primary difference is that the price of coal has been steadily increasing since at least 2004, while future natural gas price increases are from a fundamentally different and lower baseline than from just a few years ago. Yet DTE Electric continues to act as if nothing has changed, thereby ignoring the fundamentally changed market conditions that have made its generating units less competitive.

[65] Palmer Rebuttal at 3 Tr 457-58.

[66] Palmer Cross at 3 Tr 496-98.

5. DTE Electric's Participation in MISO Does Not Excuse Its Failure to Adjust to Fundamentally Changed Market Conditions.

In a final attempt to excuse its failure to adjust to fundamentally changed market conditions, DTE Electric asserted in rebuttal testimony that its participation in MISO somehow provides its ratepayers with the full benefits of those changed conditions. For example, witness Wojtowicz contended that because MISO economically dispatches generating units, DTE Electric's ratepayers will only have to pay for the operation of the Company's coal units when those units are the lowest cost resources available.[67] According to DTE Electric's witnesses, if lower natural gas or market energy prices mean that there are resources available that are less costly than the Company's coal units, ratepayers automatically benefit because such lower cost resources will be purchased on the market.[68]

This MISO argument ignores the fact that DTE Electric's ratepayers benefit from MISO economic dispatch only <u>if</u> their utility is bidding in resources that are found to be economic. Otherwise, ratepayers are put in a situation where they are paying to maintain their utility's generating resources while at the same time having to pay to purchase power from the MISO market. And that is exactly the situation that DTE Electric's ratepayers are in here. Under the Company's five-year forecast, ratepayers would pay to continue the operation of virtually all of DTE Electric's aging coal units. Yet because those units are not being economically dispatched as much by MISO, the ratepayers will also have to pay for increased market purchases, which DTE Electric projects will increase in cost from $323

[67] Rebuttal Testimony of DTE Electric witness Angela P. Wojtowicz ("Wojtowicz Rebuttal"), 3 Tr 568.

[68] *Id.*; Palmer Rebuttal at 3 Tr 461.

million in 2013 to $573 million in 2017.[69] The combined result would be increasing PSCR costs and customer bills that would not be just and reasonable, and would not reflect DTE Electric taking "all appropriate actions to minimize" PSCR costs.

The Commission has already frowned upon the type of blanket reliance on MISO dispatching that DTE Electric witnesses have proposed here. In particular, in a PSCR reconciliation involving Consumers Energy, the Commission rejected the argument that a utility "plays no role in MISO's dispatch decisions," finding instead that "customers benefit when the utility engages in the most economical supply possible."[70] And at the hearing, DTE Electric's witness Robert Palmer essentially conceded as much, acknowledging that many MISO dispatch decisions turn on what a utility has offered into the process.[71] Here, the declining and low MISO dispatching of DTE Electric's generating units show that the Company is not procuring "the most economical supply possible." The simple fact that MISO is making the ultimate dispatch decisions should not excuse the fact that DTE Electric's failure to adjust to fundamentally changed market conditions is a primary reason why those units are not being economically dispatched and, therefore, why ratepayers are facing unreasonably high PSCR costs.

[69] Exhibit A-13.

[70] June 16, 2011 Order in MPSC Case No. U-15675-R, 7.

[71] Palmer Cross at 3 Tr 471.

C. The Commission Should Inform DTE Electric That It Is Unlikely to Authorize Recovery of PSCR Costs For DSI and ACI Sorbents at Plants For Which Use of Such Sorbents Is Not Part of a Least Cost Compliance Plan.

DTE Electric seeks, pursuant to MCL 460.6j(7), an indication as to whether the Commission is unlikely to authorize recovery of PSCR costs related to its proposed use of ACI and DSI pollution control sorbents.[72] DTE Electric claims that such sorbent costs are just and reasonable because they are part of a "least cost strategy" for achieving compliance with state and federal environmental standards that require compliance starting in 2015.[73] But the record demonstrates considerable uncertainty regarding what the PSCR costs of the DSI would be and does not support the claim that DTE Electric is pursuing a "least cost strategy" at a number of its generating units. Instead, the DSI and ACI sorbents are a critical element in DTE Electric's continued over-reliance on aging coal units that, as explained in Section IV(B), is neither just nor reasonable. As such, the ALJ should recommend that the Commission indicate that it is unlikely, at least on this record, to authorize recovery for DTE Electric's proposed ACI and DSI sorbent PSCR costs.

1. DTE Electric's ACI and DSI Proposal.

Faced with the need to reduce hazardous air pollutant emissions from its coal units starting in 2015, DTE Electric is proposing to use ACI to reduce mercury emissions and DSI to control acid gas emissions. Under these processes, pollution control sorbents are injected into a coal plant's flue gas.[74] The sorbent then reacts with the acid gas or mercury pollutants to form particles that can be removed by the unit's particulate matter control

[72] Application at 4-5.

[73] Rogers Direct at 2 Tr 123.

[74] *Id.* at 2 Tr 128.

which, in the case of DTE Electric's coal plants, is an electrostatic precipitator.[75] DTE Electric is proposing to use DSI and ACI at its River Rouge, St. Clair, Trenton Channel, and Belle River plants in order to achieve compliance with emission standards established by the Michigan Mercury Rule and the federal MATS Standard.[76] DSI and ACI have lower capital costs (though DSI may have higher annual operating costs) than the flue gas desulfurization controls (commonly referred to as "scrubbers") that DTE Electric had previously thought would be needed to achieve compliance with the MMR and MATS rules.[77] As a result, the Company has abandoned the potential retirement of River Rouge Units 2 and 3, Trenton Channel Unit 9, and St. Clair Unit 7, and deferred the pursuit of new natural gas combined cycle replacement capacity, that had been assumed in its previous PSCR Plan (Case No. U-16892).[78]

2. There is Significant Uncertainty Regarding the Likely Costs That DTE Electric Would Incur for DSI.

A primary reason that the Commission should indicate that it is unlikely, on this record, to authorize the recovery of PSCR costs related to the DSI sorbents is that there is little evidence in the record regarding the level of costs that the DSI would entail. In its application, DTE Electric projected DSI sorbent expenses starting at $13 million in 2015 and increasing to $14.2 million by 2017.[79] But such projections are unreliable for at least two reasons.

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[75] *Id.* at 2 Tr 128-29.

[76] Direct Testimony of DTE Electric witness Kevin L. O'Neill ("O'Neill Direct"), 2 Tr 250.

[77] Rogers Direct at 2 Tr 128.

[78] Palmer Direct at 3 Tr 448-49.

[79] Exhibit A-2.

First, the $13 million to $14.2 million figures are based on the assumption that the DSI sorbents will cost $250 per ton.[80] But DTE Electric's application failed to include any support for the $250 per ton cost figure or explanation for how it was determined. During cross examination, witness Rogers testified that the $250 cost was simply "an approximate average" of the price that DTE Electric paid for Trona during the testing that the Company did of DSI between the fall of 2011 and early 2012.[81] Even though the DSI usage proposed in the PSCR plan would not start until 2015 and Trona usage by utilities throughout the country is expected to increase in 2015 due to the MATS rule, DTE Electric did not factor any inflation or otherwise increase the $250 "approximate average" from 2011/2012 in estimating the Trona costs for 2015 to 2017.[82] And while Mr. Rogers testified that his "discussions with the suppliers" led him to believe that the price of Trona would not increase by 2015, that belief was not corroborated with any actual evidence regarding the Trona price.[83]

DTE Electric's projection that the total PSCR cost of the DSI will range from $13 million to $14.25 million is also unreliable because it does not account for the fact that additional DSI sorbent would need to be used at plants, such as St. Clair and Belle River, where the Company is also planning to use REF coal.[84] Company witness Rogers estimated that the additional DSI sorbent needed if REF coal is being burned could cost

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[80] *Id.*

[81] Rogers Cross at 2 Tr 145-146.

[82] *Id.* at 2 Tr 146.

[83] *Id.*

[84] *Id.* at 2 Tr 150.

between $1.4 million and $6.9 million per year, which could bring the total annual DSI costs at issue here to over $20 million.[85]

Given the wide disparity in the potential costs related to DSI, and the lack of a reliable basis for DTE Electric's $250 estimate of the per ton cost of DSI, the Commission should indicate that it is unlikely to authorize collection of PSCR costs related to DSI without further development of the record on these matters.

3. DTE Electric Has Not Demonstrated that its DSI and ACI Proposal is Part of a Least Cost Plan.

In proposing the DSI and ACI pollution control plan, DTE Electric witness Rogers repeatedly asserted that the proposal was part of a "least cost strategy" or plan for achieving environmental compliance at its coal units.[86] While DTE Electric's application includes no further discussion of the purported basis for the claim that DSI and ACI are part of a least cost strategy, the Company produced in response to discovery a Levelized Cost of Energy ("LCOE") analysis that purportedly supports the least cost strategy claim. In reality, the LCOE analysis left out numerous costs that show that a number of Detroit Edison's coal units would be cheaper to retire and replace than to incur additional PSCR costs relating to pollution control. So while DTE Electric has identified the correct standard - least cost - for determining whether the DSI and ACI PSCR expenses are just and reasonable and minimize costs, the record shows that the Company has not come close to demonstrating that its DSI and ACI proposal satisfied those standards.

[85] Exhibit MEC-45, 2. DTE Electric's assertion that such additional DSI expense related to the use of REF would be reimbursed by the Fuels Companies is unsupported, as discussed in Section IV(D)(1)(c)(3), below.

[86] Rogers Direct at 2 Tr 123; Rogers Cross at 2 Tr 155.

a. The LCOE Analysis.

In its LCOE analysis, DTE Electric offers a comparison of the cost of electricity over the time period of 2015 through 2030 from various Company coal units with either a scrubber and ACI or DSI and ACI, versus from building a new natural gas combined cycle ("NGCC") plant.[87] The analysis purports to have factored in the costs of fuel, variable and fixed operating costs, and pollution controls needed for other current or expected environmental standards in evaluating what sources would lead to the lowest per megawatt-hour cost of electricity. According to the LCOE analysis, the levelized cost of electricity from a new NGCC plant would be $71 per MWh, which would be lower cost than if DTE Electric added scrubbers and ACI to River Rouge, St. Clair, and Trenton Channel Units 7 and 8.[88] The LCOE purports to show that electricity from all of those coal units is a lower cost option than NGCC if only DSI and ACI are installed. At approximately $68 per MWh, however, DTE Electric's own analysis shows that the levelized cost of electricity from the River Rouge units with DSI and ACI is less than 5% cheaper than that from a new NGCC unit.[89] Regardless, Mr. Rogers has indicated that his claim that DSI and ACI are the "least cost strategy" for environmental compliance is based upon the LCOE analysis.[90]

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[87] The result of the LCOE analysis are presented on page 2 of Exhibit MEC-46.

[88] Exhibit MEC-46, 2.

[89] Rogers Cross at 2 Tr 190-191.

[90] See Rebuttal Testimony of DTE Electric witness William C. Rogers ("Rogers Rebuttal"), 2 Tr 135.

b. Numerous Shortcomings Cause the LCOE Analysis to Understate the Costs of DTE Electric's DSI and ACI Proposal, and to Overstate the Costs of Alternatives to that Proposal.

The LCOE analysis does not support the claim that DTE Electric is proposing a least cost strategy because it leaves out numerous costs facing the Company's coal units while turning a blind eye to the potential for other, lower cost, options for replacing some of those units. As MEC/NRDC witness Richards demonstrated, shortcomings in the LCOE analysis include that it:

- Used a projected natural gas price that is approximately 15% higher than the most recent forecasts from the U.S. Energy Information Administration.[91] As a result, the levelized cost of electricity from the NGCC option was overstated.
- Did not evaluate the costs related to Detroit Edison's likely need to achieve far greater reductions in SO2 emissions than the 10-15% reductions that the Company contends that it can achieve with its planned use of DSI. This is a major oversight given that the River Rouge and Trenton Channel plants are located in an area that both the Michigan Department of Environmental Quality and the U.S. EPA have proposed to be found to be out of attainment with federal SO2 air quality standards.[92]

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[91] Exhibit MEC-16; Richards Direct at 2 Tr 359.

[92] Exhibit MEC-11; Richards Direct at 2 Tr 358.

- Assumed that there will be no cost related to carbon dioxide emissions through 2030, even though there likely will be a significant cost on carbon emissions starting around 2020.[93]
- Failed to evaluate a combination of energy sources - including energy efficiency, wind and other renewables, and natural gas - to increasing PSCR costs for Detroit Edison's aging coal units.[94]
- Failed to carry out any sensitivity analyses that would test the economics of the DSI and ACI strategy under varying market conditions.[95]

In addition, the LCOE analysis assumed that the price of the DSI sorbents would remain constant at $269 per ton for the entire 15 year period of the analysis.[96] In light of all of these shortcomings, it is readily apparent that the LCOE analysis is insufficient to justify DTE Electric's DSI and ACI proposal.

c. DTE Electric Failed to Rebut Ms. Richards' Critique of the LCOE Analysis.

In its rebuttal testimony and at hearing, DTE Electric offered surprisingly little defense of the LCOE analysis. None of the Company's witnesses offered testimony on the LCOE analysis in either their direct or rebuttal testimony. And it became readily apparent at hearing that the only sponsor of the discovery response producing the LCOE analysis

[93] Exhibit MEC-10; Richards Direct at 2 Tr 359.

[94] Exhibit MEC-47, 3-9; Richards Direct at 2 Tr 357-58.

[95] Exhibit MEC 10; Richards Direct at 2 Tr 357.

[96] Exhibit MEC-37, 16.

who also offered testimony in this proceeding - Mr. Rogers - had little knowledge about the specifics of that analysis and the inputs that went into it.[97]

(1) The LCOE analysis errs in failing to include a price for carbon emissions.

In its rebuttal testimony, DTE Electric offered a half-hearted response on two issues raised by Ms. Richards regarding the LCOE analysis. First, Company witness Rogers claimed that DTE Electric "has and will continue to consider the potential for carbon costs in future PSCR plan cases," but asserted that the Company's failure to include a carbon cost here did not matter because "the significant cost difference between the majority of the Company's coal units and a new combined cycle is large enough to support the inclusion of carbon costs."[98] Such testimony does nothing to rebut Ms. Richards' contention that a price on carbon should have been included in the LCOE analysis. Instead, the fact that DTE Electric purportedly considered carbon costs in other situations supports the contention that it should have done so here.

Regardless, the only evidence in this record regarding whether a carbon price should have been factored in is Ms. Richards' un-rebutted testimony and the study from Synapse Energy Economics that she relied on. In that study, Synapse reviewed more than 40 carbon price estimates and related analyses, including:

- McKinsey & Company's 2010 analyses of the marginal abatement costs and abatement potential of GHG mitigation technologies
- Analyses of the CO2 allowance prices that would result from the major climate change bills introduced in Congress over the past several years,

[97] See, e.g., Rogers Cross at 2 Tr 183-84, 207-09.

[98] Rogers Rebuttal at 2 Tr 135.

including analyses by the Energy Information Association (EIA) and the Environmental Protection Agency (EPA)

- The U.S. Interagency Working Group's estimates for the social cost of carbon
- Analyses of the factors that affect projections of allowance prices, including analyses by the EIA and Resources for the Future
- CO2 price estimates used by utilities in a wide range of publicly available utility Integrated Resource Plans[99]

After evaluating all of these sources, Synapse then developed three carbon price projections based on three different sets of assumptions regarding the stringency of the likely carbon legislation, the level of emission reductions to be achieved, and the development of technologies and alternatives for reducing carbon emissions. Using those assumptions and sources, Synapse then projected a low carbon price scenario starting at $15 per ton in 2020 and increasing to $35 per ton in 2040; a mid-carbon price scenario starting at $20 in 2020 and increasing to $65 in 2040; and a high carbon price scenario starting at $30 in 2020 and increasing to $90 in 2040. Finally, Synapse compared its low, mid, and high carbon price projections to the low, mid, and high projections of approximately twenty utilities throughout the country and found its projections to be in the middle of the range of the projections from those utilities.

The failure to include a carbon price in the LCOE analysis is also inconsistent with the fact that Section 111(d) of the Clean Air Act specifically requires U.S. EPA to establish carbon regulations for existing sources once the performance standards for new sources that U.S. EPA has proposed are finalized. See 42 U.S.C. § 7411(d) (the EPA

[99] Exhibit MEC-15, 4.

Administrator "shall prescribe regulations which shall establish a procedure" for states to submit proposed "standards of performance for any existing source for any air pollutant," such as CO2, "for which air quality criteria have not been issued" but for which new source performance standards have been established); 77 Fed. Reg. 22,392, 22,424 (April 13, 2012) (noting that, once EPA finalizes new source performance standards for new power plants, it will be legally obligated to address existing power plants under 42 U.S.C. § 7411(d)).[100] As such, the record and law clearly demonstrate that it was unreasonable for the Company to assume that major sources of carbon emissions such as the DTE Electric coal plants will not incur any costs for their carbon emissions between now and 2030.

Mr. Rogers' rebuttal testimony also suggests that even if a carbon price had been included it would not have changed the outcome of the LCOE analysis because of the "significant cost difference" between the coal units and a new NGCC unit. But the cost difference between DSI and ACI versus NGCC for the River Rouge plants was less than 5% or only about $3 per MWh. During cross examination, Mr. Rogers acknowledged that a price on carbon of $1 per ton over 15 years would increase the levelized cost of electricity from a coal unit by approximately $1 per MWh.[101] Given that an NGCC unit emits about half the amount of carbon as a coal unit per MWh of electricity produced,[102] the same $1 carbon price would increase the levelized cost of electricity from an NGCC unit by approximately $0.50 per MWh. As such, a $6 per ton carbon cost over the 2015

[100] In fact, consistent with these standards, the Obama Administration earlier this week issued a Presidential Memorandum, to be printed in the Federal Register, direction U.S. EPA to issue final carbon standards for existing sources by June 1, 2015 and to set a deadline for states to develop plans to implement such standards by June 30, 2016. See http://www.whitehouse.gov/the-press-office/2013/06/25/presidential-memorandum-power-sector-carbon-pollution-standards.

[101] Rogers Cross at 2 Tr 193-94.

[102] Rogers Cross at 2 Tr 184-85.

to 2030 timeframe would equalize the levelized cost of electricity from River Rouge versus an NGCC reported in the LCOE analysis. Given that the Synapse study assumes that a carbon price would not go into effect until 2020, one would need to add an additional ⅓ to that $6 figure, so a carbon price of $8 per ton would equalize the levelized cost for River Rouge versus an NGCC plant. As noted above, the Synapse study, which is the only carbon price forecast in the record, projects a carbon price of between $15 and $30 per ton starting in 2020 and then increasing from there. As such, a relatively low carbon price alone would be enough to demonstrate that the DSI and ACI proposal is not a "least cost strategy" for the River Rouge plant.

(2) DTE Electric's coal units are likely to face additional PSCR costs for controlling SO2 emissions.

In response to Ms. Richards' contention that the LCOE analysis ignores the likelihood that DTE Electric will face additional costs relating to the need to achieve greater reductions in SO2 emissions, Mr. Rogers opines that it is unlikely that DTE Electric will need to install a scrubber on any of its coal units that are receiving DSI.[103] But Mr. Rogers acknowledges "it is too early to determine what, if any, additional SO2 reductions may be required from River Rouge or Trenton Channel to bring the SO2 non-attainment area into compliance with the new SO2 NAAQS."[104] Similarly, it is too early for DTE Electric to be committing to a DSI and ACI strategy that will significantly increase PSCR costs without factoring in the likelihood that the Company will face additional PSCR costs to comply with other regulations. Mr. Rogers also contends that scrubbers will not be needed because DTE Electric can achieve greater than the 10-15% SO2 removal that would be achieved

[103] Rogers Rebuttal, p. 2.

[104] *Id.*

under the current DSI proposal with the use of additional DSI sorbent. But even if such use of additional sorbent were to obviate the potential need for scrubbers, such sorbents would impose additional PSCR costs that should be factored into an LCOE analysis that purports to project levelized costs through 2030.

D. DTE Electric Has Again Failed to Justify Its Proposed REF Project, and the Commission Should Disapprove the That Project In its Entirety.

This is the fourth consecutive PSCR case in which DTE Electric has sought some form of approval from the Commission with respect to its REF project.[105] In each of the prior cases, DTE Electric failed to present a sufficient evidentiary record to warrant approval of the project. In particular, the Company has previously failed to demonstrate that the proposed structure of the REF project represents "all appropriate actions to minimize the cost of fuel,"[106] that the project as a whole represents a reasonable and prudent course of utility conduct,[107] or that the Company's proposed course of conduct complies with the Commission's Code of Conduct and Affiliate Transaction Guidelines.[108]

This case is no different.[109] The Company has again failed to fully explain critical details about the REF project, and it has again failed to carry several critical statutory

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[105] See Case Nos. U-16434, U-16892, U-16434-R. As in prior cases, it is not clear from the DTE Electric's application what relief the Company is seeking in this case with respect to REF. See Direct Testimony of MEC and NRDC witness George E. Sansoucy ("Sansoucy Direct"), 2 Tr 381.

[106] MCL 460.6j(6).

[107] MCL 460.6j(1)(a); MCL 460.6j(6).

[108] See, e.g., December 6, 2011 Order in MPSC Case No. U-16434, 11 ("The REF Project must also be shown to comply with the Code of Conduct.").

[109] As Mr. Sansoucy testified, DTE Electric has presented its arguments pertaining to REF through a new witness, but the Company's arguments and supporting evidence are essentially identical to those presented in prior cases. Sansoucy Direct at 2 Tr 382.

burdens placed upon DTE Electric by the Michigan statute governing PSCR cases. The record in this case, moreover, affirmatively shows that the REF project is not reasonable and prudent, that its proposed structure will not minimize the Company's fuel costs, that a series of underlying agreements were not negotiated on an arm's length basis, and that the REF project violates the Code of Conduct. Based on this record, MEC and NRDC respectfully urge the ALJ to recommend that the Commission disapprove of the REF project in its entirety.

1. Because the Proposed REF Project Does Not Bear the Hallmarks of an Arm's Length Transaction, It Is Not Reasonable and Prudent and It Will Not Minimize the Company's Fuel Costs.

There is little dispute in this case that the proposed REF project will generate substantial revenue for DTE Electric's corporate parent, the DTE Energy Company, and for unknown third-party investors. As designed, however, the project will provide very little corresponding benefits for DTE Electric and its customers. The starkly disproportionate manner in which the REF project's revenues and benefits are divided among DTE Electric and its corporate affiliates, along with the Company's agreement to shoulder significant financial and strategic risks with little contractual protection in the event of unforeseen circumstances, suggests that the agreements underlying the project were not negotiated on an arm's length basis. These disproportionate benefits and increased risk to DTE Electric demonstrate that the project is an imprudent and unreasonable practice for a public, regulated utility.[110] Moreover, because the project may in fact increase PSCR costs for the Company's customers – and because it certainly could be designed in a way that

[110] See MCL 460.6j(1)(a).

lowered PSCR costs much farther – the project cannot be squared with DTE Electric's obligation to take "all appropriate actions to minimize the cost of fuel."[111]

a. Basic Structure of the REF Project.

In general terms, "[t]he REF project involves DTE Electric selling a portion of its coal inventory, at book cost, to three subsidiaries of the DTE Energy Company called "the Fuels Companies."[112] As indicated by their individual names – the Belle River Fuels Company ("BRFC"), the St. Clair Fuels Company ("SCFC"), and the Monroe Fuels Company ("MFC") – the Fuels Companies are each located at one of DTE Electric's power plants.[113] The Fuels Companies are owned by an entity called DTE Energy Services, which is in turn owned by the DTE Energy Company, which also owns DTE Electric.[114] After purchasing "feedstock" coal from DTE Electric, the Fuels Companies apply a proprietary chemical blend to the coal and thereby produce "refined" coal.[115] DTE Electric then buys the refined coal from the Fuels Companies just before the coal enters the boilers at each respective power plant,[116] as required by a series of contracts called "Refined Coal Supply Agreements" ("RCSAs") between DTE Electric and each of the Fuels Companies.[117]

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[111] MCL 460.6j(6).

[112] Sansoucy Direct at 2 Tr 381.

[113] *Id.*

[114] See Cross Examination of DTE Electric witness Karthik Krishnamurthy ("Krishnamurthy Cross"), 4 Tr 745.

[115] See Sansoucy Direct at 2 Tr 381; see also Direct Testimony of DTE Electric witness Karthik Krishnamurthy ("Krishnamurthy Direct"), 2 Tr 614-15.

[116] See Krishnamurthy Cross at 3 Tr 683.

[117] The RCSAs are included in the record of Case No. U-16434-R as Exhibit A-30 and A-30 supplemental. The Administrative Law Judge in this case took official notice of these earlier exhibits. 2 Tr 110-11.

DTE Electric maintains that the Fuels Companies become eligible for a federal tax credit, under Section 45 of the Internal Revenue Code, when they sell refined coal to DTE Electric.[118] This per-ton tax credit increases each year because it is indexed to the Consumer Price Index.[119] The credit, which was $6.33 per ton in 2011,[120] increased to $6.475 in 2012[121] and to $6.59 per ton in 2013.[122]

b. The REF Project Will Provide Substantial Benefits to Unregulated Corporate Affiliates of DTE Electric.

Because the Fuels Companies are projected to sell significant tonnages of refined coal to DTE Electric, the Fuels Companies theoretically stand to receive substantial tax credit revenue from the federal government. The Monroe Fuels Company sold 7,438,570 tons of refined coal to DTE Electric in 2012,[123] and it is projected to sell 7,084,757 tons in 2013.[124] In light of each year's respective tax credit, those sales translate to $48.1 and $46.7 million in annual revenues for just one of the three Fuels Companies alone.

The Fuels Companies do not retain all of this revenue, however.[125] For each ton of refined coal sold during 2011, the Fuels Companies retained "approximately $2.05/ton of

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[118] See Exhibit A-21, 2.

[119] Sansoucy Direct at 2 Tr 382.

[120] Exhibit A-21, 2.

[121] Krishnamurthy Cross at 4 Tr 757.

[122] *Id.* at 4 Tr 765.

[123] Rebuttal Testimony of DTE Electric witness Karthik Krishnamurthy ("Krishnamurthy Rebuttal"), 3 Tr 650.

[124] Exhibit AG-2.

[125] Cross Examination of DTE Electric witness Kevin L. O'Neill ("O'Neill Cross"), 2 Tr 293.

the tax credit to cover operating costs of the REF facilities."[126] The Belle River Fuels Company and St. Clair Fuels Company, moreover, are paid additional amounts, up to their annual revenue requirement of approximately $10-11 million per year, that correspond to any monetary benefit obtained by DTE Electric as a result of burning refined coal.[127] The Company has not explained in this case why the BRFC and SCFC need to be reimbursed by DTE Electric if they are also retaining a third of the tax credit revenue generated by the sale of refined coal, especially when both amounts appear to be earmarked for the Fuels Companies' operating costs. Still, these combined sums are the total amount of revenue retained by the Fuels Companies themselves.

After some portion of the per ton tax credit revenue is retained by the Fuels Companies -- $2.05 out of $6.33 in 2011 – the remaining tax credit revenue stream is diverted to third party investors who have purchased membership interests in the Fuels Companies.[128] Thus far, membership interests have been sold in the St. Clair Fuels Company and the Monroe Fuels Company,[129] but no witness in this case has any knowledge of the terms of those transactions.[130] When asked about the revenues received by the DTE Energy Company in exchange for selling membership in the Fuels Companies, DTE Electric witness Kevin O'Neill stated that he did not know the value of those sales. When asked who would know, Mr. O'Neill stated: "I don't know, because I knew Gary Lapplander didn't know that, and he knew more about the REF project than anyone at the

[126] Sansoucy Direct at 2 Tr 382.

[127] See *id.* at 2 Tr 382-83.

[128] See *id.*

[129] O'Neill Cross at 2 Tr 293.

[130] *Id.* at 2 Tr 303-04.

time."[131] Mr. O'Neill then testified that DTE Electric has never attempted to learn the details of these transactions.[132]

Although no witness in this case knows how much money the DTE Energy Company receives in its transactions with third-party tax investors, former DTE Electric witness Gary Lapplander testified in an earlier case that the DTE Energy Company's revenues from the sale of these membership interests would amount to approximately $2.28 per ton of refined coal sold by the Fuels Companies.[133] Using Mr. Lapplander's calculation in the earlier case, which was based on a per-ton tax credit of only $6.33, the DTE Energy Company can be expected to receive approximately $266 million in tax credit revenue over the life of the project.[134] And for at least two reasons, the annual amount of tax credit revenue accrued by the DTE Energy Company presumably will increase over time. First, the overall per-ton value of the tax credit has already increased from $6.33 – at the time of Mr. Lapplander's estimate – to $6.59 in 2013.[135] Although the Company has not explained how the portion of the tax credit revenue retained by the DTE Energy Company may vary with annual increases on the overall per-ton tax credit,[136] it certainly stands to reason that it will increase. Second, when Mr. Lapplander testified that the Fuels Companies would retain $2.05 per ton of refined coal to cover their operating costs, his calculation was based on a much lower overall REF tonnage than the Fuels Companies are actually projected to

[131] *Id.* at 2 Tr 303.

[132] *Id.* at 2 Tr 303-04.

[133] Sansoucy Direct at 2 Tr 383.

[134] *Id.*

[135] Krishnamurthy Cross at 4 Tr 765.

[136] Sansoucy Direct at 2 Tr 383-84.

produce in 2013 and beyond.[137] As the Fuels Companies' operating costs are spread over an increased tonnage, then, the portion of the tax credit that will be retained by the Fuels Companies will go down, leaving a greater portion of the tax credit for the DTE Energy Company and its third party investors. The same effect would be seen if the Fuels Companies' variable operating costs – i.e., the cost of the chemical additives used in the REF process – decrease over time.[138] In sum, Mr. Lapplander has estimated that the DTE Energy Company stands to receive at least $266 million in revenue over the life of the REF project. He has also suggested that some or all of this revenue may be tax-free.[139]

Other evidence in the record indicates that the DTE Energy Company stands to profit even more significantly from the REF project than Mr. Lapplander previously suggested. A DTE Energy Company investor presentation, for example, projects that annual REF earnings of $40 million in 2012 and $50 million in 2013 will grow to between $60 and $65 million in each year from 2014 to 2017.[140] This represents a total revenue stream of up to $350 million by 2017. Another recent investor presentation of the DTE Energy Company projects potential REF earnings of at least $480 million between 2012 and 2021.[141] Although the Company has suggested in an earlier case that these earnings projections include revenues associated with REF agreements between the DTE Energy

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[137] *Id.* at 2 Tr 384; see also Exhibit MEC-25, 125-26.

[138] *Id.* at 2 Tr 384.

[139] Sansoucy Direct at 2 Tr 384.

[140] Exhibit MEC-14, 27. Please note that all references to exhibit pages in this brief are references to the page numbering found in the exhibit header, where applicable, rather than to the pagination of the original document.

[141] Exhibit MEC-27, 24.

Company and entities other than DTE Electric, the Company has consistently refused to provide information regarding even basic details about those other agreements.[142]

Importantly, the Fuels Companies, the DTE Energy Company, and the third party investors could not receive any of these substantial REF-related benefits without having access to DTE Electric's power plants and coal purchasing expertise. DTE Electric not only provides these unregulated entities with substantial benefit by purchasing large volumes of refined coal, in other words, but it also provides the Fuels Companies with an easy source of feedstock coal, a variety of coal handing services, and access to Company power plants for the refined coal facilities themselves. Although DTE Electric, the Fuels Companies, and the DTE Energy Company "may be separate entities on paper," Mr. Sansoucy observed in his direct testimony, "without DTE Electric's ability to sell electricity to its captive customers, the monetary benefits of the REF project could not be realized by the Fuels Companies, DTE Energy, or the third party tax credit investors."[143] Even more fundamentally, Mr. Sansoucy testified, "[the Fuels Companies could not exist without DTE Electric continuing to run the coal supply chain to its power plants the way it always has."[144]

c. The REF Project Generates Only Uncertain, Disproportionately Small Benefits for DTE Electric and Its Customers.

DTE Electric claims that the REF project, in its proposed form, will provide its customers with three benefits: power plant emissions reductions and associated cost savings, a reduction in working capital and a corresponding reduction in electric rates, and,

[142] Sansoucy Direct at 2 Tr 385; see also Exhibit MEC-30, 9-16.

[143] Sansoucy Direct at 2 Tr 390.

[144] *Id.* at 2 Tr 399.

at Monroe only, discounted coal costs.[145] The record in this case, however, demonstrates that the Company has substantially overstated each of these claimed benefits. At best, DTE Electric and its ratepayers are likely to receive only minor benefits from the REF project. At worst, the record shows that the REF project may actually increase PSCR costs for DTE Electric customers.

(1) The Company has overstated REF-related emissions benefits.

(a) *Overview of claimed emissions benefits*

The Company claims that the use of refined coal at its power plants will reduce those plants' emissions of Nitrogen Oxides ("NOx"), Sulfur Dioxide ("SO2"), and mercury.[146] As a result, the Company alleges, DTE Electric customers will realize various cost savings in the form of unused emissions allowances, reduced chemical treatment costs, and certain avoided capital costs related to emissions control. Despite Mr. Krishnamurthy's claim that reducing emissions is the "primary purpose" of the REF project,[147] the record in this case demonstrates that these claimed REF-related emissions benefits are significantly overstated.

In assessing the true value of emissions-related REF benefits claimed by the Company in this case, it is important to note three threshold points. First, the Company has acknowledged that it is not necessary to burn refined coal in order to meet the standards of any environmental rules and regulations with which DTE Electric must

[145] See, e.g., O'Neill Direct at 2 Tr 246-47; see also Exhibit A-21 at 10.

[146] Krishnamurthy Direct at 3 Tr 615.

[147] *Id.* at 3 Tr 615.

comply.[148] In all instances, alternative technologies are available that would allow the Company to attain such compliance.

Second, the tax credit can only be collected for ten years from the date on which a given refined coal facility is placed into service. Because the refined coal facilities at St. Clair and Belle River went into service in 2009, therefore, both the SCFC and BRFC will become ineligible for the tax credit in 2019.[149] The Belle River REF facility is still being tested and, although the Company has stated that it "may never produce REF commercially,"[150] it appears that the Belle River unit may come on line in 2014 at the earliest.[151] Assuming that to be the case, DTE Electric will be limited to less than six years' worth of any benefits that may be generated by burning REF at Belle River. Similarly, the facility at Monroe went into service in 2011, and the MFC will become ineligible for the tax credit in 2021.[152] Because the principal emissions-related benefit of burning REF at Monroe involves reduced mercury compliance costs beginning in 2015 (see discussion below), those benefits will only truly be realized for a period of six years.

A third important threshold point is that any claim of emissions-related cost savings as a result of burning REF at St. Clair and Belle River is somewhat misleading. Although emissions-related costs savings claimed to arise from burning REF at Monroe are overstated by the Company, some amount of those savings will at least flow directly to DTE Electric customers in the form of a PSCR credit. This is not the case at St. Clair or

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[148] See, e.g., Rogers Cross at 2 Tr 216-17.

[149] O'Neill Cross at t 2 Tr 306.

[150] O'Neill Direct at 2 Tr 286.

[151] See Palmer Direct at 3 Tr 451; Krishnamurthy Direct at 3 Tr 618.

[152] O'Neill Cross at 2 Tr 306.

Belle River, however, because DTE Electric is required to pay the St. Clair and Belle River Fuels Companies for the value of any emissions-related cost savings realized by burning REF at those plants – up to a maximum amount equal to the respective Fuels Companies' revenue requirement. In other words, every dollar of benefit realized by DTE Electric as a result of burning refined coal at St. Clair or Belle River will be offset by a dollar payment from the Company to the Fuels Companies. These payments are referred to by the Company as the "REF adder," and the only way in which DTE Electric or its customers will realize any net savings as a result of burning REF at those plants is in the unlikely event that the overall benefit – and therefore the REF adder amount – reaches and exceeds each Fuels Companies' $10-$11 million annual revenue requirement.

(b) *The Company has provided no evidence of NOx emissions reductions or associated cost savings*.

The Company's application in this case states that the "REF process is expected to reduce the need for NOx and SO2 emission allowances, the costs of which is recovered in [the Company's] PSCR process."[153] This claim is repeated by several witnesses throughout the Company's presentation in this case.[154] Despite this claim, however, the Company has not provided a projection of REF-related NOx emissions allowance savings. Although DTE Electric witness Angela Wojtowicz estimates specific SO2 emissions allowance savings in her direct testimony, the same testimony conspicuously lacks an estimate for NOx emissions allowance savings.[155] Likewise, while Exhibit A-19 (concerning SO2 emissions allowances) specifically attributes savings to the use of REF, Exhibits A-17

[153] Application, 6.

[154] See O'Neill Direct at 2 Tr 245; Wojtowicz Direct at 3 Tr 563; Krishnamurthy Direct at 3 Tr 615, 617.

[155] Wojtowicz Direct at 3 Tr 563-64.

and A-18 (concerning seasonal and annual NOx emissions allowances) omit any reference to REF whatsoever.[156] The omission of any such projection is striking given that Company witness Karthik Krishnamurthy testified that the use of REF "is expected" to result in "a reduction in annual and seasonable NOx emissions allowance expense."[157]

Even if it is true that quantifying the "precise level of reduced NOx emissions directly related to" REF would be difficult, as Mr. Krishnamurthy claimed elsewhere in his direct testimony,[158] it is still odd that no witness in this case could present even an estimate of such reduced expense.[159] When asked whether he could provide such an estimate, Mr. Krishnamurthy stated in his cross examination that Company witness William Rodgers may be better equipped to provide one.[160] Mr. Rodgers had earlier been asked about this during his cross examination, however:

> Q: Your testimony does not quantify the total NOx emission reductions you expect to achieve through the use of REF; is that correct?
>
> A: Correct.
>
> Q And do you know what level of NOx emission reductions you expect to achieve through the use of REF?
>
> A: We do not know what level NOx reductions will be attributed specifically to REF in the units.
>
> Q: And do you -- your testimony does not quantify any potential monetary savings due to reduced NOx emissions due to burning of REF, correct?

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[156] Compare Exhibit A-19 with Exhibits A-17 and A-18.

[157] Krishnamurthy Direct at 3 Tr 617.

[158] *Id.*

[159] Krishnamurthy Cross at 3 Tr 694.

[160] *Id.* at 3 Tr 690.

A: That's correct.

Q: And is that also a figure you have not estimated?

A: That is correct.[161]

Later, Mr. Krishnamurthy acknowledged that he did not know who might be able to estimate NOx emissions allowance savings due to REF:

> Q: So to go back to my original question: Is there any witness in this case who, in testimony or exhibit in the record, presents a projection of the actual NOx reductions at Detroit Edison's actual units?
>
> A: I wouldn't be the right person to talk about it. I don't know.
>
> Q: Do you know who would be?
>
> A: No, I don't know.[162]

The Company's apparent inability to estimate REF-related NOx emissions reductions is important for at least two reasons. First, the Company repeatedly relies on alleged NOx emissions allowance reductions, and a corresponding claim of PSCR savings, as a core justification for the REF project.[163] This case is the fourth time that DTE Electric has requested the Commission's approval of the project, and it is the fourth case in which the Company has submitted evidence concerning the reasonableness and prudence of burning REF. The Commission specifically found, in response to the Company's first request in the 2011 PSCR plan, that:

> The evidence offered simply does not demonstrate the reasonableness and prudence of the amounts to be paid for services rendered by the affiliates, nor does it demonstrate exactly to what extent the REF adder will actually reduce SO2 and NOx emissions . . . . [The Commission finds that, in order

[161] Rogers Cross at 2 Tr 141.

[162] Krishnamurthy Cross at 3 Tr 694.

[163] See, e.g., *id.* at 3 Tr 621; see also Krishnamurthy Rebuttal at 3 Tr 649.

> to authorize these costs in future plan cases, it will require additional evidence . . . .[164]

Given this prior Commission order, and given that DTE Electric has made a request for approval of the REF project in three different cases since presenting is 2011 PSCR plan, it is striking that the Company still cannot provide even an estimate of the NOx emissions savings that it claims will result from REF.

Second, although the Company has acknowledged that the availability of the underlying tax credit in this case depends on NOx emissions reductions of at least 20%,[165] it has provided no proof that such reductions are actually being met. The Company states that any corresponding tax risk is borne entirely by the Fuels Companies, the DTE Energy Company, and third party investors,[166] but that is misleading. Indeed, it is critical to recognize that the Company is designing its entire emissions control and fuel supply strategy around the use of REF, and that if REF becomes unavailable due to an inability of the Fuels Companies to qualify for the tax credit, DTE Electric will be left with a sudden need to control its emissions by different – and potentially more expensive – means. The Company is betting heavily on the REF project as a lynchpin of its fuel and power supply plan, despite the fact that it cannot even estimate – let alone prove – that the Fuels Companies will qualify for the underlying tax credit and therefore continue providing REF over the life of the project. In sum, DTE Electric's inability to estimate REF-related NOx emissions reductions hints at the very real risk to the Company and to its customers of relying so heavily on REF in its PSCR plan and 5 year PSCR forecast.

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[164] See December 6, 2011 Order in MPSC Case No. U-16434 at 8.

[165] Krishnamurthy Cross at 3 Tr 692.

[166] *Id.* at 3 Tr 693.

(c) *The Company's projected SO2 cost savings are at best* de minimis*, and at worst they may result in a net increase in PSCR costs.*

The Company also claims that its REF project produces PSCR cost savings associated the sale of avoided SO2 emissions allowances. Essentially, the Company argues, the use of refined coal at its power plants reduces SO2 emissions, and therefore reduces its need to use SO2 emissions allowances for compliance with environmental regulations.[167] The Company plans to sell any SO2 allowances that go unused as a result of burning refined coal, and any revenue from these sales is considered a benefit of the project.[168] As Mr. Lapplander testified in the Company's 2012 PSCR plan case, however, the Company expects that any such benefit will be *de minimis*.[169] In fact, Mr. Lapplander was referring in that case to a projected 2012 SO2 cost savings of $544 dollars,[170] while the Company has subsequently acknowledged that it incurred zero dollars in SO2 emissions cost savings in 2012.[171]

There are two reasons why any SO2 benefit associated with the REF project is so small. First, current market prices for SO2 emissions allowances are low.[172] The market for SO2 emissions allowances is so weak, in fact, that it is not always possible to find a

[167] See Krishnamurthy Direct at 3 Tr 615, 626.

[168] Wojtowicz Direct at 3 Tr 564.

[169] Exhibit MEC-25 at 119-120.

[170] *Id.*

[171] Krishnamurthy Cross at 3 Tr 707.

[172] Wojtowicz Direct at 3 Tr 564; see also Cross Examination of DTE Electric witness Angela P. Wojtowicz ("Wojtowicz Cross"), 3 Tr 595.

buyer for such allowances in the first place.[173] Ms. Wojtowicz stated in her direct testimony that the Company will "attempt" to sell any SO2 emissions allowances that are saved as a result of burning refined coal, but that it may not be able to do so.[174] During cross examination, Ms. Wojtowicz testified that the current market price for SO2 allowances "is close to zero," and that "it's not likely" the Company will be able to sell avoided allowances in 2013 at all.[175] This is apparently what happened in 2012, too, when the Company received no REF-related SO2 benefit.[176] And as a result, even the relatively small SO2 benefit projected in the Company's PSCR plan for 2013 – $6,297 – may be overstated if the Company must sell its avoided allowances at less than its projected price of $0.75 or if it cannot sell them at all.

Second, the DTE Electric plant that is expected to burn the highest volume of refined coal over time – Monroe[177] – has alternative environmental control technologies that essentially swallow any SO2 emissions reductions that may otherwise be attributable to REF. Exhibit A-19 shows that of the $6,297 SO2 benefit projected to result from the REF project, only $1,907 is attributable to the St. Clair and Belle River power plants.[178] That leaves an SO2 benefit of $4,390 that is solely attributable to burning REF at the Monroe power plant. Looking ahead to future years, however, the overall projected SO2 benefit associated with the REF project declines from $6,297 in 2013 to $4,046 in 2017, while the

[173] Wojtowicz Direct at 3 Tr 564.

[174] *Id.* at 3 Tr 564.

[175] *Id.* at 3 Tr 595.

[176] Krishnamurthy Cross at 3 Tr 707.

[177] See Exhibit AG-2.

[178] Exhibit A-19, lines 48-49.

Monroe-only benefit declines from $4,390 to $263.[179] Likewise, the REF-related reduction in tons of SO2 emissions at Monroe is projected to decline from 2927 in 2013 to 123 in 2017.[180] This is because, as Mr. Palmer testified in this case, only two of Monroe's four units will have had operational scrubbers for all of 2013, while new scrubbers on the remaining two units "are going to start up shortly."[181] As Mr. Palmer further explained, any SO2 reductions attributable to burning REF in a scrubbed unit – as opposed to the scrubber itself – are in his words "*de minimis*."[182] That is because, according to Mr. Palmer, the scrubbers at Monroe remove approximately 98 percent of all SO2 from the plant's stack emissions, even if REF is not used.[183] Mr. Krishnamurthy's claim that the use of REF at Monroe will provide an SO2 benefit, then, is largely overstated.[184] Indeed, it is somewhat odd that the Company plans to burn substantially more REF at Monroe – despite its expensive, existing pollution control systems – when the primary purpose of burning REF, according to Mr. Krishnamurthy, is to reduce emissions at the Company's plants.[185]

Even if the use of REF allowed DTE Electric to sell substantially more SO2 emissions allowances than the record in this case suggests, there is strong evidence that the Company's ratepayers would still receive no real SO2 benefit from the use of refined coal. First, as discussed above, DTE Electric customers will receive a net SO2 benefit for

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179 *Id.*

180 Exhibit AG-1 (Workpaper A25-1); see also Palmer Cross at 3 Tr 528-29.

181 Palmer Cross at 3 Tr 531.

182 *Id.*

183 *Id.* at 3 Tr 527.

184 See Krishnamurthy Direct at 3 Tr 628.

185 *Id.* at 3 Tr 615.

reductions at St. Clair and Belle River only if the overall environmental benefit and REF adder at those plants exceeds the respective Fuels Companies' revenue requirements. Given that the level of SO2 benefit at St. Clair is projected to be something in the range of a few thousand dollars – assuming the Company can sell any of its avoided allowances – it is highly unlikely that customers will ever see an REF-related SO2 emissions reduction benefit.

The second reason why the Company has overstated any REF-related S02 emissions reduction benefit is that, even if it could sell substantially more SO2 emissions allowances as a result of the project, it is highly likely that all such sales would be written off as PSCR losses. As Ms. Wojtowicz stated in her direct testimony and also during cross examination, the market for SO2 allowances is weak.[186] So weak, in fact, that "[i]f we were to sell the allowances we would be selling them at a loss because the average inventory price is currently higher than the current market price."[187] Even if DTE Electric could sell its avoided SO2 allowances, in other words, it would be forced to sell them at a lower price than the Company paid for them in the first place – and it would then write this sale off as a PSCR loss.

To illustrate, Ms. Wojtowicz stated in her direct testimony that the Company plans to sell 8,396 excess SO2 allowances in 2013 as a result of the REF project, and that it plans to sell these allowances at a price of $0.75 each, "resulting in an SO2 avoided expense of $6,297."[188] This is the SO2 benefit that the Company attributes to the REF

[186] Wojtowicz Direct at 3 Tr 564; see also Wojtowicz Cross at 3 Tr 595.

[187] Wojtowicz Cross at 3 Tr 594.

[188] Wojtowicz Direct at 3 Tr 564.

project for 2013.[189] What Ms. Wojtowicz's Exhibit A-19 shows, however, is that the average inventory cost of these 8396 allowances – essentially, the amount the Company paid for them – is $15.84.[190] By selling the allowances for only $0.75 each, as it plans to do, the Company will incur a loss of $15.09 per allowance sold. The Company then plans to write off the entire loss as an increase to PSCR expense of over $126,000 for 2013, as shown in line 37 of Exhibit A-19.[191] Indeed, this is the Company's plan for each of the years in its 5 year PSCR forecast:

> Q: . . . Am I correct that your intent for 2013 through 2017 is to attempt to sell the allowances, the excess allowances that are due to the REF program?
>
> A: That is correct.
>
> Q: And if you were to do so, you're projecting that you would take -- there would be a PSCR expense that would be charged to ratepayers; is that correct?
>
> A: That is correct.[192]

Even though the Company projects an REF-related SO2 "benefit" of $6,297 for 2013, PSCR customers will have to pay more than $126,000 in PSCR costs in order to have this benefit. And what is more, all $6,297 in SO2 "benefit" will actually be paid back to the Fuels Companies as part of the REF adder, leaving DTE Electric customers with a $126,000 PSCR charge and no SO2 benefit to show for it. Given that the Company is not required to sell any SO2 allowances that are saved as a result of burning REF,[193] and given

[189] Exhibit A-19, line 48, column (b).

[190] *Id.* at line 44, column (b).

[191] See Wojtowicz Cross at 3 Tr 580, 594.

[192] Wojtowicz Cross at 3 Tr 595.

[193] See Krishnamurthy Cross at 3 Tr 717.

that any such sale will result in a loss written off to PSCR expense, the Company's plan to "attempt to sell" such allowances is unreasonable and imprudent, and it certainly does not minimize the Company's fuel costs.

(d) *Mercury benefits.*

In addition to PSCR cost savings related to NOx and SO2 emissions reductions, the Company argues that the REF project will reduce mercury emissions control costs when mercury becomes a regulated pollutant in 2015. The Company has not calculated the exact amount of mercury control savings, however, and the record in this case indicates that the Company's estimates are overstated.

At the St. Clair and Belle River plants, the Company plans to control mercury emissions by installing an ACI system.[194] In this system, various forms of PAC are injected into the flue gas stream of a coal-fired boiler; the PAC absorbs vapor phase mercury, allowing it to be collected and disposed of rather than emitted into the air.[195] DTE Electric argues that the use of REF at St. Clair and Belle River reduces the variable cost of the plants' ACI systems, since the Company can allegedly use a standard form of PAC rather than a more expensive chemically treated form of PAC known as BrPAC.[196] The Company claims that the use of REF also allows it to use a lesser quantity of PAC than it would otherwise have to employ in its ACI systems.[197] The Company has not provided an exact

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[194] Rogers Direct, 2 Tr 125-26.

[195] *Id.* at 2 Tr 125.

[196] *Id.* at 126-27.

[197] *Id.*

estimate of these cost savings, however, because it apparently cannot generate an estimate until the installation and testing of its ACI systems are completed.[198]

Just as DTE Electric must pay the St. Clair and Belle River Fuels Companies an amount equal to any realized SO2 emissions savings at those plants, it must also pay SCFC and BRFC an amount equal to any realized mercury benefit – i.e., the avoided cost of BrPAC – until and unless the total environmental benefit of burning REF at one or both plants exceeds the respective Fuels Companies' revenue requirements. And just as this so-called REF adder essentially negates any claimed SO2 benefit resulting from the use of refined coal, it negates any purported mercury benefit. Indeed, DTE Electric witness William Rogers estimates that the use of REF at St. Clair and Belle River combined will save somewhere between $5 and $6 million of mercury control expense each year starting in 2015.[199] Mr. Rogers could not provide even a rough estimate of how much of this cost savings is attributable to each individual plant, but he acknowledged that the total savings presented in his exhibit accounts for both plants.[200] Assuming for the sake of argument that the cost savings is divided equally between the two plants, however, the use of REF creates an annual mercury benefit at the St. Clair and Belle River power plants of approximately $3 million. When added to a virtually non-existent SO2 benefit, it seems highly likely that the environmental benefit of burning REF at those plants will never reach their respective Fuels Companies' revenue requirements, and that neither DTE Electric nor its customers will ever actually realize any net emissions-related benefit from the project.

[198] *Id.*; see also Rogers Cross at 2 Tr 139.

[199] See Exhibit A-2, line 17; see also Rogers Cross, 2 Tr 140-41.

[200] Rogers Cross, 2 Tr 140-41.

The Company argues that burning refined coal will also create a mercury emissions reduction benefit at the Monroe power plant.[201] The Company does not plan to employ an ACI system at Monroe, as it does at St. Clair and Belle River, because it has already installed both wet FGD and SCR systems at Monroe. As Mr. Rogers explained in his direct testimony, these systems were "installed primarily for SO2 and NOx reductions."[202] But because the SCR system is "very effective at oxidizing vapor phase mercury," oxidized mercury emissions at Monroe are likely to be "captured in the water-based slurry of [the] Wet FGD."[203] The Company nonetheless maintains that burning refined coal at Monroe will result in an additional mercury emissions benefit, because REF contains "an effective agent for oxidizing vapor phase mercury," and because "[i]f REF were not used at Monroe Power Plant, then a separate system would be required to inject this additive onto the coal or into the fuel gas to promote compliance level mercury removal by the Wet FGD to consistently meet the MATS mercury standards."[204]

There are three flaws in the Company's projection of an REF-related mercury benefit at Monroe. First, there is no evidence in the record to prove that the Monroe plant requires <u>either</u> the use of REF or an alternative chemical injection system in order to comply with the mercury emissions standards of MATS or the Michigan Mercury Rule. Although Mr. Rogers testified in his cross examination that, "in [his] opinion, the Company would have to add an additive system to consistently 100 percent of the time meet those limits," he did not point to any corroborating evidence such as combustion test results or

[201] Rogers Direct at 2 Tr 127.

[202] *Id.* at 2 Tr 123.

[203] *Id.* at 2 Tr 124-25.

[204] *Id.* at 2 Tr 127.

some other analysis.[205] In fact, Mr. Rogers appeared to equivocate on this point during cross examination: when asked how the Company would meet the MATS standard at Monroe if REF was unavailable in the future, Mr. Rogers stated that "at the Monroe plant we would have a backup chemical injection system if one were necessary to meet compliance with the mercury there."[206] In other words, Mr. Rogers later suggested that the Company is not certain that such a chemical injection system would be required to meet the MATS standard in the absence of REF. Indeed, Mr. Rogers' earlier opinion about the avoided cost of an additional chemical injection system is hard to reconcile with his direct testimony that the existing SCR catalysts at all Monroe units are "very effective at oxidizing vapor phase mercury" – the exact same benefit that he claims will be derived from burning refined coal. In other words, Mr. Rogers' testimony elsewhere in this case suggests that any mercury oxidization attributable to REF is duplicative of a benefit already being provided by the Company's costly SCR system. To the extent that burning REF at Monroe provides a "benefit" that is unnecessary, then, it does not really provide a quantifiable benefit at all.

The second flaw in the Company's estimation of an REF-related mercury benefit at Monroe is that, even if refined coal will provide some incremental increase in mercury oxidization over and above that provided by existing SCRs, the Company has not actually quantified such a benefit.[207] This is because the Company has not yet designed or estimated the cost of the "separate system" Mr. Rogers says would be required in the

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[205] Rogers Cross at 2 Tr 138.

[206] *Id.* at 2 Tr 220.

[207] *Id.* at 2 Tr 139-40.

absence of burning REF.[208] Nor has the Company evaluated the variable cost – that is, the cost of associated chemicals – of such a system.[209] It is hard to evaluate the Company's claim of a mercury benefit at Monroe without an estimate of what that benefit may actually be.

The third flaw in the Company's projection of an REF-related mercury benefit at Monroe is that it fails to account for the risk that REF may become unavailable at some point in the future. The Company has repeatedly argued that any tax risk associated with the REF project falls on the Fuels Companies, the DTE Energy Company, and third party investors, but it has never explained why the potential termination of the project is not a risk that must be built in to DTE Electric's heavy reliance on that project for its approach to controlling emissions at its plants. If the Company must burn refined coal at Monroe in order to meet the mercury requirements of MATS, as Mr. Rogers opined, then it stands to reason that Monroe may be forced to shut down if and when REF became unavailable in the future due to some contingency such as mechanical failure on the REF production line or the Fuels Companies' potential disqualification from the underlying tax credit.[210] For this reason, in fact, Mr. Rogers testified in his cross examination that the Company may have to install a "backup chemical injection system" at Monroe. Even if this back up system is smaller than an alternative primary system, and even if the Company will save the variable cost of the required chemicals, as Mr. Rogers testified,[211] it is somewhat misleading for the

[208] Rogers Direct at 2 Tr 127; Rogers Cross at 2 Tr 139.

[209] Rogers Cross at 2 Tr 139-40.

[210] As discussed below, the Company is not sufficiently protected against such a risk in the Monroe RCSA.

[211] *Id.* at 2 Tr 220.

Company to claim that the avoided cost of a chemical injection system at Monroe provides a true benefit associated with burning refined coal.

(2) Burning REF results in increased fly ash disposal costs.

As already explained, any emissions-related cost savings obtained through the use of REF at St. Clair and Belle River will be offset by a corresponding payment from DTE Electric to the respective Fuels Company at each plant. Until and unless REF cost savings exceed the Fuels Companies' $10-$11 million annual revenue requirements, DTE Electric PSCR customers will not experience any net cost savings. This point is important to emphasize because the record in this case demonstrates that REF-related cost savings are not likely to exceed the Fuels Companies' revenue requirements, and that any claimed REF benefit is really not a benefit at all. Several reasons for this have been discussed above – i.e., the de minimis nature of the SO2 benefit and the relatively small mercury benefit at St. Clair and Belle River – but there is at least one other reason that must be discussed.

The REF adder, by which DTE Electric calculates the environmental benefit of burning REF at St. Clair and Belle River, and by which the corresponding payments to the Fuels Companies are measured, includes what is known as a "negative fly ash benefit."[212] The main reason for this is that burning REF increases the production of fly ash in the coal combustion process.[213] Although the Company at one time predicted that this fly ash could be sold at a profit,[214] experience to date has proven that burning REF has actually

[212] See Krishnamurthy Direct at 3 Tr 625-26; Krishnamurthy Cross at 3 Tr 695-97.

[213] See Rogers Cross at 2 Tr 217.

[214] See Krishnamurthy Cross at 3 Tr 698-99.

increases the Company's fly ash disposal cost.[215] And as Mr. Krishnamurthy testified in his cross examination, the Company currently faces various pending environmental rules and regulations that may further increase the cost of fly ash disposal.[216] Because this benefit is negative, it is treated as an offset to any positive environmental benefit derived from the use of refined coal when calculating the REF adder.[217] This is illustrated by Mr. Krishnamurthy in Exhibit A-22, where the Company estimates no mercury benefit for 2012, a $4,218 SO2 benefit for that year, and a fly ash benefit of negative $30,233.[218] Because the negative fly ash benefit swallows the positive SO2 benefit in this projection for 2012, the overall REF-related environmental benefit to DTE Electric in 2012 was negative.[219] In fact, Mr. Krishnamurthy later acknowledged that the Company ultimately incurred no SO2 benefit in 2012,[220] meaning that its actual overall environmental benefit was even farther into negative territory than projected in Exhibit A-22. Because the use of REF increases the cost of fly ash disposal, it is even less likely that the Company's overall environmental benefit will ever reach and exceed the revenue requirements of the Fuels Companies at St. Clair and Belle River, and therefore even less likely that DTE Electric customers will ever realize any net PSCR savings from the project.

Finally, the record is unclear as to how DTE Electric accounts for the increased fly ash disposal costs associated with burning REF. Exhibit A-22, for example, states that

[215] Krishnamurthy Direct at 3 Tr 626.

[216] Krishnamurthy Cross at 3 Tr 702.

[217] See Krishnamurthy Direct at 3 Tr 625-26.

[218] Exhibit A-22, lines 11-13.

[219] *Id.* at line 14.

[220] Krishnamurthy Cross at 3 Tr 707.

negative fly ash benefit is part of a purported overall REF-related environmental benefit – along with the Company's claimed SO2 and mercury benefits.[221] This exhibit also shows that the overall environmental benefit – of which the negative fly ash benefit is a part – is netted against the revenue requirements of SCFC and BRFC in order to calculate the annual REF adder payment owed to those Fuels Companies. The problem with this accounting is that DTE Electric considers SO2 and mercury benefits to be PSCR credits, while at the same time it considers the negative fly ash benefit to be an O&M expense.[222] Although Mr. Krishnamurthy testified that negative fly ash benefit is "treated separately" from SO2 and mercury benefits, and that any reimbursement to DTE Electric for increased fly ash disposal costs is credited to O&M,[223] the evidence in this case still suggests that the REF arrangement muddles the accounting of PSCR and O&M charges. If the negative fly ash benefit is offset by some positive SO2 or mercury benefit, as shown in Exhibit A-22, then DTE Electric is not fully reimbursed for its increased O&M costs. As a practical matter, then, the REF agreements at St. Clair and Belle River appear to use reduced PSCR costs (in the form of SO2 or mercury savings) as a way to offset increased O&M costs (in the form of fly ash disposal costs). Mr. Krishnamurthy insisted during cross examination that the two items are "apportioned in the right account," but he could not explain how this is done, and he deferred to "the accounting folks to provide that

[221] Exhibit A-22, lines 10-14.

[222] See Krishnamurthy Cross at 3 Tr 697.

[223] *Id.*

answer."[224] Regardless of which DTE Electric witness may be able to provide that answer, it cannot be found in the record here.[225]

(3) Burning REF results in increased sorbent costs for other pollution control technologies.

There is at least one other way in which the REF project may actually increase PSCR costs to DTE Electric customers, despite the Company's repeated claim that "[o]n a PSCR basis the costs of REF to [DTE Electric] customers are zero or less . . . ."[226] As Mr. Rogers testified in this case, the Company plans to install a DSI system at its St. Clair and Belle River units in order to comply with the acid gas, or HCl, emissions limits established in the EPA's MATS rule (the Wet FGD system at the Company's Monroe plant makes the use of DSI there unnecessary).[227] DSI involves the injection of a chemical called trona "into the hot flue gas leaving a coal-fired boiler," and it therefore results in an increased variable expense related to purchasing trona.[228] Mr. Rogers also testified, in his cross examination, that the use of refined coal increases the amount of trona that is necessary for MATS compliance using a DSI system.[229] Mr. Rogers has previously stated in a discovery response that, if the St. Clair and Belle River units burned 100% LSW coal, the volume of trona used in the Company's DSI system will be anywhere from 1.5 to 3.5

[224] See Krishnamurthy Cross at 3 Tr 697.

[225] Later in Mr. Krishnamurthy's cross examination, he suggested that the use of REF at St. Clair and Belle River increases O&M costs at those plants in other ways, too, but he could not explain how DTE Electric is reimbursed for those additional, non-fly ash-related O&M cost increases, much less how those reimbursements are accounted for. See *id.* At 4 Tr 787-91.

[226] O'Neill Direct at 2 Tr 247.

[227] See Rogers Direct at 2 Tr 127-28.

[228] Rogers Direct at 2 Tr 128-29.

[229] Rogers Cross at 2 Tr 150-153; see also Exhibit MEC-45.

times higher with refined coal than without refined coal.[230] This increased volume, in turn, is projected to increase the Company's annual cost for trona by anywhere from $1.4 million to $6.9 million. In other words, the use of REF will force the Company to purchase and use larger quantities of trona than would be necessary without REF, and because the Company seeks the Commission's permission to recover trona costs as PSCR expense, the use of REF will increase this aspect of its PSCR costs.

During cross examination, two of the Company's witnesses addressed this REF-driven increase in DSI costs. First, Mr. O'Neill confirmed that these costs are considered by the Company to be PSCR costs.[231] Mr. O'Neill also confirmed that the Company's agreements with the St. Clair and Belle River Fuels Companies do not contain a specific provision related to the reimbursement of these increased costs as part of the REF adder.[232] When asked whether and how the Company expected to recover these costs, Mr. O'Neill stated that the Company plans to "demand payment of the fuels companies so that the customer would be held harmless."[233] The basis for Mr. O'Neill's understanding in this regard, he testified, was a discovery response in which Mr. Krishnamurthy stated that Section 9.4 of the Refined Coal Supply Agreements between BRFC, SCFC, and DTE Electric would provide a basis for such a demand.[234] But Mr. O'Neill, having only "sped

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[230] Exhibit MEC-45.

[231] O'Neill Cross at 2 Tr 288.

[232] *Id.*

[233] *Id.* at 2 Tr 289.

[234] *Id.*

read [Section 9.4] at one point," deferred to Mr. Krishnamurthy for any further explanation.[235]

For his part, Mr. Krishnamurthy confirmed that it is DTE Electric's "position" that Section 9.4 of the RCSAs would allow the Company to demand that the Fuels Companies reimburse it for increased DSI costs related to the use of REF.[236] According to Mr. Krishnamurthy, a "plain reading of the contract" allows for such a demand.[237] When asked to identify the portion of Section 9.4 that supported his position, Mr. Krishnamurthy pointed to the first sentence:

> Seller shall reimburse Buyer for increased operation and maintenance expenses incurred and that Buyer demonstrates are related to Buyer's use of Refined Coal (and not increased levels of chemical additives pursuant to Section 8.3) as a fuel in the Belle River Power Plant that would not have been incurred from use of coal (other than Refined Coal), but only to the extent such costs are not included in the calculation of Detroit Edison Benefits ("Increased Expenses").[238]

A "plain reading" of this sentence, despite Mr. Krishnamurthy's reliance on it, suggests that it is only applicable to "operation and maintenance expenses" – and not to increase PSCR costs such as the trona used in a DSI system. Section 9.4, in fact, is labeled "O&M and Capital Cost Reimbursement," and does not appear to apply to PSCR costs at all. When asked about this in his cross examination, Mr. Komjathy first suggested that "operation and maintenance expenses" is uniquely defined in the RCSAs:

> Q: So is it your position then that the increased DSI sorbent costs referred to by Mr. Rogers would be operation and maintenance expenses?

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[235] *Id.*

[236] Krishnamurthy Cross at 3 Tr 703; see also Exhibit MEC-59.

[237] *Id.*

[238] Exhibit A-30 in Case No. U-16434-R, 24.

> A: Related to this contract, that is a definition that has been provided.[239]

Mr. Krishnamurthy then immediately changed his answer:

> Q: Operation and maintenance expenses as a phrase means something different in the contract than it does elsewhere in Detroit Edison's filings in various cases; is that what you're saying?
>
> A: No. That's not what I'm saying. We believe that this provision would provide us the reimbursement for any increased expenses due to REF, which are not included.
>
> Q: So it's your position that these operation and maintenance expenses referred to in Section 9.4(a) include increased sorbent costs resulting from the use of DSI?
>
> A: Yes.[240]

A review of the RCSAs confirms that no specific definition of "operations and maintenance expenses" is provided in the contract,[241] and it therefore remains to be seen how the Company believes it can demand reimbursement for increased PSCR costs under Section 9.4. In sum, the Company's position that the RCSAs will allow it to demand payment for additional DSI costs from the Fuels Companies appears to be based, at most, on a very strained reading of Section 9.4. And if those expenses are not collected from the Fuels Companies, the use of REF at St. Clair and Belle River could increase PSCR costs by as much as $6.9 million per year.[242] If the variable cost of trona increases over time, the increased cost of DSI using REF may also increase.

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[239] Krishnamurthy Cross at 3 Tr 705.

[240] *Id.*

[241] See, e.g., Exhibit A-30 in Case No. U-16434-R, 5-12.

[242] Exhibit MEC-59.

(4) The coal fee rate at Monroe is an overstated benefit.

Unlike at St. Clair and Belle River, DTE Electric's arrangement for the supply of refined coal at Monroe does not include payment to that plant's Fuels Company in the form of an "REF adder."[243] Instead, the Company sells feedstock coal to MFC at book cost, but then buys refined coal back from MFC at a discounted value known as the "Coal Fee Rate."[244] As in past cases, the Company has explained that this discount is $1.0375 per ton for the first seven million tons of refined coal purchased by DTE Electric from the Monroe Fuels Company, and that it increases to $1.50 per ton for any amount purchased beyond seven million tons.[245] Applying this formula to the Company's projected annual REF purchase of 7,084,757 tons in 2013, for example, would suggest an anticipated overall discount of $7,389,635.50.[246] In rebuttal testimony, Mr. Krishnamurthy claimed that the Coal Fee Rate resulted in a $1.07 per ton overall discount on coal at Monroe in 2012. Exhibit A-20, however, projects that the Monroe Coal Fee Rate will result in a PSCR benefit of only $4,677,000 in 2013.[247] It is clear that PSCR customers are not receiving the entire benefit of the Coal Fee Rate touted by the Company, and the reason is that $0.3875 per ton for the first seven million tons of refined coal purchased at Monroe is credited to the Monroe power plant's O&M expense rather than to the PSCR.[248] As Mr. Krishnamurthy further acknowledged, the reason for this credit to O&M is that the Company incurs

[243] See Sansoucy Direct at 2 Tr 366; Krishnamurthy Direct at 3 Tr 627-28.

[244] Krishnamurthy Direct at 3 Tr 627-28.

[245] See Krishnamurthy Cross at 4 Tr 783; see also Exhibit MEC-31.

[246] See Exhibit AG-2, 1 (Discovery Response MEC/DE-1.45a).

[247] Exhibit A-20, line 5.

[248] See Krishnamurthy Cross at 4 Tr 784.

increased O&M costs at the Monroe power plant as a result of burning REF, and that a portion of the Coal Fee Rate is therefore designed as a reimbursement for this incremental increase in expense rather than as a discount.[249] The actual discount received by the Company in the form of a Coal Fee Rate, therefore, is projected only to be about $0.66 per ton in 2013, or only about half of the discount that the Company has touted in this case and in others.[250] In sum, even though the REF arrangement at the Monroe power plant may provide DTE Electric customers with a more substantial benefit than the arrangements at St. Clair and Belle River, the benefits claimed by the Company are overstated.

(5) The working capital benefit is overstated.

In addition to emissions related benefits and the Coal Fee Rate discount at Monroe, DTE Electric argues that the REF project provides its customers with a benefit in the form of decreased working capital expense.[251] Because it has sold existing coal inventory to the Fuels Companies, DTE Electric claims that its working capital has been reduced by a corresponding amount, and that customers are therefore charged less in the form of base rates.[252] Most of this claimed benefit is derived from the sale of existing DTE Electric coal inventories to the St. Clair and Belle River Fuels Companies. The Company sold 1.7 million tons of coal to SFC and BRFC, combined, in December 2009.[253] Mr. Krishnamurthy claims that this sale has resulted in an annual working capital benefit to DTE Electric

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[249] See *id.* at 4 Tr 785-87.

[250] See Krishnamurthy Rebuttal at 3 Tr 650.

[251] See Krishnamurthy Direct at 3 Tr 623; O'Neill Direct at 2 Tr 247-48.

[252] See Sansoucy Direct at 2 Tr 387.

[253] Krishnamurthy Direct at 3 Tr 622.

customers of $4 million.[254] Mr. Krishnamurthy goes on to say that DTE Electric has sold additional tonnages to SFC and BRFC since that time, but the Company has subsequently acknowledged that these later sales do not create a working capital benefit for ratepayers because base rates have not been re-set since 2009.[255] In fact, the Company does not plan to re-set base rates until 2015 at the earliest, more than half-way through the 10 year life of the REF project at St. Clair and Belle River.[256] Although DTE Electric sold 250,000 tons of existing coal inventory to the Monroe Fuels Company at the time the agreement between MFC and DTE Electric closed (after base rates were last re-set, it should be noted), MFC will take possession of all future coal deliveries as they are in transit and before they are ever added to DTE Electric's working capital fuel inventory.[257] As a result, sales of feedstock coal to MFC – by far the largest consumer of DTE Electric's feedstock coal[258] – will result in only a minor working capital reduction, and only at the time that DTE Electric resets its base rates.

In rebuttal testimony, Mr. O'Neill acknowledged that the Company's base rates have not been re-set since 2009, and that ratepayers are receiving only a limited amount of REF-related working capital benefit as a result.[259] Mr. O'Neill claimed that DTE Electric ratepayers are receiving a benefit by having base rate frozen at 2009 levels, however,

[254] *Id.* at 3 Tr 623.

[255] See O'Neill Rebuttal at 2 Tr 265; O'Neill Cross at 2 Tr 285; see also Sansoucy Direct at 2 Tr 388.

[256] Sansoucy Direct at 2 Tr 388.

[257] Krishnamurthy Direct at 3 Tr 629.

[258] *See* Exhibit AG-2 at 1.

[259] O'Neill Rebuttal at 2 Tr 265.

because the Company's 2009 overall fuel inventory "was a historically low value."[260] Whether or not DTE Electric ratepayers are benefitting by having base rates pegged to a historically low fuel inventory value in 2009, however, has nothing to do with the working capital benefit that is specifically attributable to the REF project. As Mr. O'Neill acknowledged during his cross examination, it is entirely possible that the Company's overall fuel inventory could rise at the same time that any working capital reduction attributable to the REF project could also rise.[261] Because this case concerns the reasonableness and prudence of the REF project, and the level of benefits received by DTE Electric customers as a result of that project, Mr. O'Neill's argument about historically low overall fuel inventories is irrelevant. In sum, the Company continues to overstate the working capital benefit of the REF project, which will be frozen at 2009 levels until and unless the Company resets base rates. When combined with evidence of other overstated benefits of the REF project, "it appears that DTE Electric, in [its] negotiations [with the Fuels Companies], made no attempt to structure the use of REF in a manner that provides benefits to DTE Electric customers that are proportional to the benefits flowing to the Fuels Companies and DTE Energy."[262]

d. Burning REF Subjects DTE Electric and Its Customers to Increased Risk.

The record in this case demonstrates that, although DTE Electric has repeatedly referred to the REF project as "risk free,"[263] the project actually saddles the Company and

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[260] *Id.*

[261] O'Neill Cross at 2 Tr 287.

[262] Sansoucy Direct at 2 Tr 390.

[263] See, e.g., O'Neill Direct at 2 Tr 247; Krishnamurthy Direct at 3 Tr 619-20.

its customers with significant risk. The most important risk incurred by DTE Electric under the REF project involves the possibility that the Fuels Companies will not be able to produce or deliver refined coal at some point in the future. Such a scenario could arise in numerous ways: among others, the Fuels Companies could go bankrupt, experience technical difficulties, lose a steady supply of REF chemicals, or become ineligible for the underlying REF tax credit. Indeed, although the Company has stated many times that these risks fall on the Fuels Companies rather than DTE Electric, that premise is undermined by the fact that DTE Electric has made the REF project such a central component of its approach to emissions control and compliance with other environmental regulations. To the extent that the Company's 2013 PSCR plan and five year PSCR forecast are founded in large part on the burning of REF at three of its power plants, the prospect that REF might suddenly become unavailable is a significant risk to the Company and its customers. It is also a risk against which DTE Electric is barely insulated, if at all.

To begin with, Mr. Sansoucy has explained that the RCSAs require DTE electric "to buy all the refined coal the Fuels Compan[ies] can produce, but the Fuels Compan[ies] do[] not have a reciprocal obligation to produce all of the refined coal that DTE Electric may need. The Fuels Compan[ies] ha[ve] a guaranteed buyer, but the buyer does not have a guaranteed seller."[264] In addition, the RCSAs for Belle River and St. Clair provide that, if the Fuels Companies are unable to supply refined coal for any reason, DTE Electric's sole recourse is to buy back the unrefined feedstock coal that it previously sold to the Fuels Companies.[265] This arrangement not only provides the Fuels Companies with an additional benefit – in that they can recoup sunk costs in raw materials even if they cannot turn those

[264] Sansoucy Direct at 2 Tr 392.

[265] *Id.* at 2 Tr 392-93.

materials into a finished product for sale – but it does so without providing any comparable benefit to DTE Electric.[266] In fact, as Mr. Sansoucy testified, one of the core premises underlying the REF project "is that the refined coal has value to DTE Electric, yet the specified remedy for DTE Electric in the even of non-performance does not provide for damages for or replacement of the lose value."[267] As discussed previously, DTE Electric stands not only to lose the value of the refined coal it would otherwise have purchased and burned, but it stands to incur significant expenses in controlling its emissions – and re-evaluating its PSCR plan – in the event that REF cannot be supplied by the Fuels Companies.

This imbalance is even more obvious in the RCSA between DTE Electric and the Monroe Fuels Company. Because DTE Electric receives a discount on the refined coal it purchases from MFC – in the form of a Coal Fee Rate, as discussed above – there is a direct and obvious monetary benefit to DTE Electric under this arrangement. And yet "in the event of Fuels Company non-performance" under the Monroe RCSA, as Mr. Sansoucy explained, "DTE Electric may bypass and purchase available unrefined coal from the Fuels Company. There is no remedy for the loss of the discount."[268] Moreover, "the Monroe RCSA allows the Fuels Company to immediately suspend all deliveries of refined coal if the Section 45 tax credits are phased out. In that event, DTE Electric loses the value of the discount and the Fuels Company is completely protected."[269] This contractual imbalance – when viewed in addition to the disproportionate level of benefits generated for DTE

[266] See *id.* at 2 Tr 392.

[267] *Id.* at 2 Tr 392-93.

[268] *Id.* at 2 Tr 393.

[269] *Id.*

Electric and its unregulated affiliates by the REF project – further suggests that the agreements underlying the project were not negotiated on an arm's length basis.

e. The Agreements Underlying the REF Project Were Not Reasonably Negotiated.

Although Mr. Lapplander insisted in an earlier case that the REF project represented an arm's length negotiation, the only basis for that assertion was that "It was my responsibility to lead the negotiations on behalf of Detroit Edison and at all times I acted in the best interests of Detroit Edison and I was never under pressure or duress to do otherwise."[270] Whether or not it is plausible that Mr. Lapplander could have acted in a fully independent manner in negotiating an agreement with his employer's parent company, his mere assertion to that effect cannot alone prove that the negotiation was at arm's length. This is especially true given the fact that, as Mr. Sansoucy stated in his direct testimony, "DTE Electric never made any inquiries with any other potential suppliers of REF other than the subsidiaries of [the DTE Energy Company]."[271] In negotiating the agreements, in other words, Mr. Lapplander was unable to compare the reasonableness of various terms against comparable terms in comparable agreements between other utilities and other REF suppliers. At the time Mr. Lapplander was negotiating the Company's agreements for facilities at St. Clair and Belle River, in fact, Mr. Lapplander only had one benchmark against which to make such a comparison.

Mr. Lapplander asserted in his direct testimony in Case No. U-16434-R that the agreement he negotiated

> seemed reasonable since DTEES had already reached a similar agreement with the Michigan Public Power Agency (MPPA), a partial owner of the Belle River Power Plant. The

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[270] Exhibit MEC-36.

[271] Sansoucy Direct at 2 Tr 391.

> MPPA is an unaffiliated entity that negotiated at arms-length with DTEES. The MPPA had no particular incentive to reach an agreement with DTEES as opposed to reaching an agreement with any other unrelated third party. As such, the agreement reached with the MPPA was rightfully considered to represent the market for a business deal of this nature.[272]

During cross examination by the ALJ in that case, however, Mr. Lapplander expressly disclaimed any meaningful prior reliance on the agreement between MPPA and DTEES:

> JUDGE EYSTER: Really, quite honestly, I mean I get the impression that the Belle -- that the MPPA's agreement had very little to do with your decision to enter into the Detroit, or your agreement with the Belle River Fuels Company?
>
> A: That's an absolutely true statement.[273]

Mr. Krishnamurthy's testimony in this case repeats – word-for-word – Mr. Lapplander's prior assertion that the agreement between MPPA and DTEES provided an important benchmark for DTE Electric when negotiating their own agreements with the Fuels Companies.[274] Given Mr. Lapplander's later statement during cross examination in Case No. U-16434-R, however, Mr. Krishnamurthy's assertion in this case carries no evidentiary weight. Likewise, neither Mr. Lapplander's testimony in Case No. U-16434-R nor Mr. Krishnamurthy's testimony in this case provide any support whatsoever for the Company's assertion that its REF agreements were negotiated at arm's length with the Fuels Companies, DTEES, or the DTE Energy Company.

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[272] Exhibit MEC-34 at 20.

[273] *Id.* at 155-56

[274] Krishnamurthy Direct at 3 Tr 620-21.

f. The Company's Benchmarks Fail to Support the Project.

As in past cases, the Company here has identified other refined coal projects – of which it was not aware at the time it originally negotiated its own REF agreements – that it now claims provide ex post evidence that the DTE Electric agreements were and are reasonable arm's length transactions.[275] In his rebuttal testimony, for example, Mr. Krishnamurthy argued that a Duke Energy project in Indiana resulted in a benefit to that utility of approximately $0.42 per ton of refined coal consumed.[276] For several reasons, however, this assertion is without any meaningful evidentiary support. First, Mr. Lapplander made the same assertion in Case No. U-16434-R,[277] and later stated that he had calculated this per-ton benefit by dividing Duke Energy's claimed overall REF benefit by the total coal burn at the relevant Duke Energy plants.[278] By contrast, the Company's calculation of a per-ton REF benefit for its own plants has been based on the plants' REF burn only.[279] Assuming for the sake of argument that the overall coal burn at the Duke plants was greater than their REF burn alone – Mr. Lapplander did not know[280] – the comparison of a $0.42 per ton benefit for Duke to DTE Electric's project is meaningless. The Company has stated in this case that the REF burn at Belle River is expected to be

[275] See Krishnamurthy Rebuttal at 3 Tr 646.

[276] *Id.* at 3 Tr 646.

[277] *Id.* at 46.

[278] *Id.* at 144.

[279] *Id.*

[280] *Id.* at 143.

only about 75% of that plant's total coal burn,[281] for example, and it would make little sense to base a per-ton REF benefit calculation on the total burn rather than the REF burn alone.

Second, Mr. Krishnamurthy's knowledge of the Duke Energy project is based upon publicly-filed testimony in a proceeding before the Indiana Utility Regulatory Commission, certain portions of which were originally attached as an exhibit to his rebuttal testimony in this case.[282] Mr. Krishnamurthy admitted in his cross examination that he had not reviewed any of the testimony filed by other parties in the Indiana case, and that he was unaware whether or not that project ever received approval from the Indiana regulatory authority.[283] In fact, as demonstrated by Exhibit MEC-61, Duke Energy ultimately abandoned this refined coal project before it could be approved:

> Duke Energy Indiana has conducted testing at the Cayuga and Gibson generating stations to determine the effectiveness of the relined coal process. After analyzing the testing results, it was determined that the results did not support moving forward with the refined coal project at either generating station.[284]

For its part, although DTE Electric ultimately withdrew the exhibit upon which Mr. Krishnamurthy based his testimony about the Duke project, Mr. Krishnamurthy's corresponding assertions about project remain in the record as part of his testimony.[285] At the very least, Exhibit MEC-61 suggests that neither the Company nor Mr. Krishnamurthy have sufficient knowledge of the Duke Energy project from which to make a meaningful comparison to the project proposed in this case.

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[281] Palmer Direct at 3 Tr 451.

[282] Krishnamurthy Rebuttal at 3 Tr 646; Krishnamurthy Cross at 3 Tr 712.

[283] Krishnamurthy Cross at 3 Tr 712.

[284] Exhibit MEC-61, 1.

[285] Krishnamurthy Cross at 4 Tr 817-18.

Mr. Krishnamurthy also claims in this case that at least one alternative REF producer – the Arthur J. Gallagher Company ("AJ Gallagher") – has offered an average pre-tax discount to host utilities of $0.75 per ton.[286] This claim only highlights the fact that DTE Electric's REF arrangements do not appear to have been negotiated at arm's length on behalf of ratepayers, however, given that the Company's agreements at both St. Clair and Belle River include no cash discount on refined coal. Mr. Krishnamurthy argues that the working capital benefit at St. Clair and Belle River amounts to $0.96 and $1.41 per ton, respectively, but it is hard to compare this claimed working capital benefit to a cash discount – partly because the record does not indicate whether the AJ Gallagher projects include a working capital benefit for its utilities on top of a cash discount. And although Mr. Krishnamurthy again says that the Coal Fee Rate at Monroe amounts to a discount of at least $1.0375 per ton, the actual discount is really only about $0.66 per ton when adjusted for O&M reimbursement. Because there is little additional information in the record about the structure of AJ Gallagher's REF agreements with other utilities – whether they include reimbursements for incremental O&M costs in addition to a cash discount of $0.75 per ton, for example – any comparison to this average after-tax discount is meaningless at best, and at worst it suggests that DTE Electric should have negotiated for a better arrangement with the Fuels Companies. Indeed, DTE Electric apparently turned down an unsolicited offer from AJ Gallagher to place an REF facility at the River Rouge plant in exchange for a $0.50 per ton discount on refined coal,[287] despite the fact that AJ Gallagher's investor presentation strongly suggests that the Company could have negotiated for a discount of at least $0.75 per ton.

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[286] Krishnamurthy Rebuttal at 3 Tr 646.

[287] *Id.*; see also Exhibit A-37.

In sum, none of the alternative refined coal arrangements offered by DTE Electric provide real support for the Company's claim that its REF project is based upon reasonable agreements negotiated at arm's length.

g. The Company Unreasonably Failed to Pursue Alternative Structures for its REF Project.

Given the substantial benefits received by the Fuels Companies and DTE Energy under the REF project, and the corresponding risk and insignificant benefits flowing to DTE Electric, it should be noted that the Company apparently did not try to create an alternative REF structure in which the Company itself would receive any resulting tax credit revenue. Mr. Krishnamurthy testified in this case that DTE Electric did not itself construct REF facilities because it did not want to assume any corresponding risk.[288] The problem with this argument, however, is that DTE Electric does assume significant risk under its REF arrangement, in large part because its RCSAs with the Fuels Companies provide it with no recourse or compensation in the event that REF becomes unavailable and the Company's fuels supply and emissions control plans are thrown into chaos.

In rebuttal, Mr. Krishnamurthy additionally argued that DTE Electric's "position is that it did not, and could not, have availed itself of the Production Tax Credit because [DTE Electric] cannot produce and sell REF to itself while still qualifying for IRS Section 45 tax credits."[289] The reason for this position, Mr. Krishnamurthy explained, is that Section 45 of the Internal Revenue Code requires refined coal to be sold to an "unrelated person" in order for the seller to qualify for the tax credit.[290] This all may be true, but it fails to explain why DTE Electric could not take the same approach to qualifying for the tax credit that the

[288] Krishnamurthy Direct at 3 Tr 619-20.

[289] Krishnamurthy Rebuttal at 3 Tr 636.

[290] *Id.*

DTE Energy Company did – that is, by assigning production of refined coal to a subsidiary and then purchasing REF from that subsidiary. If the Fuels Companies are sufficiently "unrelated" to DTE Electric to qualify for the tax credit, it is hard to see why DTE Electric could not purchase refined coal from one of its own subsidiaries, generate tax credit revenue, and pass that revenue on to customers. Indeed, the Fuels Companies and DTE Electric are themselves both subsidiaries of the DTE Energy Company, which, as the Company stipulated during cross examination, files a single consolidated tax return for all of its subsidiaries, "regulated and unregulated," including both the Fuels Companies and DTE Electric.[291]

When asked for the basis of the Company's position in this regard, in Case No. U-16892, Mr. Lapplander said that a tax attorney named Brian Wheeler explained that DTE Electric could not itself own subsidiary Fuels Companies and still qualify for the tax credit.[292] Although Mr. Lapplander referred to Brian Wheeler as "our tax counsel" in Case No. U-16892,[293] Mr. Lapplander later acknowledged in Case No. U-16434-R that Wheeler is an in-house tax attorney for the DTE Energy Company.[294] Mr. Krishnamurthy confirmed this on cross examination:

> Q: Well, your -- first of all, who is Mr. Wheeler?
>
> A: He's a corporate tax attorney.
>
> Q: And working for DTE, the holding company, does he?
>
> A: That's my understanding.

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[291] Krishnamurthy Cross at 4 Tr 764.

[292] Exhibit MEC-25, 128-30.

[293] Exhibit MEC-25 at 128.

[294] Exhibit MEC-34 at 186-87.

> Q: He doesn't work for the utility, Detroit Edison, does he?
>
> A: I'm not sure Detroit Edison has a tax attorney.[295]

Even if it may be reasonable in other circumstances for corporate affiliates to share common legal counsel, it is not reasonable to do so in circumstances where two affiliates are allegedly bargaining at arm's length over a transaction involving hundreds of millions of dollars and significant tax risks. In this case, however, Mr. Wheeler's opinion was apparently the only professional tax advice that DTE Electric ever sought. Among other things, this stands it fairly stark contrast to efforts by the AJ Gallagher Company to obtain private letter rulings from the IRS concerning the eligibility of its REF projects for the underlying tax credit.[296] In Case No. U-16434-R, Mr. Lapplander did not know whether the Company had ever sought a private letter ruling from the IRS.[297] As a result, the only advice that DTE Electric appears to have sought with respect to its ability to operate its own subsidiary Fuels Companies came from an employee of DTE Electric's parent company – an entity that stands to receive substantial cash revenue under the current REF arrangement.[298]

In rebuttal testimony, Mr. Krishnamurthy attempted to support the Company's argument that it could not have created its own refined coal subsidiaries by claiming that no other utility receives tax credits under Section 45 of the Internal Revenue Code.[299] Specifically, Mr. Krishnamurthy referred to a public filing by a Missouri utility, Ameren,

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[295] Krishnamurthy Cross at 4 Tr 743.

[296] Exhibit A-34, 34.

[297] Exhibit MEC-34 at 126.

[298] See Sansoucy Direct at 2 Tr 394.

[299] Krishnamurthy Rebuttal at 3 Tr 637-39.

concerning another REF project.[300] That filing, which Mr. Krishnamurthy quotes in his testimony, states that "Ameren Missouri will not receive any tax credits directly from these agreements."[301] The obvious flaw in using the Missouri filing as a benchmark, however, is that Ameren's witness says only that his utility does not receive tax credits directly. This does not address the argument made by MEC and NRDC – as well as by other parties – that DTE Electric could potentially have assigned subsidiaries or affiliates with the task of producing and selling refined coal, and thereby received tax credit revenue on an indirect basis. Whether or not Ameren Missouri receives tax credits indirectly is unknown, because the quoted filing (found in an exhibit that DTE Electric later withdrew[302]), contained substantial redacted portions, and Mr. Krishnamurthy acknowledged that he had no knowledge of what was in the redacted portions or even what the ultimate outcome of the Missouri proceeding was.[303]

2. Because the REF Project Involves DTE Electric's Subsidization of Corporate Affiliates, It Violates the Commissions Code of Conduct and Affiliate Transaction Guidelines, and It Is Contrary to Law.

The Commission declined to approve of the REF project in Case No. U-16434 – the only case in which the Commission has yet addressed the project – in part because, as explained in a final order, "[t]he REF Project must [] be shown to comply with the Code of Conduct."[304] Because the record in this case demonstrates that DTE Electric's REF project

[300] *Id.* at 3 Tr 637-38.

[301] *Id.* at 3 Tr 637.

[302] Krishnamurthy Cross at 4 Tr 817-18

[303] *Id.* at 3 Tr 711-12.

[304] December 6, 2011 Order in MPSC Case No. U-16434 at 11.

violates both the letter and the spirit of the Code of Conduct, the project should not be approved.

Michigan law requires the Commission to establish a code of conduct for electric utilities:

> The code of conduct shall include, but is not limited to, measures <u>to prevent cross-subsidization, information sharing, and preferential treatment, between a utility's regulated and unregulated services, whether those services are provided by the utility or the utility's affiliated entities</u>.[305]

Under this statute, the Commission has adopted a Code of Conduct that includes a variety of provisions relevant to this case, including:

> II(B). An electric utility's . . . regulated services shall not subsidize in any manner, directly or indirectly, the unregulated business of its affiliates or other separate entities.[306]

and

> III(C). If an electric utility . . . offering regulated service in Michigan provides services, products, or property to any affiliate or other entity within the corporate structure, compensation shall be based upon the higher of fully allocated embedded cost or market price. If an affiliate or other entity within the corporate structure provides services, products, or other property to an electric utility . . . offering regulated service in Michigan, compensation for services and supplies shall be at the lower of market price or 10% over fully allocated embedded cost and transfers of assets shall be based upon the lower of fully allocated embedded cost or market price.[307]

Later, as part of a settlement agreement in Case No. U-13502, DTE Electric agreed to adopt guidelines for affiliate transactions that include provisions similar to those found in the Code of Conduct. For example, these Affiliate Transaction Guidelines provide that:

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[305] MCL 460.10a(4) (emphasis added).

[306] October 29, 2001 Order of the MPSC in Case No. 12134, Exhibit A ("Code of Conduct"), 1.

[307] *Id.* at 3.

> Asset transfers from regulated to non-regulated shall be at the higher of cost or fair market value and nonregulated to regulated shall be at the lower of cost or fair market value. All services and supplies provided by nonregulated enterprises shall be at market price or 10% over fully allocated cost, whichever is less.[308]

Both the Code of Conduct and the Affiliate Transaction Guidelines, as a result, apply in situations where DTE Electric is either buying or selling assets, services, products, or other property.

Under the Code of Conduct, the disproportionate level of benefits provided by the REF project to DTE Electric and to its affiliates generally suggests that DTE Electric is subsidizing, "directly or indirectly," its affiliates. In return for granting its affiliates access to the Company's coal purchasing and handling expertise, its coal storage capacity, and the vast appetite of its coal burning power plants, DTE Electric has incurred a variety of risks and received only marginal benefits under the terms of the REF project. The Company's affiliates, on the other hand, receive substantial benefits – hundreds of millions of dollars – under the same transactional terms. The REF project is founded upon numerous agreements between DTE Electric and various corporate affiliates, most of which, as discussed above, appear not to have been negotiated at arm's length. This general fact alone suggests that DTE Electric is subsidizing its corporate affiliates in violation of Section II(B) o the Code of Conduct, and the record in this case fails to dispel that suggestion.

More specifically, there are several aspects of the REF project that violate the Code of Conduct. DTE Electric and the Fuels Companies at St. Clair and Belle River are parties

[308] January 21, 2003 Order in MPSC Case No. 13503, Exhibit A-1 ("Affiliate Transaction Guidelines"), 2.

to separate Coal Handling and Consulting Agreements, for example, under which DTE Electric provides the Fuels Companies with a variety of services, including:

> fuel procurement, fuel processing and fuel handling activities including consumption forecasting, specification of coal quality, coal purchasing, coal transportation, coal shipment scheduling, receiving and unloading of coal, coal sampling and analysis, coal stockpile management and maintenance, etc.[309]

In short, the Fuels Companies pay DTE Electric to perform all of the activities that it "has always performed" related to acquiring and storing the coal consumed by DTE Electric power plants.[310] As Mr. Krishnamurthy stated in his direct testimony, all of these services are provided by DTE Electric to the Fuels Companies "at cost." Section III(C) of the Code of Conduct, however, requires regulated Michigan utilities to sell such services (at least when the buyer is an unregulated affiliate like the Fuels Companies) at the higher of the seller's "fully allocated embedded cost" or "market price."[311] Because there is no evidence in the record that DTE Electric has performed any study or analysis to identify the market price of its coal handling and consulting services, it is impossible to know whether this transaction actually complies with the Code of Conduct.

The Code of Conduct is also implicated by DTE Electric's purchasing of REF from the Fuels Companies. Not only is the Code of Conduct implicated by these purchase, in fact, but the statute governing PSCR cases requires the Commission to:

> [d]isallow the cost of fuel purchased from an affiliated company to the extent that such fuel is more costly than fuel of requisite

[309] Krishnamurthy Direct at 3 Tr 624.

[310] *Id.*

[311] Code of Conduct, 3.

> quality available at or about the same time from other suppliers with whom it would be comparably cost beneficial to deal.[312]

Although statutory this provision applies only to PSCR reconciliation cases, it clearly indicates the Legislature's intent that regulated utilities not be allowed to subsidize affiliates by purchasing any sort of fuel from them at above-market prices. And yet DTE Electric apparently makes no effort to ensure that its affiliate fuel purchasing, under the REF project, complies with this statute:

> Q: Well, markets change, several months in some cases between the sale of the coal and the purchase back of the coal. When Edison is undertaking the function of buying the coal back, do they compare it to any other prices or any other sources of coal or any other qualities of coal that they might be able to get a better deal than from the fuel companies?
>
> A: We do not do that process, no.[313]

During his cross examination in this case, Mr. Krishnamurthy confirmed that – at least for St. Clair and Belle River – it is likely that significant time passes between the date on which feedstock coal is sold to the Fuels Companies and the date on which refined coal is later purchased from the Fuels Companies at the point of consumption. Mr. Krishnamurthy stated that sales of feedstock coal to SCFC and BRFC are made at DTE Electric's Midwest Energy Resources Company ("MERC") transshipment facility in Superior, Wisconsin, at the time the coal arrives at the facility. Although it takes only three days to ship that feedstock coal to the joint coal yard at the St. Clair and Belle River plants, a "period of months" passes between the time the coal arrives at MERC and the time that it is loaded onto a boat for delivery to the coal yard. During this time, however, the Company does not track

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[312] MCL 460.6j(13)(e).

[313] Exhibit MEC-34 at 99.

any shifts in the market price of either feedstock coal or refined coal, meaning that its power plants may well be purchasing REF from an affiliate at an above-market cost.

Because the Company does not make any comparison of the price at which it must purchase REF from the Fuels Companies and the market price at which REF could be obtained elsewhere on the market – even if a period of months did not pass between the time feedstock coal is sold to the Fuels Companies and REF is purchased back from the – there is no way to know whether DTE Electric could be purchasing REF from another vendor, at a lower price, at any given time. To the extent DTE Electric is now seeking approval for a PSCR plan that is likely to require disallowances in future PSCR reconciliation proceedings, the Commission should at least indicate that such costs are, in fact, likely to be disallowed without a better demonstration by the Company that it has not run afoul of this statutory provision.

The same problem arises with respect to DTE Electric's periodic purchases of untreated coal from the Fuels Companies under the RCSAs.[314] Purchase of untreated "resold coal" are made by DTE Electric at the Fuels Companies' book cost – that is, the same price at which DTE Electric originally sold that coal to the Fuels Companies. The most prominent RCSA provision concerning resold coal, as Mr. Krishnamurthy explained in his direct testimony, provides that "[a]t the end of the 10-year REF consumption period, the remaining coal inventory will be resold to Detroit Edison at the [Fuels Company's] book cost."[315] If this resold coal is classified as "products," "other property," or "supplies," both the Code of Conduct and the Affiliate Transaction Guidelines state that the compensation for such purchases "shall be at the lower of market price or 10% over fully allocated

[314] See, e.g., Krishnamurthy Direct at 3 Tr 622 ("[A]ll of the coal will ultimately be resold to [DTE Electric] as either REF or untreated coal (resold coal) . . . ." (emphasis added)).

[315] *Id.* at 3 Tr 629.

embedded cost."[316] If the purchase and sale of resold coal is classified as the "transfer[] of assets," on the other hand, the Code of Conduct and Affiliate Transaction Guidelines require any compensation to be "based upon the lower of fully allocated embedded cost or market price."[317] Because the RCSAs underlying the REF project do not allow DTE Electric to conduct any market analysis to determine whether the market price of untreated coal at any given time is more or less than the price at which it is bound to purchase resold coal from the Fuels Companies, it is again impossible to determine whether these proposed transactions can or will comply with the Code of Conduct or Affiliate Transaction Guidelines.

Another potential violation of the Code of Conduct is implicated where DTE Electric sells feedstock coal to the St. Clair and Belle River Fuels Companies. These sales are made at DTE Electric's book cost, according to Mr. Krishnamurthy, regardless of what the market price for that coal may be at any given time.[318] Indeed, Mr. Krishnamurthy acknowledged during cross examination that the Company does not even evaluate the market price of coal at the time it makes sales to SCFC and BRFC at the MERC facility:

> Q: So when Detroit Edison sells the coal, is there a study done as to what Edison could obtain from the sale of that coal to a third party at market prices compared to the price that it is selling it to the fuels company?
>
> A: Your first part of the question was whether we conduct any study. The answer is no, we don't. The second portion, I lost you on that.
>
> Q: When –

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[316] Code of Conduct at 3.

[317] *Id.*

[318] See Krishnamurthy Direct at 3 Tr 618-19.

> JUDGE FELDMAN: So let me be clear then. When you're talking about a study, you're saying there's no study of the difference between the prices at which the coal is sold to the fuel company and whatever the market prices might be at that point in time or any subsequent point in time?
>
> A: Because Detroit Edison is consuming the coal after refining.
>
> Q: O.K. But at the point that Detroit Edison sells the coal to the fuel companies, Edison does not seek the higher of the market price for coal at that time compared to the cost of the coal; is that right?
>
> A: That is correct.[319]

In sum, DTE Electric apparently does not even attempt to determine whether its sales of feedstock coal to the Fuels Companies, or its subsequent purchases of REF and resold coal from the Fuels Companies, comply with the Code of Conduct. In the absence of any evidence on this point, it impossible to determine whether compliance with the Code is ever or even can be achieved.

Instead, Mr. Krishnamurthy claims that no adjustments for market price are necessary – notwithstanding the Code of Conduct – because "any adjustments to the sale price to reflect any higher market pricing would only serve to increase the resale price to Detroit Edison."[320] Even though these transactions do not actually comply with the letter of the Code of Conduct, in other words, Mr. Krishnamurthy argues that "[s]ince the asymmetrical pricing provision of the Code of Conduct is intended to prevent Detroit Edison from subsidizing its unregulated affiliates, it is clear that this transaction is consistent with that intent and effectuates the proper outcome."[321] There are two problems with this statement. First, the Code of Conduct says nothing about the ability of a utility to ignore

[319] Krishnamurthy Cross at 4 Tr 773.

[320] Krishnamurthy Direct at 3 Tr 619.

[321] *Id.*

the Code's provisions as long as – by the utility's own unchecked estimation – a given transaction "effectuates the proper outcome." Second, the REF project clearly does not effectuate the proper outcome, given that the underlying "agreements were no-bid, single-source contracts whose overarching purpose was to maximize income to DTE Energy from the sale of entitlements to the tax credits,"[322] that project is built entirely upon "DTE Electric's ability to sell electricity to its captive customers,"[323] and that it saddles DTE Electric and its captive customers with significant risks in exchange for very little – if any – net benefit.

Mr. Krishnamurthy is not the only DTE Electric witness to argue that the Code of Conduct can be ignored for purposes of evaluating the REF project. In his rebuttal testimony, Mr. O'Neill argues that "[i]t is clear that the asymmetric pricing provisions contained in the Code of Conduct did not anticipate the situation where the Company and an affiliate would plan to buy and sell the identical asset (coal) to each other."[324] During his cross examination, Mr. O'Neill clarified that it is his "nonlegal opinion that the Code of Conduct does not apply" to the situation he described.[325] Mr. O'Neill did acknowledge that the Code of Conduct would apply where a regulated utility and an affiliate buy and sell a non-identical asset to each other, and he then admitted that feedstock coal and refined coal are not identical assets.[326] Although Mr. O'Neill asked to change his answer, when pressed as to why the Code of Conduct does not apply to the REF project if DTE Electric

[322] Sansoucy Direct at 2 Tr 391.

[323] *Id.* at 2 Tr 390.

[324] O'Neill Rebuttal at 2 Tr 264.

[325] O'Neill Cross at 2 Tr 277.

[326] *Id.* at 2 Tr 277-78.

and the Fuels Companies are buying and selling non-identical assets to each other, he ultimately could not explain why the Code of Conduct would not, in fact, apply to the REF project.[327] There is little question that the Code of Conduct does apply to the REF project, and, given the nature of the underlying transactions and the Company's failure to demonstrate that those transactions can and will comply with the Code, the project should be disapproved by the Commission.

V. CONCLUSION AND REQUESTS FOR RELIEF

For the reasons explained above, MEC and NRDC respectfully request that the ALJ recommend that the Commission:

A. Reject DTE Electric's 2013 PSCR Plan and corresponding 5-year PSCR forecast as imprudently reliant on a forecasting methodology that has consistently produced inaccurate results to the detriment of PSCR customers;

B. Require the Company to develop and implement a newer and more accurate methodology for forecasting its generation, sales, and market purchasing; or, in the alternative, require the Company to provide a detailed explanation for why a better methodology cannot be developed or implemented;

C. Indicate that it is unlikely to permit the recovery of various sorbents used in the Company's proposed DSI and ACI systems until and unless the costs of those sorbents is more clearly established and the proposed DSI and ACI systems are better demonstrated to be part of the most reasonable, least-

[327] *Id.* at 2 Tr 279-84.

cost approach to achieving compliance with existing and expected environmental regulations;

D. Reject the Company's 5-year PSCR forecast as overly and imprudently reliant on a "business as usual" strategy that fails to account for significant market and regulatory changes facing the electric utility industry;

E. Indicate that based on present evidence the Commission is unlikely to permit full recovery of the PSCR costs for continued operation of DTE Electric's aging coal units; and

F. Disapprove the Company's proposed REF project as unreasonable, imprudent, and contrary to both the Code of Conduct and the Affiliate Transaction Guidelines.

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Date: June 27, 2013

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STATE OF MICHIGAN

MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of THE DETROIT EDISON COMPANY for Authority to Implement a Power Supply Cost Recovery Plan in its Rate Schedules For 2013 Metered Jurisdictional Sales of Electricity.	Case N$^{o.}$ U-17097 ALJ Sharon L. Feldman

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ELECTRONIC SERVICE LIST

On the date below, an electronic copy of **Initial Brief of the Michigan Environmental Council and the Natural Resources Defense Council** was served on the following:

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The statements above are true to the best of my knowledge, information and belief.

Date: June 27, 2013

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